MARYLAND DEPARTMENT OF NATURAL RESOURCES

PPRP – CEIR – 18
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PPRP

# Maryland Power Plants and the Environment

*A review of the impacts of power plants and transmission lines on Maryland's natural resources*

December 2016

MARYLAND POWER PLANT RESEARCH PROGRAM

Larry Hogan, Governor
Boyd Rutherford, Lt. Governor

*"The Maryland Department of Natural Resources (DNR) seeks to preserve, protect, and enhance the living resources of the state. Working in partnership with the citizens of Maryland, this worthwhile goal will become a reality. This publication provides information that will increase your understanding of how DNR strives to reach that goal through its many diverse programs."*

***Mark J. Belton**, Secretary*
*Maryland Department of Natural Resources*

*This document is available in alternative format upon request from a qualified individual with a disability.*

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# Chapter 1 – Background

The Maryland Department of Natural Resources (DNR) Power Plant Research Program (PPRP) evaluates how the design, construction, and operation of power plants and transmission lines impact Maryland's environmental, socioeconomic, and cultural resources. PPRP's legislative mandate seeks to ensure that the citizens of Maryland can continue to enjoy reliable electricity supplies at a reasonable cost while minimizing impacts to Maryland's resources. The program plays a key role in the licensing process for power plants and transmission lines by coordinating the State agencies' review of new or modified facilities and developing recommendations for license conditions.

PPRP is directed by the Maryland Power Plant Siting Act to prepare a biennial Cumulative Environmental Impact Report (CEIR). The intent of the CEIR is to assemble and summarize information regarding the impacts of electric power generation and transmission on Maryland's natural resources, cultural foundation, and economic situation. A listing of key PPRP projects and reports, as well as a complete Program bibliography, is available at www.pprp.info.

This eighteenth edition of CEIR (CEIR-18) is divided into chapters as follows:

- Chapter 1 provides background on PPRP and the Certificate of Public Convenience and Necessity (CPCN) process.
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- Chapter 5 discusses evolving energy and climate change policy and associated technical issues relevant to Maryland, and gives a summary overview of PPRP research and demonstration projects.

- Clean Energy Policies
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## The Role of PPRP

The Maryland legislature passed the Power Plant Siting Act in 1971 as a result of extensive public debate over the potential effects of the Calvert Cliffs Nuclear Power Plant, which was in the approval and design stage, and the legislature's desire that the State of Maryland play a significant role in the decision-making process. At that time, Calvert Cliffs was a source of concern mainly due to its once-through cooling system, designed to withdraw up to 3.5 billion gallons of water per day from the Chesapeake Bay and then discharge it back into the Bay with an increase in temperature of up to 12°F. This and other issues prompted the creation of PPRP to ensure a comprehensive, objective evaluation based on sound science to investigate environmental and economic issues.

Today, PPRP continues this role by coordinating the comprehensive review of proposals for the construction or modification of power generation and transmission facilities and by developing technically based licensing recommendations for submission to the Maryland Public Service Commission (PSC). Consistent with the original statute, PPRP also conducts research on power plant impacts to Maryland's natural resources, including the Chesapeake Bay. In addition to surface water concerns, PPRP evaluates impacts to Maryland's ground water, air, land, and socioeconomics for proposed power facilities and transmission lines, both for new installations and for modifications to existing structures.

## Power Plant and Transmission Line Licensing

The PSC is the regulating entity whose jurisdiction includes licensing power generating facilities and overhead transmission lines greater than 69 kilovolts (kV) within the state. The PSC is an independent commission created by the State legislature with commissioners appointed by the Governor for set terms.

An electric company that is planning to construct or modify a generating facility or a transmission line must receive a permit, called a Certificate of Public Convenience and Necessity (CPCN) from the PSC prior to the start of construction. The approved CPCN constitutes permission to construct the facility and incorporates several, but not all, additional permits required prior to construction, such as air quality and water appropriation (see Appendix A).

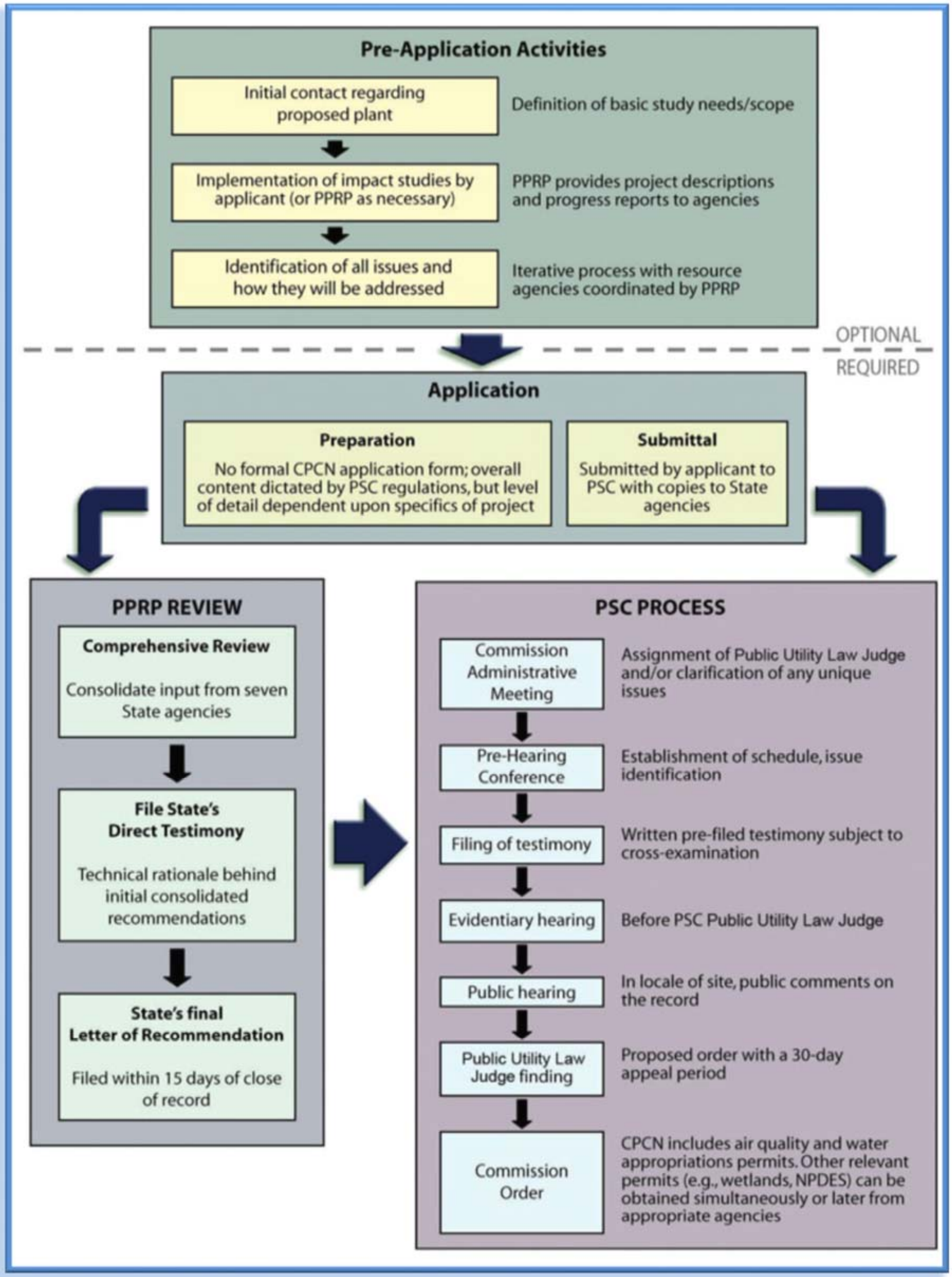
Applications for a CPCN are reviewed by the PSC, or a delegated Public Utility Law Judge, in a formal adjudicatory process that includes written and oral testimony, cross examination, and the opportunity for full public participation. Parties to a CPCN licensing case include the applicant, the PSC Staff, the Office of People's Counsel (acting on behalf of the Maryland ratepayers), and PPRP (acting on behalf of DNR and six other State agencies). Other groups, such as federal agencies and private environmental organizations, as well as individuals with a specified interest, also may have a right to participate as intervenors in these hearings. The broad authority of the PSC allows for the comprehensive review of all pertinent issues and was designed in 1971 to be a "one-stop shop" for power plant licensing.

The CPCN licensing process provides an opportunity for the State to examine all of the significant aspects and impacts of a proposed power facility or transmission line, including the cumulative effects of interrelations between various impacts. This is a unique process within the State's regulatory framework. The CPCN mechanism recognizes that electricity is a vital public need, but its generation and transport can result in impacts to the state's natural, social, and cultural resources. A distinguishing feature of PPRP's role in the CPCN process is the high degree of interagency coordination involved. PPRP coordinates the project review and consolidates comments from the Departments of Natural Resources, Environment, Agriculture, Commerce, Planning, and Transportation, and the Maryland Energy Administration. PPRP then develops a consolidated set of scientifically supported recommended license conditions, unique to each facility's CPCN, and submits these recommendations to the PSC on behalf of the State agencies. In many instances, conditions go beyond regulatory requirements to incorporate creative measures for mitigating potential facility impacts, often as stipulations agreed to by the applicant and other parties to the case prior to the conclusion of the adjudicatory process.

In the case of multiple facilities proposed in close proximity to each other or to existing plants, or for transmission lines that span multiple regions and resource areas, PPRP includes cumulative impacts within the consolidated review process. In such a case, impacts to air, water, terrestrial, socioeconomic, and other resources are evaluated and compared to any identified thresholds of acceptability. Additionally, the cumulative analysis identifies any licensing conditions needed to address cumulative impacts.

Figure 1-1 illustrates the elements of the CPCN licensing process. The primary steps in the CPCN licensing process are described below.

*Figure 1-1 The CPCN Licensing Process*



**Pre-application.** While there are no required pre-CPCN application procedures, PPRP encourages prospective applicants to meet with PPRP staff to identify potential issues of concern with the proposed generation or transmission project and to determine whether and how all relevant concerns will be addressed. This process provides an opportunity for the applicant to become familiar with the PSC regulations and procedures. By the time the applicant files for a CPCN, there usually has been a significant amount of dialogue and, often, the applicant has determined that there is a high likelihood that the proposed facility can obtain a CPCN, subject to the license conditions adopted by the PSC. Through a diligent and thorough pre-application process, a prospective developer can limit the risk of submitting an unsuccessful CPCN application by making changes during the preliminary design to minimize certain impacts.

**Application**. PSC regulations require the CPCN applicant to summarize the proposed project and its potential environmental, social, cultural, and economic impacts. The application is often accompanied by an environmental review document that presents the applicant's supporting environmental and socioeconomic studies. Once the applicant has submitted a CPCN application to the PSC, PPRP, in coordination with other State agencies, evaluates the potential impacts of the proposed project on Maryland's resources, including water (surface and ground water), air, land, ecology, and socioeconomics, including visual and noise-related impacts. In the case of transmission line projects, the need for the project is evaluated and a review of alternative routes is conducted as part of the review process. In the case of generation there is no need or justification requirement; because Maryland is a market-based state, applicants seeking a CPCN for a generating unit do not have to demonstrate that the State has a need for the power.

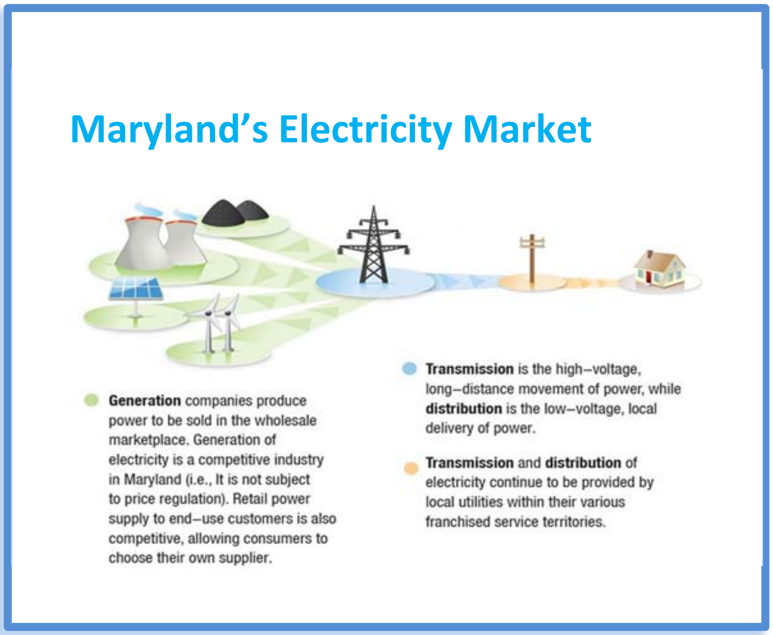
**PSC Process and PPRP Review**. The PSC typically assigns a Public Utility Law Judge (PULJ) to the licensing case at a preliminary administrative meeting after an application for a CPCN has been received. The PULJ then schedules a pre-hearing conference to establish an overall procedural schedule, including dates for evidentiary and public hearings. The adjudicatory process commences with a discovery phase, and proceeds to the filing of direct testimony from the applicant summarizing the impact analyses that have been completed and providing the basis for the applicant's request for a CPCN. During the PSC evidentiary hearing, all the parties to the proceeding may actively participate and file their findings as formal testimony. PPRP and any other parties that have intervened in the process may cross examine applicant testimony and present their own analyses in direct testimony. PPRP's testimony, presented on behalf of the various State agencies, typically includes initial recommended license conditions along with justifying analyses (in the form of testimony and an independent environmental review document), which can be subject to vigorous cross examination by all parties. Other intervening parties can prepare direct testimony and present their opinions and arguments in turn, and are also subject to cross examination. The PULJ also presides over public hearings to accept comments on a project from the general public.

The PULJ takes into consideration the briefs filed by the applicant, the State, and any other parties, recommended license conditions, and public testimony, and issues a decision in the form of a Proposed Order on whether or not the CPCN should be granted and under what conditions. After a prescribed appeal period, a Final Order is released granting or denying the CPCN.

# Chapter 2 – Power Generation, Transmission, and Use

As a basis for discussing the impacts of power plants in Maryland, it is helpful to understand how electricity is generated, transmitted, and used within the state. This chapter provides information on the electric industry in Maryland from generation to final consumption.

Maryland's electricity industry is functionally separated into three lines of business: generation and supply; transmission; and distribution (see sidebar). While customers are billed for each of these three separate functions, most only receive one consolidated electric bill. The generation and supply of electricity is not price-regulated in Maryland; prices are established by the competitive wholesale and retail electricity markets. The high-voltage bulk electric transmission system is a monopoly function, regulated by the Federal Energy Regulatory Commission (FERC), and the distribution of electricity is a monopoly function provided by local utilities (for more information on FERC see Section 3.4.1). It is therefore subject to price and quality-of-service regulation by the Maryland Public Service Commission (PSC).

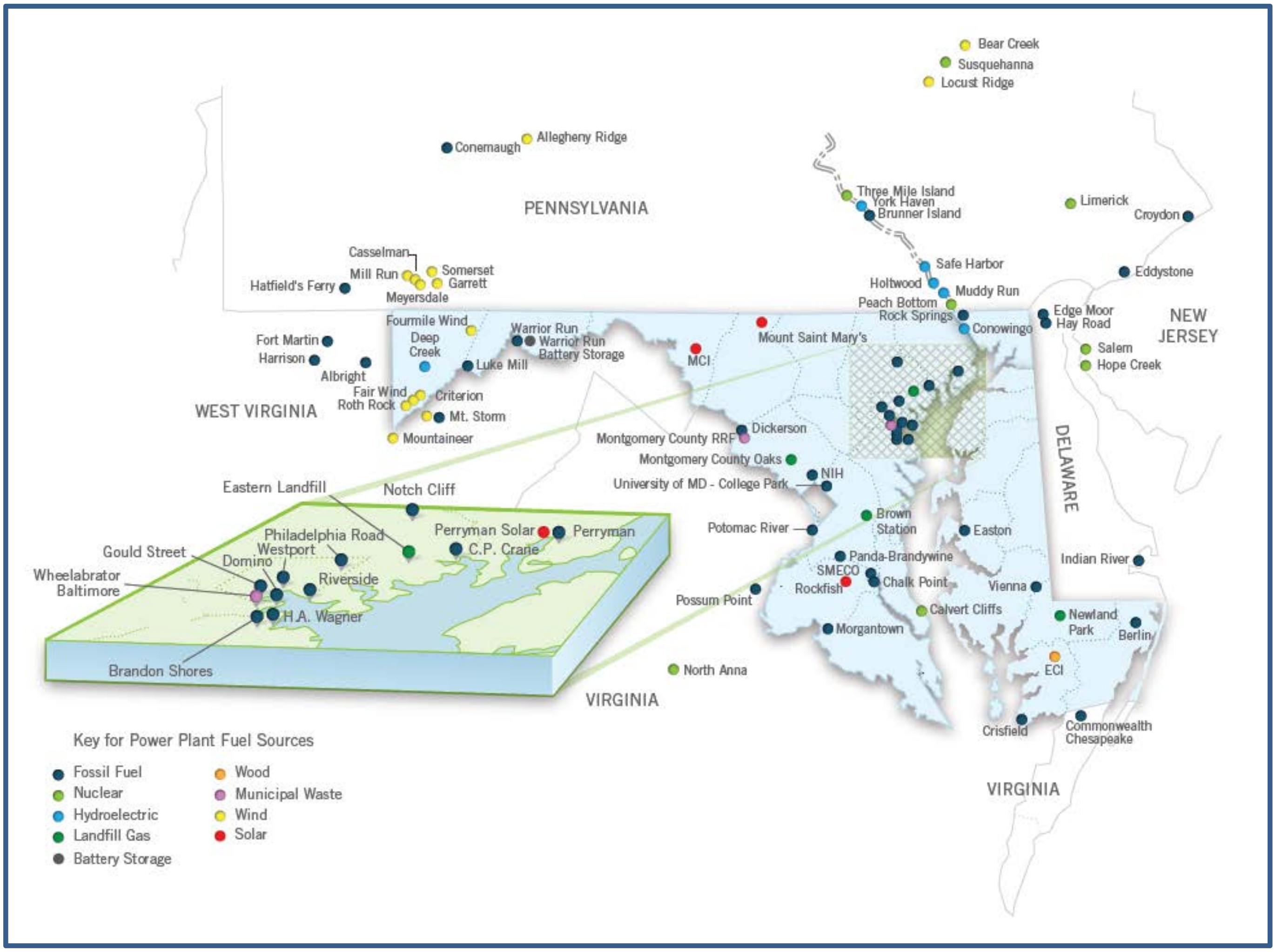



Retail competition for power supply provides Maryland consumers with an opportunity to choose their own electricity suppliers. For more information about electric choice, visit the PSC website.

## 2.1 Electricity Generation in Maryland

Currently in Maryland, 55 power plants with generation capacities greater than 2 megawatts (MW) are interconnected to the regional transmission grid. Table 2-1 lists the individual power plant sites; Figure 2-1 shows the plant locations (with the exception of solar installations under 10 MW). In aggregate, Maryland power plants represent over 13,753 MW of operational capacity. The largest portion of Maryland's generating capacity comes from fossil fuels (see Figure 2-2), with the remainder attributed to nuclear and renewables.

### *Figure 2-1 Power Plants in Maryland*



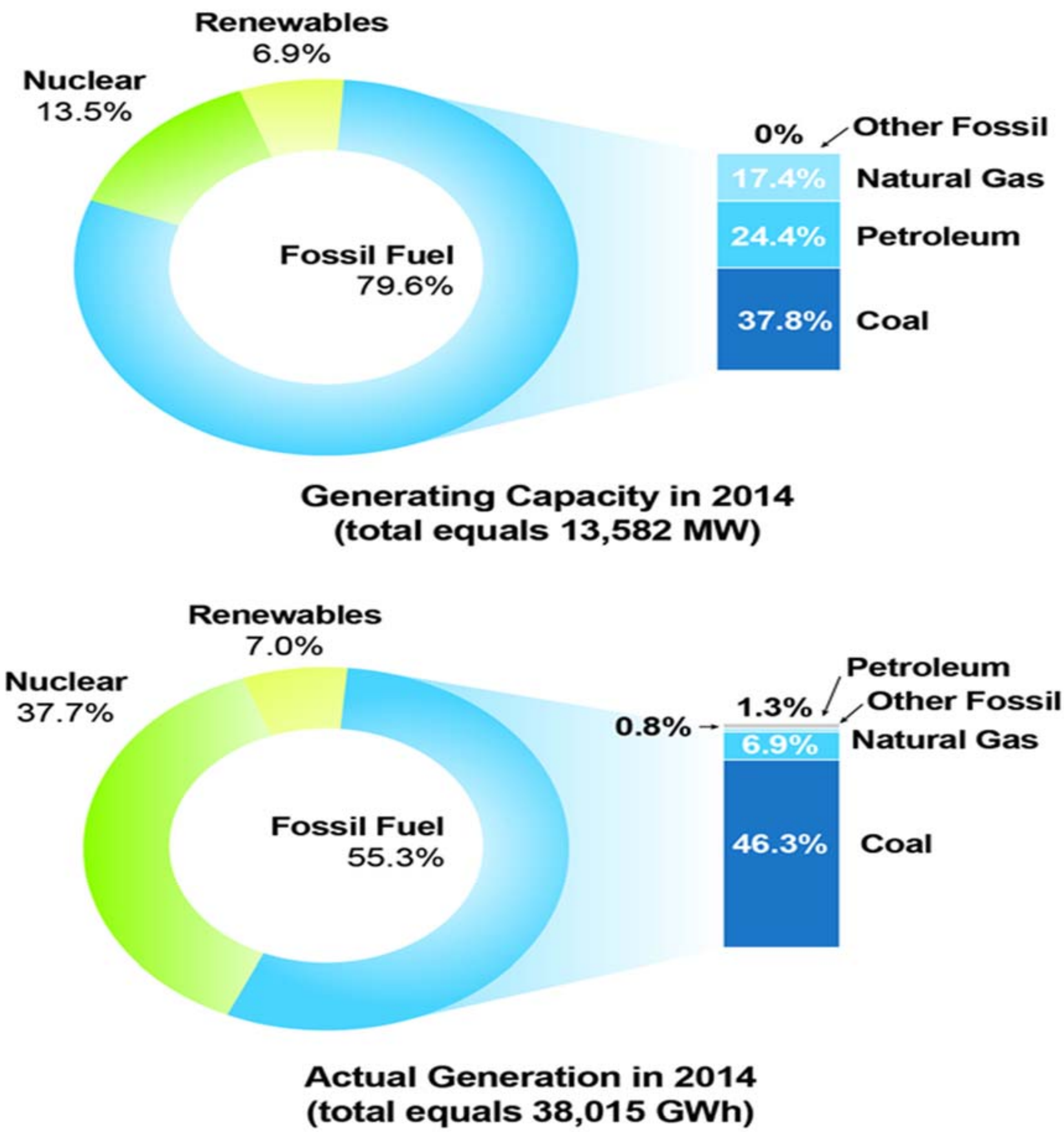
### *Table 2-1 Operational Generating Capacity in Maryland, 2015 (>2 MW)*

| Owner | Plant Name | Fuel Type | Nameplate Capacity (MW) |
|---|---|---|---|
| **INDEPENDENT POWER PRODUCERS** | | | |
| AES Enterprise | Warrior Run | Coal | 229 |
| AES Warrior Run Energy Storage Project | AES Tait LLC | Batteries | 11 |
| BP Piney & Deep Creek, LLC | Deep Creek | Hydroelectric | 20 |
| Calpine Corporation | Crisfield | Oil | 12 |
| CNE at Cambridge MD | Constellation Solar Maryland II LLC | Solar | 3 |
| Dominion Cove Point LNG, LP | Cove Point | Natural Gas | 92 |
| Eastern Landfill Gas | Eastern Landfill | Landfill Gas | 3 |
| Exelon Generation Company | Calvert Cliffs | Nuclear | 1,829 |
| | Conowingo | Hydroelectric | 531 |
| | Criterion Wind Park | Wind | 70 |
| | Gould Street | Natural Gas | 104 |
| | Mount Saint Mary's | Solar | 14 |
| | Notch Cliff | Natural Gas | 144 |
| | Perryman | Oil/Natural Gas | 545 |
| | Philadelphia Road | Oil | 83 |
| | Riverside | Oil/Natural Gas | 122 |
| | UMMS at Pocomoke | Solar | 3 |
| | Westport | Natural Gas | 122 |
| Fair Wind Power | Fair Wind Power Partners | Wind | 30 |
| First Solar, Inc. | Hagerstown | Solar | 27 |
| Fourmile Wind Energy, LLC | Fourmile Ridge | Wind | 40 |
| INGENCO | Newland Park Landfill | Landfill Gas | 5 |
| LES Operations Services | Millersville Landfill | Gas | 3 |
| Montgomery County | Resource Recovery Facility (RRF) | Waste | 68 |
| NRG Energy | Chalk Point | Coal/Oil/Natural Gas | 2,647 |
| | Dickerson | Coal/Oil/Natural Gas | 933 |
| | FedEx Field Solar Facility | Solar | 2 |
| | Morgantown | Coal/Oil | 1,548 |
| | Vienna | Oil | 181 |
| New Page | Luke Mill | Coal | 65 |

| Owner | Plant Name | Fuel Type | Nameplate Capacity (MW) |
|---|---|---|---|
| Panda Energy | Brandywine | Natural Gas | 289 |
| Pepco Energy Services | National Institutes of Health | Natural Gas | 22 |
| Gestamp Wind | Roth Rock Wind Facility | Wind | 50 |
| Raven Power Holdings, LLC | Brandon Shores | Coal | 1,370 |
| | H.A. Wagner | Coal/Natural Gas/Oil | 1,059 |
| Rockfish Solar LLC | Rockfish Solar LLC | Solar | 10 |
| SCE Engineers | Montgomery County Oaks | Landfill Gas | 2 |
| Solar City | Queen Anne's County | Solar | 2 |
| Suez Energy North America | University of Maryland – College Park | Oil/Natural Gas | 27 |
| | Inner Harbor East Heating | Natural Gas | 2 |
| SunEdison | University of Maryland - Eastern Shore | Solar | 2 |
| | Cecil County CCVT HS | Solar | 2 |
| Talen Energy | C.P. Crane | Coal/Oil | 416 |
| Wheelabrator Technologies | Wheelabrator Incinerator | Waste | 65 |
| **PUBLICLY OWNED ELECTRIC COMPANIES** | | | |
| Baltimore City Council | Back River Waste Water Treatment Plant | Biomass/Solar | 3 |
| Town of Berlin | Town of Berlin | Oil | 9 |
| Easton Utilities | Easton | Oil/Biodiesel | 72 |
| Frederick County Landfill Energy | FC Landfill Energy | Landfill Gas | 2 |
| Old Dominion Electric Cooperative and Essential Power | Rock Springs | Natural Gas | 773 |
| Prince George's County | Brown Station Road | Landfill Gas | 7 |
| Southern Maryland Electric Cooperative (SMECO) | SMECO Solar | Solar | 65 |
| **SELF-GENERATORS** | | | |
| American Sugar Refining Co. | Domino Sugar | Oil/Natural Gas | 18 |
| IKEA | IKEA Property Inc | Solar | 2 |
| GSA Metropolitan Service Center | Central Utility Plant | Oil/Natural Gas | 54 |
| Maryland Department of Public Safety and Corrections | Eastern Correctional Institution (ECI) | Oil/Wood | 6 |
| **Total** | | | **13,753** |

Source: U.S. Energy Information Administration, Form EIA-860, 2015 Early Release.

*Figure 2-2 Power Plant Capacity and Generation in Maryland by Fuel Category*




Source: “Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860),” U.S. Energy Information Administration, October 21, 2015, https://www.eia.gov/electricity/data/state/; “Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923),” U.S. Energy Information Administration, October 21, 2015 https://www.eia.gov/electricity/data/state/.

Note: EIA data for generation contains the fossil fuel category, “Other,” which is not included in EIA data for capacity.

### *2.1.1 Fossil Fuels*

In Maryland coal, natural gas, and petroleum are the fossil fuels utilized to produce electricity. The primary fuel used for electricity in Maryland in coal. However, due to declining prices in recent years, the use of natural gas used to generate electricity has increased.

#### *Coal*

In 2015, Maryland consumed 6 million tons of coal for electricity generation, which was a decrease of 19 percent compared to 2013. Most Maryland power plants cannot efficiently burn coal mined in the state because they were designed for coal with higher volatility characteristics. Based on 2015 data, 96 percent of the coal received by Maryland plants was mined in the Appalachia region of the U.S. Table 2-2 lists the amount of coal received at each power plant in 2015 and its origin. According to the U.S. Energy Information Administration (EIA), U.S. bituminous coals sold for an average of $60.61/ton in 2013 compared to $14.86/ton for sub-bituminous coals.

***Table 2-2 Tons of Coal Purchased at Maryland Power Plants in 2015***

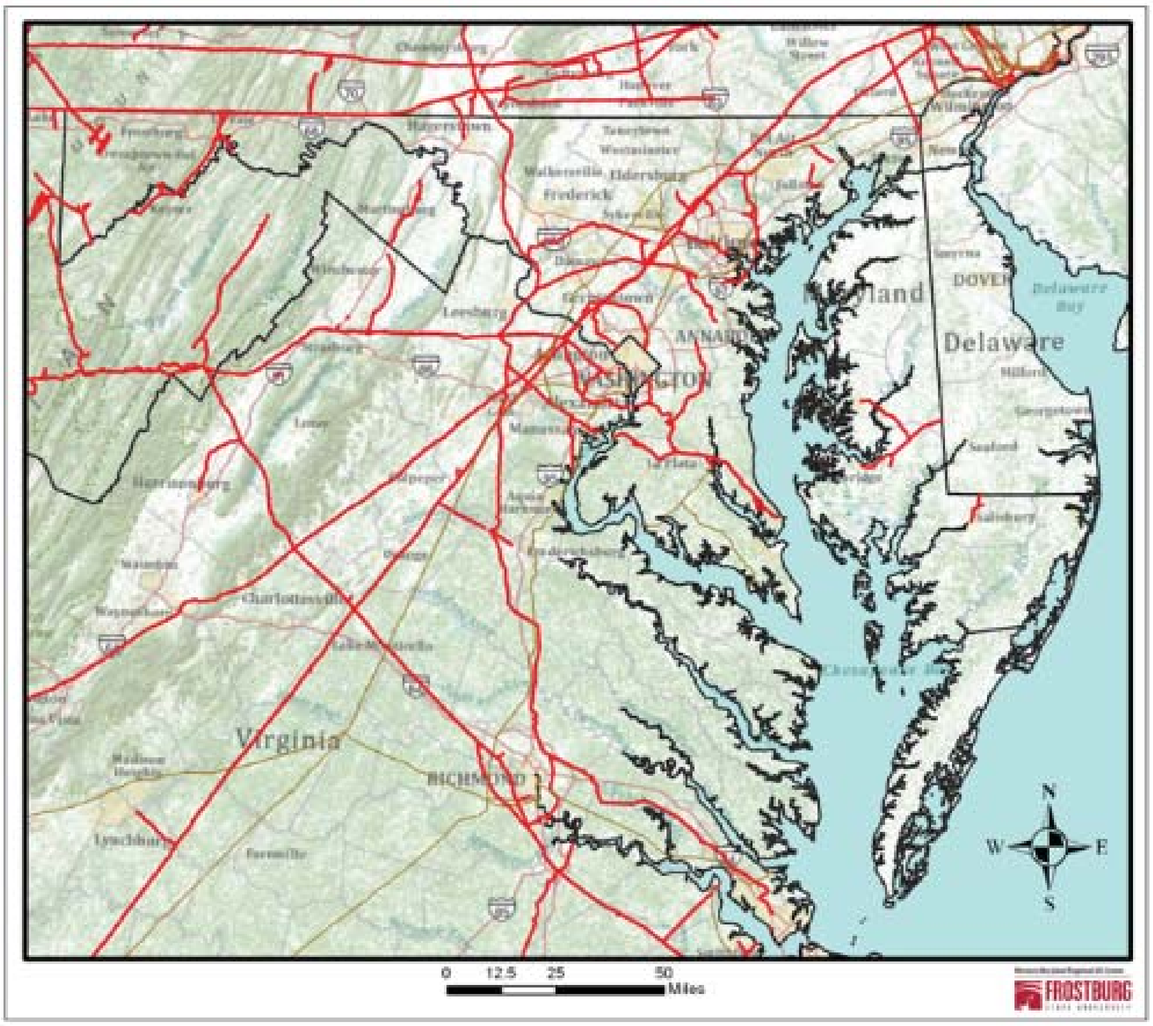
| Origin of Coal | Brandon Shores | H.A. Wagner | C.P. Crane | Dickerson | Chalk Point | Morgantown | Warrior Run | Luke Mill | Total By Source | |
|---|---|---|---|---|---|---|---|---|---|---|
| Appalachia | 2,083,583 | 525,307 | 6,622 | 239,371 | 730,089 | 1,663,120 | 607,497 | 275,525 | 6,131,114 | 95.23% |
| River Basin | - | 40,135 | 267,191 | - | - | - | - | - | 307,326 | 4.77% |
| **Total Coal by Plant** | **2,083,583** | **565,442** | **273,813** | **239,371** | **730,089** | **1,663,120** | **607,497** | **275,525** | **6,438,440** | **100.00%** |

Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Maryland, July 29, 2016.

### *Natural Gas*

In 2015, approximately 39.6 million cubic feet (MMcf) of natural gas was used for electricity generation in Maryland, representing 19 percent of total statewide consumption of natural gas for all uses. Currently, Maryland receives natural gas from several interstate pipelines that traverse the state (see Figure 2-3). Interstate gas suppliers operate storage areas, usually in depleted production fields, where natural gas can be accumulated during low demand periods and released during high demand periods. Maryland has one such storage area, Accident Dome in Garrett County, with a storage capacity representing 2 percent of the underground gas storage capacity in the region (which includes Maryland, New Jersey, Pennsylvania, Virginia, and West Virginia). Other potentially suitable storage sites may also exist in Western Maryland.

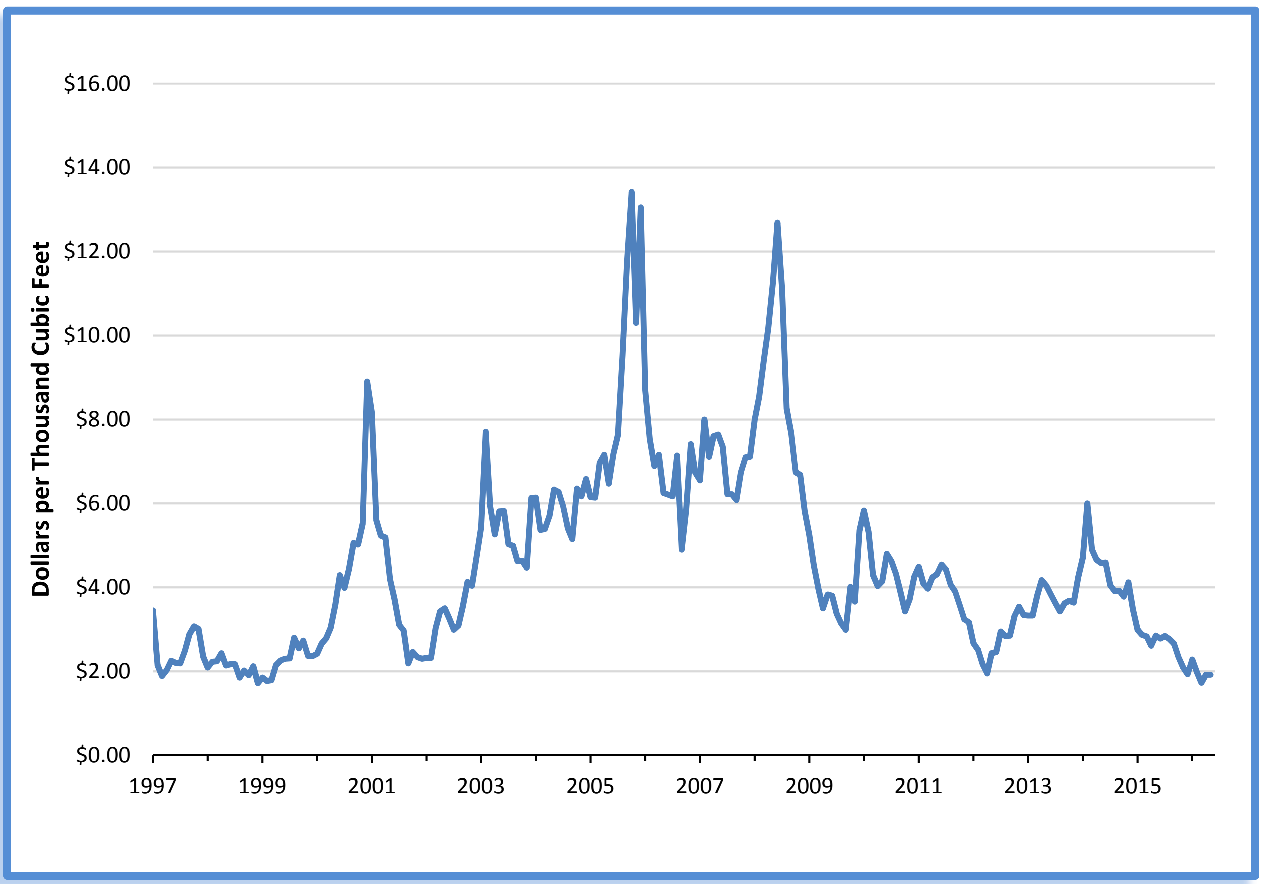
***Figure 2-3 Interstate Natural Gas Pipelines in Maryland***



There has been a significant increase in natural gas production in the U.S. resulting from the use of new drilling techniques. Shale gas trapped in deep, fine-grained rock formations in the southwest and northeast regions of the U.S. was not economical to recover until the development of horizontal drilling and hydraulic fracturing techniques in the 1990s. Between 2010 and 2015, as natural gas producers continued utilizing these techniques, U.S. natural gas production increased 29 percent. Domestic natural gas consumption over the same period increased only 14 percent, resulting in decreased imports of natural gas via pipeline from Canada and a reduction in liquefied natural gas (LNG) imports.

U.S. natural gas spot prices at Henry Hub were between $2.00 and 2.50 per million British thermal units (MMBtu) in the late 1990s, and then began a steady increase, more than doubling to over $5.00/MMBtu by 2003 and reaching a high of $13.42/MMBtu in late 2005. Since then, natural gas prices have decreased to an average of $2.62/MMBtu in 2015, primarily attributable to increased shale gas production coupled with the economic slowdown (see Figure 2-4).

***Figure 2-4 U.S. Natural Gas Henry Hub Spot Prices, 1997-2016***




Source: U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price.

The LNG price is linked to that of crude oil, which has increased as domestic natural gas prices have declined. The annual average export LNG price increased slightly from $1.05/MMcf in 2010 to $1.08/MMcf in 2015. Import volumes at the Cove Point LNG facility in Lusby, Maryland declined 72 percent between 2010 and 2015. Cove Point, which is owned by Dominion Cove Point LNG, LP, an affiliate of Dominion Resources, Inc., is one of 12 LNG import facilities operating in the U.S. Plans for new or expanded LNG facilities in the U.S. have either been canceled or modified for operation as LNG export facilities, in response to high LNG export prices. On October 7, 2011, the U.S. Department of Energy (DOE) authorized Dominion Cove Point LNG, LP to enter into contracts to export LNG to countries that have free trade agreements with the U.S. On April 1, 2013, Dominion announced that it had entered into 20-year contracts for all of the export capacity at Cove Point. Pacific Summit Energy, LLC, a U.S. affiliate of Japanese trading company Sumitomo Corporation, and GAIL Global (USA) LNG LLC, a U.S. affiliate of GAIL (India) Ltd., have each contracted for half of the marketed capacity. On September 29, 2014, the FERC issued an order authorizing Dominion Cove Point LNG to export LNG. The next month, construction began, and Cove Point is targeted to begin operating as an LNG export facility in late 2017.

#### *Petroleum*

A small amount of electricity — less than 1 percent of the State's total — is generated by combusting distillate or residual fuel oil. According to the EIA, fuel oil consumption for electric power in Maryland totaled 37.5 million gallons in 2014, or less than one percent of statewide consumption for all fuel oil uses. Since there are no crude oil reserves or refineries in Maryland, all supplies of petroleum necessary to meet the State's consumption needs are imported. Petroleum is transported via barge to the Port of Baltimore and via the Colonial Pipeline. The Colonial Pipeline, a major petroleum products pipeline, traverses the state on its way to New York.

### 2.1.2 Nuclear

Maryland is home to one nuclear power facility, Exelon's Calvert Cliffs plant. In March 2000, the U.S. Nuclear Regulatory Commission (NRC) approved a 20-year extension to the original operating licenses for Units 1 and 2. The units' licenses will expire in 2034 and 2036, respectively. This 1,829 MW facility represents approximately 13 percent of the State's total electricity generation capacity and accounted for about 40 percent of the State's total generation in 2015.

More information on Calvert Cliffs is included in Section 4.5.2.

## 2.1.3 Distributed Generation

### Distributed Solar Generation

Distributed solar generation has played an increasing role in Maryland as a source of total generation. The increasing use of solar rooftop photovoltaic (PV) in Maryland is largely attributable to Maryland's Renewable Portfolio Standard (RPS) and a 30 percent federal tax credit.

FERC issued Order No. 792 in November 2013 that amends its existing rule on small generator interconnection agreements and procedures. The regulatory reforms are intended to streamline the grid interconnection process for solar projects that meet certain technical standards.

Distributed generation (DG) refers to those generating resources located close to, or on the same site as, the facility using power. It is typically installed on the customer side of the meter and used to serve on-site power needs; because of this, distributed generators are not centrally dispatched by the regional grid operator. Types of DG technologies include internal combustion engines, small wind, solar, small hydroelectric, micro gas turbines, and fuel cells. Some of these technologies can be used to provide electricity to the grid during times of peak demand. The majority of DG units are diesel-fired emergency backup generators. However, an increasing share of this capacity comes from solar energy, which is predominantly grid-tied for the purposes of net-metering and generating solar renewable energy credits (RECs) for sale or trade (see Section 5.1.1 for discussion on RECs).

On-site generators with a capacity of 2 MW or less are not required to obtain a Certificate of Public Convenience and Necessity (CPCN) or apply for a CPCN waiver (or exemption). In addition, certain generators of up to 70 MW in capacity are eligible to seek a CPCN exemption:

- *Facilities with a capacity of less than 70 MW, consuming at least 80 percent of the electrical output on-site;*
- *Facilities less than 25 MW in capacity, consuming at least 10 percent of the electrical output on-site; and*
- *Land-based, wind-powered generating stations with a capacity of less than 70 MW, subject to additional qualifications (see Section 2.1.5).*

The Maryland PSC requires an applicant seeking a CPCN exemption to identify its facility as one of four specific types:

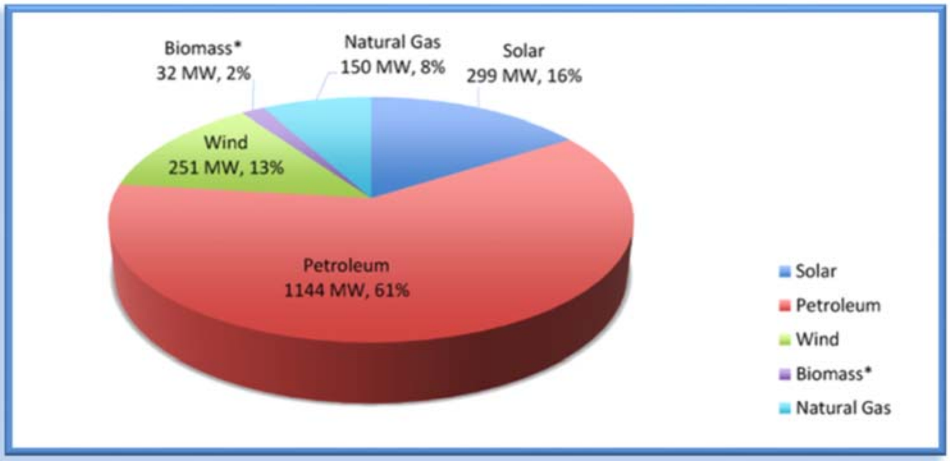
- *Type I – a generator that is not synchronized with the local electric company's transmission and distribution system, and will not export electricity to the grid;*
- *Type II – a generator that is synchronized with the electric system, but will not export electricity to the grid;*
- *Type III – a generator that is synchronized with the electric system and will be exporting electricity to the grid for sale in the wholesale energy market; or*
- *Type IV – a generator that is synchronized with the electric system but is inverter-based and will automatically disconnect from the grid in the event of a grid power failure.*

It is difficult to accurately estimate the total amount of DG in Maryland as systems smaller than 2 MW are not required to obtain a CPCN exemption. The vast majority of solar DG systems fall into this category.

As of the end of 2015, about 1,637 MW of generation capacity had been granted CPCN exemptions in Maryland, including 62 MW of solar capacity and 250 MW of land-based wind power. According to the 2015 PSC report on net metering, 236 MW of solar DG and 1.2 MW of small wind facilities had been installed in Maryland by mid-2015 under net-metering arrangements.

DG units are often used to provide emergency backup power in the event that large and essential loads, such as government offices, hospitals, colleges and universities, commercial and industrial facilities, telecommunications installations, and farming operations, lose electricity service. By fuel type, Maryland's distributed generators (see Figure 2-5) are mostly fossil-fueled, consistent with their use for backup power. An increasing, but still small, share of DG capacity is solar, which is predominantly grid-tied for purposes of net-metering and generating solar RECs for sale or trade. Between June 2014 and June 2015, for example, statewide net-metered solar system capacity increased 66 percent. The solar energy requirement in the Maryland Renewable Energy Portfolio Standard (RPS) will also continue to provide an incentive to add distributed solar generation to the Maryland grid.

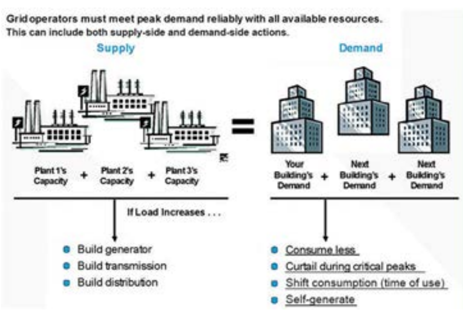
***Figure 2-5 Distributed Generation by Fuel Type (as of 2015)***




Source: PSC CPCN Database and Maryland Public Service Commission, "Report on the Status of Net Energy Metering in the State of Maryland," January 2016, http://www.psc.state.md.us/wp-content/uploads/2015-MD-PSC-Report-on-the-Status-of-Net-Metering-Report.pdf (Download Adobe Acrobat Reader).

Note: This figure only includes solar from net-metered systems and CPCN-exempted systems.

## The Importance of Demand Response




Demand Response (DR) is a competitive resource that can be used to maintain the balance of supply and demand for grid operations and the associated wholesale markets. Retail electricity consumers tend to be unresponsive to wholesale prices. Therefore, as demand goes up, less efficient generators may be called on to serve higher demand. By reducing demand during these periods, the use of potentially less efficient and more expensive generation resources to meet higher demand can be avoided.

### 2.1.4 Demand Response

Demand response (DR) rapidly grew between 2010 and 2015 in Maryland and serves as a powerful tool used to bolster energy efficiency and conservation efforts in the state. DR allows end-use customers to reduce their energy consumption during periods of high demand (and high prices). Demand response occurs when a customer reduces electricity use in response to either a change in the price of electricity or an incentive payment. Customers that reduce electricity consumption in response to high real-time electricity prices or when called on by the system operator or utility are used as an alternative to generation resources as a means of meeting load requirements. Voluntary usage reductions can come from customers of all sizes. Large industrial customers may choose to shift some high-energy intensity processes to lower-cost hours. Small residential consumers can cycle air conditioning and electric water heaters. When aggregated across thousands of customers, these residential energy use reductions can create significant savings during times of peak demand.

Demand response within the PJM Interconnection, LLC (PJM) is utilized as a supply resource in the same way as generators. PJM runs several DR programs that compensate customers for reducing their load. DR resources are eligible to participate in PJM's energy markets, PJM's ancillary services markets, and PJM's capacity market (see Appendix B for a description of these markets).

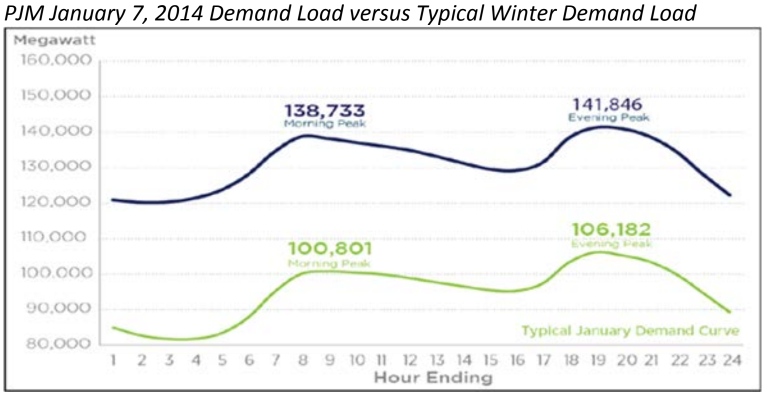
PJM members that act as DR providers are called curtailment service providers (CSPs). Customers can act as their own CSP or sign with another CSP that can bid load reductions into PJM markets. CSPs can participate as a capacity resource in the capacity market and can bid load reductions into the energy markets, both for reductions needed during emergency events or reductions in response to high prices (economic events).

Demand response resources with adequate response times (i.e., within ten minutes) may bid into PJM's synchronized (spinning) reserve market, allowing PJM to utilize demand-side resources to respond to unexpected generator outages, unexpected changes in electric demand, or other system contingencies. DR resources are eligible to provide regulation reserves, synchronized reserves, and day-ahead reserves, limited to 33 percent for each category and for two of the three services. DR resources can also provide non-synchronized (non-spinning) and supplemental reserves in PJM.

## Polar Vortex

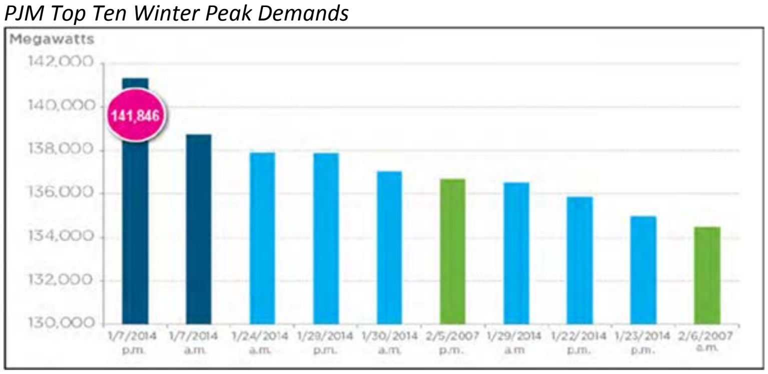
The Northeast experienced extended periods of extremely cold temperatures in January 2014. The first event, known as the Polar Vortex, occurred January 6 through 8 and set a PJM winter peak demand record of 141,846 MW, a difference of approximately 35,000 MW from typical winter peak demand. To maintain system reliability, PJM called upon all available generation, as well as demand response resources, and also purchased emergency power. Approximately 25 percent of the demand response capacity responded to the voluntary events. During the Polar Vortex, the real-time Locational Marginal Price (LMP) reached as high as $1,800 per MWh. Not only did the Polar Vortex set the record for highest winter peak demand, the series of storms in January 2014 established eight of the top ten historic winter peak demands in PJM. A second set of winter storms from January 17 through January 29 resulted in natural gas scheduling difficulties. During this second set of winter storms, natural gas generators were forced to operate for a full day to ensure gas deliveries, even if less expensive power was available, causing a significant spike in energy prices. Some retail electricity customers receiving power supply under variable rate arrangements with a competitive retail electric supplier experienced extremely high electric rates during January and February 2014. Several state utility commissions, including the Maryland PSC, opened investigations into the rates charged by certain electric suppliers that received a high number of complaints during the first few months of 2014.

*PJM January 7, 2014 Demand Load versus Typical Winter Demand Load*




Source: PJM Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events

*PJM Top Ten Winter Peak Demands*




Source: PJM Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events

PJM's competitive capacity auction, known as the Reliability Pricing Model Base Residual Auction (RPM BRA) is conducted every three years prior to the delivery year to allow power supply resources to bid into the market to either increase energy supply or reduce demand. Prior to the RPM BRA for delivery year 2018-2019 (held in 2015), PJM allowed for three different types of demand resources to be bid in:

- **"Annual"** wherein a customer could be curtailed an unlimited number of times per year (the specific hours of the day vary by season), but each curtailment can only last for a maximum of ten hours;
- **"Extended Summer"** wherein customer loads can be curtailed between May and October between 10:00 a.m. and 10:00 p.m., subject to the same 10-hour limitation; and
- **"Limited"** wherein customers may only be curtailed ten weekdays between June and September between the hours of 12:00 p.m. and 8:00 p.m. for a maximum of six hours at a time.

In response to poor generator performance during the Polar Vortex in 2014, PJM revised and restructured its capacity market. Approved by the FERC in 2015, the PJM proposal eliminated the three types of DR products and created a single DR resource—Capacity Performance. The purpose of the product is to provide larger capacity payments for performance, including bonuses for over-performing, as well as to increase penalties for non-performers. The revised capacity market went into effect with the most recent auction, the

2018/2019 RPM BRA, where 11,676 MW of Capacity Performance DR was offered, of which 11,084 MW cleared the auction.

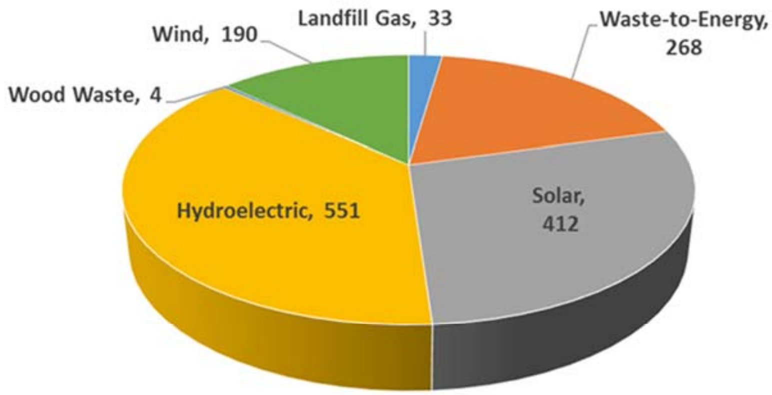
In March 2011, the FERC issued Order 745 which established that, where it is cost-effective to do so, demand response resources are to be paid the same wholesale price of energy for energy reductions as a generator would be paid for the sale of energy at that same time. Allowing DR to bid into electricity markets and be treated as a dispatchable resource has encouraged the expansion of DR programs and services offered by both investor-owned utilities and competitive CSPs. In the spring of 2012, PJM became the first grid operator to comply with FERC Order 745. On May 22, 2014, in response to a petition filed by the Electric Power Supply Association, the American Public Power Association, and the Edison Electric Institute, the D.C. Circuit Court of Appeals vacated FERC Order 745, finding that FERC overstepped its jurisdiction because states have the jurisdiction to regulate the electric retail market. In January 2016, the Supreme Court of the United States upheld FERC Order 745. The Supreme Court found that although FERC did intentionally impact the retail market; DR is a wholesale function and therefore FERC has the power to regulate the wholesale market even if it has indirect impacts on the retail market. The Supreme Court ruling did not have a significant impact on the PJM market, as PJM continued to conduct auctions.

Approved by the FERC in May 2012, PJM offers Price Responsive Demand (PRD) as another class of demand response. PRD applies only to those customers on Advanced Metering Infrastructure (AMI) dynamic rate structures where consumption can vary in response to PJM wholesale market price signals (see Section 5.5.3 for a description of AMI). PRD is an aspect of the smart grid and requires the widespread deployment of advanced meters to retail customers and the introduction of dynamic retail rates. The voluntary participation of PRD providers in PJM’s markets was designed to enhance grid operations and reliability and provide a closer link between the wholesale and retail electricity markets. PJM’s capacity and energy markets would be cleared with the predicted reductions from PRD already included in the supply forecast. This process allows PJM’s operators to better forecast system demand under real-time conditions, as a separate forecast of DR supply becomes less necessary. To date, there has been no participation in PRD. See Chapter 5 for more information on DR and smart grid technologies.

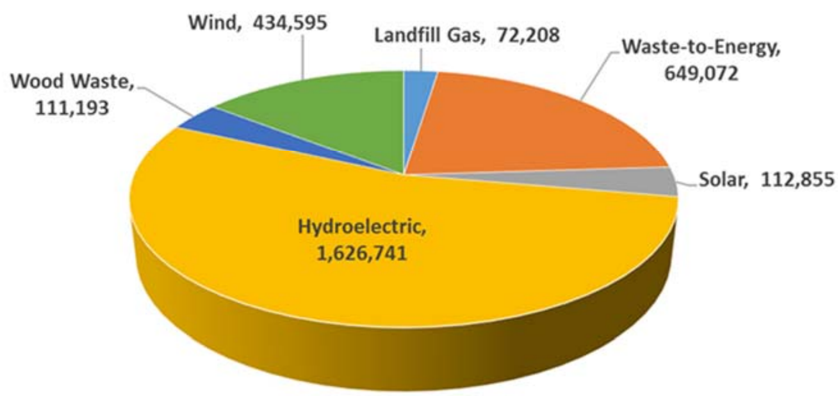
### 2.1.5 Renewable Resources

Presently, there are four main types of renewable energy resources in use in Maryland: wind, biomass, solar, and hydropower. Approximately 1,458 MW of generation capacity in Maryland comes from these resources, with hydroelectric accounting for the largest share (see Figure 2-6).

*Figure 2-6 Renewable Energy in Maryland, as of 2015*




**Installed Renewable Energy Capacity (MW) in 2015**




**Renewable Energy Generation (MWh) in 2015**

Source: PJM Generator Attributes Tracking System for capacity, and EIA-923 for generation. Solar capacity includes both utility-scale and rooftop solar. Solar generation excludes rooftop solar.

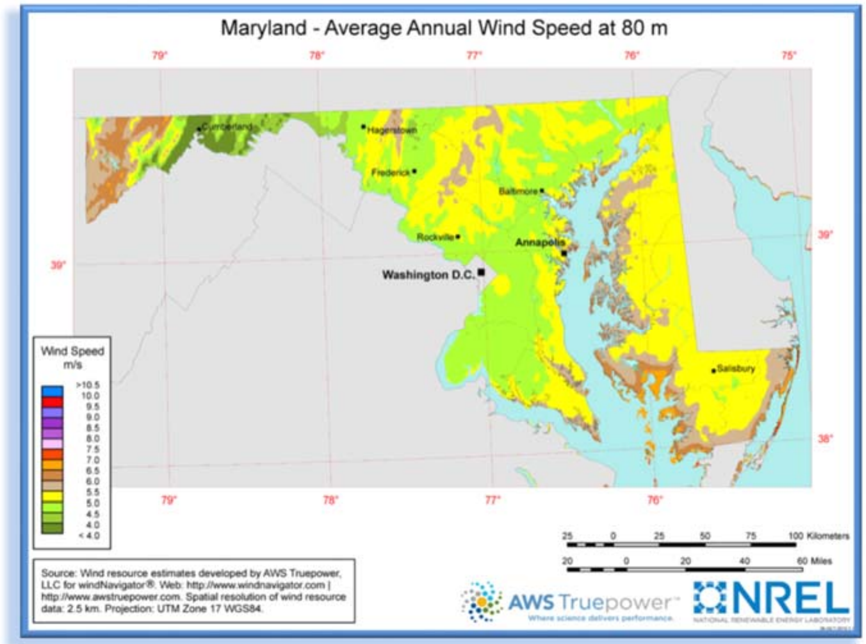
## *Wind*

The conversion of wind power to electricity is typically accomplished by constructing an array of wind turbines in a suitable location. Utility-scale wind projects range in size from just a few turbines to hundreds of turbines, depending on the location and capacity of the project, among other things. Wind turbines range in size from 20-watt micro-turbines (used for small-scale residential or institutional applications) to new 10 MW prototypes, with manufacturers now researching the possibility of 20 MW turbines for offshore facilities. Land-based, utility-scale wind turbines typically have a rated capacity between 1.5 and 3 MW, although some are as large as 5 MW.

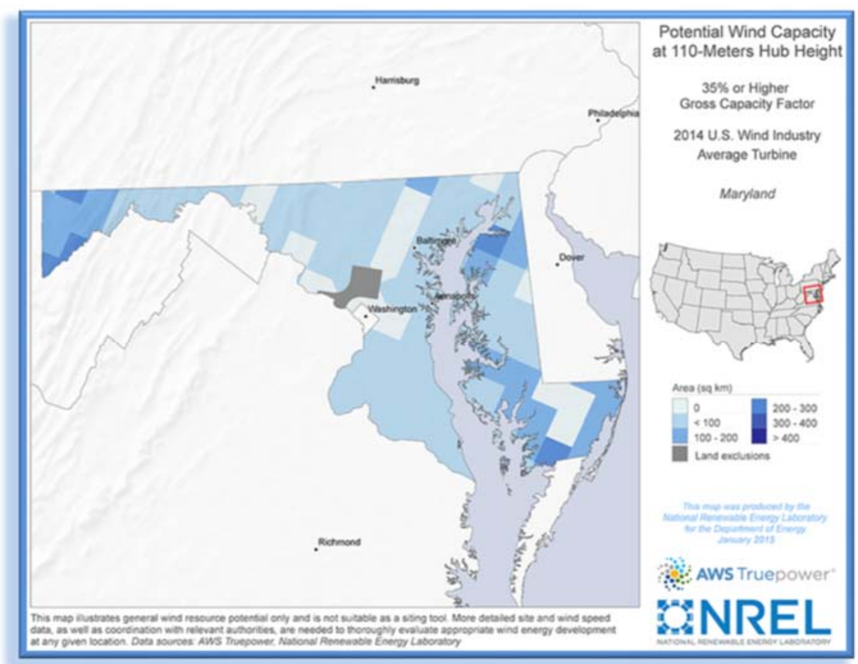
By the end of 2016, the United States will have its first operating offshore wind energy plant, a 30 MW project at Block Island, Rhode Island. Five 6 MW wind turbines will be at the site. Twenty-one offshore wind projects totaling 15,650 MW are in various stages of development. Whether these projects will ever come online will depend on the status of the federal Production Tax Credit (PTC), the ability of developers to secure financing and power purchase agreements (PPAs), and navigating federal and state permitting requirements. For land-based wind, 74 gigawatts (GW) of wind is in operation, making the United States the second-leading installer of wind capacity in the world after China.

In Maryland, the greatest wind resources are located in the western-most counties and off of the Atlantic Coast on the Outer Continental Shelf. The DOE’s National Renewable Energy Laboratory (NREL) estimates that the United States may have a potential land-based wind resource capacity in excess of 10,000 GW. Maryland is estimated to have a potential land-based wind resource capacity of approximately 1.5 GW when the hub height is at 80 meters. Maryland’s potential land-based wind resource capacity increases considerably at higher hub heights: 10,258 MW at 110 meters and 18,034 MW at 140 meters. Figure 2-7 illustrates the prospective land-based wind resource areas in Maryland.

*Figure 2-7 Maryland Potential Wind Resources*

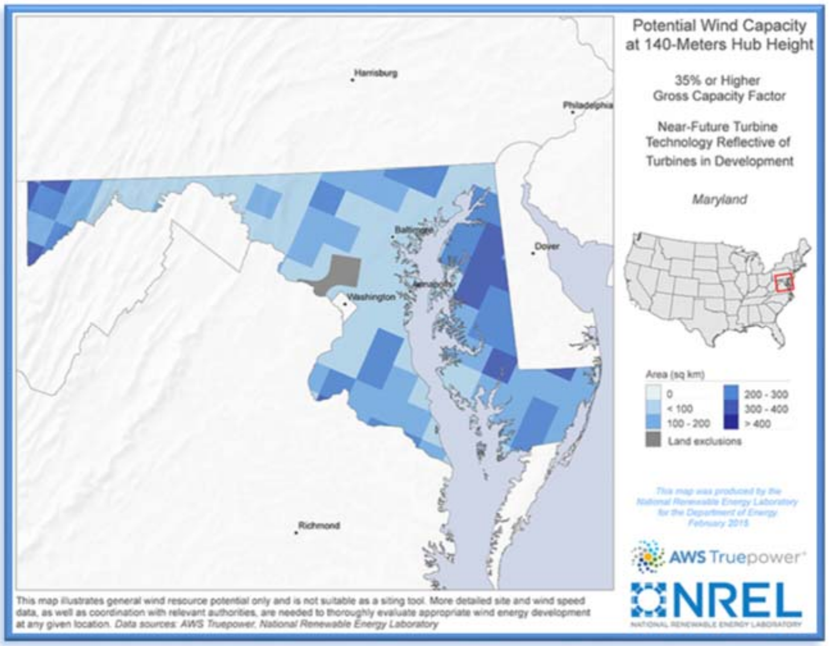



Source: "Maryland Wind Resource Map and Potential Wind Capacity," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=md.

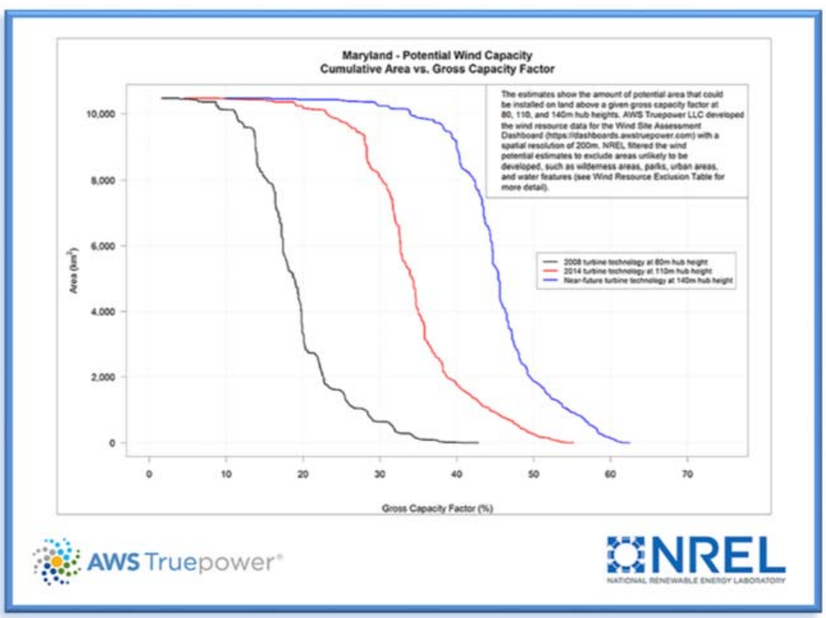



Source: "Maryland Wind Resource Map and Potential Wind Capacity," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=md.

## *Figure 2-7 Maryland Potential Wind Resources (continued)*




Source: "Maryland Wind Resource Map and Potential Wind Capacity," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=md.




Source: "Maryland Wind Resource Map and Potential Wind Capacity," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=md.

**Counties in Maryland with Wind Energy Ordinances**


The Maryland General Assembly passed legislation in 2007 allowing new wind power facilities equal to or less than 70 MW in capacity to request an exemption from the CPCN requirement if:

- The wind facility is located on land;
- The electricity output is sold only on the wholesale market under an interconnection, operating, and maintenance agreement with the local utility; and
- The PSC allows for public input at a public hearing.

Wind facilities are still subject to any federal, State, and local approvals needed to address (among other things) erosion and sediment control, Federal Aviation Administration (FAA) lighting requirements, and threatened and endangered species impacts. In addition, the Maryland General Assembly passed an amendment in 2012 further requiring that any wind facility be no closer than a PSC-determined distance from the Patuxent River Naval Air Station. The radius of this exclusion zone may not exceed 46 miles.

The majority of counties in Maryland have adopted some form of zoning ordinance for wind turbine development (see sidebar). Until very recently, Garrett County did not have any zoning regulations regarding the development of commercial-scale wind turbines. However, in 2013, the Maryland General Assembly enacted legislation establishing minimum setback requirements for utility-scale wind turbines in Garrett County — the only instance to date of the State legislature imposing county-specific requirements on wind power development. The statute requires a minimum distance from schools and residences of no less than 2.5 times the height of the wind turbine. Wind projects that have filed interconnection agreements with PJM before March 1, 2013 are exempt from this requirement. Wind developers can request a variance from the Garrett County Department of Planning and Development of up to 50 percent of the minimum setback requirement as long as all adjacent property owners give written authorization. The legislation also requires wind developers to post a bond equal to 100 percent of the estimated cost of decommissioning and site restoration.

### *Land-based Wind Projects in Maryland*

Table 2-3 and Figure 2-8 show the operating and proposed wind facilities in Maryland. Currently, there are four operating utility-scale wind facilities in Maryland, all located in Garrett County. Their combined power capacity of 190 MW is estimated to represent about 12 percent of Maryland's land-based wind resource potential at a hub height of 80 meters. Two other projects, representing about 140 MW, are currently in the planning and development stages.

### *Table 2-3 Status of Land-based Wind Projects in Maryland*

| Project – Developer/Owner | Size (MW) | Location | Nearest Town | Status |
|---|---|---|---|---|
| Criterion – Exelon | 70 | Backbone Mountain, Garrett County | Oakland | Operational |
| Roth Rock – Gestamp Wind | 50 | Backbone Mountain, Garrett County | Oakland | Operational |
| Fourmile Ridge – Exelon | 40 | Fourmile Ridge, Garrett County | Frostburg | Operational |
| Dans Mountain – Laurel Renewable Partners | 70 | Dans Mountain, Allegany County | LaVale | CPCN Application Pending |
| Fairwind – Exelon | 30 | Backbone Mountain, Garrett County | Oakland | Operational |
| Terrapin Ridge EDF Renewables | 69 | Garrett County | Friendsville | Proposed |

### *Figure 2-8 Approximate Locations of Wind Energy Projects in Maryland*


Originally developed by Clipper Windpower, the 70 MW Criterion Wind Project was acquired by Constellation Energy (Constellation) in April 2010. More recently, the Criterion Wind Project was acquired by Exelon in 2012 through Exelon's merger with Constellation. Located on Backbone

Mountain in Garrett County, the wind facility is comprised of 28 turbines that are approximately 415 feet tall with a maximum output of 2.5 MW each. Construction was completed in December 2010. Constellation signed a 20-year PPA with the Old Dominion Electric Cooperative for both the energy and the RECs produced by the wind facility. The Criterion Wind Project generated about 174,000 MWh in 2014.

The Roth Rock Wind Facility, developed by Synergics and now owned by Gestamp Wind, has a total installed power capacity of 50 MW. This facility, also located on Backbone Mountain near the Criterion Wind Project, consists of twenty 2.5 MW turbines, and stretches approximately three-and-a-half miles along a ridge near the West Virginia border. Gestamp Wind has a 20-year PPA with DPL for both the energy and the RECs produced at the facility. The Roth Rock Wind Facility generated about 125,000 MWh in 2014.

In January 2013, Fourmile Wind Energy, LLC, a subsidiary of Synergics, submitted an application to the PSC for a CPCN exemption for a 60 MW wind project in Garrett County. The PSC conducted a hearing in Garrett County to receive public comments in March 2013, and subsequently approved the CPCN exemption in April 2013. The project was revised to be developed under Exelon as a 40 MW project consisting of sixteen 2.5 MW turbines. The project commenced operations in 2015.

Clipper Windpower proposed the 30 MW Fairwind Project to be located adjacent to the Criterion Wind Project. The PSC granted a CPCN exemption for this project in December 2013. Exelon took over the development rights to the Fairwind Project and brought the project online in 2015. The project consists of twelve 2.5 MW wind turbines.

Maryland's two other proposed land-based wind power proposals are described below. The ultimate generating capacity of these projects will depend on the specific turbine models selected for each project:

- Dans Mountain is a 70 MW wind project in Allegany County originally proposed by US Wind Force. The PSC granted US Wind Force a CPCN exemption in March 2009, but the developers delayed the project after Allegany County enacted revised zoning regulations in May 2009. Laurel Renewable Partners purchased the project in May 2013. In December 2015, the PSC granted a request to delay construction to the end of 2016 and for the project to be online by the end of 2018. Earlier, in November 2015, the Allegany County Board of Zoning Appeals denied the developer's application for a special exception and variances from the county zoning requirements for wind projects. In January 2016, Laurel Renewable Partners petitioned the PSC for a CPCN, asking the Commission to preempt Allegany County's ordinances on wind turbines; the case is still ongoing as of October 2016.

- The PSC approved the 69.65 MW Terrapin Ridge wind project in 2012 to be located east of Friendsville. The project developer switched its interconnection point and plans to be online by 2017.

Two proposed wind projects in Maryland were converted to solar. Apex abandoned its proposed Mills Branch wind project in Kent County and proposed a 60 MW solar facility near Chestertown. Apex's application is pending before the PSC. Pioneer Green Energy proposed the 150 MW Great Bay wind project in Somerset County, but public opposition and concerns by the U.S. Department of Defense

(DoD) about the wind turbines' potential effect on radar at the Patuxent River Naval Air Station delayed the project. In 2014, U.S. Senator Barbara Mikulski (D-MD) successfully added an amendment to the DoD's appropriations bill that prevents the U.S. Navy from finalizing any agreement with Pioneer Green Energy until a $2 million study regarding the potential impact on test range and turbine motion was completed by the Massachusetts Institute of Technology (MIT). Pioneer Green Energy recently received approval by the PSC for the 150 MW Great Bay solar project. If the project proceeds, the U.S. General Services Administration (GSA) will purchase half of the output.

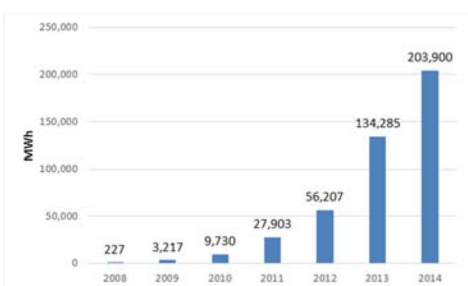
### *Offshore Wind Resource Potential*

According to an NREL study, the United States may have a usable offshore wind resource capacity of over 4,000 GW, with approximately 480 to 570 GW of that potential in the Mid-Atlantic region. NREL estimates that Maryland alone has an unrestricted (not accounting for siting or possible conflicts with freight ships) offshore wind power capacity in excess of 25 GW. A report prepared by the University of Delaware suggests that Maryland's unrestricted offshore wind potential is even higher, at 60 GW. Using existing offshore wind turbine technology and limiting development to shallow waters reduces the offshore wind potential to 14.6 GW. Still, if fully developed, offshore wind could supply 70 percent of the State's electric demand. For more information regarding Maryland's offshore wind, see Section 5.5.1.

## Growth of Solar Energy in Maryland

Solar energy generation capacity in Maryland has gone from 0.1 MW in 2007 to 244 MW in 2014 due, in large part, to Maryland's implementation of a solar carve-out under the Maryland Renewable Portfolio Standard (RPS). As a mechanism to further accelerate this growth, the General Assembly passed a bill in 2012 that advanced the final compliance date for the 2 percent solar carve-out in the Maryland RPS from 2022 to 2020. To meet the accelerated schedule, the solar carve-out of Maryland's RPS increased, beginning in 2013 and continuing through 2020. Likely attributed to the accelerated schedule, solar generation in Maryland increased 263 percent, or approximately 147,700 MWh between 2012 and 2014.

Solar Generation in Maryland, 2008-2014

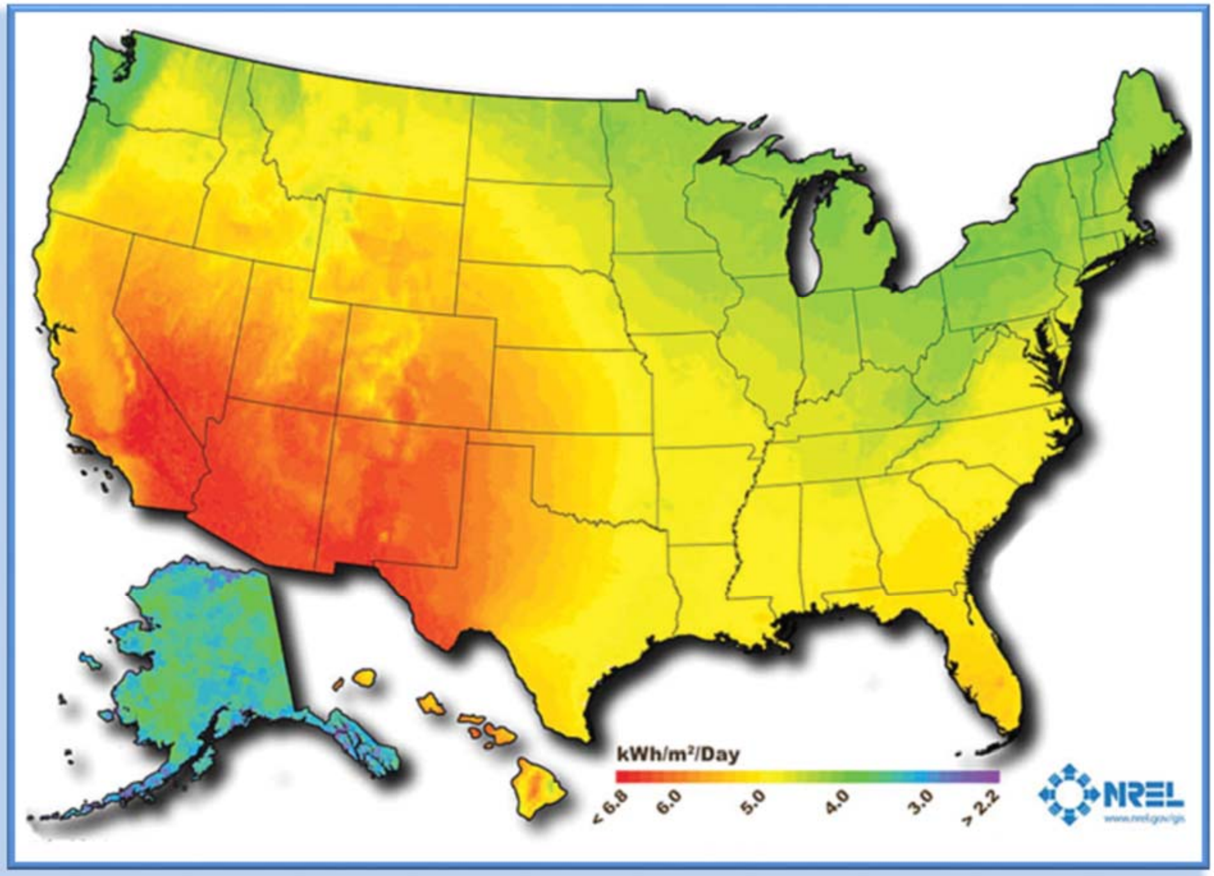



Source: Maryland PSC, Renewable Energy Portfolio Standard Report, Various Years. Appendix A in this publication lists aggregate SRECs retired in Maryland

### *Solar*

By virtue of its location, Maryland has only an average solar resource with moderate solar energy intensities, as illustrated in Figure 2-9. However, Maryland has several policies in place that encourage the deployment of solar energy systems. One such policy is the State's RPS, which calls for 20 percent renewable energy by 2022, with 2 percent coming from solar energy sources by 2020. Solar systems must be connected with the distribution grid in Maryland to be eligible. Load-serving entities (LSEs) can self-generate solar power, purchase solar renewable energy credits (SRECs), or pay the solar alternative compliance payment (ACP), providing a financial incentive to homeowners, businesses, and independent developers to install solar renewable energy systems. Solar generators must offer SRECs for sale to Maryland electric suppliers before offering them to anyone else.

***Figure 2-9 Quality of Photovoltaic (PV) Resource***




Source: "Solar Explained, Where Solar is Found," U.S. Energy Information Administration, National Renewable Energy Laboratory, http://www.eia.gov/energyexplained/index.cfm?page=solar_where.

At the conclusion of 2015, there were 23,304 in-state solar projects representing more than 411 MW of generating capacity in Maryland, according to the PJM Generation Attribute Tracking System (GATS). GATS tracks SRECs that are eligible for use in complying with the Maryland RPS. While most of the facilities are smaller than 10 kilowatts (kW), 45 systems larger than 1 MW have come online. Table 2-4 lists the GATS-registered solar facilities by system size. First Solar, Inc. recently constructed the largest solar PV facility in the state at 20 MW; it is capable of powering more than 2,700 homes at peak operation. Constellation began operation of another 20 MW solar facility at its Perryman site in Harford County in early 2016, and in December 2015, Great Bay Solar received PSC approval to construct up to 150 MW of solar generating capacity in Somerset County, the largest solar installation under development in Maryland. In total, since early 2015, the PSC has issued CPCNs to 12 solar facilities with a combined capacity of 295 MW.

*Table 2-4 Maryland's Solar Facilities Listed in PJM GATS, 2015*

| System Size (kW) | Number of Projects | Total Capacity (MW) |
|---|---|---|
| 0 to ≤ 3 | 2,011 | 4.62 |
| > 3 to 6 | 6,127 | 28.57 |
| > 6 to 10 | 8,422 | 66.64 |
| > 10 to 50 | 6,373 | 92.68 |
| > 50 to 100 | 108 | 7.13 |
| > 100 | 263 | 211.99 |
| **Total** | **23,304** | **411.63** |

Source: PJM Generation Attribute Tracking System.

## Solar Energy Facility at Mount St. Mary's University

Mount St. Mary's University and Constellation Energy partnered to build one of the largest solar facilities on any private college campus in the United States. As part of the State of Maryland's Generating Clean Horizons initiative, Constellation Energy developed a 17.7 MW solar PV installation on land leased from Mount St. Mary's University in Emmitsburg, Maryland. In an agreement with Constellation, the University leased 100 of its 1,400 acres on the east campus to house the PV facility, which is expected to create more than 22,000 MWh per year. The facility began commercial operation in mid-2012. The University System of Maryland, Maryland Department of General Services, and Mount St. Mary's University purchases the output of the facility under a 20-year power purchase agreement. The State buys 16.1 MW, while the University purchases output from the remaining 1.6 MW.

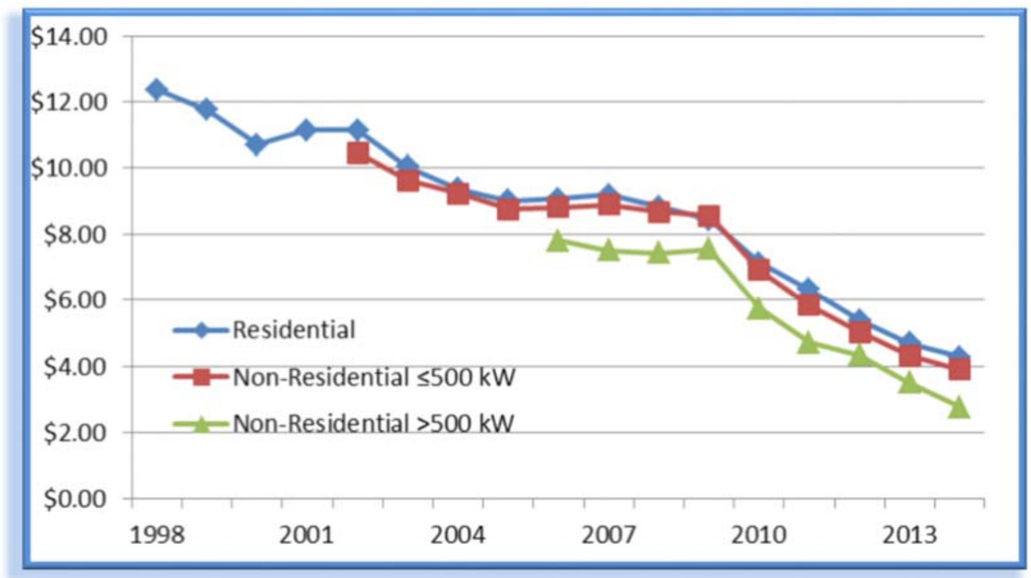
According to PSC's Renewable Energy Portfolio Standard Report, Maryland's solar RPS resources generated 239,279 MWh of renewable electricity in 2014. Based on the installed solar capacity in 2015, Maryland's solar generation must grow by over 30 percent per year to meet the 2020 solar requirement.

Similar to Maryland, New Jersey also provides strong policy support for solar technologies. New Jersey's 20 percent RPS requirement initially featured a 2.12 percent solar PV set-aside that has since been changed to 4.1 percent of all retail electric sales by 2028. As of November 2015, New Jersey had 1.6 GW of installed solar capacity.

Nationally, installed solar costs have declined, on average, by 6 to 12 percent per year since 1998, depending on customer class (residential or non-residential). Cost declines, however, have not occurred at a steady pace. In fact, installed costs declined markedly until 2005 but remained stable through 2009 despite widespread deployment. National median costs of solar systems dropped by 9 percent for residential systems, 10 percent for non-residential systems below 500 kW, and 21 percent for non-residential systems over 500 kW (see Figure 2-10) in 2014, as compared to 2013, and preliminary data suggest that the costs of installed systems continued to decline in 2015.

Certain incentive policies, like the Maryland and New Jersey RPSs, have assumptions of declining PV installation costs built into the enforcement mechanisms. In the case of the RPS policies, the alternative compliance payment (ACP), which effectively places a ceiling on solar REC costs since it provides an alternative method by which to comply with the requirement, generally moves lower year to year. If the solar industry cannot match these downward cost profiles, utilities may begin opting to pay the ACP in lieu of installing solar facilities.

***Figure 2-10 The Cost of Solar PV in the United States, 1998-2014***




Source: Barbose, Galen and Naim R. Darghouth, Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States, Lawrence Berkeley National Laboratory, 2015, https://emp.lbl.gov/publications/tracking-sun-viii-installed-price.

## Hydroelectric Potential at Existing Dams

A report by the Department of Energy's Oak Ridge National Laboratory (ORNL) found that adding powerhouses to 54,000 existing U.S. dams that do not currently have generation facilities could garner up to 12.6 GW — enough renewable energy to power about 12.6 million homes. Moreover, most of these dams can be converted to generation facilities with minimal impact to critical habitats or wilderness areas. Several small (& 30 MW) sites are available in Maryland. One project is already in development. In December 2010, Fairlawn Hydroelectric Company filed an application with the Federal Energy Regulatory Commission for an original license to construct, operate and maintain its proposed Jennings Randolph Hydroelectric Project. The 13.4 MW project will be located at the U.S. Army Corps of Engineers' Jennings Randolph Dam and Lake in Garrett County, Maryland and Mineral County, West Virginia. The Jennings Randolph Dam (also known as Bloomington Lake Dam) is on the North Branch of the Potomac River near the towns of Barnum, West Virginia, and Swanton, Maryland, and was completed in 1985 by the Corps (Baltimore Division) for the purposes of flood control, recreation, and natural resource management. The proposed project would occupy approximately 5.0 acres of federal land under the jurisdiction of the Corps. FERC issued a 50-year operating license on April 30, 2012; construction must begin by April 2016 for Fairlawn to keep its hydro license.

The project has been unable to move forward as it has been awaiting approval by the U.S. Army Corp of Engineers since December 2013. In an effort to extend the hydro license, Representative David McKinley introduced legislation that would extend the permit for construction for up to six years. As of September 2016, the permit extension for the hydro license is included as part of an energy bill currently before the Energy Conference Committee. If the bill does not pass, FERC has the opportunity to extend the permit.

*Jennings Randolph Dam*

### *Hydroelectric*

Hydropower is one of the oldest sources of power, used thousands of years ago to grind grain. The first U.S. hydroelectric power plant began operations in the 1880s. A hydroelectric dam is the most well-known form of hydropower production, often built on a very large scale by closing off an entire river and forming a large lake-like reservoir.

In 2013, President Obama signed two bills aimed at boosting development of the nation's hydropower resources. H.R. 267, the Hydropower Regulatory Efficiency Act, promotes the development of small hydropower and conduit projects and aims to shorten regulatory timeframes of certain other low-impact hydropower projects, such as adding power generation to the nation's existing non-powered dams and closed-loop pumped storage. As of June 2015, the FERC reported that it has received 58 notices of intent to build small conduit hydropower projects that would be exempt from FERC jurisdiction. Of these, FERC accepted 43, rejected eight because they did meet statutory criteria, and seven are pending.

President Obama also signed into law H.R. 678, the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act, which authorizes small hydropower development at existing Bureau of Reclamation-owned canals, pipelines, aqueducts, and other manmade waterways. Such development could provide enough power for 30,000 American homes with no environmental impact.

### Conduit Hydroelectric Power in Maryland

The City of Frostburg received an exemption from FERC licensing to construct the 75 kW Frostburg Low Head Project, a small conduit hydropower project located on Frostburg's municipal raw water line in Allegany County. The plant uses the water main already in place on the eastern slope of Big Savage Mountain. As the water comes down the mountain, it turns the turbine, generating electricity. The project is expected to generate approximately 240 MWh annually. The construction of the plant was completed in 2012 and is fully operational.

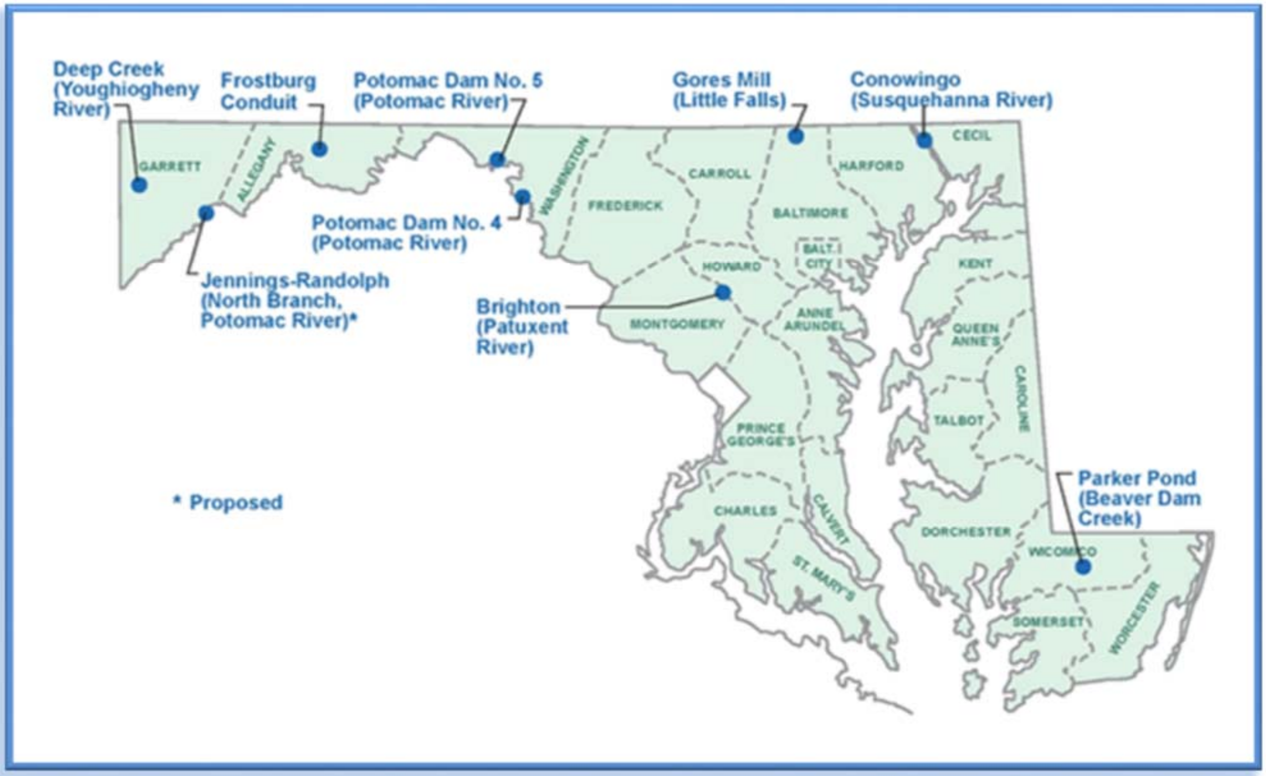
Conduit hydropower projects are able to extract power from water without the need for a large dam or reservoir. Existing or newly constructed tunnels, canals, pipelines, aqueducts, and other manmade structures that carry water can be fitted with electric generating equipment to produce hydropower. Conduit hydro projects are efficient and often cost-effective, as they are able to generate electricity from existing water flows using infrastructure that is either already in place or is proposed regardless of a need for power.

Maryland has two large-scale (greater than 10 MW capacity) hydroelectric dam projects and six additional small-scale facilities that are currently in operation. Maryland's hydroelectric plants are listed in Table 2-5 with locations shown in Figure 2-11. Conowingo Dam, the state's largest hydro facility, is currently operating under a temporary license from FERC until Maryland issues a water quality permit under the Clean Water Act. The Maryland Department of Environment has not issued the permit yet as it wants Exelon, the dam's owner, to address nutrient and sediment releases from the dam that eventually flow to the Chesapeake Bay. Maryland is required to comply with a U.S. Environmental Protection Agency (EPA) rule to meet Clean Water Act standards for the Chesapeake Bay by 2025. Chapter 4 includes further discussion about hydroelectricity and its potential impacts.

## Table 2-5 Hydroelectric Projects in Maryland

| Project Name | Name-plate Capacity | River / Location | FERC Project No. | Owner | FERC License Type | FERC License Issued | FERC License Expires | Year Operational |
|---|---|---|---|---|---|---|---|---|
| **LARGE-SCALE PROJECTS** | | | | | | | | |
| Conowingo | 572 MW | Susquehanna/ Conowingo, Harford County | 405 | Susquehanna Power Co. and PECO Energy Power Co. | Major License | 1980 | 2014 | 1928 |
| Deep Creek | 20 MW | Deep Creek/ Oakland, Garrett County | - | Brookfield Power | None | - | - | 1928 |
| Jennings Randolph (proposed) | 13.4 MW | North Branch Potomac River/ Bloomington, Garrett County | 12715 | Fairlawn Hydroelectric at USACE dam | Major License | 2012 | 2062 | (Proposed for 2015) |
| **SMALL-SCALE PROJECTS** | | | | | | | | |
| Potomac Dam 4 | 1,900 kW | Potomac River/ Shepherdstown, WV | 2516 | Harbor Hydro Holdings LLC | Major License | 2004 | 2033 | 1909 |
| Potomac Dam 5 | 1,210 kW | Potomac River/ Clear Spring, Washington County | 2517 | Harbor Hydro Holdings LLC | Major License | 2004 | 2033 | 1919 |
| Gores Mill | 10 kW | Little Falls/ Baltimore County | - | C. Lintz | None | - | - | 1950s |
| Parker Pond | 40 kW | Beaver Dam Creek/ Wicomico County | - | W.H. Hinman | None | - | - | 1950s |
| Brighton | 400 kW | Patuxent River/Clarksville, Montgomery County | 3633 | KC Brighton LLC | Minor License | 1984 | 2024 | 1986 |
| Frostburg | 75 KW | Big Savage Mountain Pipeline/Allegany County | 14059 | City of Frostburg | Conduit Exemption | 2011 | | 2012 |

*Figure 2-11 Location of Hydroelectric Facilities in Maryland*




Wave and tidal power also harness the energy of moving water, specifically in ocean settings. Wave energy facilities typically float in the water and employ the vertical motion of the waves to create energy. Tidal power is produced by tidal stream generators, which capture the kinetic energy of moving water caused by tidal currents or the fluctuation of the sea level due to the tide. They work much the same way as wind power generators, but because water is much denser than air and tides are steady and almost continuous, the generators can produce significantly more power. Maryland has limited tidal resources at its Chesapeake Bay and Atlantic coast sites. Some potential exists for small-scale projects. Various technical obstacles and the relative immaturity of wave and tidal power technologies also limit potential development.

### *Biomass*

In the energy production sector, biomass refers to biological material that can be used as fuel for transportation, steam heat, and electricity generation. Biomass fuels are most commonly created from wood and agricultural wastes, alcohol fuels, animal wastes, and municipal solid waste. Biomass can be combusted to produce heat and electricity, transformed into a liquid fuel such as biodiesel, ethanol, or methanol, or transformed into a gaseous fuel such as methane.

### *Waste-to-Energy*

Waste-to-energy (WTE) facilities generate energy from municipal solid waste. While the precise details of the processes may vary, the general method involves combusting the waste in order to heat boilers and create high-pressure steam, which is used to turn a turbine and generate electricity. In addition to the energy produced, WTE plants typically reduce the volume of incoming waste by about 90 percent and the weight of incoming waste by about 75 percent.

Until 2011, WTE was classified as a Tier 2 resource under the Maryland RPS, but the Maryland General Assembly enacted legislation that made WTE a Tier 1 resource and added refuse-derived fuel as a Tier 1 resource. See Section 5.1.1 for information on the Maryland RPS Tier 1 and Tier 2 requirements.

There are 85 WTE facilities currently operating nationwide according to the Energy Recovery Council, including three major facilities in Maryland that are certified under Maryland's RPS. As displayed in Table 2-6, there is also one WTE plant in the planning and development stages in Maryland. WTE facilities are heavily regulated due to various environmental impacts. As an energy source, WTE is similar to coal and oil electricity generators in terms of carbon dioxide ($CO_2$), sulfur dioxide ($SO_2$), and nitric oxide (NO) emissions. However, WTE facilities can also contribute to the environmental deposition of mercury, dioxin, furan, and other toxic metals and organic compounds unless adequate pollution controls are installed.

### *Table 2-6 Waste-to-Energy Facilities in Maryland*

| Facility Name (Location) | Project Status | Nameplate Capacity (MW) | Operator/Developer |
|---|---|---|---|
| Montgomery County Resource Recovery Facility (Dickerson, Maryland) | Operational | 68 | Covanta Montgomery |
| Wheelabrator Baltimore Refuse Facility (Baltimore, Maryland) | Operational | 65 | Wheelabrator Baltimore |
| Harford Waste-to-Energy Facility (Joppa, Maryland) | Operational | 1.2 | Energy Recovery Operations |
| Fairfield Renewable Energy Power Plant (Baltimore, Maryland) | Permitted | 140 | Energy Answers International |

Note: The Harford Waste-to-Energy Facility generates steam from the processing of the waste and sells it to the Edgewood Area of the U.S. Army's Aberdeen Proving Ground. Since it does not sell electricity into the PJM grid, it is not considered an eligible Maryland RPS resource.

### *Landfill Gas*

Landfill gas (LFG) is created when organic solid wastes decompose in a landfill. The amount of gas produced in a landfill depends upon the characteristics of the waste, the climate, the residence time of the waste, and operating practices at the landfill. If no capture or extraction measures are employed, LFG will be released into the atmosphere as a combination of methane and CO2, with small amounts of non-methane organic components. If the LFG is extracted and combusted (e.g., flared or used for energy), then the methane produced in the landfill is converted entirely to CO2. Both CO2 and methane are greenhouse gases (GHGs); however, methane has 20 times the global warming potential of CO2, so converting methane to CO2 provides an important benefit. Many landfills capture LFG and simply burn it off in a flare to prevent a potentially explosive buildup of gas. Combusting LFG instead to generate power makes use of this otherwise wasted energy and also reduces odors, contaminants, and GHGs. Table 2-7 lists the LFG-to-energy projects that are currently operating in Maryland. Not listed in the table is the Millersville LFG project, which collects LFG and sells it directly to the Army's Fort Meade base to fuel operations at the base.

### *Table 2-7 Landfill Gas Projects in Maryland*

| Name and Location | Estimated Total Waste in Place (Tons) | Project Status | LFG Energy Project Start Date | LFG Energy Project Type | MW Capacity | Project Developer |
|---|---|---|---|---|---|---|
| Brown Station Road (Prince George's County) | 6,964,110 | Operational<br>Operational<br>Operational | 1987<br>1987<br>2003 | Reciprocating Engine<br>Boiler<br>Reciprocating Engine | 2.6<br>Steam<br>3.5 | PG County |
| Eastern/White Marsh (Baltimore County) | 5,213,000 | Operational | 2006 | Reciprocating Engine | 2.5 | Pepco Energy Services |
| Newland Park (Wicomico County) | 1,238,743 | Operational | 2007 | Reciprocating Engine | 2.6 | INGENCO |
| Central Landfill (Worcester County) | 1,244,656 | Shutdown | 2008 | Reciprocating Engine | 2.0 | Curtis Engine |
| Gude (Montgomery County) | 4,800,000 | Shutdown<br>Operational | 1985<br>2009 | Reciprocating Engine<br>Reciprocating Engine | 2.0<br>0.8 | Covanta<br>SCS Engineers |
| The Oaks (Montgomery County) | 6,874,060 | Operational | 2009 | Reciprocating Engine | 2.4 | SCS Engineers |
| Quarantine Road (Baltimore County) | 10,632,202 | Operational | 2009 | Cogeneration | 1.5 | Ameresco Federal Solutions |
| Reichs Ford Landfill (Frederick County) | 3,940,387 | Operational | 2010 | Reciprocating Engine | 2.1 | Energenic-US |
| Sandy Hill (Prince George's County) | 5,125,946 | Shutdown<br>Operational | 2003<br>2011 | Boiler<br>Boiler | Steam<br>Steam | Toro Energy |
| Millersville (Anne Arundel County) | 2,888,404 | Operational | 2012 | Reciprocating Engine | 3.2 | Northeast Maryland Waste Disposal Authority |
| Alpha Ridge (Howard County) | 2,276,586 | Operational | 2012 | Reciprocating Engine | 1.1 | Pepco Energy Services, Inc. |

Notes: The Brown Station, Gude, and Sandy Hill landfills are closed and are no longer accepting waste, but the LFG facilities continue to operate. LFG from Sandy Hill is combusted to generate heat only, not electricity. The capacity rating of Newland Park reflects the capacity rating for single fuel/LFG mode landfill gas and not the maximum capacity rating of 6 MW which includes use of diesel fuel.

## 2.2 New and Proposed Power Plant Construction

### New Natural Gas Power Plants

In the past five years, the PSC granted CPCN approval to three new gas-fired power generation facilities in southern Maryland. All three facilities are combined-cycle power generating stations.

The Competitive Power Ventures (CPV) St. Charles facility is located in Charles County, and received initial CPCN approval in 2008. A modified and amended CPCN was subsequently filed and approved in 2012. CPV began construction in December 2014, and targets a 2017 in-service date. Originally filed as 640 MW combined-cycle power plant, the project was updated with more efficient technology and now yields a 725 MW name-plate capacity.

The Keys Energy Center, located in Prince George's County, will be a 755 MW facility, and received CPCN approval in November 2014. PSEG Power acquired the project from Genesis Power, LLC in 2015, and anticipates operations beginning in 2018.

Mattawoman Energy, LLC, a subsidiary of Panda Power Funds, LLC, is building the Mattawoman Energy Center near Brandywine in Prince George's County. The 990 MW project received CPCN approval in October 2015. Mattawoman expects plant operations to start in 2018.

Since the start of 2015, the PSC has received 17 CPCN applications from developers of proposed new generating facilities - an unprecedented level of licensing activity. Over the past 16 years, the PSC has received 52 CPCN applications for new generation, representing several thousand megawatts of potential generating capacity at existing facilities and at greenfield sites with several application reviews ongoing (see Figure 2-12). While the majority of these proposed plants did obtain a CPCN, only 18 are now in operation, with the remainder under construction or being delayed or abandoned because of various financial or commercial reasons, compounded by the reduction in electricity demand resulting from the economic recession and state energy efficiency initiatives in PJM.

Maryland has seen a sharp increase in utility-scale solar projects in recent years. Developers are proposing these solar projects to capitalize on Maryland state tax incentives and support the Maryland Renewable Energy Portfolio Standard (see Solar discussion in Section 2.1.5).

*Figure 2-12 CPCN Requests, 2000 through August 2016*


Bar length indicates the duration of the CPCN process from the time the application was filed to the time it was withdrawn or a PSC order was filed. Bar coloring indicates whether the project is now in operation:

= Project is operational

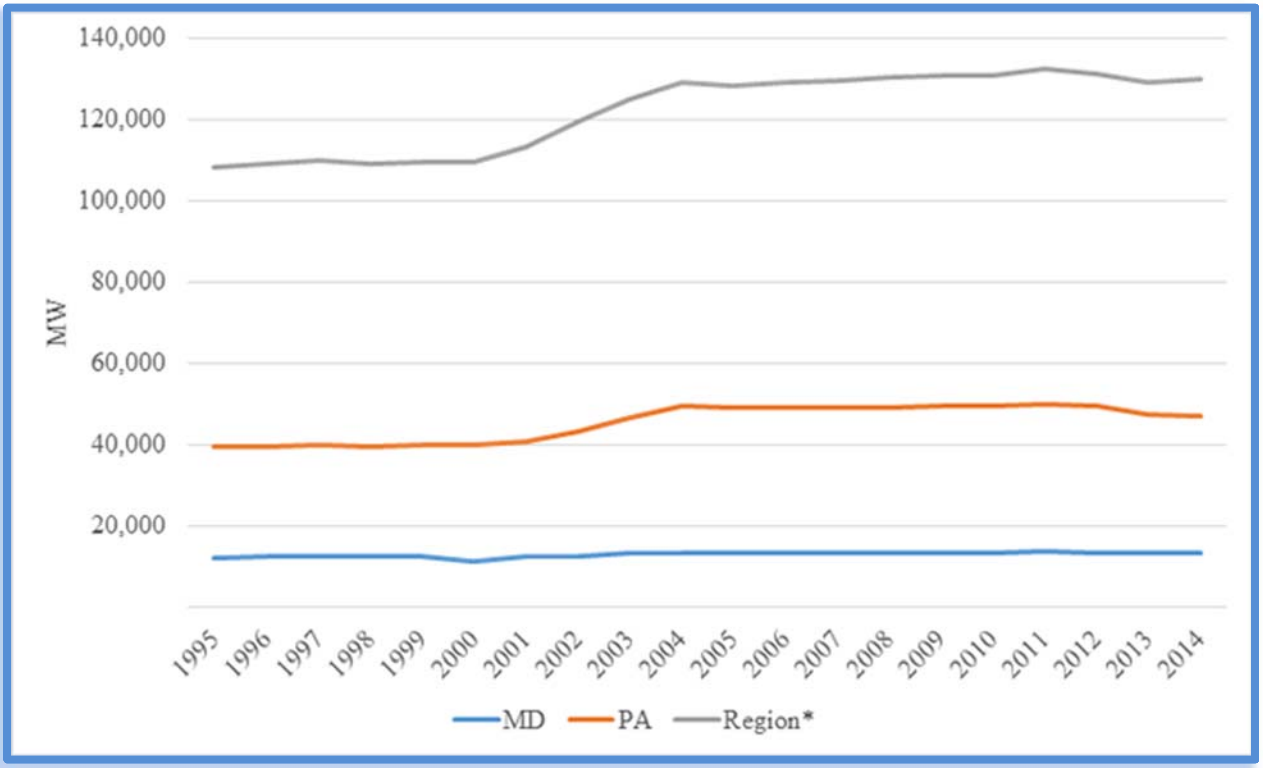
= Project is not operational

* Project was subsequently reconfigured, granted a CPCN exemption, and is now operational. See Section 2.1.5 for more information.

Chart does not reflect CPCN cases ongoing as of September 2016: OneEnergy Blue Star Solar, OneEnergy Ibis Solar, Pinesburg Solar, Big Spring Solar, Massey Solar, Perennial Solar, Gateway Solar, Mills Branch Solar, Todd Solar, and Dan's Mountain Wind Force.

The process by which new power plants are proposed and developed in Maryland has changed as a result of the move to retail competition and electric utility restructuring. Maryland's regulated utilities are no longer responsible for building new generation. Resource planning resides with the competitive electricity market, driven by economics and price signals. High prices that result from tight supply markets are expected to attract investors, developers, and demand response providers; low prices that result from over-supplied markets are projected to discourage new generation development and demand response providers. However, substantial and sustained price differentials are required to elicit such market behaviors. The up-and-down movement of wholesale prices in PJM has resulted in a "boom-bust" cycle in the development of new generating plants in PJM. This trend produces a situation where many power plants are proposed and built in a short time frame followed by a period where few plants are built. Figure 2-12 demonstrates the recent increase in the number of CPCN requests in Maryland after a multi-year period with relatively few open applications. Figure 2-13 shows the amount of capacity on-line for Maryland, Pennsylvania, and the region.

*Figure 2-13 Maryland and Regional Capacity*

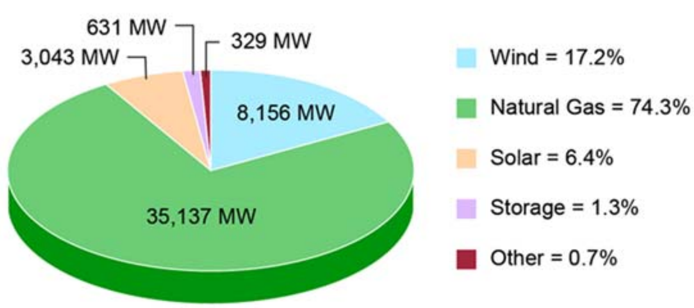



*Region includes Delaware, Maryland, New Jersey, Pennsylvania, Virginia, Washington, D.C., and West Virginia.

Source: Energy Information Administration, EIA-860 Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type, and State, Release Date October 21, 2015.

**PJM Generation Interconnection Queue**

New generation projects seeking to connect to the PJM grid must submit a generator interconnection request. PJM performs the requisite studies for generator interconnection in clusters grouped together based on a six-month queue cycle. The aggregate list of dated interconnection requests is referred to as the generation interconnection queue. As of early 2016, the PJM interconnection queue consisted of projects totaling 47.3 GW of capacity (stated as winter net capacity). Natural gas is the dominant resource, followed by wind; the breakdown by fuel type is shown in the pie chart below. Renewable energy projects accounted for around 25 percent of the total capacity in the PJM interconnection queue. Although the majority of generation projects in the interconnection queue are not ultimately constructed, the interconnection queue provides an initial estimate of the potential new generation capacity in PJM.

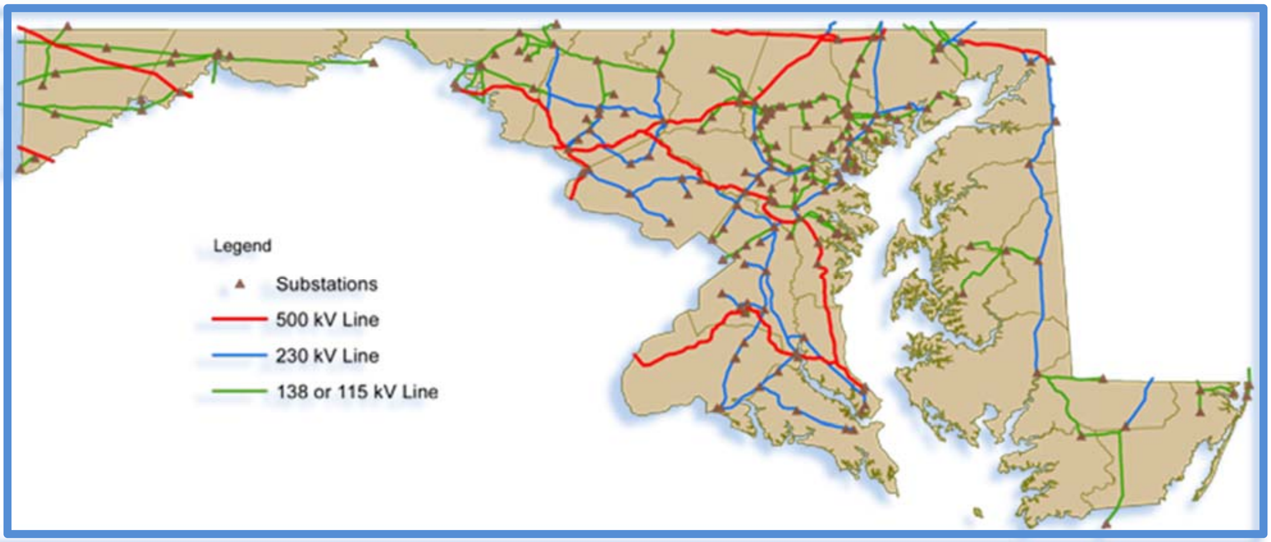



Over the last decade, capacity growth has been stagnant in Maryland, Pennsylvania, and the region as a whole. This “bust” period followed a brief period of growth in the early 2000s. Projects that had started construction prior to the decrease in wholesale market prices in 2002 went on-line by 2004, after which there was a slowdown in new facilities coming on-line in the region. Since then, a combination of several factors have suppressed the growth of capacity in the region, including energy efficiency and demand response efforts, transmission upgrades, capacity in excess of reliability requirements, and low load growth. These factors will likely continue to maintain a stagnant growth pattern in future years.

## 2.3 Electric Transmission

The network of high-voltage lines, transformers, and other equipment that connect power generating facilities to distribution systems are part of an expansive electric transmission system. In Maryland, there are more than 2,000 miles of transmission lines operating at voltages between 115 kV and 500 kV. Figure 2-14 shows a map of this high-voltage transmission grid in Maryland.

***Figure 2-14 Transmission Lines in Maryland (>115 kV)***

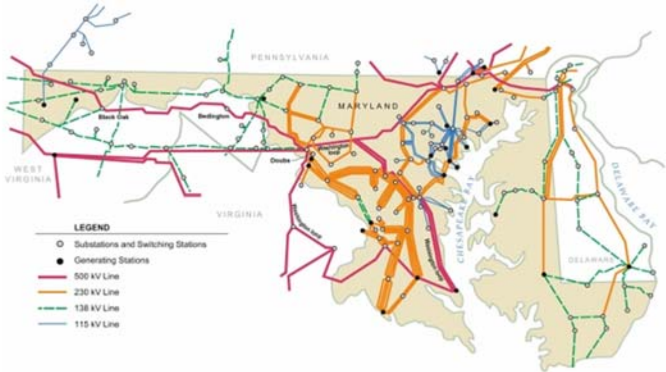



While the economic and environmental effects of generation are substantial, transmission also has major environmental and socioeconomic implications in Maryland, particularly since Maryland is a net importer of electricity. Building new transmission facilities is costly with significant environmental impacts and ratepayer costs. Upgrading existing heavily used facilities must be done quickly, often in short windows of time, while minimizing environmental impacts. Shortages of transmission capacity or congestion can lead to higher priced out-of-merit generation dispatch and extremely high energy and capacity prices over peak time periods.

## Artificial Island Project on Delmarva Peninsula

The Delmarva Peninsula, consisting of Maryland's Eastern Shore, Delaware, and a portion of Virginia, experiences high congestion costs due to the isolation of the transmission system. As noted in the figure below, the entire Delmarva Peninsula relies upon a transmission interconnection at the northern part of the Peninsula in Delaware. The lack of transmission interconnection points elsewhere on the Peninsula causes increased transmission congestion. While projects, such as the Mid-Atlantic Power Pathway (MAPP), have been proposed in the past, none have come to fruition.

*Maryland Transmission Lines*




Instead, reliability improvements in surrounding areas, such as Central Maryland, serve to strengthen reliability on the Peninsula and reduce outage risk until the need for another transmission interconnection point to allow additional imported power onto the Peninsula is identified. One project, the Artificial Island project, proposes the construction of a new underwater 230 kV transmission tie from the Salem and Hope Creek nuclear power plants in New Jersey to the western side of the Delaware Bay. This project, if it proceeds, is expected to address stability issues at the plants while increasing their generation output; however, PJM recently put the project on hold to allow further evaluation.The second proposed project is the construction of a pair of 230 kV transmission lines, one from Pennsylvania to a BGE-owned substation in Central Maryland and the second from Pennsylvania to a PE-owned substation north of Hagerstown. Although neither of these projects are located within Maryland's Eastern Shore, each would provide stability to the transmission system that supports the Delmarva Peninsula's transmission lines and would assist in mitigating power outages.

*Proposed Artificial Island Transmission Project*


Source: "PJM Staff Picks LS Power for Artificial Island Stability Fix; Dominion Loses Out," Herel, Suzanne, April 28, 2015, RTO Insider, http://www.rtoinsider.com/pjm-ls-power-artificial-island-14775/.

PJM has operational control over and planning responsibility for most of the high-voltage transmission facilities in Maryland. As part of its transmission planning responsibilities, PJM routinely examines projections of generation, transmission and loads to determine if additional transmission facilities are needed to comply with applicable transmission planning standards and associated reliability criteria. PJM also periodically examines whether certain new transmission lines will produce economic benefits even if they are not needed for reliability reasons. To the extent PJM determines a need for a transmission project and includes it in the Regional Transmission Expansion Plan (RTEP), there is an expectation that the transmission owner will file for a CPCN seeking permission to construct the proposed transmission line.

Most recently, PJM participated in the DOE-funded interconnection-wide plans as part of the 2009 economic stimulus effort. Planners selected three scenarios and analyzed the transmission systems of each in the year 2030. The Eastern Interconnection Planning Collaborative submitted its plan to the U. S. Department of Energy in late April 2013 that included estimates of transmission operations and maintenance in 2030, along with the cost to build new facilities that may be required to meet the multi-policy future. This plan is detailed in Section 3.3.

### 2.3.1 New and Proposed Transmission Projects

The PSC has received two CPCN applications for new and modified transmission line projects, both from Delmarva Power since early 2014.

- **Church to Steele** is a rebuild of an existing 138 kV transmission line from the Church Substation in Queen Anne's County to the Steele Substation in Caroline County. The Church to Steele project received CPCN approval from the PSC in 2015.

- **Piney Grove to State Line** is a new 138 kV line of about 25 miles in Maryland. It begins at the Piney Grove Substation in Wicomico County and terminates at the Maryland/Delaware state line. The entire project extends to the Wattsville Substation in Virginia. PPRP has completed its review of the portion in Maryland; the PSC issued a Proposed Order on August 18, 2016 giving Delmarva Power its CPCN for the project.

Transmission planning and regulatory drivers, as well as oversight, are described in Section 3.3.

### 2.3.2 Transmission Line Designs

Transmission lines can be designed and constructed in a variety of ways to accommodate site-specific conditions, such as topography, soil types, and proximity to existing infrastructure, sensitive resources, and urban areas. While traditional overhead alternating current (AC) transmission lines are the most common, alternative transmission line types, such as direct current (DC), underground, and submarine, are becoming more prevalent. These types of technologies are discussed in the following sections.

#### *DC Transmission Lines*

According to DOE, several thousand miles of high-voltage DC transmission lines are installed in the U.S., which is relatively small compared to the over 200,000 miles of total installed high-voltage transmission lines (including AC and DC) in the U.S. However, the implementation of DC technology into project design is becoming increasingly more common. Direct current systems are most often implemented for large-scale bulk power transfers over long distances, such as undersea cables, or to connect different transmission networks between countries. In some applications, high-voltage DC (HVDC) systems can be more cost effective at long transport distances compared to high-voltage AC (HVAC) systems. DC technology allows for the use of fewer conductors or cables (two versus three for AC), allowing for typically more compact installations than a comparable AC system. However, DC systems require large conversion stations at each interconnection with the traditional AC grid. Precise, fast, and flexible control of energy flows at any level within the capacity limit of the line is another significant advantage of a DC system. While this technology is becoming more widely used, there are no current projects within Maryland proposing the use of this technology. This technology may be implemented in the 300-mile Atlantic Wind Connection project that is contemplated for support of offshore wind projects from New Jersey to Virginia (see Section 5.5.1).

### *Underground Transmission Cables*

In September 2009, the PSC granted a CPCN to the Southern Maryland Electric Cooperative (SMECO) for the construction of a new 230 kV transmission line from Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary's County. The project includes an underground construction component, for a short segment of the project under the Naval Recreation Facility (see below for submarine construction component of this project). Underground transmission lines are typically implemented in locations where overhead lines are difficult to place or would create aesthetic or environmental issues.

In this type of construction, underground transmission cables are typically placed four to five feet below ground surface in conduits or reinforced duct banks, or are directly buried in specially prepared soil, as shown in Figure 2-15. Instead of wide spacing between conductors, as is required for overhead transmission lines, underground cables are typically placed close together and insulated to protect the cables from one another. Often times, the individual cables required to make up a circuit are placed in polyethylene, PVC, or fiberglass conduits and are installed as a group.

*Figure 2-15 Direct-burial Underground Transmission Line Installation*

Source: ABB, 2008.

Modern underground cables, such as cross-linked polyethylene (XLPE), do not require pressurized liquid or gas insulating and cooling systems that were predominant in earlier cable types, and therefore, no longer have the environmental contamination risk associated with coolant releases. The cables can be designed for AC or DC systems and are manufactured in finite lengths that need to be spliced together, on the order of every 1,000 to 2,000 feet.

The advantages of underground transmission include reduced visual impacts and narrower right-of-way width requirements, due to the close spacing of the cables. For short distances, right-of-way widths of approximately 20 feet are possible, whereas in open country, a 30- to 50-foot width is preferred. Most of this width is to permit access for construction and maintenance equipment, since the duct bank itself is usually less than 10 feet wide. In some instances, these improvements may also coincide with reduced environmental impacts; however, in sensitive areas the installation of an underground transmission cable can be more disruptive than an overhead line.

Disadvantages of underground cables include thermal impacts during operation, significantly higher project costs versus comparable overhead installations, and longer cable repair times due to difficulties locating and accessing the cables and re-installation. Despite the longer repair times, underground cables generally have a longer useful life, are not damaged as often, and can be more secure.

### *Submarine Transmission Cables*

Submarine cables are installed beneath a river bottom or seabed, via trenching or (for shorter lengths) horizontal directional drilling, or are laid on top of the river bottom or seabed. These cables have been used sparingly historically, but are becoming more common for higher voltage transmission lines, as the reliability of the technology is being proven. The above mentioned SMECO 230 kV transmission line from Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary’s County includes an approximately one-mile submarine crossing of the Patuxent River near Solomons, to be achieved with horizontal directional drilling. The construction of this project was completed in 2014 and was monitored by PPRP.

Submarine cables are typically manufactured and installed as one continuous line to provide the greatest reliability and can stretch up to 10 miles in one segment for AC cables, or several times longer for DC cables. Submarine cables are similar in design to underground cables with additional shielding layers. Like underground cables, submarine cables can be designed for both AC and DC systems and can be bundled and installed together in the same trench or conduit. Trenching techniques typically involve fluidizing the seabed using a jet plow pulled along the seabed in order to allow the cable to sink down to the desired installation depth of approximately 6 to 15 feet, depending on specific site conditions.

The benefits of implementing a submarine system are limited disruption to navigation and minimized visual impacts once the cables are installed, compared to the use of an overhead waterway crossing. Impacts from submarine cables are typically associated with disruption of the seabed, sedimentation, and release of nutrients sequestered in the sediments, as well as heat dissipation during operation.

## 2.4 Electricity Distribution

There are 13 utilities distributing electricity to customers in Maryland (see Table 2-8). Four of these are large, investor-owned electric companies organized as for-profit, tax-paying businesses: Potomac Edison (formerly Allegheny Power); Baltimore Gas and Electric (BGE); Delmarva Power and Light Company (DPL); and Potomac Electric Power Company (Pepco). Until recently, they were owned by three holding companies—FirstEnergy (which owns Potomac Edison); Exelon (which owns BGE); and Pepco Holdings (which owns both DPL and Pepco). In 2015, Exelon sought approval from the public service commissions in Maryland, the District of Columbia, Delaware, and New Jersey to merge with Pepco Holdings, and as of March 2016, all approvals had been granted. Maryland's investor-owned utilities serve approximately 90 percent of the customers in the state.

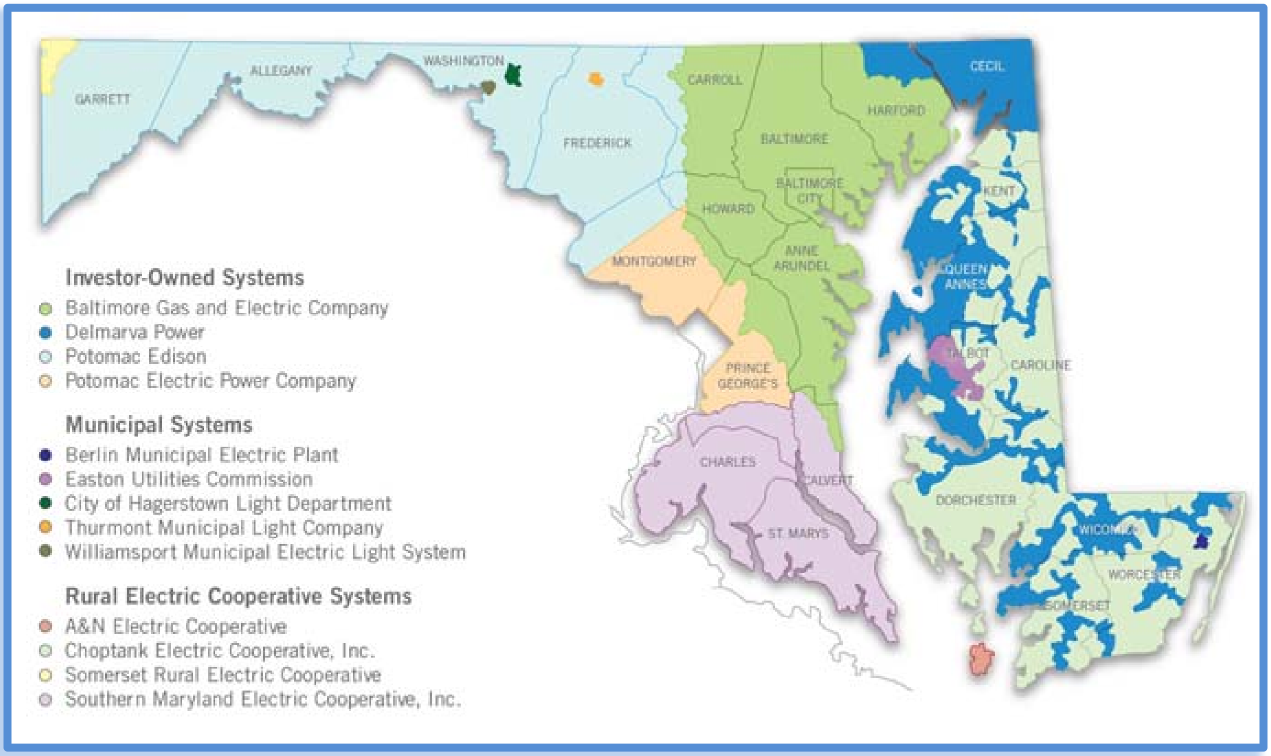
Five utilities are owned and operated by municipalities providing local electric distribution to a specific area. Four utilities are electric cooperatives, serving generally less populated rural areas. The service territories for the State's distribution companies are illustrated in Figure 2-16.

***Table 2-8 Maryland Electric Distribution Companies, 2014***

| Company | Approximate Number of Maryland Consumers |
|---|---|
| **INVESTOR OWNED** | |
| Potomac Edison (owned by First Energy) | 257,198 |
| Baltimore Gas & Electric (owned by Exelon) | 1,248,746 |
| Delmarva Power & Light (owned by Pepco Holdings)* | 201,949 |
| Potomac Electric Power Company (owned by Pepco Holdings)* | 539,072 |
| Subtotal | 2,246,965 |
| **MUNICIPAL SYSTEMS** | |
| Berlin Municipal Electric Plan | 2,459 |
| Easton Utilities Commission | 10,541 |
| City of Hagerstown, Light Department | 17,207 |
| Thurmont Municipal Light Company | 2,837 |
| Williamsport Municipal Electric Light System | 991 |
| Subtotal | 34,035 |
| **COOPERATIVE SYSTEMS** | |
| A&N Electric Cooperative | 313 |
| Choptank Electric Cooperative, Inc. | 52,647 |
| Somerset Rural Electric Cooperative** | 793 |
| Southern Maryland Electric Cooperative, Inc. | 158,141 |
| Subtotal | 211,894 |
| **Total Customers** | **2,492,894** |

Source (except where noted): U.S. Energy Information Association. Accessed January 16, 2016. Number of customers in 2014 is the most recent data available.
* Subsidiary of Exelon as of March 2016
** Source: Pennsylvania Rural Electric Association.

*Figure 2-16 Electricity Distribution Service Areas*

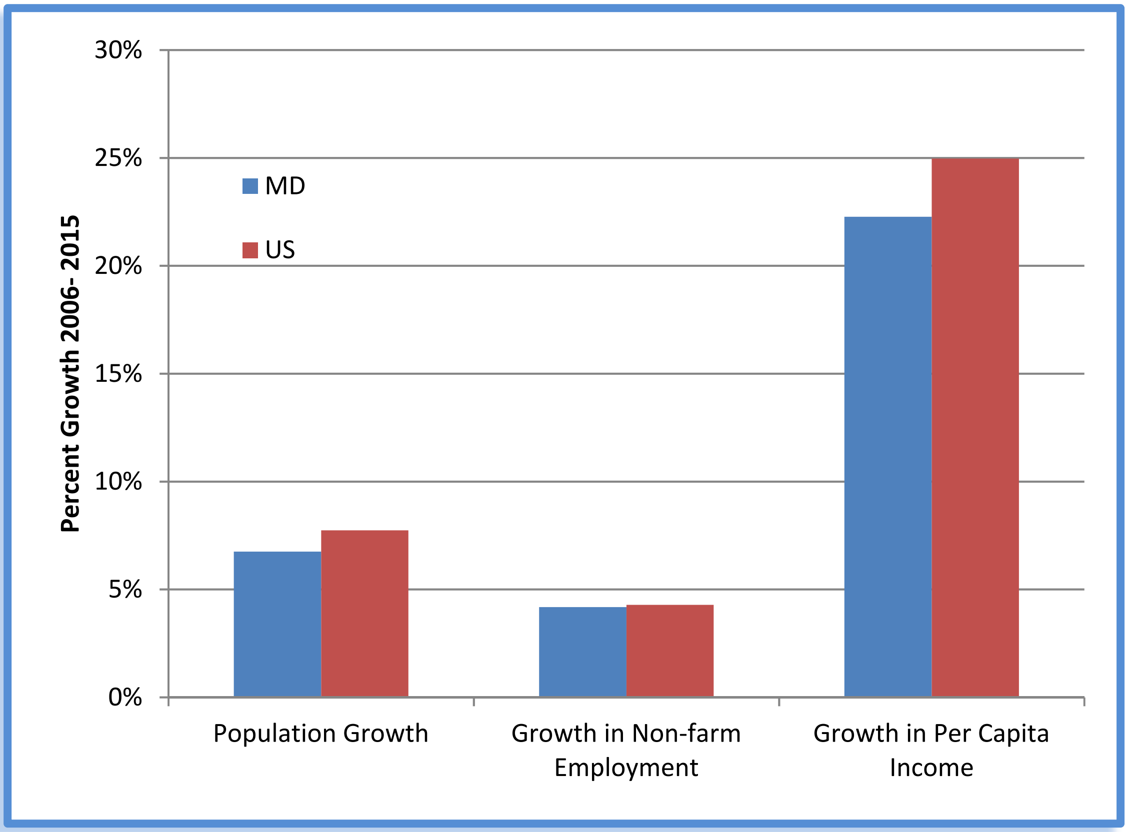



## 2.5 Maryland Electricity Consumption

Maryland end-use customers consumed about 62 million MWh of electricity during 2015. Between 2006 and 2015, the annual average growth rate in electricity consumption in Maryland was lower than in the U.S. as a whole—negative 0.97 percent in Maryland versus 0.23 percent in the U.S. Figure 2-17 compares some of the key factors contributing to growth in electricity demand in Maryland and the U.S. from 2006 through 2015. Maryland's population growth accelerated between 2007 and 2010, but slowed significantly between 2010 and 2015, as depicted in Figure 2-18. The decline in electricity consumption is also affected by the slower growth in per capita income despite increased growth in non-farm employment during the same time period. In general, slower population and per capita income growth will negatively affect electricity use, other factors held constant.

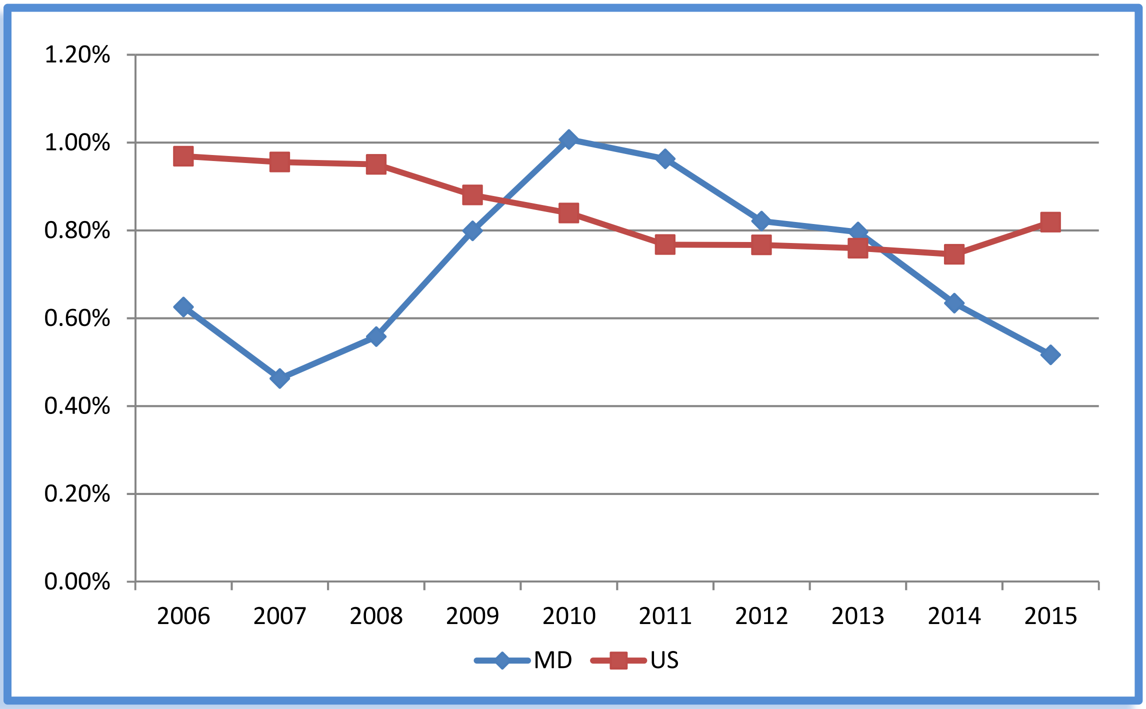
The shares of electricity consumption in Maryland used by residential and commercial sectors exceeded the consumption levels of the United States as a whole (see Figure 2-19). Conversely, the industrial sector's electricity use in Maryland is significantly lower than the rest of the country—26 percent for the nation as a whole (958 million MWh). In 2006, the industrial sector accounted for 10 percent, or 6 million MWh, of Maryland's energy consumption; comparatively, in 2015, the industrial sector consumed approximately 3.8 million MWh, or 36 percent less electricity than in 2006.

*Figure 2-17 Comparison of U.S. and Maryland Growth Factors Affecting Electricity Consumption (2006-2015)*



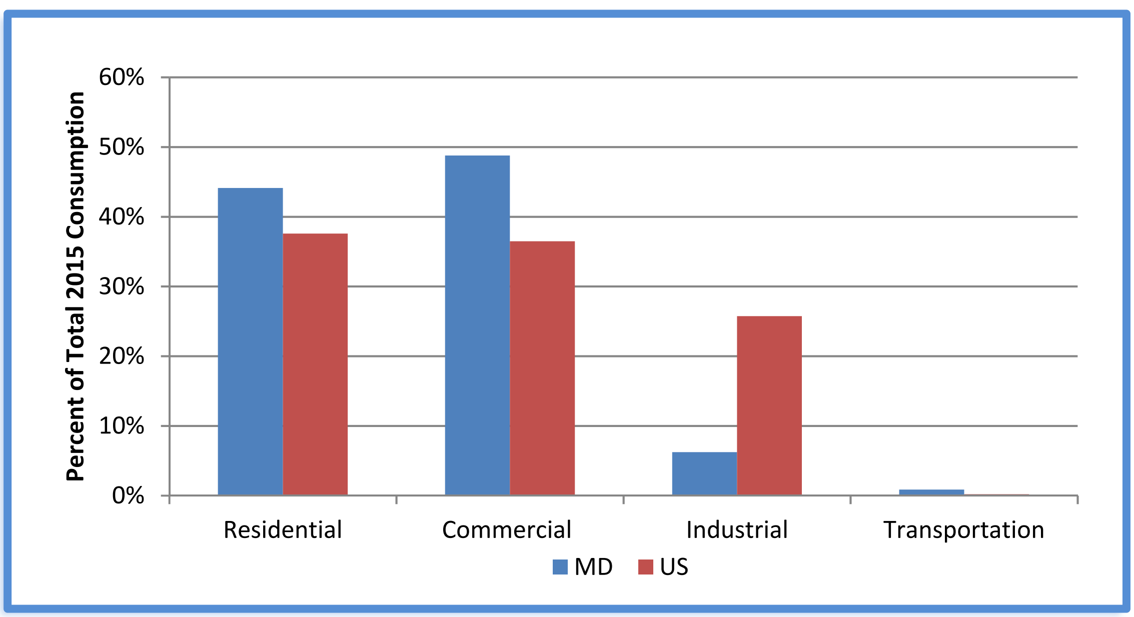

Source: Bureau of Economic Analysis Regional Data; Bureau of Labor Statistics.

*Figure 2-18 Population Growth Trends in Maryland and the U.S. (2006-2015)*




Source: Bureau of Economic Analysis Regional Data, SA1 Population.

*Figure 2-19 Electricity Consumption by Customer Class for 2015*




Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annually."

## 2.5.1 Maryland Electricity Consumption Forecast

The economic recession that began in 2008 resulted in a downward trend for electricity consumption in Maryland. While Maryland was not as seriously affected by the recession as many other states, it was not immune to the higher unemployment levels and lower levels of economic activity generally. Electricity sales in 2009 were about 1 percent below 2008 levels, largely explained by the recession-induced declines in economic activity. As the economy began to recover in 2010, electricity consumption also increased in Maryland by 4.4 percent compared to 2009. However, since 2010, electricity consumption has fallen. This decline is largely due to the impact of the EmPOWER Maryland legislation. This law targeted a 15 percent reduction in per capita electricity consumption by 2015 from 2007 levels. For more information about EmPOWER Maryland, refer to Section 5.1.2. Table 2-9 compares the average change in electricity consumption by sector for both the United States and Maryland from 2013 through 2015. Recent reductions in electricity consumption in Maryland have been outpacing those in the United States across all non-residential sectors.

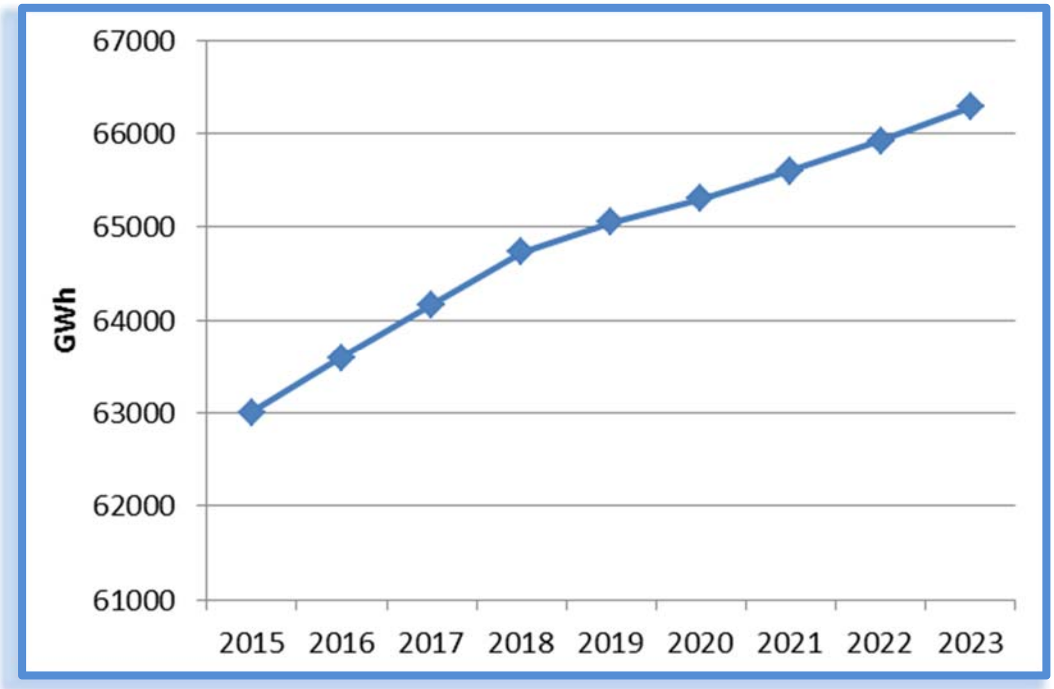
***Table 2-9 Annual Change in Retail Sales of Electricity by Sector, 2013-2015***

| | All | Residential | Commercial | Industrial | Transportation |
|---|---|---|---|---|---|
| Maryland | -0.15% | -0.40% | 0.23% | -1.22% | -0.89% |
| United States | 0.00% | 0.18% | 0.79% | -1.37% | 0.22% |

Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annually"

Figure 2-20 illustrates the most recent forecast for future electricity consumption in Maryland, as projected by the utilities serving loads in the state. The growth rate in electricity consumption in Maryland averages about 0.6 percent per year over the 10-year forecast period. By comparison, the average annual growth rate in electricity consumption in Maryland was around 2 percent during the 1990s, but less than 1 percent between 2000 and 2010. The slower growth in recent and forecasted electricity consumption compared to historical growth during the 1990s is largely attributable to increases in the real price of electricity, slower growth in population and employment, and the impacts of EmPOWER Maryland. Higher electricity prices dampen the demand for electric power in two ways. First, the existing stock of electricity-consuming equipment and appliances is used less intensively because operation is more costly. Second, the stock of electricity-consuming equipment and appliances is replaced over time with equipment and appliances that are more energy-efficient.

*Figure 2-20 Maryland Forecasted Consumption (GWh), 2015-2023*




Source: Maryland Public Service Commission 2014 Ten Year Plan

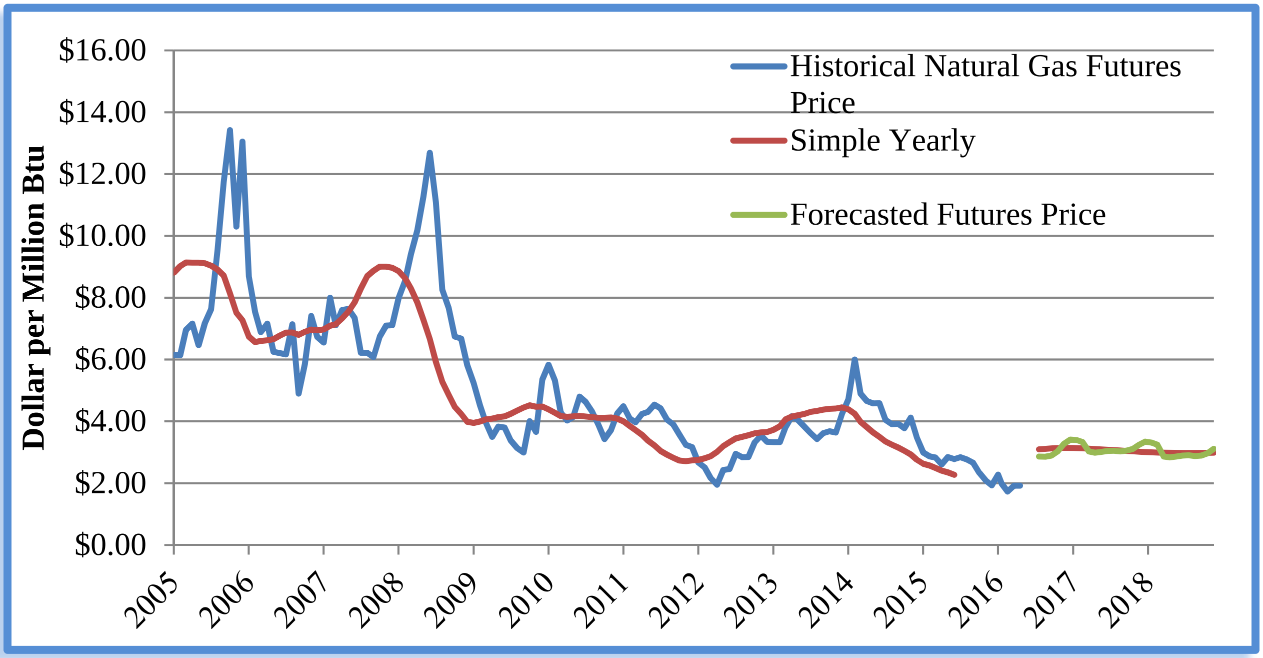
PJM produces an independent forecast of electric energy consumption, and PJM's most recent forecast covers the 15-year forecast period of 2016 through 2031. The relatively slow growth in electricity consumption in Maryland is projected by PJM to persist throughout the PJM 15-year forecast period. Over this period, consumption is expected to grow at an average annual rate of approximately 0.4 percent, which is slightly below the 0.6 percent average annual rate of growth over the 10-year period ending in 2023, as forecasted by the Maryland utilities.

Future electricity prices (and hence consumption of electricity) are affected by wholesale natural gas prices, in addition to a range of other factors. Wholesale natural gas futures contracts priced on the New York Mercantile Exchange (NYMEX) are based on the delivery price at the Henry Hub in Erath, Louisiana. Henry Hub is a major intersection of pipelines and the crossroads for a significant amount of natural gas moving to locations across the country. Wholesale natural gas is priced and traded at over 30 hubs throughout the country where major pipelines intersect. The difference between the Henry Hub price and another hub is based on supply and demand at that particular point.

As shown in Figure 2-21, natural gas prices between 2005 and 2008 peaked near $13 per million British thermal units (MMBtu). In late 2008, natural gas prices began to drop. By mid-2009, wholesale natural gas prices were below $4.00 per MMBtu, compared with prices in mid-2008. Abundant natural gas supplies resulting from shale gas and an abnormally warm winter allowed wholesale prices to drop below $2.00 per MMBtu in 2012. Prices recovered in 2013, averaging between $3.50 and $4.50 per MMBtu, as the excess supply of natural gas in the market returned closer to 5-year average levels.

However, in 2014, the Polar Vortex caused high demand and resulted in significant declines in gas storage levels which caused prices to spike to $6.00 per MMBtu (see Section 2.1.4, Demand Response, for more information on the Polar Vortex). As storage levels normalized throughout 2014, the price decreased to under $3.00 per MMBtu by 2015.

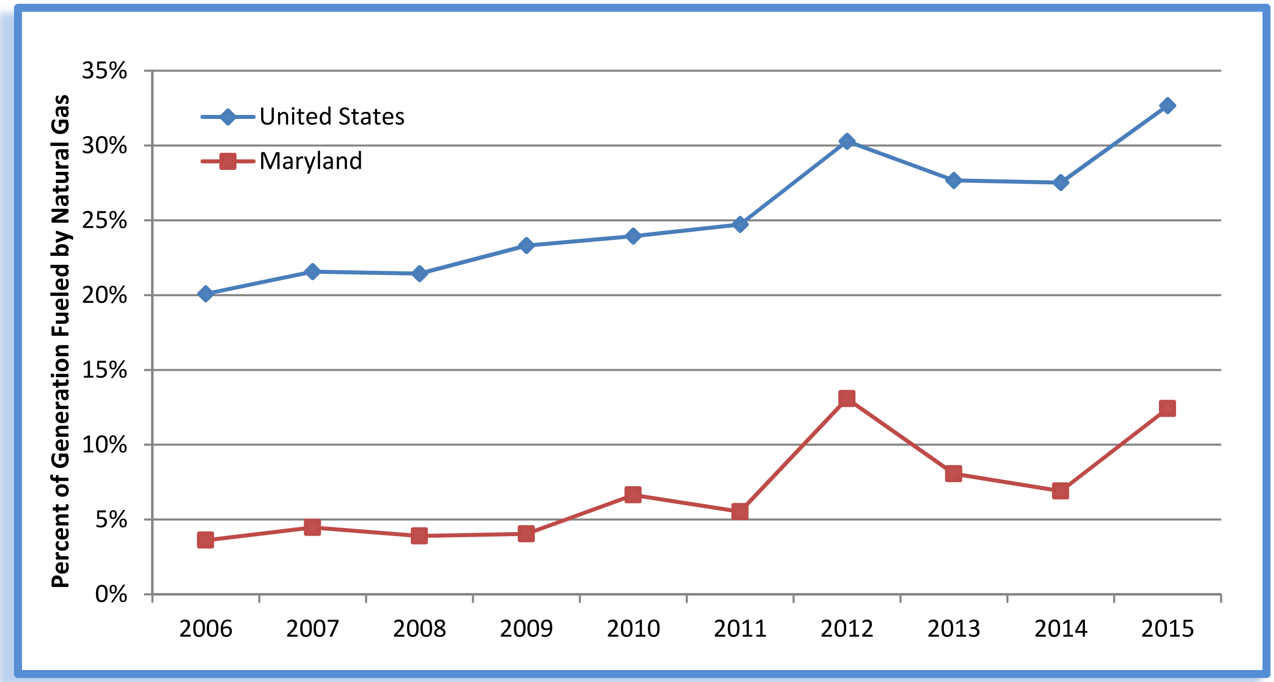
***Figure 2-21 Historical and Future NYMEX Henry Hub Natural Gas Prompt Month Futures Prices, 2005-2018***




Source: Historical prices: U.S. Energy Information Administration; futures prices: The CME Group.

As is shown in Figure 2-22, natural gas has been steadily growing as a share of fuels used for electricity generation in the United States. In 2012, the proportion of electricity generated from natural gas increased significantly in both the United States and Maryland, owing primarily to fuel switching and natural gas generating facilities operating for more hours of the year. Natural gas futures show that wholesale natural gas prices may remain below $4.00 per MMBtu through 2018 or longer due to abundant supplies of shale gas (see Figure 2-21). Therefore, since natural gas-fired facilities are often the marginal resources within the PJM Interconnection region, and therefore often set the spot market prices in PJM, electricity prices are anticipated to show only modest increases through 2018. Refer to Chapter 3 for more information on natural gas and electricity markets.

*Figure 2-22 Natural Gas Share of Fuel for Electricity Generation in Maryland, 2006-2015*




Source: U.S. Energy Information Administration, "U.S. and Maryland Natural Gas Generation Data."

In addition to economic factors and EmPOWER legislation, future electricity consumption may be affected by additional energy conservation, fuel switching, and distributed generation. For example, achievement of the 2015 EmPOWER Maryland goals resulted in much of the State's street lighting inventory being upgraded.

The Maryland DNR also published the *Long-Term Electricity Report for Maryland* (LTER) in 2011, which examines various approaches to meeting Maryland's long-term electricity needs through 2030 and provides another tool to examine future electricity consumption. The assessment considers how environmental regulation, land-use restrictions, and the transmission infrastructure affect energy and capacity costs, fuel use, fuel diversity, emissions, power plant construction and retirements, and renewable energy credit prices. The LTER Reference Case, which represented then-current regulatory and economic conditions, was developed to evaluate load levels and fuel prices based on projections assessed to be most plausible. A total of approximately 40 alternative scenarios were also assessed to evaluate potential impacts of changes in legislation, fuel prices, load growth, power plant construction, and various other factors. The LTER is a useful sensitivity analysis tool that can be used to evaluate current conditions compared to the Reference Case and how any differences may affect future electricity needs in Maryland going forward. A major update to the Reference Case, as well as alternative scenarios, is scheduled to be released in December 2016.

## 2.5.2 Generation: Comparison with Consumption

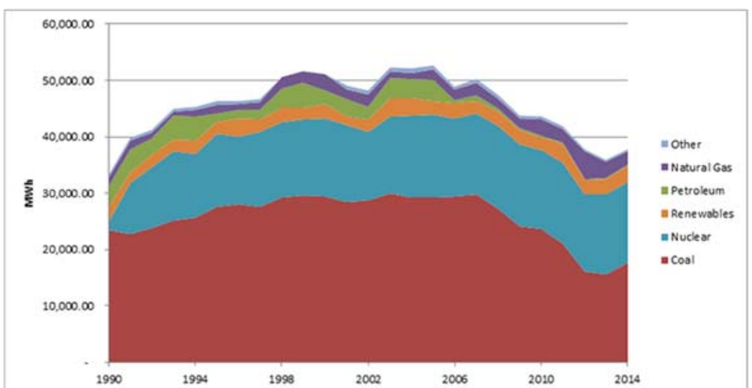
The provision of adequate levels of electric power generation for Maryland consumers does not require that the level of power generation within the State's geographic border match or exceed the State's consumption. Historically, Maryland's consumption of electricity has exceeded the amount of energy generated within the state, necessitating imports from out-of-state resources. Although there is sufficient generating capacity in Maryland to meet the State's electricity consumption needs, Maryland, as part of PJM, often relies on lower-cost generating resources from within PJM as a whole, as well as electric power that can be imported into the PJM footprint. Consequently, imbalances between Maryland consumption and generation should not be viewed as adversely affecting reliability or availability of electricity in Maryland.

With high import requirements, interregional transmission plays a much more critical role in sustaining reliable service. In addition, Maryland's high electric demand relative to in-state generation supply can produce high electricity prices when transmission limits and congestion require the use of higher-cost electricity resources located closer to load centers.

### Generation Fuel Mix Since 1990

Over the last several decades, the generation fuel mix in Maryland has shifted. The shifts in fuel mix are the results of various factors, including plant closures, economics, technology advancements, and environmental requirements. Since 1990, coal, the predominant generating fuel in Maryland, has seen its share of total generation decline relative to that of natural gas. In addition, the amount of electricity generated in Maryland has significantly declined since it peaked in 2005 with 52.6 million MWh. In 2014, Maryland generated 37.8 million MWh, a decline of approximately 28 percent compared to 2005 generation.

***Maryland Generation Fuel Mix (Thousands of MWh)***




Source: U.S. Energy Information Administration

Electricity consumption in Maryland during 2015 exceeded electricity generation in the state by approximately 44 percent. Table 2-10 compares electricity consumption and generation in Maryland over the past ten years. The largest reduction in in-state generation was from coal-fired power plants. In 2015, coal-fired power plants generated 13,923 MWh as compared to 23,668 MWh in 2010.

PJM's 2015 *Regional Transmission Expansion Plan* (RTEP) report notes that power plant deactivation requests significantly decreased in 2015 when compared to the prior three years. In 2015, PJM received deactivation requests totaling 1,626 MW, compared to the 2012-2014 deactivation requests which collectively equaled 26,480 MW. PJM noted that the 2012-2014 deactivation requests were the result of environmental regulations, competition from new generating plants fueled by Marcellus Shale natural gas, new renewable units, and market impacts from demand response and energy efficiency programs. PJM also noted that the market indicates that gas-fired generation may exceed coal-fired generation within the next several years. This is the result of an array of factors including the low price of natural gas, environmental regulations which have served to increase the cost of generation by coal plants more than generation by natural gas plants (for example, the Regional Greenhouse Gas Initiative (RGGI)), and the retirement of coal-fired generating resources in PJM over the past several years.

***Table 2-10 Total Maryland Electric Energy Consumption and Generation (thousands of MWh), 2006-2015***

| | Retail Sales (Consumption) | Sales + T&D Losses* | Generation | Net Imports | Percentage of Sales Imported |
|---|---|---|---|---|---|
| 2006 | 63,173 | 66,964 | 48,957 | 18,007 | 27% |
| 2007 | 65,391 | 69,314 | 50,198 | 19,116 | 28% |
| 2008 | 63,326 | 67,125 | 47,361 | 19,764 | 29% |
| 2009 | 62,589 | 66,344 | 43,775 | 22,570 | 34% |
| 2010 | 65,335 | 69,256 | 43,607 | 25,648 | 37% |
| 2011 | 63,600 | 67,416 | 41,818 | 25,598 | 38% |
| 2012 | 61,814 | 65,522 | 37.810 | 27,713 | 42% |
| 2013 | 61,899 | 65,613 | 35.851 | 29,763 | 45% |
| 2014 | 61,684 | 65,385 | 37.834 | 27,551 | 42% |
| 2015 | 61,709 | 65,412 | 36.390 | 29,022 | 44% |

*Assumes Transmission and Distribution (T&D) losses of 6 percent.

Source: U.S. Energy Information Administration, “Retail Sales of Electricity, Annual.”

# Chapter 3 – Markets, Regulation, and Oversight

Traditionally in the U.S., the electricity system was dominated by regulated vertically integrated utilities, each operating its local generation, transmission, and distribution system. Following deregulation of other industries, such as telecommunications and air travel, in the 1990s, some states began to examine ways to restructure the electricity industry. California was the first state to begin restructuring its electricity sector, but suspended retail electric restructuring following the 2000-2001 electricity crisis in which electricity supplies were constrained and prices increased dramatically. Though the California experience caused some states to halt restructuring efforts, 15 other states, typically states characterized by high electricity prices, continued with their restructuring plans. This has led to a national electricity system landscape in which some states continue to operate under a traditional regulated regime and others have moved toward competitive generation at the retail level. In Maryland, the Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry to functionally separate it into three distinct businesses: generation and supply, transmission, and distribution.

## *3.1 Wholesale Markets and PJM*

The costs of generation and supply of electricity are not regulated by the State of Maryland and prices are set by the competitive wholesale and retail electricity markets. The high-voltage transmission system is regulated at the federal level and operated by the regional transmission organization, PJM (see Appendix B for a map of the PJM zones and additional information on PJM). Note that the State of Maryland retains regulatory control over siting for new generation and high-voltage transmission development (i.e., over 69,000 volts) through the Certificate of Public Convenience and Necessity (CPCN) process (see Chapter 1).

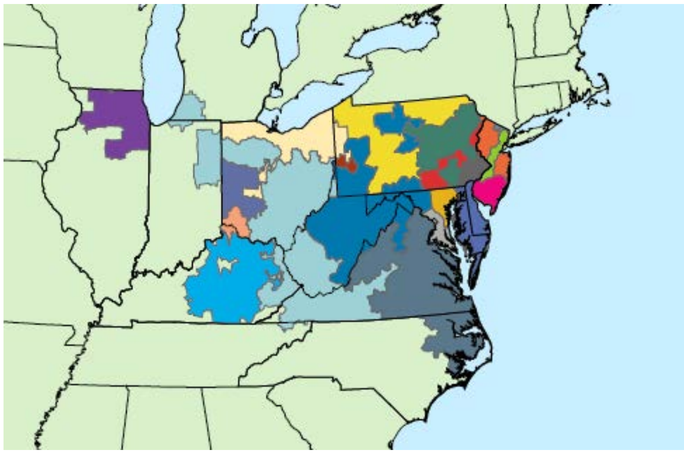
In states with restructured markets, such as Maryland, electricity is generated by a power company that is separate from the entity responsible for transporting and delivering power to end-use customers. Entities selling energy on the wholesale market include competitive suppliers and power marketers that are affiliated with utility holding companies, independent power producers not affiliated with a utility, and traditional vertically integrated utilities located within the region. Entities that purchase energy in the wholesale market to supply to end-use consumers are referred to as load serving entities (LSEs) and can be either distribution utilities or independent energy suppliers. Like many other commodities, electricity is frequently bought and re-sold several times before finally being consumed. These sales and re-sale transactions make up the wholesale market.

PJM operates and independently monitors the markets for the purchase and sale of both energy and capacity. Energy refers to the electric power that is used by customers over a given period of time and is measured in units of watt-hours. Energy costs typically include fuel and operating expenses. Capacity refers to the infrastructure and physical plant available to produce electrical power at some instant in time and is measured in watts. Costs for capacity typically include fixed and capital-related costs.

## Evolution of PJM

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM manages the high-voltage transmission grid to serve over 61 million people. PJM also operates a wholesale competitive power market that annually exceeds $42 billion in volume. PJM is the oldest, continuously operating power pool in the world.

*PJM's Service Areas*



Source: Sustainable FERC. http://sustainableferc.org/wp-content/uploads/2014/09/pjm-map.png.

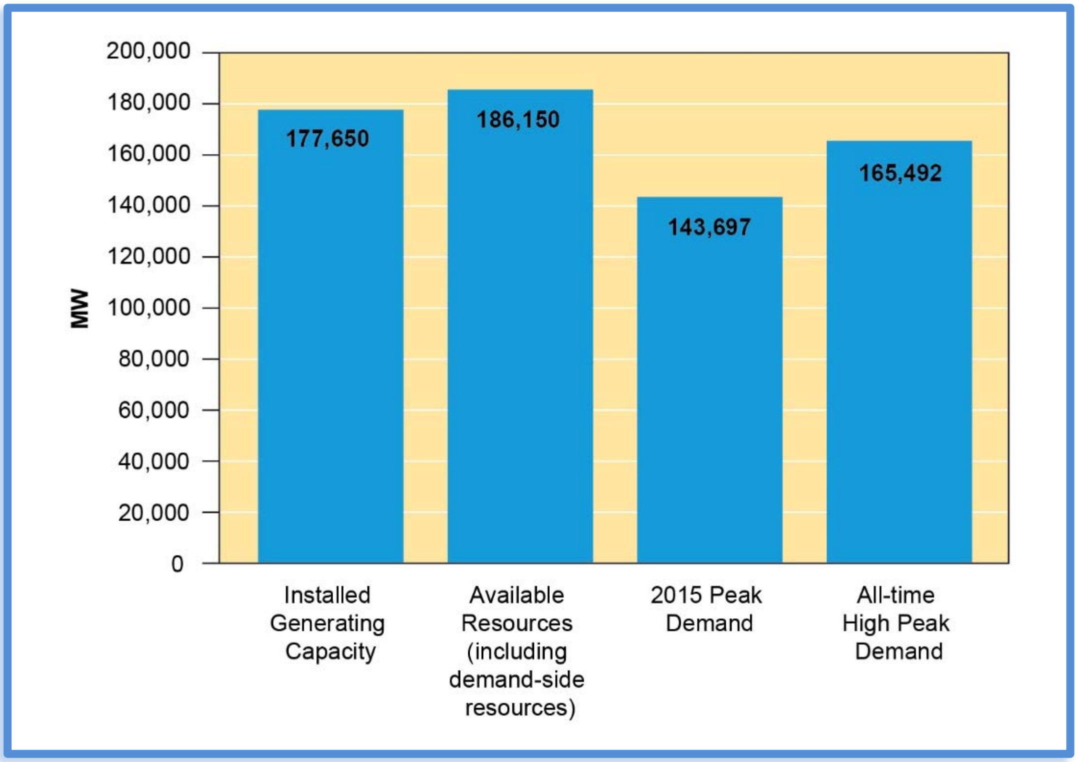
PJM began in 1927 when the Public Service Electric and Gas Company, Philadelphia Electric Company (now a subsidiary of the Exelon Corporation) and Pennsylvania Power & Light Co. formed the P.A. N.J. Interconnection power pool. The intent of the power pool was to centrally dispatch electric generating plants in the pool by cost, decreasing the generation costs for all members. The P.A.-N.J. agreement also called on member utilities to make transmission capacity available for power interchange, share load and reserves and assist each other during system emergencies. Each member utility was responsible for planning its own generation and transmission, which were reviewed by a PJM planning and engineering committee to ensure that, in combination with other member utilities, would meet PJM reliability targets. The name was changed to the Pennsylvania-New Jersey Maryland Interconnection, or PJM, in 1956 when Baltimore Gas & Electric (now a subsidiary of the Exelon Corporation) and General Public Utilities (now a part of FirstEnergy) joined.

In 1997, FERC approved PJM as the first fully functioning independent system operators (ISO), which operate but do not own transmission systems and allow non-utility users access to the transmission grid. In an effort to develop competitive wholesale power markets and operate a multi-state transmission system, FERC encouraged PJM to form a regional transmission organization (RTO). PJM became the first fully functioning RTO in 2001 and integrated a number of utilities into its system between 2002 and 2005, including: Allegheny Power (2002), Commonwealth Edison (2004), American Electric Power (2004), Dayton Power and Light (2004), Duquesne Light (2005) and Dominion (2005).

Source:
PJM, PJM Annual Report for 2015, May 2016, http://www.pjm.com/~/media/about-pjm/newsroom/annual-reports/2015-annual-report.ashx
“PJM History,” PJM Interconnection, http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx accessed May 20, 2016.

A reliable supply of energy depends upon sufficient electric generating capacity at times of high demand. States in the Northeast that have restructured their retail electricity markets rely on a combination of energy markets and capacity markets to create sufficient economic incentives for development of new generation capacity necessary to meet electricity demand. Figure 3-1 shows supply and demand in PJM in 2015.

*Figure 3-1 PJM Supply and Demand for 2015*




## 3.1.1 Wholesale Energy Pricing

PJM uses a uniform price auction based upon locational marginal prices (LMPs), which vary across PJM zones and time of day, to establish energy prices. Electricity generators bid in the amount of energy they would like to sell at a particular time and price.

PJM administers and operates two wholesale energy markets—the day-ahead market and the real-time market. As implied by the names of the markets, the day-ahead market clears a day in advance of actual usage, that is, sellers commit supplies to PJM and purchasers commit to purchase the supply based on expected loads. The real-time market is typically used as a balancing market for loads and generation in real time but can also be relied upon to meet full load requirements. Together, these markets are referred to as the “spot” energy market. In addition to the spot energy market administered and operated by PJM, there are also bilateral transactions for energy between a particular buyer and seller, with prices largely determined by the “forward” markets, where sellers offer to provide, and buyers offer to purchase, specific quantities of energy (e.g., 50 MWh) over a defined period of time (e.g., each hour of the month). Forward markets extend several years into the future.

For energy products on the day-ahead market, the PJM operator determines the sub-hourly dispatch of plants on the basis of price bids submitted by suppliers. Energy prices in PJM are based upon the bids designating a price and quantity at which a generator is willing to sell electricity. PJM stacks these bids from lowest price to highest price until it is able to satisfy the quantity required to meet energy requirements in its footprint. It is the price of the last resource called upon—the marginal price—that becomes the PJM-wide energy component of the hourly, day-ahead LMP. Energy prices may vary considerably by location due primarily to transmission congestion. The average PJM region day-ahead and real-time LMPs for 2015 are shown in Table 3-1.

### *Table 3-1 PJM Off-Peak and On-Peak Hourly Locational Marginal Prices for 2015*

| | Day Ahead | | Real Time | |
|---|---|---|---|---|
| | Off-Peak ($/MWh) | On-Peak ($/MWh) | Off-Peak ($/MWh) | On-Peak ($/MWh) |
| Average | 28.11 | 40.97 | 28.08 | 39.44 |
| Median | 24.51 | 33.69 | 23.62 | 29.95 |

Source: Monitoring Analytics, *2015 State of the Market Report for PJM*, March 10, 2016.

PJM must also account for congestion costs. Congestion occurs between two delivery points on the transmission system when the transmission grid cannot accommodate the power flows between these specific locations. When congestion occurs, higher-priced local resources are used instead of lower-cost electricity that would otherwise be used to meet load by being transported into the area via transmission lines. During periods of congestion, PJM must dispatch generation resources that are located at or near the load zone even if those resources are not the most economic resources that would otherwise be available to meet load. The cost of congestion refers to the incremental cost of dispatching these more expensive location-specific resources.

Congestion most often occurs during times of high demand, when transmission lines are reaching full capacity and certain sections become constrained. LMP differentials between PJM regions (see Table 3-2) have been mainly due to congestion between the western region, where abundant low-cost generation is located, and the Mid-Atlantic region, where the large load centers are located. PJM estimates that in 2015, congestion added approximately $8.69/MWh to the average LMPs in the BGE zone, $5.35/MWh in the Pepco zone, and $3.38/MWh in the Delmarva Power & Light (DPL) zone based on real-time market outcomes. Congestion accounted for 18 percent, 12 percent, and 8 percent of load-weighted, average, real-time LMPs in the BGE, Pepco, and DPL zones, respectively.

***Table 3-2 Real-time Average Annual Load-weighted Locational Marginal Prices ($/MWh)***

| PJM Zone | 2014 | 2015 |
|---|---|---|
| BGE | 67.78 | 47.22 |
| Pepco | 65.61 | 43.04 |
| DPL | 65.03 | 42.27 |
| APS | 52.94 | 38.04 |
| ComEd | 42.04 | 29.85 |

Source: Monitoring Analytics, *2015 State of the Market Report for PJM*, March 10, 2016.

Congestion costs and LMPs have dropped in the last few years and the differences in LMPs between the eastern and western zones of PJM have declined. This can be attributed to low natural gas prices, continuing transmission system improvements, and to an overall reduction in peak demand resulting in fewer instances where transmission capacity constrains energy supply transfers.

The biggest contributor to LMPs is the cost of fuel to generators. With natural gas prices declining to multi-year lows, and energy demand lower than usual due to reduced economic activity and relatively mild weather, LMPs in 2015 remained at lower-than-average levels throughout the year. The factors that affect LMPs are discussed at length in Appendix B.

Historically, coal plants were the least-cost generators due to the long-term availability of low-cost coal as a fuel, as well as the economies of scale arising from the construction of large, baseload coal plants. However, over the last several years natural gas has increasingly been used in place of coal for baseload generation. Shale gas discoveries in the United States have increased natural gas supplies, which in turn have led to sharp decreases in wholesale natural gas prices. The decrease in wholesale prices has trickled down into reductions in wholesale electricity price and, subsequently, retail electricity prices. These conditions are expected to continue since natural gas supplies are plentiful and wholesale natural gas prices are expected to remain low for the next decade. As a result of lower wholesale electricity prices coupled with other factors, such as stricter environmental regulations for fossil-fuel plants and the aging of the coal fleet, some companies have opted to either retire older, less efficient coal plants or convert them to fire natural gas. PJM's Market Monitor reports that approximately 23,700 MW of coal, oil, and older natural gas plants have retired within the PJM footprint between the beginning of 2011 and the end of 2015, with another approximately 3,300 MW expected to retire by the end of 2020. PJM does not expect these retirements to result in degraded reliability since there is currently excess generating capacity in PJM.

### 3.1.2 Power Plant Construction

Prior to electricity restructuring, Maryland, like other states, would identify a need for generating capacity as part of an Integrated Resource Planning (IRP) process. Capacity was constructed, typically by vertically integrated utilities, once a need was identified and a permit to construct was issued by the PSC. The cost of building and operating the new generation capacity was included in customer rates, which were regulated by the PSC. With the adoption of electric industry restructuring in Maryland, as well as in many other states, generation is now considered competitive, and the competitive market is now relied upon to provide new generation resources to meet load requirements. Capacity is constructed by independent power producers or the competitive affiliates of the regulated electric distribution companies in response to wholesale electricity market price signals. PJM established the Reliability Pricing Model (RPM) capacity auction to provide a three-year forward market for new and existing generation capacity. The RPM has undergone multiple rounds of changes to improve the operation of the capacity market and to help ensure the availability of needed capacity to meet load requirements. See Section 2.1.4 Demand Response and Appendix B for more information on the RPM.

From the late 1990s through mid-2010s, relatively little new generation was constructed in the Mid-Atlantic region even with the implementation of the RPM capacity market. The lack of new generating capacity in the Mid-Atlantic gave rise to concerns regarding the reliability of power supply in Maryland and other nearby states. Though RPM capacity prices have remained higher in eastern PJM than in western portions of PJM, no new large generation projects were constructed in Maryland. Independent power producers and competitive affiliates proposed various generation projects, but they were mainly expansions of existing sites. Without the financial assurances that were previously available through utility ownership and rate base cost recovery, and the inability of power plant developers to secure long-term contracts for generation, it has become increasingly difficult for developers to obtain third-party financing to build new generation.

In September 2009, the PSC opened Case No. 9214 to "investigate whether it should exercise its authority to order electric utilities to enter into long-term contracts to anchor new generation or to construct, acquire, or lease, and operate, new electric generating facilities in Maryland." In September 2011, the PSC made a preliminary determination that new generation was needed to meet long-term, anticipated electricity demand in Maryland. Subsequently, the PSC directed the State's four investor-owned utilities to issue Request for Proposals for up to 1,500 MW of new, natural gas-fired generation in Maryland that will clear the RPM auction. In April 2012, the PSC issued an order accepting one of three bids for natural gas generation, a Competitive Power Ventures (CPV) bid for a 661 MW (later increased to 725 MW) combined cycle facility located in Charles County, originally slated to be operational by June 1, 2015.

Also prompted by high RPM capacity prices and no new large generation development, New Jersey conducted an auction to develop new large generating plants. New Jersey selected two companies to build new natural gas plants, with the condition that each plant must clear the RPM auction. PJM and some existing generators considered the New Jersey auction to be anti-competitive since the new, state-supported generating capacity could bid into the capacity auctions at an artificially low price (i.e., below their cost of construction), thereby lowering the RPM clearing price. In fact, with the requirement that new capacity clear the PJM capacity auction, new generation would have been bid into the auction at a price of zero. All resources clearing the auction receive the market-clearing price rather than the bid price. In May 2013, PJM received Federal Energy Regulatory Commission (FERC) approval to change the RPM rules to remove the exemption for state-sponsored projects from the Minimum Offer Price Rule (MOPR). In essence, the MOPR requires that new generating projects bid a price into the RPM equal to or greater than the capacity price that is consistent with the cost of new entry. Maryland included a similar provision requiring the winning bidder to clear the RPM auction, thereby making the CPV project subject to the MOPR. This could have potentially led to the CPV project not clearing in the RPM capacity auction, making it ineligible for RPM capacity payments and to be counted towards resource adequacy requirements for Maryland utilities.

As a result of this conflict between Maryland's and New Jersey's desire to actively promote increased generation in-state, and PJM's and existing generators' desire to maintain higher capacity prices, several lawsuits emerged. Maryland and New Jersey both challenged FERC's MOPR ruling. Additionally, several generators brought lawsuits against the Maryland PSC challenging its authority to require utilities to enter into contracts with CPV. In September 2013, the U.S. District Court for Maryland ruled that the Maryland PSC order directing the utilities to enter into contracts with CPV was unconstitutional based on the Supremacy Clause of the U.S. Constitution. (Separately, in October 2013, the Circuit Court for Baltimore County ruled that it is within the Maryland PSC's statutory authority to direct the utilities to enter into such contracts.) In November 2013, the Maryland PSC appealed the U.S. District Court's decision to the U.S. Court of Appeals for the Fourth Circuit, which upheld the earlier verdict in June 2014. The Supreme Court of the United States then agreed to hear the case. Oral arguments were presented in February 2016. Despite the legal controversy, CPV was able to clear the PJM Capacity Market auction and broke ground on the Charles County project in 2014.

On April 19, 2016, the Supreme Court upheld the lower court's decision stating in its opinion that the PSC's ruling overstepped on FERC's authority as granted by the Federal Power Act. In its opinion, the Supreme Court noted that in deregulated markets, power must be procured one of two ways: 1) through bilateral contracts where load serving entities agree to purchase power through a power purchase agreement or 2) through competitive wholesale auctions held by regional transmission operators. The contract for differences for the CPV plant would not transfer the ownership of power to the load serving entities and guaranteed the plant a contract price rather than the auction clearing price; therefore, the plant's contract does not meet either of the two power procurement methods. In an effort to not discourage states' efforts to develop new or clean generation, the Supreme Court clarified that the reason the contract for differences was invalid is that it violated the interstate wholesale rate required by FERC since it conditioned the payment of funds on the clearing the capacity market.

Separately, Old Dominion Electric Cooperative (ODEC) proposed to build a 1,000 MW natural gas power plant in Cecil County (See Section 4.2.1: Low-Flow Issues). In April 2013, ODEC asked the PSC for expedited approval of a CPCN for the project, so that it could bid into PJM's May 2014 capacity auction. ODEC expects significant increases in capacity requirements over the next few years, and stated in its application that this project would reduce its need for market purchases by about 30 percent. The project, called the Wildcat Point Generation Facility, was approved by the PSC in March 2014. It is currently under construction, and is expected to be in service by June 2017.

## *3.2 Retail Electricity Markets and Billing*

The distribution of electricity continues to be a regulated monopoly function of the local utility, and hence continues to be subject to price regulation by the Maryland PSC. The fundamental objective of the 1999 Maryland Electric Customer Choice and Competition Act (the Act) was to foster retail electric competition as a means of achieving favorable retail electricity prices for customers, stimulating an array of alternative supply products (for example, green power products and innovative rate design options), and giving customers a choice in their electric power supplier.

### 3.2.1 Maryland Retail Electric Supply

Maryland's competitive market did not develop as rapidly as envisioned when the legislation was adopted. At the beginning of 2009, ten years after the Act's enactment, only 2.8 percent of residential customers were being served by competitive suppliers. By January 2016, however, 22.3 percent of residential customers had signed with competitive suppliers. The majority of medium to large commercial and industrial customers are currently purchasing electricity from competitive suppliers (see Table 3-3).

### *Table 3-3 Percentage of Customers Served by Competitive Suppliers*

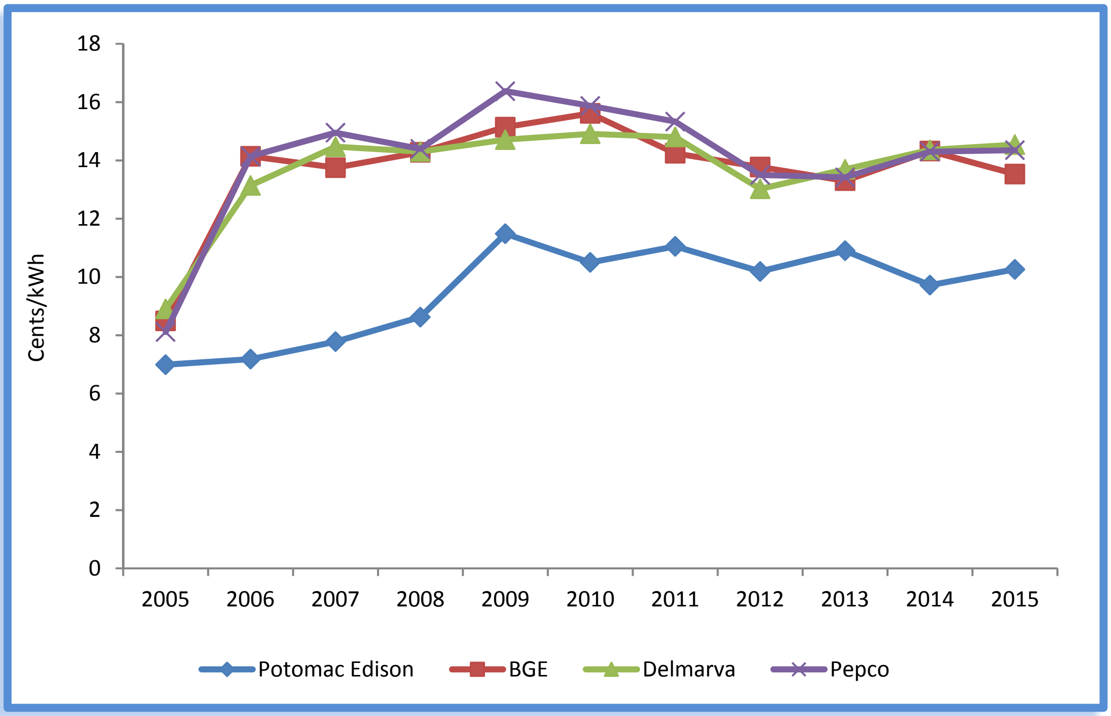
| Residential | Small Commercial & Industrial | Mid-size Commercial & Industrial | Large Commercial & Industrial |
|---|---|---|---|
| 22.30% | 33.10% | 59.90% | 92.20% |

Source: Maryland PSC, *Electric Choice Enrollment Monthly Report*, January 2016.

Residential and small commercial customers that cannot or do not choose to transact with a competitive supplier are provided with electricity service from their local utility at rates approved by the PSC. This utility-supplied service is referred to as Standard Offer Service (SOS). Maryland investor owned utilities (IOUs) procure 25 percent of the total residential SOS load every six months under two-year, fixed-price contracts with competitive wholesale suppliers.

All customers purchase electricity at prices reflecting the wholesale market, either through SOS or competitive suppliers. Wholesale market prices in Maryland rose significantly between 2005 and 2009, and as a result, residential customers saw substantial increases in their electric bills. Between 2009 and 2012, however, retail rates declined as wholesale energy prices decreased. Forward market prices have remained relatively stable since 2012. Figure 3-2 shows the average annual IOU residential rates in effect in the summer of 2005 and for each subsequent summer.

***Figure 3-2 Average Annual Retail Electricity Rates for Maryland Residential Customers, 2005-2015 (cents/kWh)***




Source: Edison Electric Institute (EEI), *Typical Bills and Average Rate Reports*

Note: Average annual rates were taken from EEI's summer editions of the *Typical Bills and Average Rates Reports*, except for BGE's 2012 rate and Potomac Edison's 2013 and 2015 rates, which were unavailable. EEI's summer editions take the average of the rates from the 12 months ending June 30 of the edition year.

## 3.2.2 Retail Electric Billing

Customers are billed for each of the three separate functions—generation, transmission, and distribution—although most customers receive just one consolidated electric bill. The PSC sets distribution rates through rate case proceedings. Generation rates are based on either SOS rates or a customers' contracted rate with a competitive supplier. Transmission rates are set by the FERC and administered by PJM. The local distribution utility is still responsible for directly billing customers with competitive generation and transmission components as direct pass-through components.

Also included in rates are several components referred to as "riders" which are used to recover costs for specific purposes or initiatives, such as energy efficiency costs under EmPOWER Maryland. These riders do not always appear on bills as separate line items but are sometimes rolled into the electric rate or charges. Riders are used to account for costs that are typically variable and can be adjusted periodically (typically quarterly, semiannually, or annually) through proceedings that are less intensive than a full rate case. Figure 3-3 shows a residential BGE bill with some details on billing components.

### *Figure 3-3 BGE Bill Detail Example*

| | | |
|---|---|---|
| **Electric Details** | Electric Choice ID: | |
| Residential - Schedule R | | |
| Billing Period: Nov 18, 2015 - Dec 17, 2015 | Days Billed: 29 | |
| Meter Read on December 17 | Meter # | |
| **Current Reading** | **Previous Reading** | **kWh Used** |
| 14112 - | 13805 = | 307 |
| **BGE Elec Supply** | 307 kWh x .0946800 | 29.07 |
| **BGE Electric Delivery Service** | | |
| Customer Charge | | 7.50 |
| EmPower MD Chg | 307 kWh x .0048100 | 1.48 |
| Distribution Chg | 307 kWh x .0359500 | 11.04 |
| RSP Chg/Misc Cr | 307 kWh x .0035100 | 1.08 |
| ERI Initiative Chg | 307 kWh x .0001700 | .05 |
| **State / Local Taxes & Surcharges** | | |
| MD Universal Svc Prog | | .36 |
| Envir Srchg | 307 kWh x .0001510 | .05 |
| Franchise Tax | 307 kWh x .0006200 | .19 |
| **Total BGE Electric Amount** | | **$50.82** |

The BGE customer profiled in Figure 3-3 is on Rate Schedule R, the standard residential service schedule. In this particular month, the customer used 307 kWh of energy and was charged a total of $50.82. The BGE electric supply rate during this billing period was $0.09468 per kWh. The electric supply rate consists of the SOS energy and capacity charges, a PJM transmission charge, and applicable taxes. The largest component of the delivery service charges is BGE's distribution charge (shown as $11.04 on this sample bill) as approved by the PSC. Delivery charges also include the fixed monthly charge and riders that compensate BGE for the cost of EmPOWER Maryland programs; a Rate Stabilization Plan that insulates BGE from either revenue shortfalls or excess revenue collections only to factors such as weather conditions; miscellaneous credits; and an Electric Reliability Initiative Surcharge used to provide funds to enhance BGE's electric distribution system. Other elements in the bill include a universal and environmental surcharge designed to pay for certain State programs, and a local franchise tax.

The largest component on the bill is the electric supply charge. For BGE, the winter 2016 SOS generation component of the supply charge was $0.08469 per kWh (this does not include taxes, fees, and PJM transmission charges that are also rolled into the total electricity supply charge). Therefore, the electric generation component makes up about $25.97 of this customer's entire bill, or 51 percent. Distribution charges comprise about 22 percent, while transmission charges only amount to about 6 percent of the total charges. The rest of the charges consist of the customer charge, riders, surcharges, and taxes (about 21 percent). As noted earlier, the utilities contract for energy supply in the wholesale market and, therefore, the electric generation price of $0.08469 per kWh is reflective of the price of energy in the PJM wholesale energy markets at the time the contracts were signed, and includes various mark-ups for the companies that provide the firm energy contracts for two years. For customers who signed with competitive suppliers, the electric supply component would be the energy charge from their supplier, which is collected by BGE and then passed through to the competitive supplier.

Figure 3-4 profiles a residential Pepco customer with a consumption pattern slightly higher than that of the aforementioned BGE customer. Note that Pepco's Residential Service rate is distinct from BGE's residential Rate Schedule R, although the rates and charges are similar. The Pepco bill example shows how PJM transmission charges and taxes are rolled into the total electricity supply charge, which is the largest component of the bill.

## Paying for Power during Storm Outages

Maryland can experience severe storms that result in power outages for electricity customers. Power outages are caused by storm-related damage to transmission or distribution infrastructure, often from downed trees or falling branches.

During a power outage, a customer is not using electricity and, therefore, the customer might expect total electricity costs to be lower. However, the Bill Stabilization Adjustment (BSA) mechanism, approved by the PSC in 2007, removes the link between electricity use and utility revenue. The BSA is an adjustment that will lower rates if a utility is receiving more revenue than the PSC has approved, and will increase rates if the utility is receiving less revenue than the PSC has approved. Prior to the BSA, the traditional rate structure created a disincentive for the utility to encourage customers to conserve energy because that would reduce revenue for the utility. The BSA was implemented to remove this disincentive. Previously, the more electricity customers used, the more revenue a utility received, but through the BSA, the level of utility revenue is independent of the level of electricity consumption.

An unintended consequence of the BSA was that it also removes a utility's incentive to restore power quickly after an outage. In January 2012, the PSC issued an order to prevent utilities from using the BSA beginning 24 hours after the commencement of a major storm and continuing until all storm-related sustained interruptions are restored.

*Figure 3-4 Pepco Bill Detail Example*

[redacted]

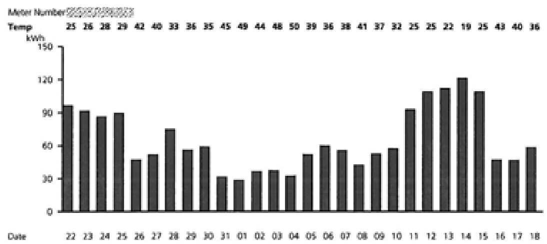
Your electric bill for the period
**January 22, 2016 to February 18, 2016**

**Account number:** [redacted]

**Supply Charges:** These charges reflect the cost of producing electricity for you. You can compare this part of your bill to offers from competitive suppliers. Supply Price Comparison Information: Standard Offer Service (SOS) electricity will cost 9.24 cents/kWh beginning on Oct 1, 2015 through May 31, 2016. The price for SOS electricity after May 31, 2016 has not yet been set. The weighted average price of SOS electricity will be 9.21 cents/kWh through May 31, 2016.

| Type of charge | How we calculate this charge | Amount($) |
|---|---|---|
| Transmission Services: | | |
| Energy Charge | 1847 kWh X $0.0075100 per kWh | 13.87 |
| Gross Receipts Tax | at 2.0408% | 0.28 |
| Generation Services: | | |
| Energy Charge | 1847 kWh X $0.0847300 per kWh | 156.50 |
| Procurement Cost Adjustment | 1847 kWh X $0.0010958- per kWh | 2.02– |
| **Total Electric Supply Charges** | | **168.63** |
| **Total Electric Charges - Residential Service** | | **265.97** |

Your daily electricity use for this bill period. Visit My Account at pepco.com to see your hourly electricity use.




**Details of your Electric Charges**

Residential Service - service number [redacted]
Electricity you used this period

| Meter Number | Energy Type | End Date | Start Date | Number Of Days | Total Use |
|---|---|---|---|---|---|
| [redacted] | Use (kWh) | Feb 18 | Jan 22 | 28 | 1847 |

Your meter records hourly use. Total use is the sum of this hourly data. Please visit My Account at pepco.com to view your energy use data.

**Your next bill period is scheduled to end on March 18, 2016**

**Delivery Charges:** These charges reflect the cost of bringing electricity to you. Current charges for 28 days, **winter rates in effect.**

| Type of charge | How we calculate this charge | Amount($) |
|---|---|---|
| Distribution Services: | | |
| Customer Charge | | 7.39 |
| Energy Charge | 1847 kWh X $0.0269750 per kWh | 49.83 |
| Grid Resiliency Charge | 1847 kWh X $0.0001400 per kWh | 0.26 |
| Franchise Tax (Delivery) | 1847 kWh X $0.0006200 per kWh | 1.15 |
| Universal Service Charge | | 0.36 |
| MD Environmental Surcharge | 1847 kWh X $0.0001470 per kWh | 0.27 |
| Empower MD Chg | 1847 kWh X $0.0087630 per kWh | 16.19 |

## 3.3 Transmission and Distribution System Planning and Reliability

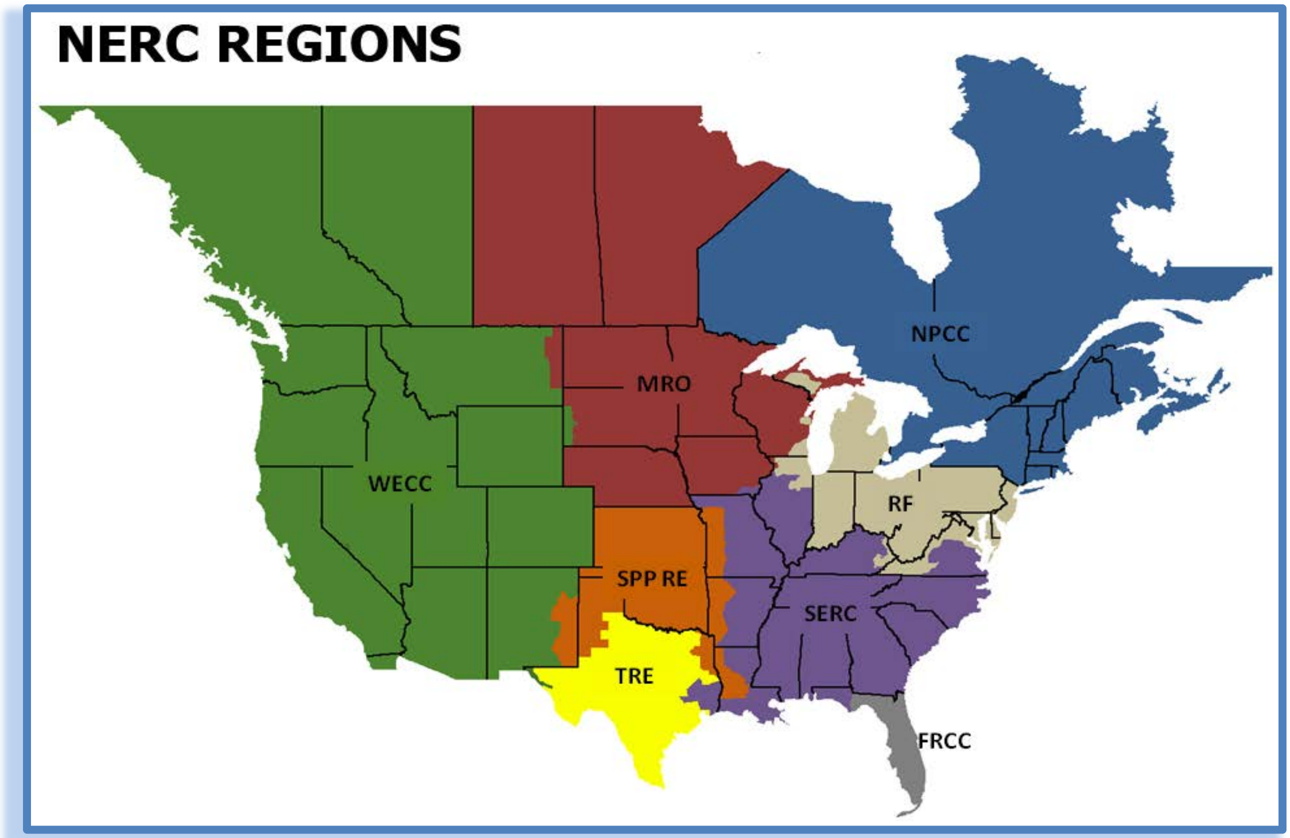
Historically, transmission infrastructure enabled utilities to locate power plants near inexpensive sources of fuel, and transmit electricity over long distances to consumers. By interconnecting different utilities' transmission systems, utilities were able to access additional sources of generation and back up each other's generating capacity, thus improving overall reliability and also reducing overall operating costs. Ultimately, the power grid grew into an interstate system subject to both federal and state regulation.

Under the federal Energy Policy Act of 1992 and FERC Order 888 issued in 1996, any generator, independent or utility-owned, may request access to the transmission grid at rates and terms comparable to those that the owner-utility would charge itself. This access to the transmission grid led to the growth of wholesale power markets. Power generators were able to use the transmission system to send power to one another as needed to serve the loads of their customers, creating larger, more regional transmission networks. With the creation of regional transmission systems and competitive wholesale markets, utilities in many areas transferred the functional control of their transmission lines to independent system operators (ISOs) or regional transmission organizations (RTOs), such as PJM, while maintaining ownership and maintenance responsibilities over their lines. Utilities retain sole control for their distribution systems.

### 3.3.1 Reliability

The North American Electric Reliability Corporation (NERC) is charged with developing and implementing reliability standards and periodically assessing the reliability of the bulk power system. NERC, which is governed by a 12-member independent board of trustees, develops mandatory reliability standards that are reviewed and ultimately approved by the FERC. The Energy Policy Act of 2005 requires electricity market participants to comply with NERC reliability standards, or be subject to fines of up to $1 million per day per violation. NERC delegates enforcement authority to eight regional reliability councils, including the ReliabilityFirst Corporation (RF) that serves the PJM RTO (see Figure 3-5).

*Figure 3-5 NERC Reliability Councils*




Source: North American Energy Reliability Corporation.

One of the NERC reliability standards applicable to PJM is the Resource Planning Reserve Requirement. This standard requires that each load serving entity (LSE) participating in PJM have sufficient resources such that there is no loss of load more than one day in ten years. In order to maintain compliance under this reliability standard, PJM conducts annual resource planning exercises to ensure all LSEs have sufficient generation resources (either owned or contracted) to supply their peak electricity load, plus a specified annual reserve margin of approximately 15 percent.

## 3.3.2 Congestion

The economic impacts of transmission congestion are described in Section 3.1.1; however, congestion may also affect reliability if a transmission line nears or exceeds its transfer limit (the physical limit of the transmission system) and there are no supplemental generation resources downstream of the constraint. If this occurs, system operators might ask large customers to voluntarily curtail their loads or, in extreme situations, may even be forced to reduce electricity deliveries to consumers. Economic congestion that results in higher electricity costs is far more common than a loss of load, or a blackout event, caused by insufficient transmission or generation resources. Economic congestion results when a transmission path is unable to provide access to the lowest cost generation to serve load requirements in particular locations. This circumstance entails more expensive generation located along an uncongested path to be used to meet load requirements. The difference in generation cost between the lowest cost (but unavailable) generation and the higher cost (but available) generation represents the congestion cost.

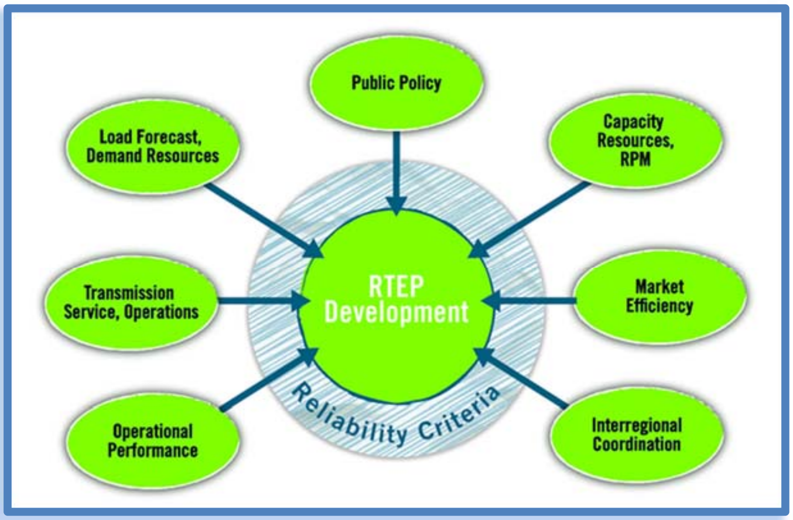
Eliminating or reducing key constraints can alleviate congestion. This may be achieved through construction of new transmission lines, building new generation within a load pocket, upgrades to existing facilities, or demand side management. PJM routinely conducts transmission planning to ensure reliability is maintained. In that regard, congestion that threatens reliability will be addressed in PJM's transmission planning process. Economic congestion, as described in Section 3.1.1, is congestion that produces localized increases in electricity prices, but does not trigger a reliability event. Economic congestion is not addressed in PJM's reliability planning since it is considered an economic decision rather than a reliability problem. However, depending on the total economic impact and benefits, PJM may suggest corrective projects as part of its economic planning process.

### 3.3.3 PJM Transmission Planning

PJM conducts annual transmission planning to forecast and address potential reliability issues. PJM's Regional Transmission Expansion Planning (RTEP) process models future load and generation, and identifies and evaluates possible new transmission projects or upgrades. PJM has authority over the transmission system and an obligation to maintain reliability. However, PJM can only put forward transmission solutions in RTEP. PJM cannot impose generation or demand response solutions, and includes in the RTEP model only those generation projects that have requested interconnection to the PJM grid and are at a relatively late stage of development. Additionally, only demand response resources that have cleared in the RPM are recognized by PJM for purposes of reliability assessment.

PJM develops a 15-year Transmission Plan that includes upgrades to help alleviate constraints identified through the modeling exercise. Once a transmission constraint is identified, PJM authorizes construction and cost recovery of transmission upgrades to address the area of concern. PJM authorization does not supersede state regulation, so a CPCN may be required depending on state siting and permitting regulations. PJM also considers market efficiency upgrades designed to relieve economic congestion by reducing overall operating and supply costs for customers. Since the 2012 RTEP planning cycle, PJM has included public policy requirements (for example, state Renewable Energy Portfolio Standard policies) when considering transmission upgrades. (See Figure 3-6 for the RTEP planning criteria.)

*Figure 3-6 PJM RTEP Transmission Planning Criteria*




Source: PJM 2015 Regional Transmission Expansion Planning.

In February 2016, PJM released the 2015 RTEP report, which outlines planned system upgrades approved by the PJM Board through December 31, 2015. The PJM Board has approved $24 billion in transmission enhancements since 1999. The 2015 RTEP contained the following high-voltage backbone transmission projects:

- Susquehanna to Roseland transmission line – this 500 kV project was placed in service in May 2015. The project runs from Pennsylvania to New Jersey.
- Cloverdale-Lexington transmission upgrade – this project is for the reconductoring of the AEP portion of the Cloverdale-Lexington 500 kV transmission line. This project connects Botetourt and Rockbridge Counties in Virginia and is expected to be completed by June 1, 2016.
- Dooms-Lexington transmission upgrade – this 500 kV rebuild project runs between Augusta and Rockbridge Counties in Virginia with an expected in-service date of October 1, 2016.
- Mount Storm-Doubs transmission upgrade – this project, an upgrade of the existing Mount Storm-Doubs 500 kV transmission line linking Pennsylvania, Virginia, and Maryland, was completed on June 1, 2015.
- Surry to Skiffes Creek transmission line – this 500 kV project for a new transmission line that crosses the James River near Williamsburg, Virginia has an anticipated in-service date of June 30, 2017.
- Loudoun-Brambleton-Goose Creek Area 500 kV Upgrades – PJM's RTEP includes two 500 kV projects in northern Virginia: a project that encompasses a rebuild of the Mosby-Brambleton-Pleasant View-Goose Creek portion of the Loudoun-Doubs 500 kV line (expected completion date is June 1, 2016); and a new, second 500 kV line from Loudoun to Brambleton (expected in-service date is June 1, 2018).
- Byron to Wayne transmission line – this 345 kV project in northern Illinois is expected to be completed in 2017.

- Mansfield to Northfield (Glen Willow) transmission line – this 345 kV project runs from Pennsylvania to Ohio. Under construction since 2013, this transmission line is past its expected in-service date of June 1, 2015. PJM does not have an updated completion date for this project.

### *Maryland RTEP Upgrades*

The 2015 PJM RTEP lists three generation interconnection-related upgrades, and four supplemental upgrades submitted by DPL (shown in Table 3-4). The cost of these transmission upgrades is expected to total $59 million. PJM RTEP only lists transmission upgrades with cost estimates greater than $5 million that were approved by the PJM Board in 2015.

***Table 3-4 Major Transmission Upgrades in Maryland Included in 2015 PJM RTEP***

| Transmission Upgrade | Date | Cost $M | Zone |
|---|---|---|---|
| Attachment facilities (Switchyard) – to be built along Pepco right-of-way. Final location to be determined by the developer. | 6/1/2016 | 20.3 | PEPCO |
| Construct underground portion of the transmission line from tower number N1085NA to the Burches Hill Substation. | 6/1/2016 | 16.2 | PEPCO |
| Install OPGW on circuit 6,727 from the Church substation to the new Y3-033 substation constructed by the Interconnection Customer pursuant to Option to Build (a distance of 15 miles). | 9/15/2015 | 5.6 | DPL |
| Build a new 230/34 kV substation (Crest substation) and loop the Cecil-Colora 230kV circuit into the new substation. | 12/31/2018 | 17.33 | DPL |
| Install four 230 kV breaker ring bus configuration at Crest substation. | 12/31/2018 | | DPL |
| Install six 34 kV breaker-breaker and half configuration at Crest substation. | 12/31/2018 | | DPL |
| Install two 230/34 kV transformers at Crest substation. | 12/31/2018 | | DPL |

Source: PJM 2015 Regional Transmission Expansion Planning.

### 3.3.4 State Distribution System and Reliability Planning

Following several incidents of storms and outages in Maryland during 2010 and 2011, the PSC initiated Rulemaking 43 (RM43) to consider revisions to State regulations in regard to electric company reliability and service quality standards, "including, but not limited to: service interruption, downed wire repair and service quality standards; vegetation management standards; annual reliability reporting; and the availability of penalties for failure to meet the standards." On April 17, 2012, the new regulations were adopted including the following:

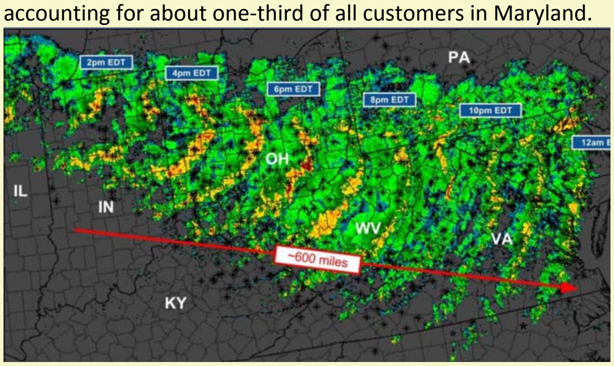
- A requirement that utilities submit a Major Outage Event Report within three weeks following the end of the event. A "major outage" is defined as an event affecting more than 10 percent of a utility's customers or 100,000 customers in total, whichever is less.
- A set of reliability standards and a requirement to collect certain related data.
- Service interruption standards that require utilities to restore service within a defined period of time.
- Downed wire standards that require utilities to respond within four hours of notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.
- A communications standard that requires utilities to answer calls within a certain period of time.
- Vegetation management standards that aim to keep power lines clear of potential hazards.
- A requirement for periodic equipment inspections.

Utilities must submit an annual report outlining their performance with respect to these regulations. In addition, the utilities are required to have a Major Outage Event Plan on file with the PSC providing a description of and procedures for its response to major events, as well as performance measures associated with the assessment of the implementation of the Major Outage Event Plan.

Being able to detect outages during storms or during normal operations has been a challenge for utilities. Historically, utilities have relied on customers to report local outages. With the advent of new technologies, being able to "see" conditions on the distribution grid in real-time is becoming a reality. Maryland utilities with PSC-approved advanced metering infrastructure (AMI) plans have either finished installing or are in the process of installing AMI in their respective service territories. While AMI allows for electronic reading of customer meter information, the communication network created by the advanced meters also serves to provide much needed information on the current status of the distribution grid. (For more information on AMI and smart grid capability, see Section 5.5.3.)

### 2012 Derecho Timeline through Radar Imagery

On June 29, 2012, a major storm system known as a derecho ("deh-REY-cho") formed and moved across Illinois through the Ohio Valley and Mid-Atlantic states, travelling roughly 600 miles in about 10 hours. During the event, the National Weather Service received over 800 preliminary thunderstorm wind reports with peak wind gusts ranging from 80-100 miles per hour. The morning after the event, electric utilities, rural electric cooperatives, and municipalities reported approximately 4.2 million customers without power across 11 states and the District of Columbia. In Maryland, the total number of customers without power reached 899,171, accounting for about one-third of all customers in Maryland.




Source: National Weather Service, https://upload.wikimedia.org/wikipedia/commons/d/d7/6-29-2012_Derecho.jpg

Damage from severe storms can be extensive and costly to repair. Some jurisdictions utilize a rider to fund storm-related repairs. In Maryland, the costs of storm repairs are included in the utility's overall revenue requirement which determines a utility's rates as approved by the PSC. In BGE's 2011 annual report submitted in its last rate case filed in July 2012, the utility noted that incidental costs associated with Hurricane Irene totaled $41.1 million. In a PSC March 2011 rate order, BGE was authorized to defer, as a regulatory asset, $15.8 million in storm costs incurred during the winter storms that took place in February 2010. These costs are being amortized over a five-year period that began in December 2010.

On December 2, 2015, the PSC adopted proposed regulations regarding the reliability and service quality standards. The proposed regulations established numerical reliability standards in terms of allowable number of outage minutes for calendar years 2016 through 2019.

## *3.4 The Role of Federal Entities*

Regulatory jurisdiction over the electricity system as a whole is shared between federal and state entities. This section describes federal authority over the generation and transmission of electricity in Maryland.

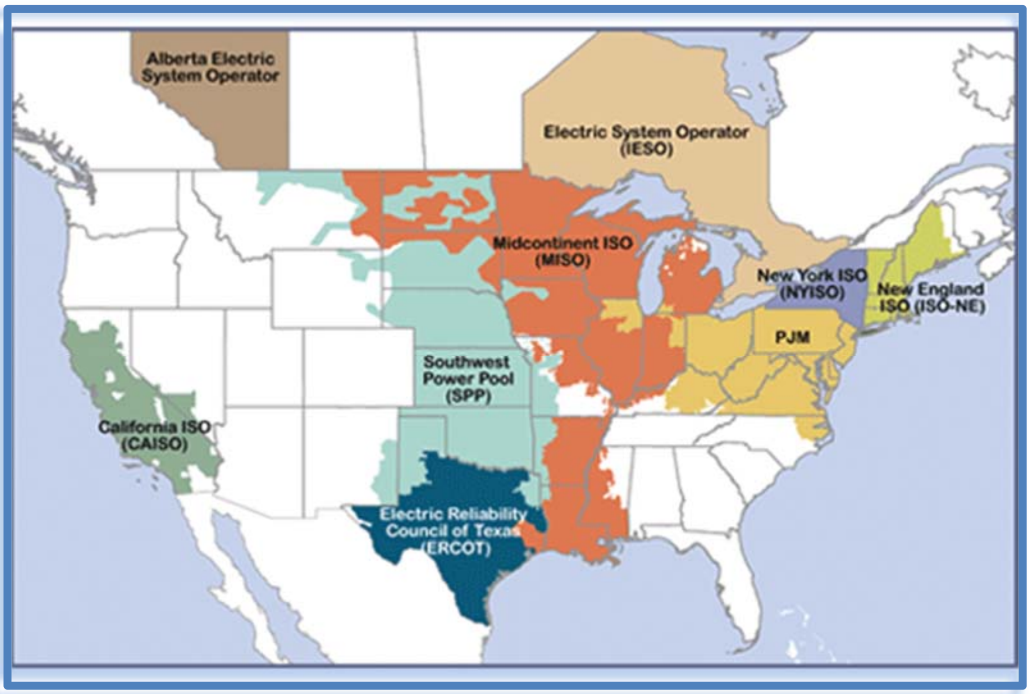
### 3.4.1 Federal Energy Regulatory Commission

The FERC is an independent regulatory arm of the U.S. Department of Energy (DOE). FERC authority derives from the Interstate Commerce Clause (Article I of the U.S. Constitution) and a large set of federal statutes, primarily the Federal Power Act, the Natural Gas Act, the Energy Policy Act of 2005, and the Interstate Commerce Act. FERC's authority specifically includes: hydroelectric projects on interstate waterways (those not otherwise regulated by other federal entities such as the U.S. Army Corps of Engineers); interstate natural gas pipelines and certain types of gas storage, transmission, and wholesale sales of electricity in interstate commerce; and import and export facilities for liquefied natural gas (LNG) (a responsibility shared with the U.S. Coast Guard). FERC also has authority over wholesale energy rates, natural gas pricing, interstate oil pipeline rates, electric reliability at a national level, and reviews of certain mergers and acquisitions by energy companies. FERC does not have authority over the following: local or otherwise non-interstate reliability; retail electricity and natural gas rates; mergers and acquisitions related to natural gas and oil companies; energy facilities; or energy issues regulated by state energy authorities (such as state public utility commissions) or regional energy authorities (such as Tennessee Valley Authority).

### *Electricity Transmission*

FERC jurisdiction over wholesale transmission applies to entities that own, control, or operate interstate transmission facilities, primarily investor-owned utilities, but could include electric cooperatives, municipal utilities, and public power agencies. In addition, FERC jurisdiction over federal agencies is limited and FERC jurisdiction does not extend to regions not engaged in interstate commerce, which includes the part of Texas under the Electric Reliability Council of Texas and the states of Alaska and Hawaii. FERC has primary jurisdiction over all U.S. ISOs and RTOs with respect to both the ISO/RTO-administered wholesale electricity markets and the ISO/RTO regional transmission planning activities (except in Electric Reliability Council of Texas). The North American ISOs and RTOs are shown in Figure 3-7.

***Figure 3-7 North American RTOs and ISOs***




### *Transmission Planning and Cost Recovery*

FERC originally issued Order No. 888 in April 1996, establishing requirements for transmission use and planning on both a local and regional level. Within this order, FERC outlined several broad planning principles for transmission providers such as PJM, but these were mainly focused on meeting reliability needs and promoting wholesale competition through establishing open access transmission service on a non-discriminatory basis to all wholesale customers. In February 2007, FERC issued Order No. 890, which strengthened the pro forma Open Access Transmission Tariff by requiring public utility transmission providers to participate in open transmission planning processes. Order 890 noted that transmission investment relative to load growth had declined in the decade following Order 888, and transmission constraints had become common occurrences. Order 890 also outlined new criteria for transmission planning. In July 2011, FERC issued Order No. 1000 to amend some of the transmission planning and cost allocation requirements established in Order 890. FERC noted that regional transmission planning processes had improved following the issuance of FERC Order 890 but some deficiencies remained. Order 1000 included several reforms with respect to transmission planning processes and cost allocation methods by FERC-jurisdictional entities, including:

- A requirement for all public (i.e., under FERC jurisdiction) transmission providers to participate in a regional transmission planning process that evaluates both transmission and non-transmission solutions and includes consideration of public policy requirements; and
- Each public utility is required through the regional planning process to coordinate with neighboring transmission planning regions and create an interregional transmission planning agreement.

Order 1000 also includes criteria that align cost allocation with transmission planning. Each public utility transmission provider is now required to have a method for allocating costs for new transmission facilities that follow principles that FERC sets out, with one set of principles for intraregional facility cost allocation within PJM and another for interregional facilities between PJM and adjacent transmission providers, such as the Midcontinent Independent System Operator (MISO). The methodology can include different cost allocation schemes for different types of projects driven by different needs; i.e., reliability, economics, and public policy goals.

PJM submitted its Order 1000 compliance plan in October 2012, outlining its proposed changes to its intraregional transmission planning process. PJM proposed to expand its current planning process to consider direct submissions by states of proposed public policies to be studied at the assumptions stage of the transmission planning process. These submissions would then form the basis for developing scenarios and ultimately could be factored into the selection of projects. PJM also proposed a new cost allocation methodology for large backbone transmission projects. Under PJM's proposal, the cost of new 500 kV or double-circuit 345 kV projects would be split evenly between the PJM system as a whole and the identified beneficiaries of the project. This method contrasts with the then-existing PJM cost allocation methodology whereby backbone transmission costs were assigned to the system as a whole, with direct beneficiaries bearing the same cost as entities receiving little if any benefit. The project costs assigned throughout PJM will be allocated *pro rata* to all LSEs based on their peak loads. The other half of project costs will be allocated to the beneficiaries of the new project as determined by PJM zonal modeling. On March 22, 2013, FERC conditionally accepted PJM's Order 1000 compliance filing, approving the new cost allocation methodology. FERC also ordered PJM to clarify its definition of "Public Policy Requirements" to include duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government.

In July 2013, PJM submitted to FERC its compliance filing for interregional transmission planning and cost allocation. Interregional planning by PJM and MISO is already provided for under their Joint Operating Agreement (JOA). The existing JOA is largely compliant with many of the requirements of Order 1000, but PJM and MISO worked with stakeholders to agree upon a number of enhancements to the JOA. However, PJM and MISO were not able to come to an agreement on the future treatment of cross-border cost allocation for reliability projects currently specified in the existing JOA, nor on the need to maintain the established reliability planning criteria in the existing JOA. Interregional planning between PJM and the New York Independent System Operator is also provided for through a JOA.

While PJM and New York Independent System Operator modified the JOA, PJM believes the enhancements only partially comply with Order 1000. Finally, PJM and the Southeast Region Transmission Planning entities filed an agreement on planning and cost allocation to meet the Order 1000 provisions. Compliance points were developed by PJM and Southeast Region Transmission Planning stakeholders, and tariff language (rather than a JOA) was filed with the FERC.

## The Eastern Interconnection

North America is comprised of two major and three minor alternating current (AC) power grids or “interconnections.” The Eastern Interconnection, one of the major grids, reaches from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida and west to the foot of the Rockies (excluding most of Texas). All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency at an average of 60Hz. The other major interconnection is the Western Interconnection. The three minor interconnections are the Québec Interconnection, Alaska Interconnection, and Texas Interconnection.


Source: http://www.powermag.com/the-odd-couple-renewables-and-transmission/?pagenum=2

Various utilities and the National Association of Regulatory Utility Commissioners have sued FERC, arguing that some of the provisions in Order 1000 are beyond FERC’s authority. In September 2013, FERC argued before the District of Columbia Circuit Court of Appeals that it does, in fact, have the authority to reform the planning of high-voltage power transmission. FERC argued that the appeals court should dismiss claims against its requirement in Order 1000 which states that FERC-jurisdictional electric transmission providers must participate in a regional planning process that takes into account state and local public policy when outlining a regional plan, and requires them to also coordinate with other adjacent providers to find better ways to boost efficiency and reliability. FERC argued that its rule did not intrude on state authority and that its public policy directive to regulate in this area is sufficiently clear.

In November 2013, the Coalition for Fair Transmission Policy along with National Association of Regulatory Utility Commissioners and various other utilities, trade associations, and public power organizations filed two reply briefs with the U.S. Court of Appeals challenging FERC’s defense of Order 1000. The first brief addressed controversial cost allocation provisions and asked that key provisions in Order 1000 be reversed. The second brief challenged FERC’s assertion that Order 1000 was simply the last in a series of evolutionary transmission restructuring orders and also addressed the effect of Order 1000 on state utility regulators. The Court heard oral arguments in March 2014 and issued a decision in August 2014 to uphold Order 1000, stating that FERC acted within its authority and that the rule was not arbitrary and capricious.

### *Hydroelectric and Liquefied Natural Gas*

Unless a project has a valid pre-1920 federal permit, non-federal hydroelectric projects are subject to FERC jurisdiction if the project:

- Is located on navigable waters of the United States;
- Occupies public lands or reservations of the United States;
- Uses surplus water or hydropower from a federal dam (such as an Army Corps of Engineers facility); and/or
- Is located on a body of water over which the U.S. Congress has Commerce Clause jurisdiction, and was constructed on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

FERC issues licenses for projects for up to 50 years and has a complex licensing procedure that incorporates interagency processes such as the U.S. Fish and Wildlife Coordination Act and local public consultation.

FERC also has authority under the Natural Gas Act to authorize the siting of facilities used to import or export liquefied natural gas, which are constructed and/or operated inside the state waters limit. State waters are generally three nautical miles from shore, but this distance varies in some areas, such as the Gulf of Mexico and Puerto Rico where this limit is nine nautical miles.

## 3.4.2 The Role of the NRC

Under federal law, the Nuclear Regulatory Commission (NRC) is responsible for regulating commercial nuclear power plants and other uses of nuclear materials, such as in nuclear medicine, through licensing, inspection, and enforcement. The NRC is charged with ensuring adequate protection of public health and safety, promoting the common defense and security, and protecting the environment. The NRC's relevance to power generation in Maryland stems from its role in overseeing the State's only nuclear power plant, Calvert Cliffs Units 1 and 2, located on the Chesapeake Bay in Calvert County. NRC staff monitor virtually every aspect of Calvert Cliffs' operations, including maintenance, security, training, and emergency response planning.

The Calvert Cliffs facility holds NRC licenses for each of the two operating units, as well as a separate license for the Independent Spent Fuel Storage Facility Installation (ISFSI) at the site. These licenses have finite periods, with the Calvert Cliffs facility receiving a license extension in 2014 through November 2052. When the NRC issues a license or a license renewal, it is required to do an environmental evaluation under the rules of the National Environmental Policy Act (NEPA). States have the option of participating in the NRC licensing process.

## 3.4.3 The Role of the EPA

In regards to generation, the U.S. Environmental Protection Agency (EPA) issues laws and regulations in regards to air, waste, and water, as well as ensure compliance with standards such as coal ash. Some of the acts and regulations enacted by the EPA include the Clean Power Plan (See Section 5.2.3), Interstate Air Pollution, National Emissions Standards for Hazardous Air Pollutants (NESHAP), the Clean Air Act (CAA), Clean Water Act (CWA), Resource Conservation and Recovery Act (RCRA), and coal ash regulations. In addition to establishing the rules, the EPA issues permits or authorizes states to issue permits related to the environmental regulations.

The CAA is a federal law that defines the responsibilities of the EPA for protecting and improving the nation's air quality and the stratospheric ozone layer. Under the CAA, EPA has developed a complex set of regulations that govern construction of new pollution sources and modifications or expansions of existing sources. Collectively, these regulations are referred to as New Source Review (NSR). There are three types of NSR permitting requirements: Prevention of Significant Deterioration permits, Nonattainment NSR permits, and minor source permits. Major NSR permits cover the construction, modification, or reconstruction of "major" stationary sources or "major" modifications of existing sources. In areas of the country where National Ambient Air Quality Standards are being met, known as "attainment areas," the NSR program is known as Prevention of Significant Deterioration (PSD). In nonattainment areas, the NSR program is referred to as Nonattainment New Source Review (NA-NSR). Construction and modification of "minor" sources are covered by "minor NSR" programs and the regulations covering these activities are established by state and local regulatory agencies. NSR permits outline what construction is authorized, emission restrictions, and how the facility must be operated.

Under Maryland law, power plants in the State are required to obtain a CPCN prior to construction of or modification to an existing facility. The CPCN serves as the air quality permit to construct the proposed project, including PSD and NA-NSR permits. For all PSD or NA-NSR permits issued by the State, the EPA is provided the opportunity to review and comment on the licensing conditions during the CPCN process. Minor NSR permits do not require review by EPA, although representatives from EPA may be consulted on issues that are new or developing.

Additionally, facility-wide Title IV Acid Rain Permits and Title V Operating Permits for power plants in Maryland are issued outside the CPCN process. These permits are processed, renewed, and submitted for public comment by the Maryland Department of the Environment (MDE). The draft permits are submitted to the EPA for review. Final permits are issued by MDE. The conditions specified in the permits are federally enforceable and compliance with certain permit conditions requires submittal to the EPA Region III.

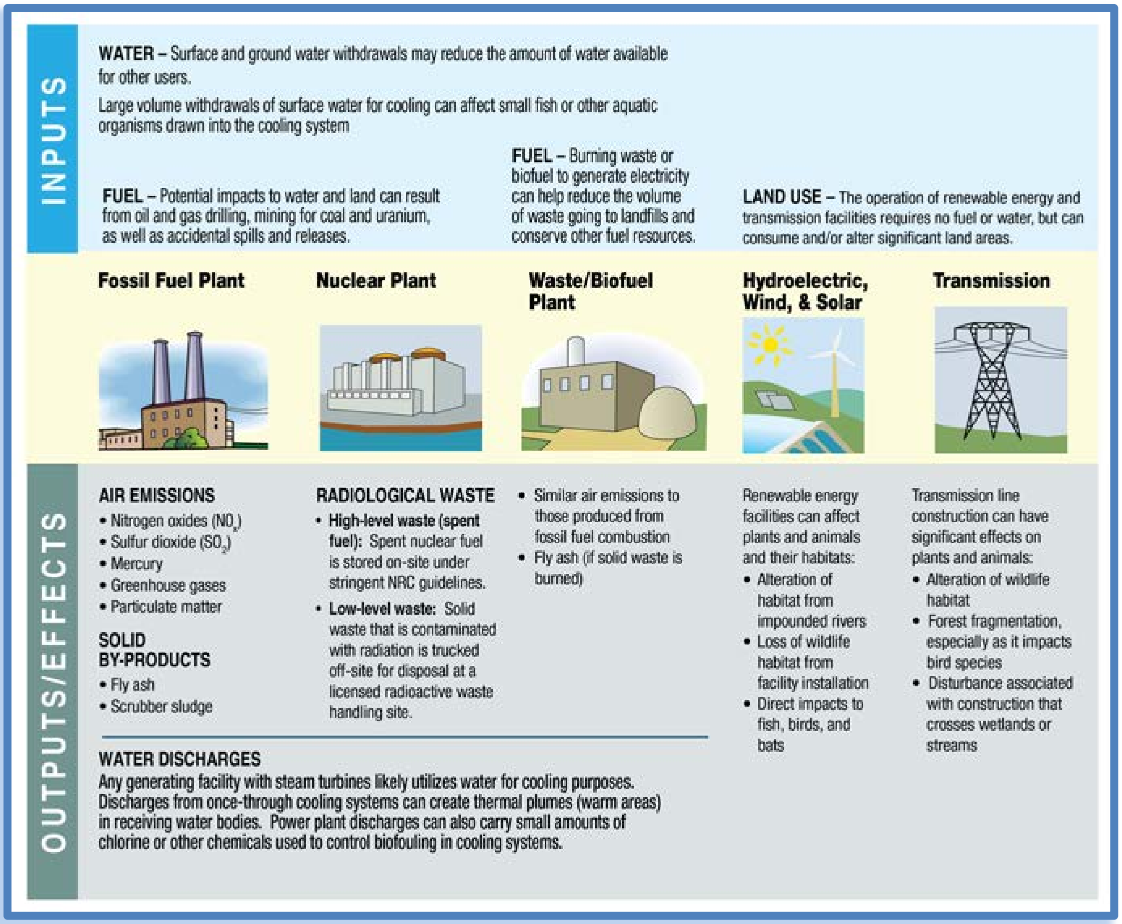
The CWA, enacted in 1948, regulates the discharge of pollutant discharge in water throughout the United States and established standards for water quality. Under the CWA, the EPA has enacted pollution control programs and standards for the electric generation industry. For example, section 316(b) of the CWA required the EPA to issue regulations regarding the design and operation of cooling water intake structures. In August 2014, the EPA finalized its National Pollutant Discharge Elimination System (NPDES) requirements, which served to reduce the adverse impact of cooling water intake systems on marine life. Each cooling water intake system must receive a state issued NPDES permit. This rule impacts electric generating units, as well as pulp and paper mills, chemical manufacturing plants, iron and steel manufacturing, and food processing.

The EPA has issued several regulations under the RCRA, a national law which regulates solid waste, regarding fossil fuel combustion (FFC) waste produced from the burning of fossil fuels. The waste can include fly ash, bottom ash, boiler slag and particles removed from flue gas. Most recently, the EPA finalized a rule for the disposal of coal combustion residuals (CCR) from electric utilities. The purpose of the rule is to establish comprehensive requirements for the safe disposal of coal ash, including addressing contamination of ground water, blowing of containments in the air, reporting requirements. The rule also supports responsible recycling of CCR.

# Chapter 4 - Impacts of Power Generation and Transmission

Abundant and reliable electricity has facilitated tremendous improvements in human health and safety as well as economic development. However, the benefits of electric power generation and transmission are accompanied by a variety of environmental and socio-economic impacts associated with the construction, operation and maintenance of these facilities.

This chapter describes each of these impact areas in some detail, and discusses PPRP's efforts to better understand the magnitude of these impacts in Maryland and how they can be managed, minimized, or mitigated. Also critical to reducing environmental impacts is controlling the amount of electrical energy we use, and the amount of fossil fuel consumed to generate that electricity. Other chapters of this report provide more information on how Maryland is promoting energy efficiency and the development of more sustainable energy sources.




Note: This figure illustrates some of the primary environmental impacts associated with electricity generation and transmission in Maryland.

## *4.1 Air Quality*

### 4.1.1 Overview

The Clean Air Act (CAA) was the first major federal environmental law in the U.S. that required the development and enforcement of regulations to protect the general public from air pollutants known to harm human health. The CAA authorized the United States Environmental Protection Agency (EPA) to develop ambient air quality standards for six common air pollutants ("criteria" pollutants). These National Ambient Air Quality Standards (NAAQS) represent the maximum pollutant concentrations that are allowable in ambient air. "Primary" NAAQS are based on health risk assessments and are designed to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly. "Secondary" NAAQS are designed to protect the public welfare by preserving visibility and preventing damage to crops, animals, vegetation, and buildings. The CAA requires EPA to review and, if appropriate, revise the NAAQS every five years. Table 4-1 lists the current NAAQS.

**Revised NAAQS**

On December 14, 2012, EPA lowered the fine particulate matter NAAQS by revising the primary annual fine particle ($PM_{2.5}$) standard to 12 micrograms per cubic meter (µg/m3) from 15 µg/m3 and retaining the 24-hour fine particle standard of 35 µg/m3. EPA also updated monitoring requirements for $PM_{2.5}$ to include a requirement for monitoring emissions near heavily traveled roads in large urban areas. By 2018, states with nonattainment areas must develop State Implementation Plans (SIPs) showing how the standards will be met. Furthermore, by 2020, states are required to meet the new air quality standards for $PM_{2.5}$ but may request an extension to 2025 depending upon the severity of $PM_{2.5}$ pollution.

In 2013, Maryland submitted a request to EPA to redesignate the Washington DC–Maryland–Virginia 1997 $PM_{2.5}$ nonattainment area to attainment. The request resulted in a revision to Maryland's attainment status leading ultimately to less restrictive major source permitting requirements.

## *Table 4-1 National Ambient Air Quality Standards as of February 2016*

| Pollutant | Primary/ Secondary | Averaging Time | Level | Form |
|---|---|---|---|---|
| Carbon Monoxide (CO) | primary | 8 hours | 9 ppm | Not to be exceeded more than once per year |
| | | 1 hours | 35 ppm | |
| Lead (Pb) | primary and secondary | Rolling 3 month period | 0.15 μg/m$^3$ [(1)] | Not to be exceeded |
| Nitrogen Dioxide($NO_2$) | primary | 1 hour | 100 ppb | 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years |
| | primary and secondary | 1 year | 53 ppb [(2)] | |
| Ozone ($O_3$) | primary and secondary | 8 hours | 0.070 ppm [(3)] | Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years |
| Particle Pollution (PM) - $PM_{2.5}$ | primary | 1 year | 12.0 μg/m$^3$ | annual mean, average over 3 years |
| | secondary | 1 year | 15.0 μg/m$^3$ | annual mean, average over 3 years |
| | primary and secondary | 24 hours | 35 μg/m$^3$ | 98th percentile, average over 3 years |
| Particle Pollution (PM) - $PM_{10}$ | primary and secondary | 24 hours | 150 μg/m$^3$ | Not to be exceeded more than once per year on average over 3 years |
| Sulfur Dioxide($SO_2$) | primary | 1 hour | 75 ppb [(4)] | 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years |
| | secondary | 3 hours | 0.5 ppm | Not to be exceeded more than once per year |

Source: "National Ambient Air Quality Standards." Reviewing National Ambient Air Quality Standards – Scientific and Technical Information. EPA, 4 March 2016 . https://www.epa.gov/criteria-air-pollutants/naaqs-table
ppm - parts per million
ppb – parts per billion
mg/m3 - milligram per cubic meter
μg/m3 - microgram per cubic meter

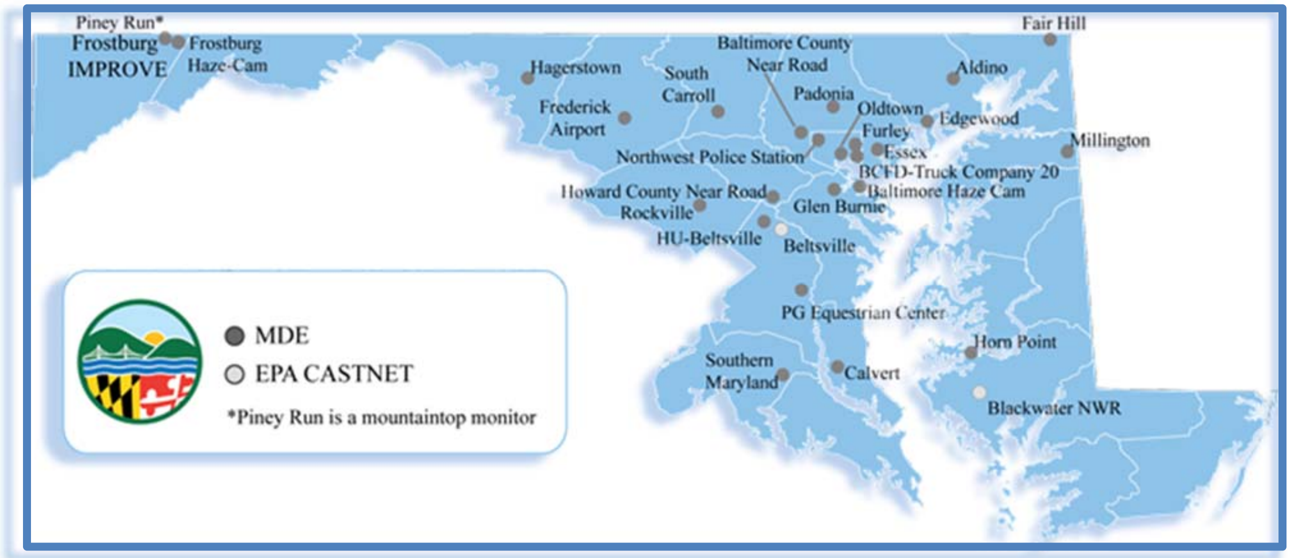
1. In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 μg/m3 as a calendar quarter average) also remain in effect.
2. The level of the annual $NO_2$ standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.
3. Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) $O_3$ standards additionally remain in effect in some areas. Revocation of the previous (2008) $O_3$ standards and transitioning to the current (2015) standards will be addressed in the implementation rule for the current standards.
4. The previous $SO_2$ standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current (2010) standards, and (2) any area for which implementation plans providing for attainment of the current (2010) standard have not been submitted and approved and which is designated nonattainment under the previous $SO_2$ standards or is not meeting the requirements of a State Implementation Plan (SIP) call under the previous $SO_2$ standards (40 CFR 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its State Implementation Plan to demonstrate attainment of the require NAAQS.

The six criteria pollutants, most of which are emitted by fossil fuel-fired power plants, are as follows:

- **Nitrogen dioxide ($NO_2$) –** a product of fossil fuel combustion. The generic nitrogen-based exhaust product from power plants and other combustion sources is termed "$NO_x$" and is primarily composed of nitric oxide (NO) and $NO_2$. $NO_x$ emitted by combustion sources is primarily in the form of NO, which is rapidly converted to $NO_2$ in the atmosphere. In the presence of sunlight and heat, $NO_2$ reacts with volatile organic compounds (VOCs) to form ground-level ozone (smog).
- **Sulfur dioxide ($SO_2$) –** a product of combustion. $SO_2$ is released when sulfur-containing fuels, such as oil and coal, are burned.
- **Particulate matter (PM) –** dust, soil, and liquid droplets that form during the combustion of fossil fuels or in the atmosphere by chemical transformation and condensation of liquid droplets. Particulate matter is defined by the size of its particles. $PM_{10}$, for example, contains particles smaller than 10 microns in diameter. $PM_{2.5}$, also referred to as "fine" particulate matter, is composed of particles smaller than 2.5 microns in diameter.
- **Carbon monoxide (CO) –** formed by incomplete combustion of carbon-based fuels during the combustion process.
- **Lead –** a metal emitted into ambient air in the form of PM.
- **Ozone ($O_3$) –** not emitted directly, but forms in lower levels of the atmosphere as "smog" when $NO_x$ and VOCs react in the presence of sunlight and elevated temperatures.

Across the country, EPA and state and local regulatory agencies monitor concentrations of the criteria pollutants near ground level. Ambient monitoring in Maryland is handled by MDE's Ambient Air Monitoring Program. The locations of ambient air monitoring stations in Maryland are shown in Figure 4-1. If monitoring indicates that the concentration of a pollutant exceeds the NAAQS in any area of the country, that area is labeled a "nonattainment area" for that pollutant, meaning that the area is not attaining the national ambient air quality standard. Conversely, any area in which the concentration of a criteria pollutant is below the NAAQS is labeled an "attainment area" for that pollutant.

***Figure 4-1 Ambient Pollutant Monitoring Stations in Maryland***



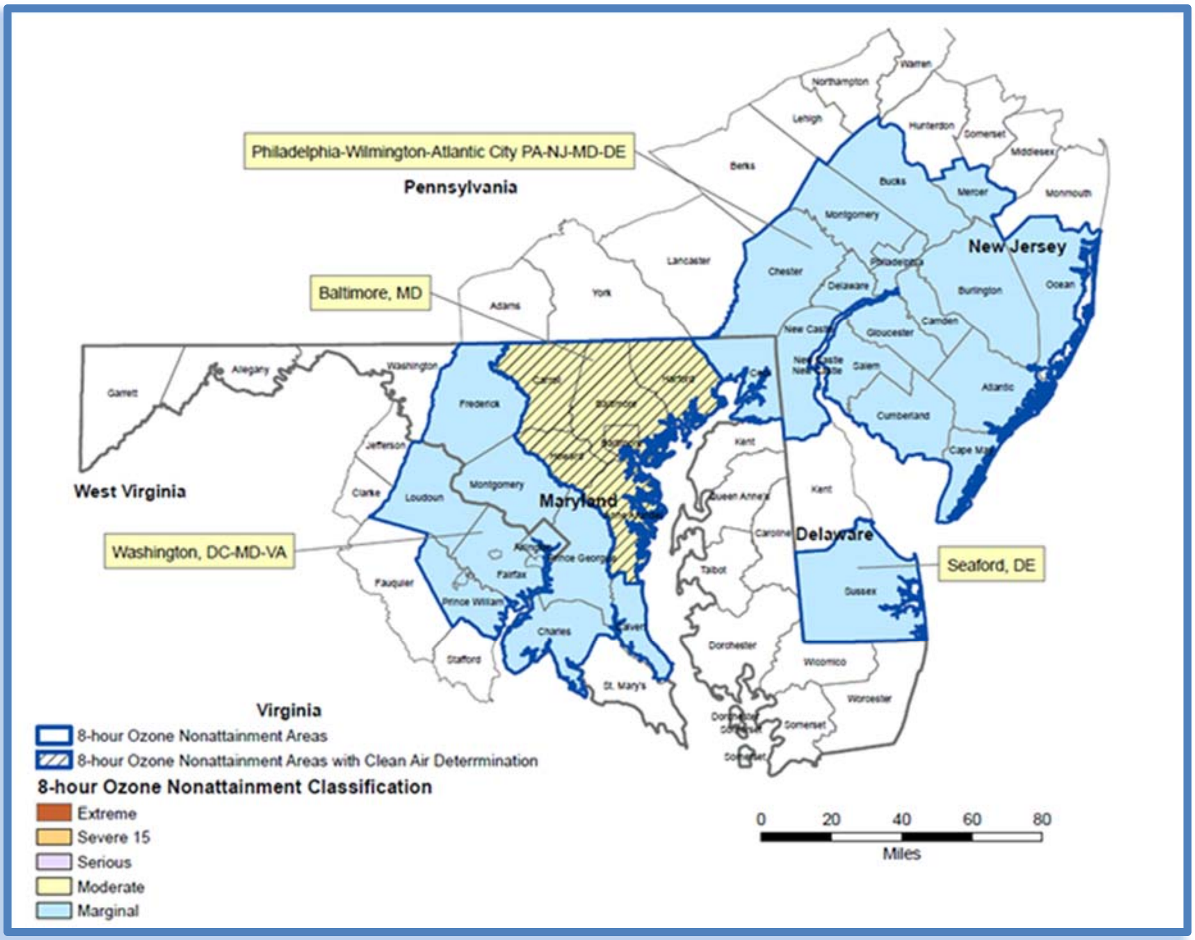

Source: http://mde.maryland.gov/programs/Air/AirQualityMonitoring/PublishingImages/MonitoringNetwork.png "Current Ambient Air Monitoring Network Map." Ambient Air Monitoring Network. MDE. Accessed 21 November 2016.

The attainment/nonattainment designation is made on a pollutant-by-pollutant basis. The air quality in an area, therefore, may be designated as attainment for some pollutants and nonattainment for other pollutants simultaneously. The designation is important because many air regulatory requirements are based in part on whether a source is located in an attainment area, where emissions must be limited to ensure the air stays in attainment with the standards, or in a nonattainment area, where emissions must be reduced to bring the area into attainment. As such, air pollution control requirements are generally more stringent for sources located in nonattainment areas.

Currently, all of Maryland is in attainment with the NAAQS for most of the criteria pollutants ($NO_2$, $PM_{2.5}$, $PM_{10}$, CO, and lead). Recently, in June 2016, EPA designated areas in Anne Arundel and Baltimore Counties as nonattainment for 2010 1 hour $SO_2$ NAAQS. This nonattainment designation was based on air quality modeling of $SO_2$ emissions from the Wagner and Brandon Shores power plants, which are located south of Baltimore in Ann Arundel County. With the June designation, Baltimore City is now identified as "unclassifiable/attainment" which is an interim designation in situations where there is insufficient data to make a final designation.

In addition to $SO_2$, much of the urbanized portions of Maryland, like most densely populated areas across the eastern U.S., are not meeting the NAAQS for ozone. Ozone is recognized as a regional rather than a local pollutant; thus in the CAA, Congress recognized that ozone pollution and its precursors can be transported from state to state. The Act created the Northeast Ozone Transport Region (OTR), comprised of 12 states (including Maryland) and the District of Columbia. As part of the OTR, the entire state of Maryland must follow nonattainment area requirements as if all areas were ozone nonattainment areas, even though ozone monitoring indicates that many counties are in attainment. Figure 4-2 depicts current 8-hour ozone nonattainment area designations in Maryland.

***Figure 4-2 Ozone Nonattainment Areas in Maryland (2008 Standard)***




Source: https://www3.epa.gov/airquality/greenbook/mddcvade8_2008.html
"Maryland/Washington D.C./Virginia/Delaware 8-hour Ozone Nonattainment Areas (2008 Standard)." EPA Greenbook. EPA, 22 February 2016. Accessed 10 February 2016 .

EPA routinely evaluates the NAAQS to determine whether more stringent or different standards are warranted. For example, EPA has lowered the standard for ozone several times, most recently in October of 2015.

While the NAAQS themselves do not directly affect stationary sources, lowering of the ambient standards means that EPA and states must eventually establish more stringent emissions limits and control technology requirements for sources such as power plants to ensure that ambient standards are met state-wide. This, in turn, likely means additional regulation at the state level of air emission sources in Maryland and throughout the United States.

## 4.1.2 Emissions from Power Plants

Power plants in the U.S. are a major source of air emissions. According to the report *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, power plants in the U.S.

contribute about 13 percent of all $NO_x$, 63 percent of $SO_2$, 38 percent of mercury, and about 61 percent of $CO_2$ emissions emitted by the industrial sector, including transportation (based on 2013, the most recently published emissions data).

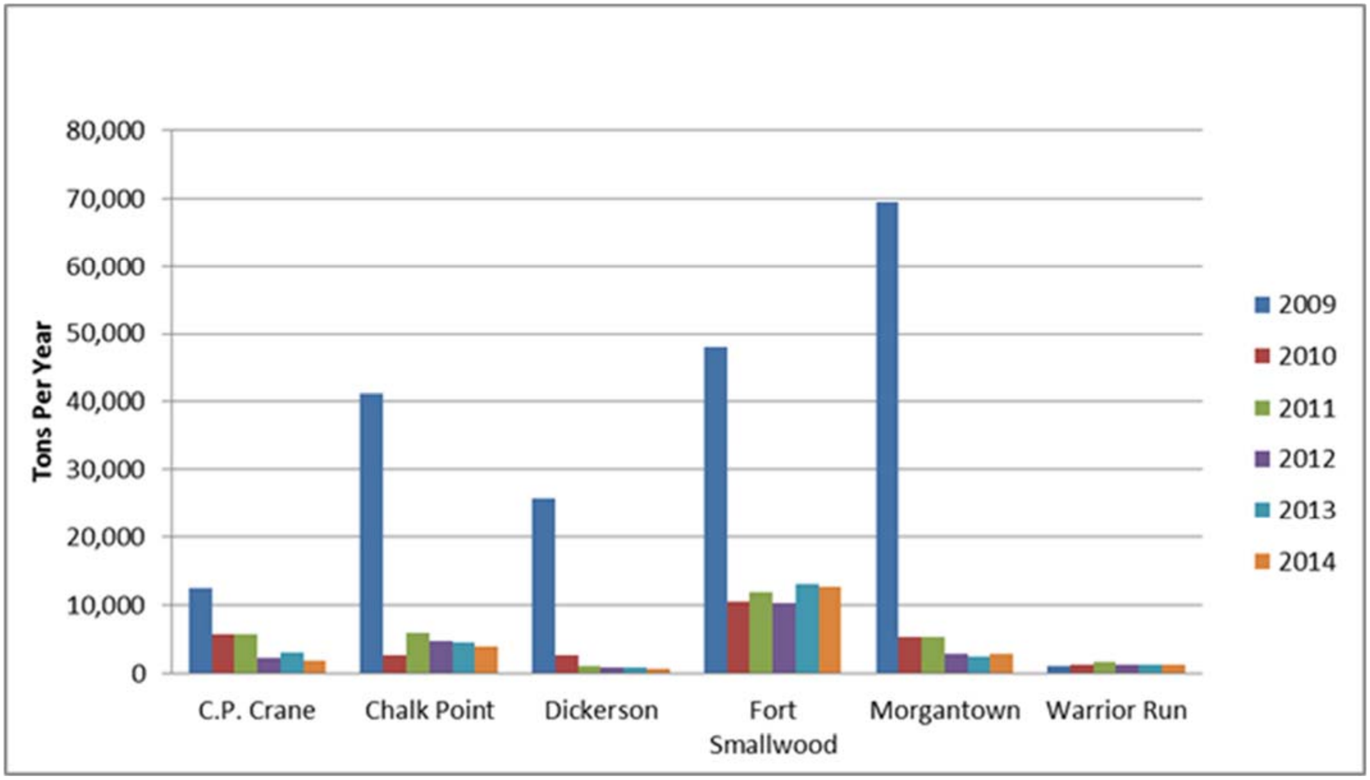
Air emissions are often discussed in terms of three classes of pollutants: criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs). This section discusses emissions of these classes of pollutants by Maryland's power plants and compares Maryland's power plant emissions to those in other states.

### *Criteria Pollutants: $SO_2$, $NO_x$, and PM Emissions*

Of the criteria pollutants, $SO_2$ and $NO_x$ are among the most stringently regulated by EPA because they are the principal pollutants that react with water vapor and other chemicals in the atmosphere to create ozone smog, cause acid precipitation, and impair visibility. Recently, there has also been an increased focus on particulate matter (PM) emissions, both particulate matter less than 10 microns ($PM_{10}$) and particulate matter less than 2.5 microns ($PM_{2.5}$), as EPA has recognized that particulates are associated with adverse health effects, including premature mortality, cardiovascular illness, and respiratory illness. EPA continually attempts to better understand which attributes of particles may cause these health effects, who may be most susceptible to their effects, how people are exposed to PM air pollution, how particles form in the atmosphere, and what sources in different regions of the country contribute to PM. This research has allowed EPA to hone its focus over time from regulating emissions of total suspended particulates to $PM_{10}$ and $PM_{2.5}$.

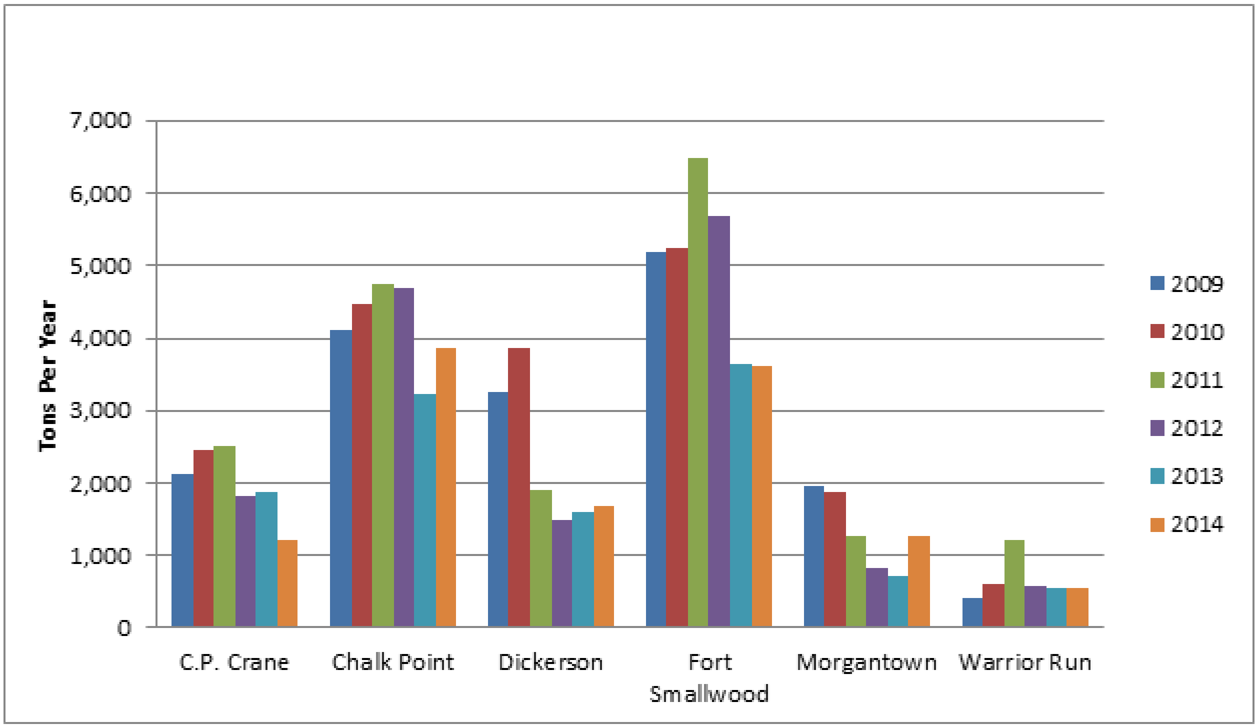
Power plants, specifically coal-fired units, are significant contributors of $SO_2$, $NO_x$, $PM_{10}$, and $PM_{2.5}$ emissions nationwide and in Maryland. Figures 4-3 and 4-4 show trends in $SO_2$ and $NO_x$ emissions, respectively, from power plants with coal-fired units in Maryland during the years 2009 to 2014. Figures 4-5 and 4-6 show trends in $PM_{10}$ and $PM_{2.5}$ during the years 2009 to 2014.

*Figure 4-3 Annual $SO_2$ Emissions from Coal-fired Power Plants in Maryland*



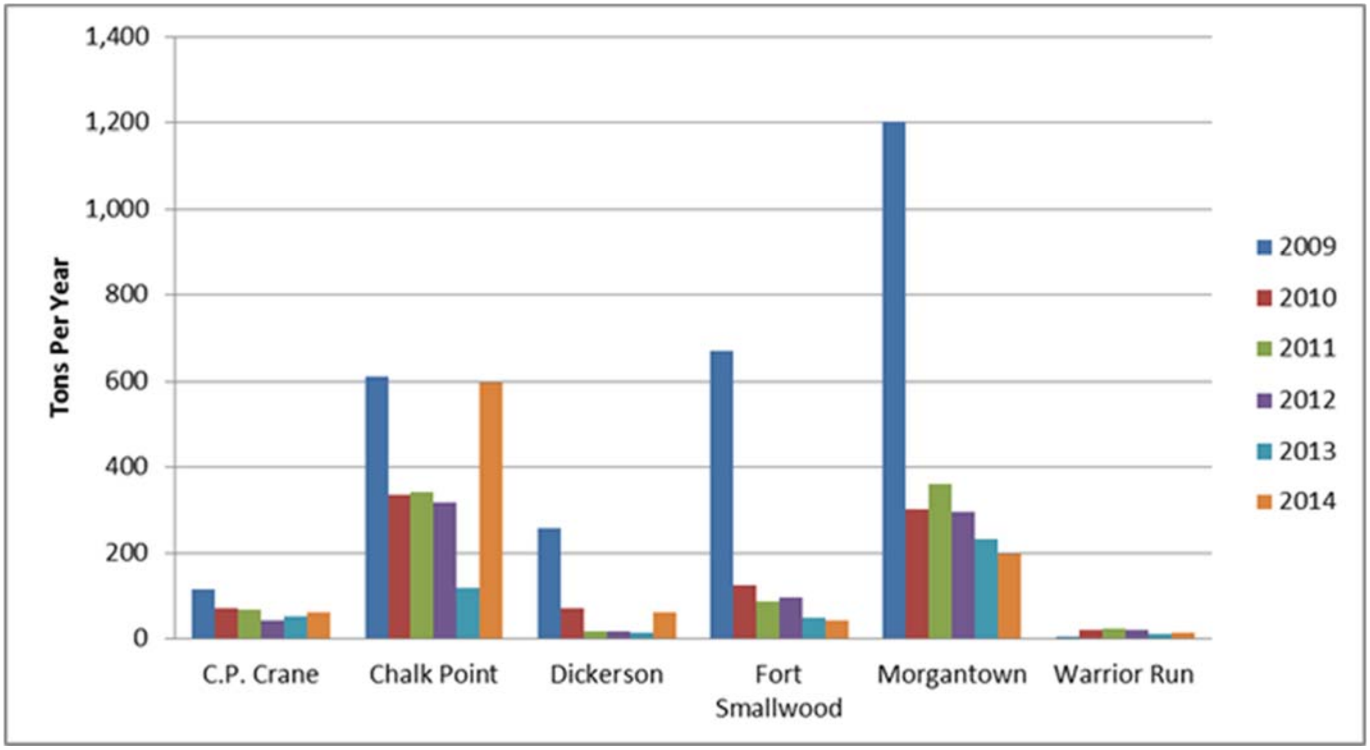

Notes: Emissions reported in Air Markets Program Data (AMPD) (https://ampd.epa.gov/ampd/)
Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

***Figure 4-4 Annual $NO_X$ Emissions from Coal-fired Power Plants in Maryland***



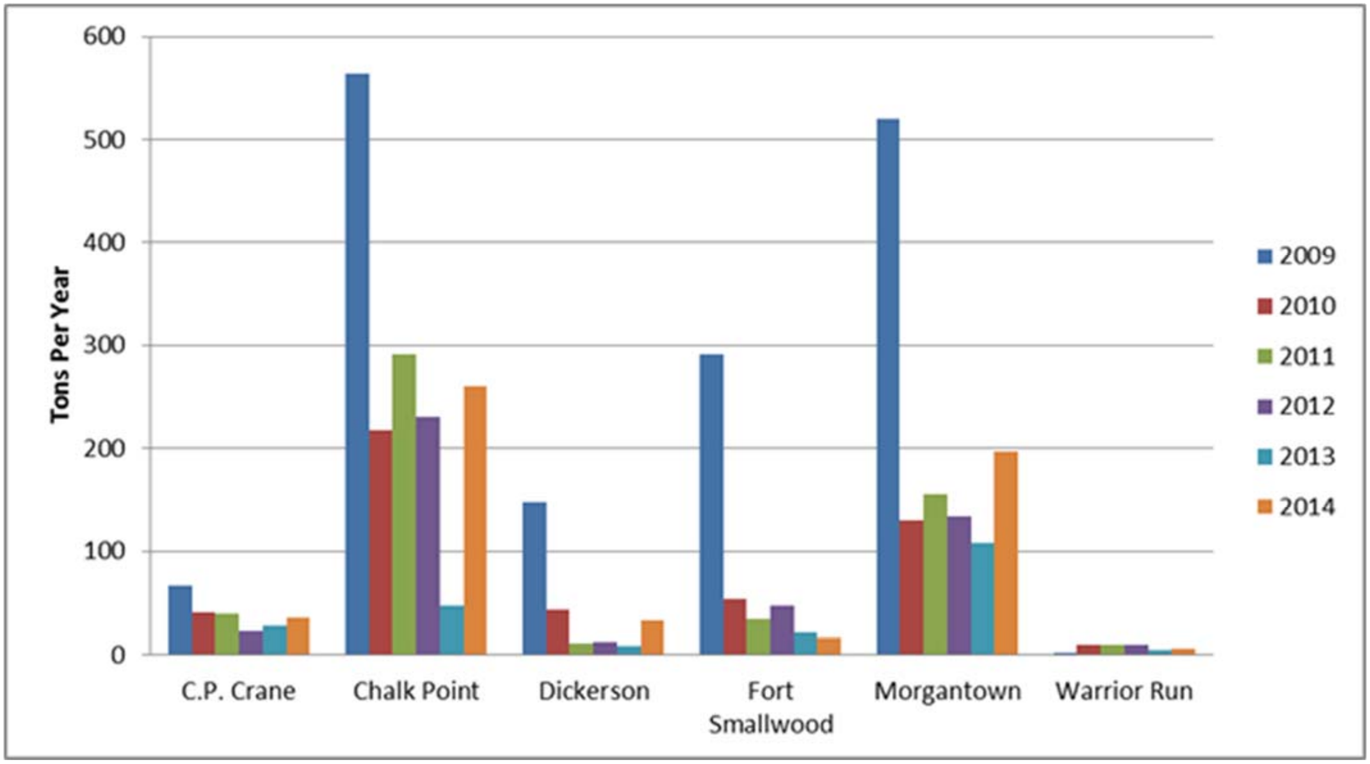

Notes: Emissions reported in AMPD (https://ampd.epa.gov/ampd/).
Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

*Figure 4-5 Annual $PM_{10}$ Emissions from Coal-fired Power Plants in Maryland*




Notes: Emissions reported in MDE Emission Summary Reports.
Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

*Figure 4-6 Annual $PM_{2.5}$ Emissions from Coal-fired Power Plants in Maryland*

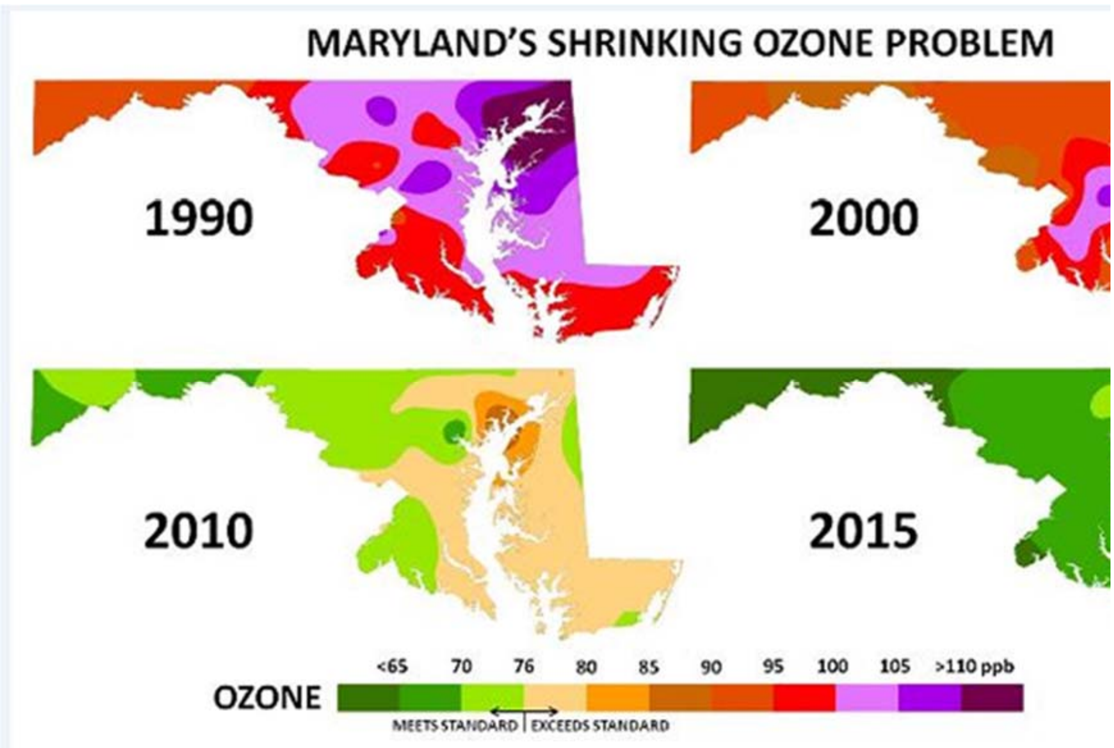



Notes: Emissions reported in MDE Emission Summary Reports.
Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

Emissions of $SO_2$, $PM_{10}$, and $PM_{2.5}$ are dependent on the types and amounts of coal combusted at specific generating units and the type, age, and configuration of any air pollution control equipment. Most coal-fired power plants in Maryland installed state-of-the-art pollution control systems to meet requirements of the Maryland Healthy Air Act (HAA). For example, wet flue gas desulfurization (FGD) scrubbers, sorbent injection systems, and fabric filters were installed at Brandon Shores in late 2009, and Wagner switched to burning lower sulfur coal in 2010. With these changes, these two co-located facilities (known collectively as "Fort Smallwood") have significantly reduced their $SO_2$ and PM emissions. C.P. Crane also switched to burning low sulfur coal in 2010, which decreased its $SO_2$ emissions. Significant $SO_2$ and PM reductions can also be seen at Morgantown, Dickerson, and Chalk Point due to the installation of FGD scrubbers at those facilities. Use of add-on control technologies, with efficient combustion and limits on sulfur content of fuels, are resulting in a decline in PM emissions since 2009. Note that some of the fluctuations in emissions seen from year to year are attributable in part to changes in fuel consumption rates caused by variations in power demand. For example, emissions from Morgantown and Chalk Point in general were reduced in 2013 likely due to a reduced load at these plants in 2013 (see Figure 4-7). The opposite effect is likely to have occurred in Morgantown in 2014. Most emissions from the facility increased in 2014 corresponding to an increased load at that time.

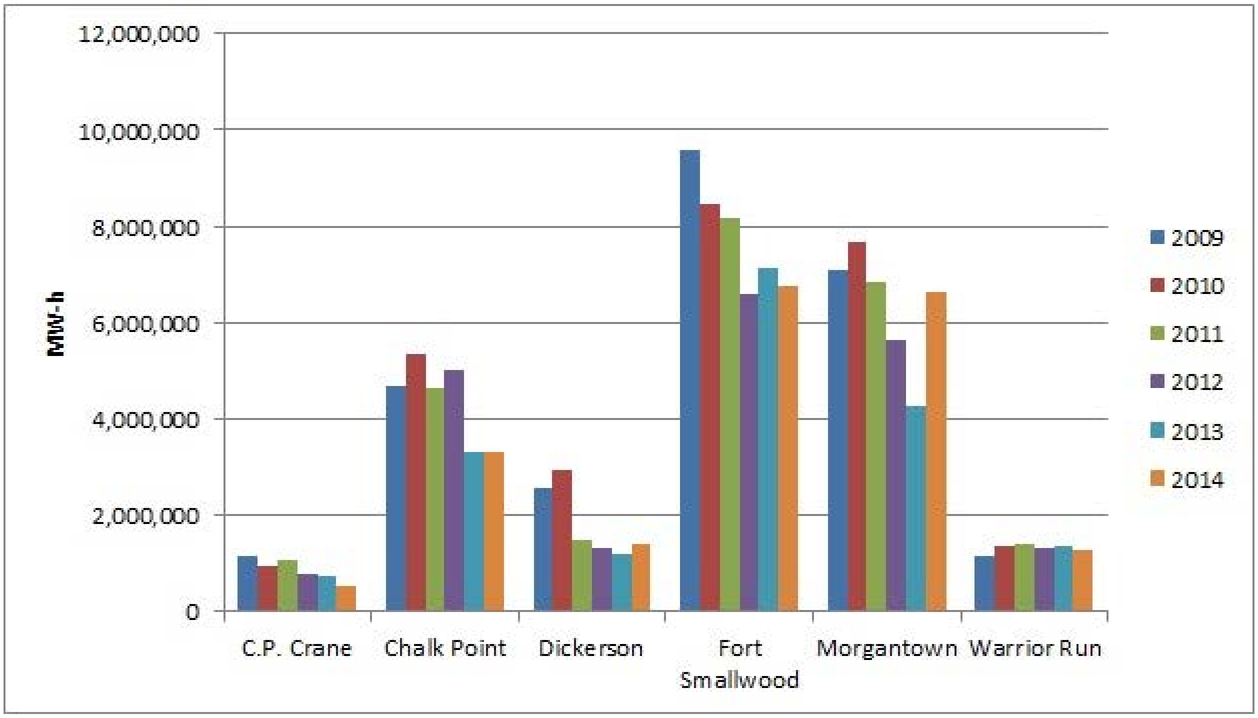
## HAA Benefits

The Maryland Healthy Air Act (HAA) adopted in 2006 is the toughest power plant emission law on the East Coast and was implemented with the objective of decreasing emissions from Maryland's coal-fired power plants, and ultimately reducing ambient air quality concentrations in the State of Maryland. Significant reductions in SO2, $NO_x$, and mercury emissions from coal-fired power plants in Maryland driven by the HAA have helped the State manage three important environmental challenges: maintaining ozone and PM2.5 concentrations at levels below ambient air quality standards, reducing acid rain and mercury deposition, and reducing harmful nutrient loading to the Chesapeake Bay. Based on the EPA's Air Markets Program Data (AMPD), emissions from the Maryland coal-fired generating facilities in 2014 reflect a reduction in SO2 emissions of approximately 91 percent, and $NO_x$ emissions of about 83 percent compared to the 2002 HAA baseline emission levels.




Source: http://www.mde.state.md.us/programs/Air/AirQualityMonitoring/Pages/HistoricalData.aspx "Historical Air Quality Data." Maryland Department of the Environment Air and Radiation. MDE. Accessed 10 March 2016.

*Figure 4-7 Coal-fired Power Plants in Maryland Gross Load*




Notes: Gross Load reported in AMPD (https://ampd.epa.gov/ampd/)
Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

Annual emissions of $NO_x$ also depend on the types and amounts of coal burned and pollution control systems in place. However, unlike $SO_2$ and PM emissions, $NO_x$ emissions have been regulated more stringently and for a longer period of time, and so there was a less remarkable decrease with implementation of the HAA. $NO_x$ emissions from power plants have been declining in previous years due to installation of control equipment and process changes. Fort Smallwood (Brandon Shores and Wagner) began year-round operation of existing state-of-the-art $NO_x$ control systems, known as selective catalytic reduction (SCR), in 2009. Previously, the $NO_x$ controls operated only during the summer "ozone season." Additionally, a selective non-catalytic reduction (SNCR) system was installed on Wagner Unit 2 in 2009. $NO_x$ emissions from C.P. Crane and Morgantown decreased prior to 2009 due to process control/process optimization software installed at Crane and SCR installed on both of the large coal-fired generating units at Morgantown. Additionally, SNCR systems were installed on C.P. Crane Unit 1 and Unit 2 and operations of the systems began in 2009. Like SOx and PM emissions, some fluctuation in emissions is seen throughout the year as a result of changes in fuel consumption. Various other factors affect facility emissions throughput the years, including the control type and usage. For example, $NO_x$ emission spikes at Fort Smallwood in 2012 were due in part to variability in operation of emission controls at Wagner. The SNCR on Unit 2 was in operation in 2012 only 28% of its potential operating time and did not operate in the ozone season at all. The spike in 2011 may also be from the limited operation of the control device.

### *Hazardous Air Pollutant Emissions*

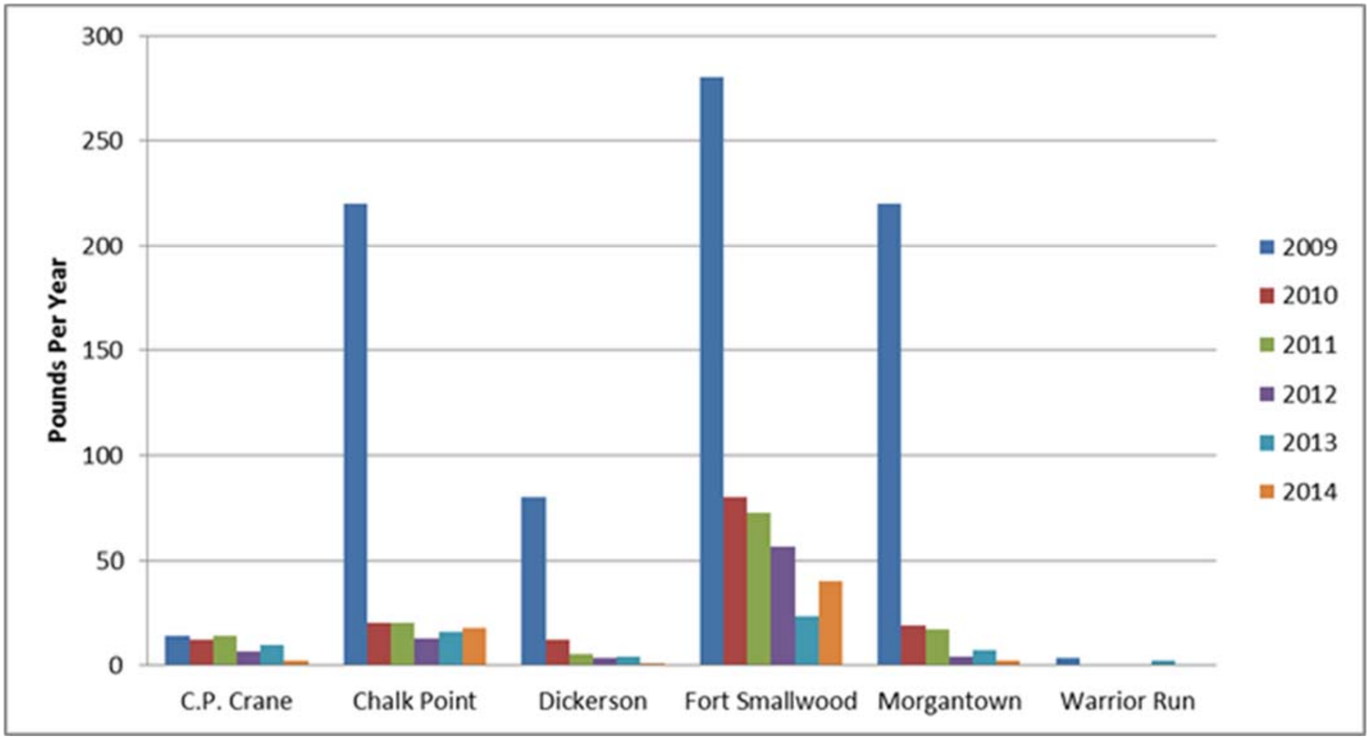
In 1990, Congress amended the CAA to regulate a class of pollutants that cause or might cause an adverse impact to health or the environment. These pollutants are referred to as hazardous air pollutants, or HAPs. There are currently 187 pollutants on EPA's list of CAA HAPs. Although some HAPs can occur naturally (such as asbestos or mercury), most HAPs originate from mobile or stationary industrial sources such as factories, refineries, and power plants.

Although fossil fuel-fired power plants emit HAPs, chemical plants and petroleum refineries that use and emit highly toxic compounds have historically been considered more significant sources of air toxics than power plants. Prior to the CAA Amendments of 1990, EPA regulations did not apply to HAP emissions from power plants and even with passage of the Amendments of 1990, power plant HAP emissions were addressed differently by Congress than those from other industrial sources. While many states, including Maryland, have developed toxic air pollutant (TAP) regulations, fuel burning sources in Maryland are exempt from TAP regulations.

Among the HAPs emitted by power plants, mercury is a pollutant of particular concern because of its significant adverse health effects. Figure 4-8 presents annual emissions of mercury from Maryland's power plants from 2009 through 2014 as reported in EPA's Toxic Release Inventory (TRI). As show in Figure 4-8, mercury emissions from Maryland's power plants dropped significantly beginning in 2010 coinciding with installation of controls in response to Maryland's HAA. Some of the smaller mercury reductions from 2009 through 2014 may be due to the type of control, the type of coal burned, and the date the controls were installed.

Another HAP of potential concern is hydrochloric acid (HCl), which can be emitted in large quantities from coal-fired plants. In response to the Maryland HAA, many of Maryland's coal-fired power plants installed FGD scrubber systems, primarily for $SO_2$ control; however, the scrubbers also reduce HCl and other acid gas emissions, and so there have been substantial declines in reported HCl emissions from Maryland's coal-fired power plants since 2009. In 2015, both Wagner and C.P. Crane facilities installed dry sorbent injection (DSI) in response to the Mercury and Air Toxics Standards (MATS) for HCl.

*Figure 4-8 Annual Mercury Emissions from Coal-fired Power Plants in Maryland*




Notes: Emissions reported in EPA's Toxics Release Inventory. Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

### *Greenhouse Gas Emissions*

A greenhouse gas (GHG) is broadly defined as any gas that absorbs infrared radiation in the atmosphere. The pollutant "GHG," as defined in federal air regulations (40 CFR Part 51.21), is the aggregate of six greenhouse gas compounds: carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$). EPA issued a Greenhouse Gas Reporting Rule and other regulations (see Section 5.2 for details) that address GHGs. The principal GHGs that enter the atmosphere due to human activities are:

- **Carbon dioxide ($CO_2$):** Carbon dioxide enters the atmosphere through the burning of fossil fuels (oil, natural gas, and coal), solid waste, trees and wood products, and also as a result of other chemical reactions (e.g., manufacture of cement).

- **Methane ($CH_4$):** Methane is emitted during the production and transport of coal, natural gas, and oil. Methane emissions also result from livestock and agricultural processes and from the decay of organic waste in municipal solid waste landfills.

- **Nitrous oxide ($N_2O$):** Nitrous oxide is emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste.

- **Fluorinated gases:** HFCs, PFCs, and $SF_6$ are synthetic, powerful GHGs that are emitted from a variety of industrial processes. Fluorinated gases are sometimes used as substitutes for ozone-depleting substances (i.e., chlorofluorocarbons (CFCs), hydrochlorofluorocarbon (HCFCs), and halons). These gases are typically emitted in smaller quantities, but because they are potent GHGs, they are sometimes referred to as High Global Warming Potential gases.

Emissions of GHGs are reported on a "carbon dioxide equivalent" ($CO_2e$) basis under EPA's GHG Reporting Rule. $CO_2e$ emissions are determined by multiplying the mass amount of emissions in tons per year (tpy), of each of the six individual greenhouse gases by each gas's "global warming potential" or GWP.

### *Global Warming Potentials*

Global warming potential (GWP) is a measurement of how "effective" individual greenhouse gases are in contributing to warming relative to the most common greenhouse gas, carbon dioxide ($CO_2$). It includes the period of time the gas remains in the atmosphere (lifetime) and its ability to absorb energy (radiative efficiency). $CO_2$, by definition, has a GWP of 1 since it is the gas used as reference. Methane is estimated to have a GWP of 28-36 over 100 years. Even though methane emissions last about a decade in the atmosphere which is less than $CO_2$, it absorbs much more energy than $CO_2$. Both the net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. $N_2O$ has a GWP of 265-298 times that of $CO_2$ because it remains in the atmosphere for over 100 years. The GWP for fluorinated gases is in the thousands or tens of thousands because they trap substantially more heat than $CO_2$. The Major Long-Lived Greenhouse Gases and Their Characteristics Table indicates the GHG average lifetime in the atmosphere and the 100-year GWP.

| Greenhouse gas | How it's produced | Average lifetime in the atmosphere | 100-year global warming potential |
|---|---|---|---|
| Carbon dioxide | Emitted primarily through the burning of fossil fuels (oil, natural gas, and coal), solid waste, and trees and wood products. Changes in land use also play a role. Deforestation and soil degradation add carbon dioxide to the atmosphere, while forest regrowth takes it out of the atmosphere. | see below* | 1 |
| Methane | Emitted during the production and transport of coal, natural gas, and oil. Methane emissions also result from livestock and agricultural practices and from the anaerobic decay of organic waste in municipal solid waste landfills. | 12 years | 28 |
| Nitrous oxide | Emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste. | 121 years | 265 |
| Fluorinated gases | A group of gases that contain fluorine, including hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, among other chemicals. These gases are emitted from a variety of industrial processes and commercial and household uses, and do not occur naturally. Sometimes used as substitutes for ozone-depleting substances such as chlorofluorocarbons (CFCs). | A few weeks to thousands of years | Varies (the highest is sulfur hexafluoride at 23,500) |

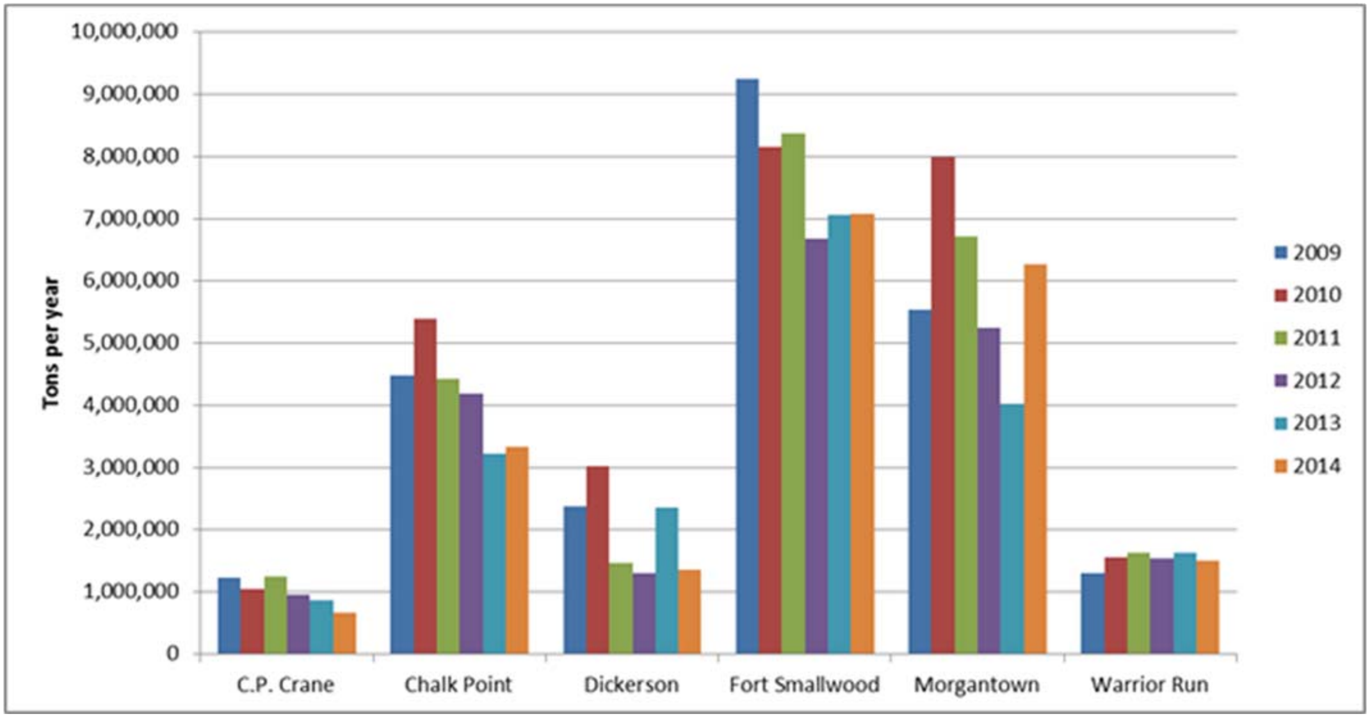
*This table shows 100-year global warming potentials, which describe the effects that occur over a period of 100 years after a particular mass of a gas is emitted. Global warming potentials and lifetimes come from the Intergovernmental Panel on Climate Change's Fifth Assessment Report.*

** Carbon dioxide's lifetime is poorly defined because the gas is not destroyed over time, but instead moves among different parts of the ocean–atmosphere–land system. Some of the excess carbon dioxide will be absorbed quickly (for example, by the ocean surface), but some will remain in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments.*

Source: https://www3.epa.gov/climatechange/science/indicators/ghg/
"Greenhouse Gases." *Climate Change Indicators in the United States.* EPA Climate Change, 24 February 2016. Accessed 16 March 2016.

Figure 4-9 presents GHG emissions from coal-fired power plants in Maryland, as reported to MDE, for the years 2009 through 2014. Similar to other regulated pollutants, fluctuations in emissions are seen throughout the years as a result of changes in fuel consumption caused by power demand.

*Figure 4-9 Annual GHG Emissions from Coal-fired Power Plants in Maryland*



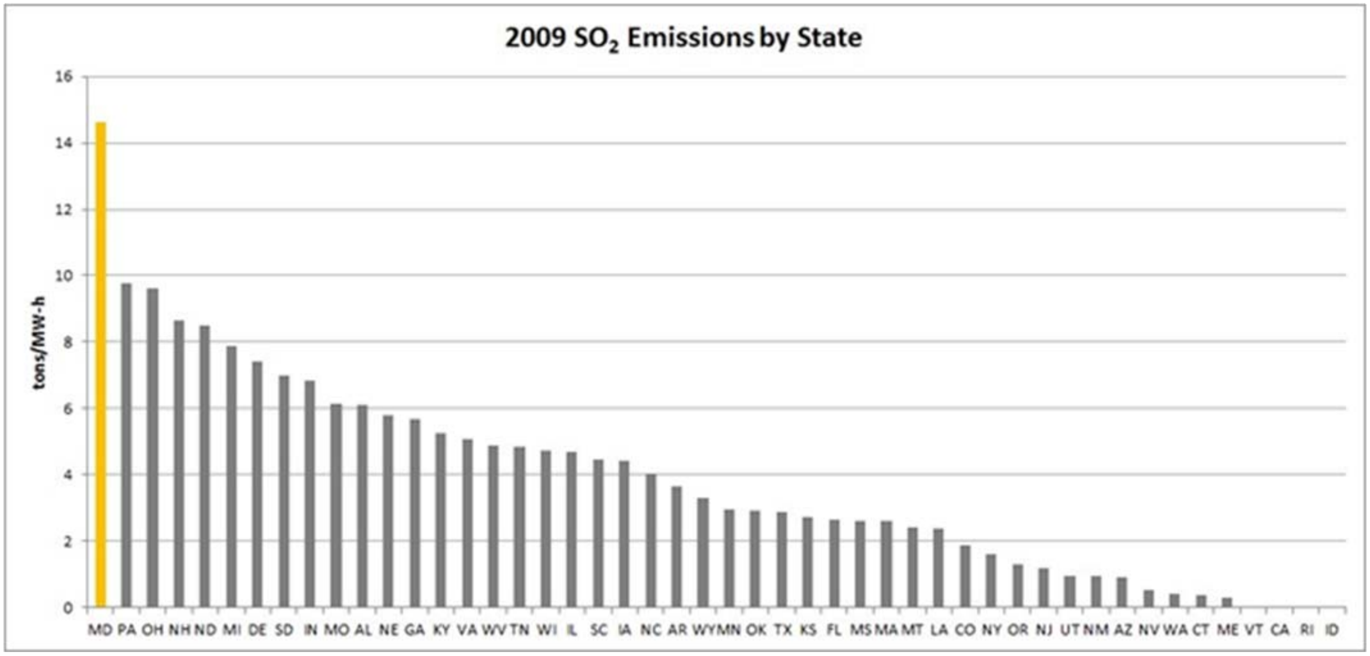

Notes: Emissions reported in MDE Emission Summary Reports.

## *Maryland Power Plant Emissions Relative to Other U.S. Power Plant Emissions*

To put Maryland's power plant emissions in perspective, Figures 4-10 through 4-13 present a comparison of $SO_2$ and $NO_x$ emissions from coal-fired power plants in Maryland in 2009 and 2014 with emissions from coal-fired power plants in other states before and after various pollution control systems were installed in Maryland facilities as a result of the HAA. These figures represent the emissions (in pounds per megawatt-hour of electricity generated) from the lower 48 states as reported in EPA's Air Markets Program Data (AMPD) for years 2009 and 2014. As seen in Figure 4-10, Maryland's power plants in 2009 were collectively among the highest $SO_2$ emitting coal-fired plants. In Figure 4-11, the $SO_2$ emissions in 2014 were in line with average emissions nationwide due to the control systems installed in Maryland's facilities as a result of the HAA. By the end of 2011, 60% of the nation's coal-fired power plants had FGD scrubbers installed to reduce $SO_2$.

As seen in Figures 4-12 and 4-13, in both 2009 and 2014, Maryland's $NO_x$ emissions were in line with average emissions nationwide due to the installation of SCR, SNCR, and low $NO_x$ burners to limit $NO_x$ emissions. By the end of 2011, 67% of the nation's coal-fired power plants had either a SCR or a SNCR installed to reduce $NO_x$.

***Figure 4-10 2009 $SO_2$ Emissions from Maryland Coal-fired Power Plants Compared to $SO_2$ Emissions in Other States***




Note: Emissions reported in AMPD (http://www.epa.gov/airmarkets).

***Figure 4-11 2014 $SO_2$ Emissions from Maryland Coal-fired Power Plants Compared to $SO_2$ Emissions from Coal-fired Plants in Other States***

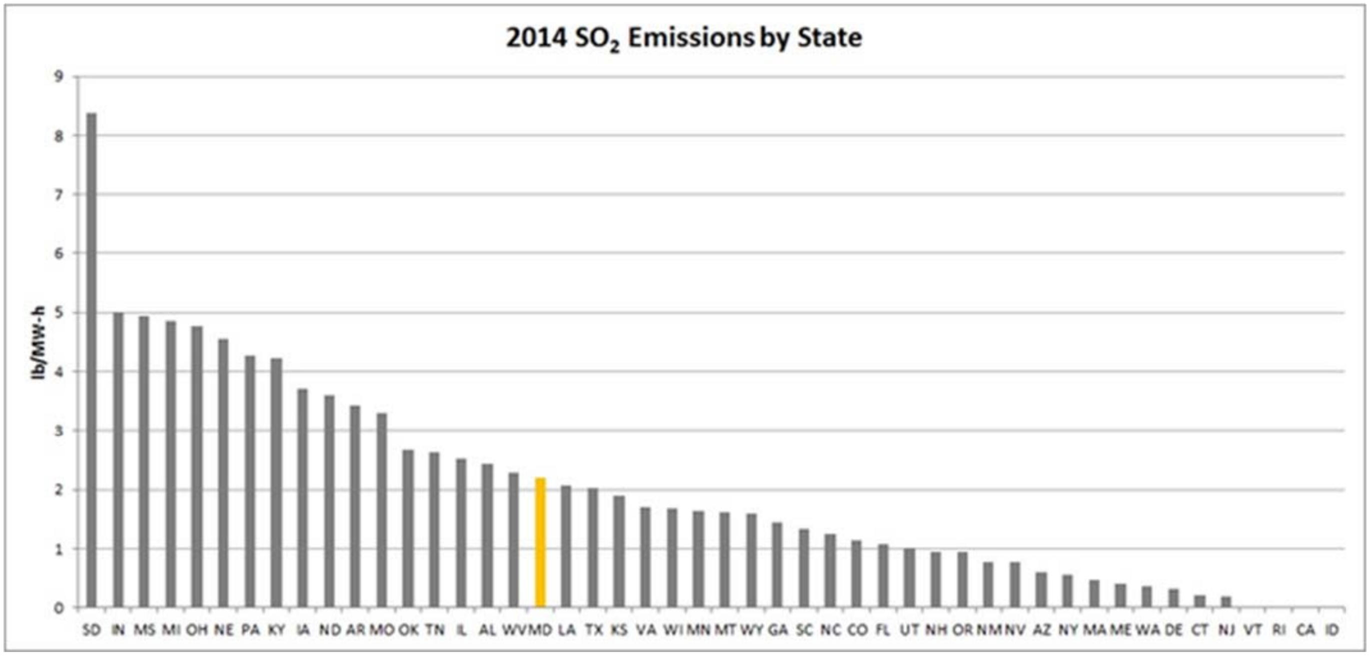
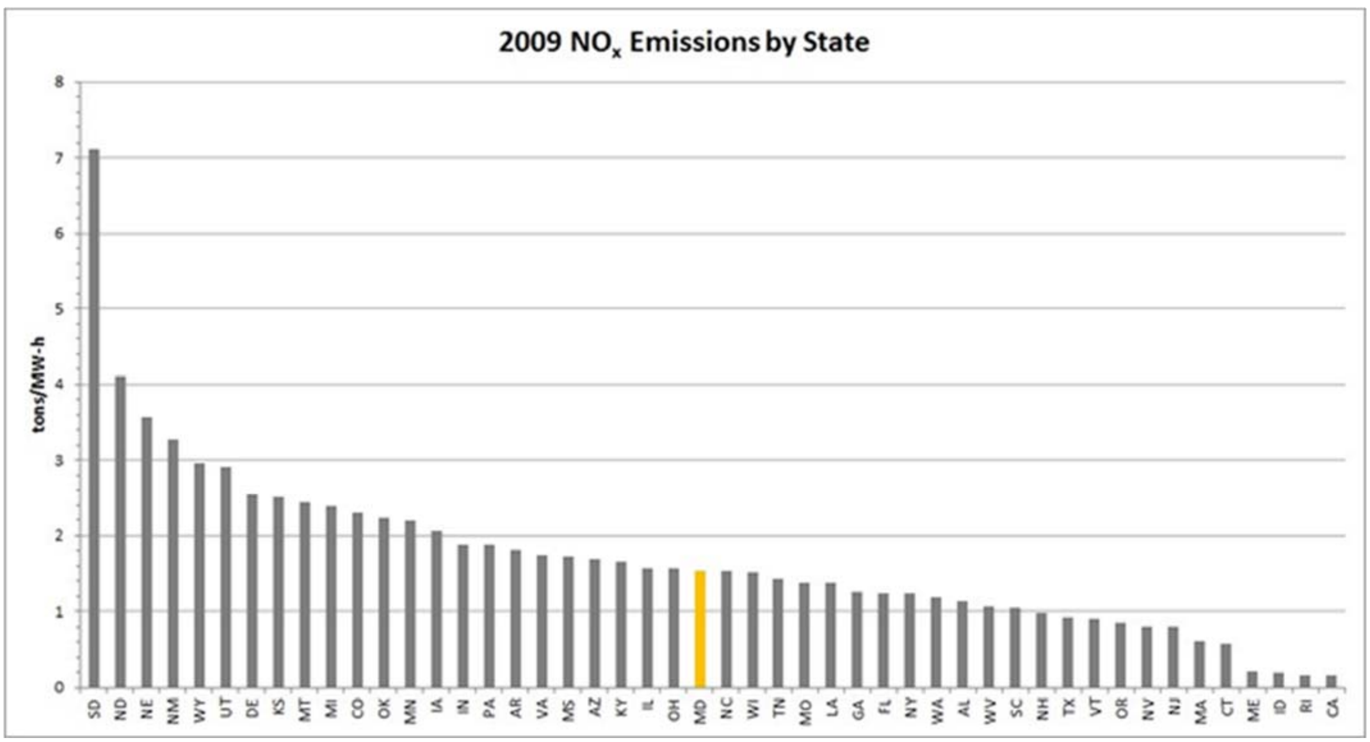
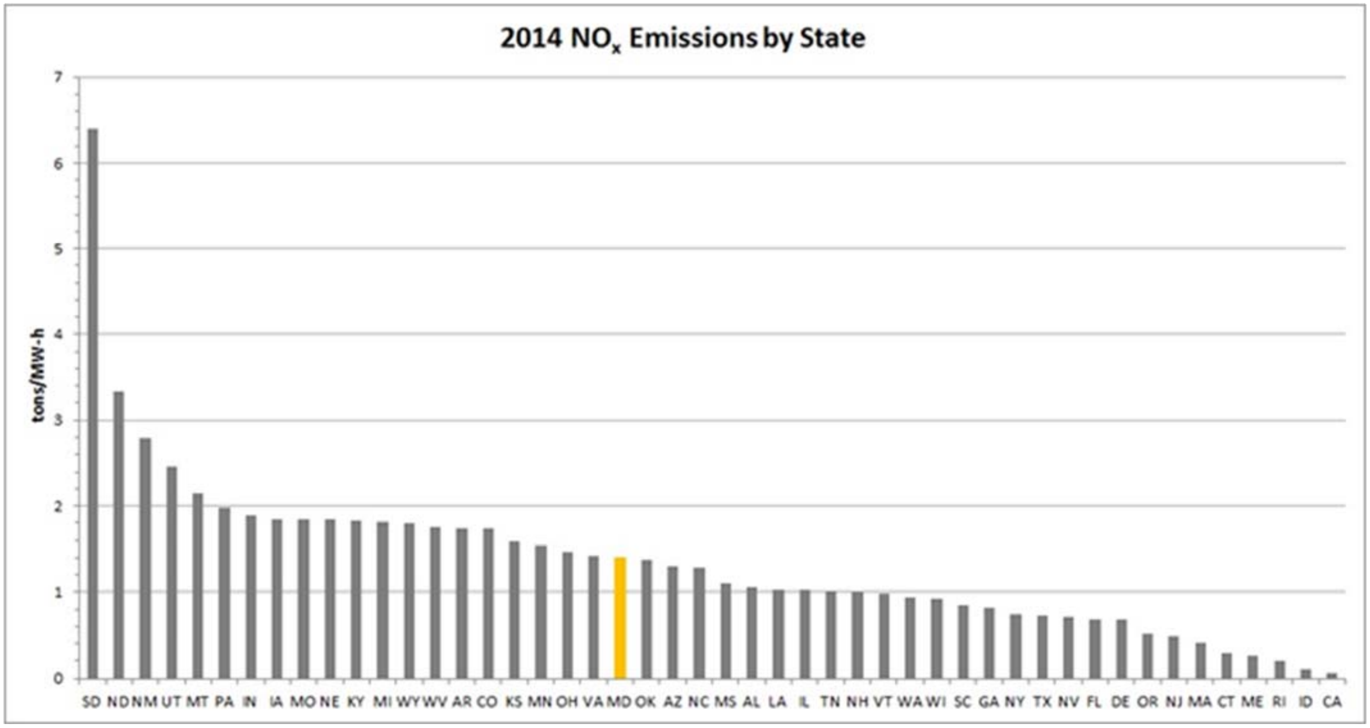



***Figure 4-12 2009 NOx Emissions from Maryland Coal-fired Power Plants Compared to NOx Emissions from Coal-fired Plants in Other States***




Note: Emissions reported in AMPD (http://www.epa.gov/airmarkets).

***Figure 4-13 2014 NOx Emissions from Maryland Coal-fired Power Plants Compared to NOx Emissions from Coal-fired Plants in Other States***




Note: Emissions reported in AMPD (http://www.epa.gov/airmarkets).

## 4.1.3 Impacts from Power Plant Air Emissions

### *Acid Rain*

Acid rain occurs when precursor pollutants, $NO_x$ and $SO_2$, react with water and oxidants in the atmosphere to form acidic compounds. These acidic compounds are deposited with precipitation ("acid rain") or as dry particles ("dry deposition"), acidifying lakes and streams, harming forest and coastal ecosystems, and damaging man-made structures. Wet deposition does not only include precipitation as rain, but also includes snow, fog, or mist. Dry deposition occurs in areas where weather is dry and materials in the atmosphere stick to the ground, buildings, homes, cars, and trees. The runoff occurring from dry deposition when it does rain is more acidic since it is a combination of both dry and wet deposition.

EPA's Acid Rain Program (ARP) was established under the CAA Amendments of 1990 with the goal of reducing acid rain by limiting $NO_x$ and $SO_2$ emissions from power plants in the U.S. The program capped total $SO_2$ emissions from power plants at 8.95 million tons nationally by 2000. The ARP for $SO_2$ was the first federal cap and trade program and, in large part, the mechanics of current pollutant trading systems were established under this program. As with regional or national cap and trade programs, $SO_2$ emissions are controlled with an "allowance" trading system, under which affected power plants are allocated a certain number of tons of $SO_2$ annually. These plants must then either reduce emissions to stay under the allowance cap or purchase $SO_2$ allowances from power plants that have over-controlled and banked excess $SO_2$ credits. $NO_x$ emissions under the ARP are controlled with rate-based limits (in units such as pounds per million Btu, lb/MMBtu) applied to certain coal-fired electric facilities.

Efforts to reduce acid rain have been largely successful nationwide. At the end of 2015, according to EPA's Air Markets Program Data, national $SO_2$ emissions totaled 2.2 million tons, a level that represents a reduction of more than 87 percent from 1980 levels and 86 percent from the 1990 levels, and is well below the annual $SO_2$ allowance of 9.5 million tons. Phase II of the ARP limited $NO_x$ emissions from affected facilities, which were either allowed to meet an emissions rate or comply with an emissions averaging plan. As of 2009, all 960 units covered by the ARP achieved compliance with the $NO_x$ emission limitation requirements. As of 2015, $NO_x$ emissions have been reduced from 1995 levels of 5.8 million tons to 1.3 million tons. The National Acid Deposition Program has been measuring deposition of oxidized nitrogen and sulfur species for over 20 years, and has noted a dramatic decrease nationally in deposition of sulfur species corresponding to the decrease in emissions, as well as a decreasing trend in deposition of oxidized nitrogen species over this time period.

### *Ozone*

The persistent ozone "smog" problem in many areas of the country has been one of the most important drivers for regulation of power plant $NO_x$ emissions over the past two decades. Ozone exists naturally in the upper levels of the atmosphere (from 6 to 30 miles above the Earth's surface) and protects the Earth from harmful ultraviolet rays. Although ozone is helpful in the stratosphere, it is harmful when it occurs in the troposphere, the layer closest to the Earth's surface. Ozone is an invisible and reactive gas that is the major component of photochemical smog. It is not emitted directly into the atmosphere in significant amounts but instead forms through chemical reactions in the atmosphere. Ground-level ozone is formed when the precursor compounds — $NO_x$ from both mobile and stationary combustion sources (such as automobiles and power plants, respectively), and VOCs from industrial, chemical, and petroleum facilities and from natural sources — react in the presence of sunlight and elevated temperatures. Ozone levels are consequently highest during the summer months when temperatures are higher, the hours of daylight are greater, and the sun's rays are more direct.

Weather plays such an important role in the formation of ozone that EPA has established an "ozone season" for each of the states, and has developed regulations that require power plants to restrict $NO_x$ emissions during the summer months. Maryland's ozone season extends from April through October.

Ground-level ozone is a problem, not only because it creates unsightly smog and inhibits visibility, but also because of the adverse human health effects it can cause. Breathing air with high ozone concentrations can cause chest pain, throat irritation, and congestion; it can also worsen pre-existing conditions like emphysema, bronchitis, and asthma. Children and the elderly are especially vulnerable to health problems caused by ground-level ozone. Recent action by EPA reduced the level of ozone standard (8-hour) from 75 ppm to 70 ppm, introducing additional challenges for states including MDE to develop a plan to achieve the standard.

Since the mid-1990s, there have been a series of federal $NO_x$ reduction regulations, implemented at the state level, that have resulted in significant reductions in summertime ("ozone season") emissions of $NO_x$ from power plants in Maryland and surrounding states. One of the most significant — referred to as the "$NO_x$ SIP Call" because it called for affected states to update their State Implementation Plans (SIP) to address ozone issues —is based on a $NO_x$ cap-and-trade program that allows sources to acquire "allowances" to emit a certain quantity of pollutants; sources can actually reduce emissions or purchase allowances from plants who have reduced emissions below their caps. In some states, including Maryland, emissions exceeded statewide $NO_x$ allocations for many years in the first decade of the 2000s, meaning that some plants in these states were buying $NO_x$ allowances rather than reducing plant-level $NO_x$ emissions. The allocation exceedance in Maryland is likely attributable to the fact that not many sources had installed state-of-the-art controls such as SCR systems over the period. Several of the coal-fired generating units in Maryland, which are among the larger $NO_x$ sources in the state, have since installed SCR systems.

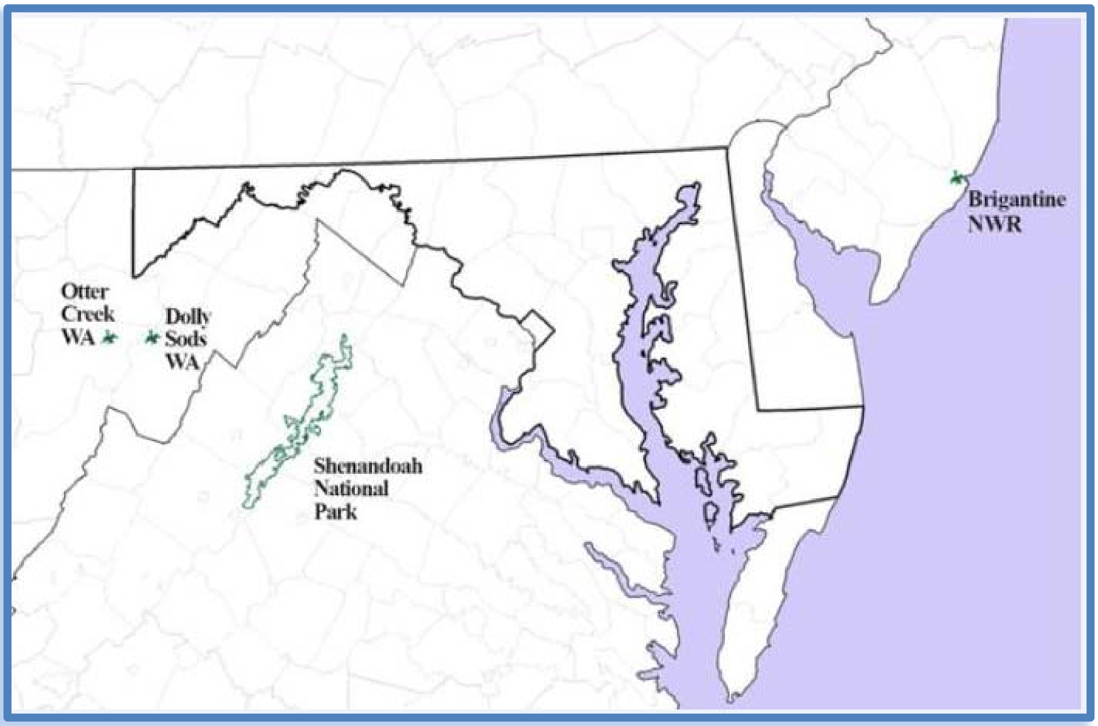
### *Visibility and Regional Haze*

Fine particulate matter, or $PM_{2.5}$, consists of particles (such as dust, soot, and liquid droplets) that are about 1/30th the diameter of a human hair. $PM_{2.5}$ can be emitted directly from stacks or created when gases react to form particles during transport in the atmosphere. $PM_{2.5}$ is different from many other air pollutants in that it is not a chemical compound itself, but is comprised of various compounds in particle form. Common sources include:

- Smoke and soot from forest fires,
- Wind-blown dust,
- Fly ash from coal burning,
- Particles emitted from motor vehicles,
- Hydrocarbons associated with vehicles, power plants, and natural vegetation emissions, and
- $SO_2$ and $NO_x$ emitted from fossil fuel combustion.

$PM_{2.5}$ affects visibility, but is not the only contributor to decreased visibility and regional haze. Certain gases and larger particles can also interfere with the ability of an observer to view an object. In general, visibility refers to the conditions that can facilitate the appreciation of natural landscapes. The national visibility goal, established as a part of the CAA Amendments of 1977, requires improving the visibility in federally managed “Class I areas.” These areas include more than 150 parks and wilderness areas across the United States that are considered pristine air quality areas (see Figure 4-14 for Class I areas near Maryland). Since 1988, EPA and other agencies have been monitoring visibility in these areas.

*Figure 4-14 Designated PSD "Pristine" Areas Near Maryland*




Source: ERM, http://www.fdlrez.com/RM/airclass1.htm "Mandatory Class I areas." Air Program Class 1 Redesignation. Fond du Lac Resource Management. Accessed 10 March 2016.

Since 2004, PPRP has participated in a coordinated effort with the Northeast States for Coordinated Air Use Management (NESCAUM) and the State of Vermont to evaluate impacts of visibility-impairing sources in the eastern United States. The studies have evaluated the tools and techniques currently available for identifying contributions to regional haze in the Northeast and Mid-Atlantic regions. PPRP was involved with the application of a dispersion model, CALPUFF, for estimating visibility degradation in Class I areas. The model identified the contributions of sources in different states in the eastern United States to visibility impairment in various Class I areas in the region. PPRP continues to support and contribute to this ongoing work. PPRP also evaluates the impacts of new power plants on Class I visibility to ensure that growth in the electrical generating sector does not contribute to impairment in these important areas.

### *Nitrogen Deposition*

The Chesapeake Bay is the largest estuary in the United States. Protection and restoration of living resources in the Bay has been the goal of the Chesapeake Bay Program since its inception in 1983. The program is a regional partnership which comprises the states of Maryland, Pennsylvania, and Virginia, the Chesapeake Bay Commission; EPA; and other participating advisory groups.

Reducing nitrogen input from controllable sources is a high priority because excess nitrogen is one of the major sources of eutrophication — caused by the increase of chemical nutrients, typically containing nitrogen or phosphorus — in the Chesapeake Bay. Eutrophication is a process whereby water bodies, such as lakes or estuaries, receive excess nutrients that stimulate excessive plant and algal growth and, ultimately, reduce the dissolved oxygen content in the water, thus limiting the oxygen available for use by aquatic organisms. The 1987 Chesapeake Bay Agreement established a goal of reducing controllable nitrogen by 40 percent compared to 1985 levels, and program participants reaffirmed that goal in their 2000 agreement. Although these goals were once again reaffirmed in the 2010 agreement, the Chesapeake Bay partners have acknowledged that the goals would not be met and EPA has initiated a process of developing a total maximum daily load (TMDL) target for the Bay. The Chesapeake Bay TMDL is a federal "pollution diet" that sets limits on the amount of nutrients and sediment that can enter the Bay and its tidal rivers to meet water quality goals.

## MDE Maryland TMDL Data Center Website

The Maryland Department of the Environment (MDE) develops total maximum daily load (TMDL) thresholds for water bodies in the State that have been impaired by pollution from man-made activities. MDE also participates in the development and evaluation of TMDLs for the Chesapeake Bay, which is impacted by pollutants from several states. A TMDL is the maximum amount of a pollutant that a body of water can receive from all sources, while still meeting water quality standards. The MDE has developed the website Maryland TMDL Data Center, http://www.mde.state.md.us/programs/Water/TMDL/DataCenter/Pages/index.aspx, which provides a TMDL Search tool, TMDL Maps, a Waste Load Allocation (WLA) Search tool, and guidance to assist stormwater permittees develop implementation plans required by municipal separate storm sewer system (MS4) permits. The approved TMDLs are searchable based on county, watershed or entire state for a specific pollutant or all available pollutants. The TMDL Maps provide the geographic extents of existing TMDLs based on pollutant. The WLA Search tool provides the stormwater or wastewater waste load allocations for an NPDES permit.

The TMDL Data Center also has a stormwater toolkit that assists in applying stormwater WLAs to regulated stormwater communities. The Stormwater Documents provide guidance documents to assist stormwater permittees in implementing TMDLs. And the P6 Bay Model Development provides information on the Chesapeake Bay Phase 6 Watershed Model data.

On June 16, 2014, representatives from each of the watershed's six states signed the Chesapeake Bay Watershed Agreement, committing to create a healthy Bay by accelerating restoration and aligning federal directives with state and local goals. This agreement contains ten interrelated goals that work toward advancing the restoration and protection of the Bay, its tributaries and the land that surround them.

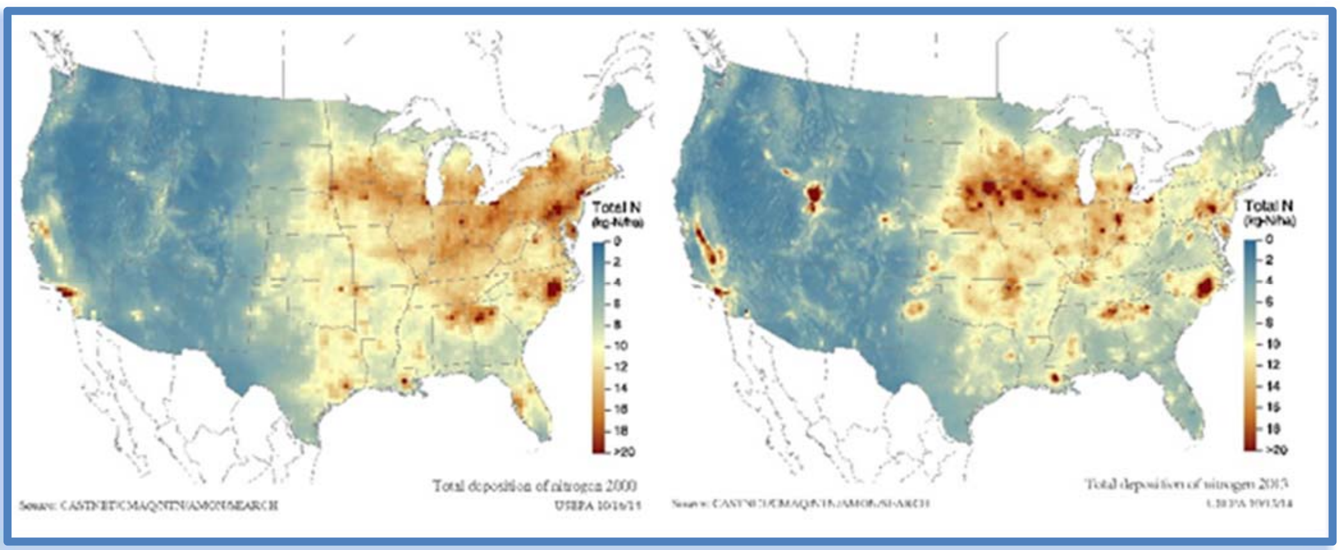
The Chesapeake Bay Program estimates that approximately 30 percent of the nitrogen load to the Bay comes from atmospheric deposition and subsequent transport of nitrogen through the watershed. Much of this loading comes from $NO_x$ emissions from power plants, industrial sources, and mobile sources. Increased efforts have been devoted recently to the role of ammonia in deposition processes.

For more than a decade, PPRP has evaluated the regional sources of $NO_x$ emissions and their impacts on the Chesapeake Bay. As a part of this effort, advanced computer modeling systems are used to simulate the transport and subsequent deposition of emissions from these regional sources to the Chesapeake Bay. The actual loading to the Bay is calculated using a methodology similar to that used by the United States Geological Survey for its land-to-bay models. The model allows PPRP to evaluate the relative contribution of Maryland sources and other regional sources to deposition totals. As a part of this study, PPRP has developed a screening tool to evaluate the potential reductions in nutrient loading to the Bay waters due to different emission control policies in different states. Using this tool, regional and local planning agencies can better develop emission reduction strategies to meet Bay restoration goals.

EPA has developed an advanced nitrogen deposition source apportionment technique, based on the photochemical grid model CMAQ, which is a refinement of the screening tool developed by PPRP. While much of the work related to deposition estimates and source apportionment going forward will be based on the CMAQ-based methodology, the screening tool is still available and can be used for developing first cut estimates of the effects of emissions changes on nitrogen loading. PPRP continues to work on updates to the underlying model (CALPUFF) and investigations of the newer SCICHEM model, to improve the accuracy of the modeled deposition rates.

The National Atmospheric Deposition Program (NADP) has developed total deposition maps for nitrogen and total sulfur for use in critical loads and other ecological assessments. The total deposition estimates are determined from the sum of both wet and dry deposition. Wet deposition values are obtained from combining NADP/National Trends Network (NADP/NTN) measured values or precipitation chemistry with precipitation estimates from the Parameter-elevation Regression on Independent Slopes Model (PRISM). The PRISM model estimates precipitation across the US based on elevation and slope. Dry deposition values are obtained by combining air concentration data with modeled deposition velocities. Figure 4-15 is a national map of total nitrogen deposition in 2000 and 2013. As shown in this figure, while total nitrogen deposition increased in some parts of the country, in the eastern US it decreased significantly from 2000 to 2013.

***Figure 4-15 Total Nitrogen Deposition in 2000 and 2013***




Source: http://nadp.isws.illinois.edu/committees/tdep/tdepmaps/preview.aspx
"Total Deposition Maps." National Atmospheric Deposition Program. Accessed 10 March 2016.

### *Mercury Impacts*

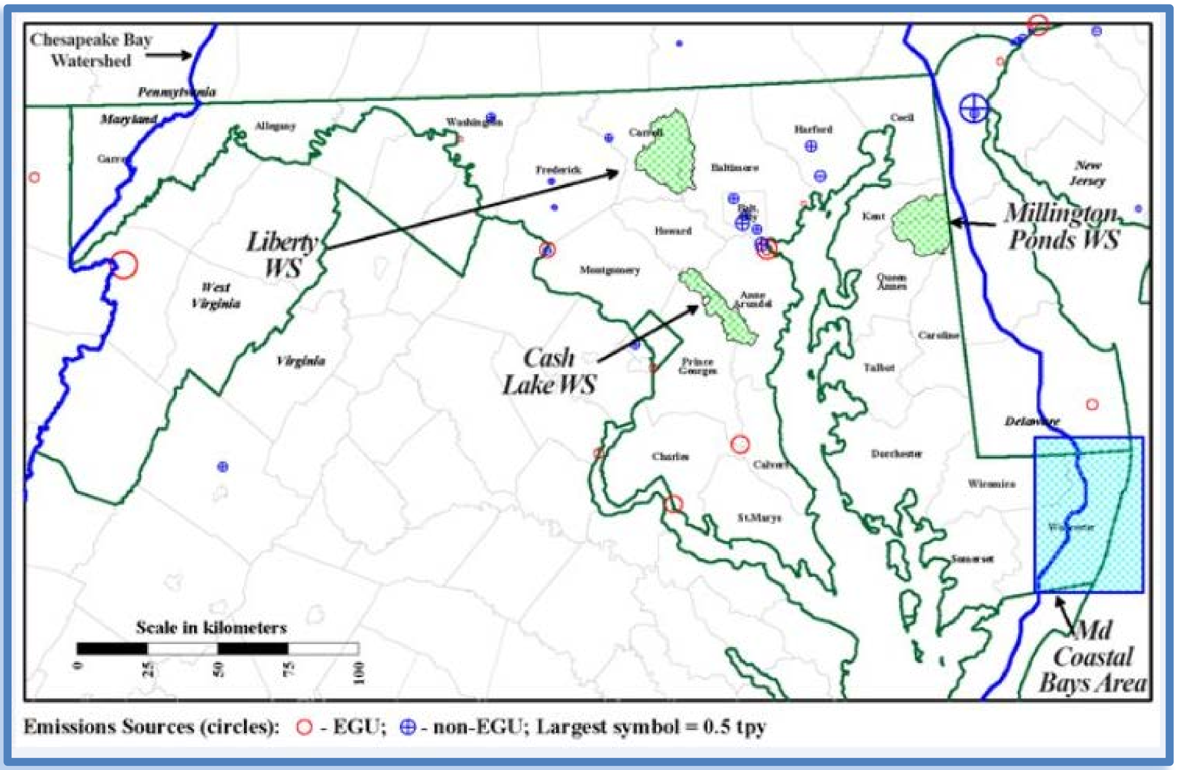
The primary stationary sources of mercury in the U.S. are, in order of decreasing emissions, coal-fired power plants, gold mining, municipal waste combustors, chlor-alkali plants, medical waste incinerators, and cement plants. Emissions from some source categories — notably medical waste incinerators — have decreased dramatically in recent years due to stringent EPA regulations. Additionally, as shown in Figure 4-8, mercury emissions from power plants in Maryland have decreased significantly since the implementation of the Healthy Air Act (HAA).

Due to the significance of power plant mercury emissions (including emissions from out-of-state sources), PPRP plays a significant role in supporting scientific research on this topic. PPRP has been actively involved in the study of regional sources of mercury emissions and their impacts on Maryland and the Chesapeake Bay. In cooperation with the University of Maryland, PPRP has sponsored several deposition monitoring programs and continues to evaluate the impacts of toxic emissions from power plants in Maryland. PPRP has also supported a project to measure ambient air mercury concentrations at the Piney Run monitoring site in Garrett County, Maryland, using a continuous mercury monitoring instrument. This state-of-the-art monitoring effort provides valuable data to the mercury research community.

PPRP is also involved with other on-going projects related to the effects of mercury emissions. The first project involves working with the Smithsonian Environmental Research Center and the University of Maryland Center for Environmental Science – Chesapeake Bay Laboratory to investigate the biogeochemistry of the processes involved with the fate of atmospheric mercury and how it ends up in fish tissue. In another cooperative project with MDE, researchers are monitoring mercury tissue burden in young fish — a long-term effort that will lead to a better understanding of trends in mercury tissue burden in response to federal and state regulations aimed at reducing mercury releases to the environment. PPRP also participates in discussions and planning sessions with NADP regarding the Mercury Deposition Network (MDN) that measures wet deposition of mercury across the U.S. and Canada, and the new Atmospheric Mercury Network (AMNet) that collects data consisting of speciated mercury concentrations and meteorological data. AMNet is intended to supplement the wet measurement network to lead to more complete understanding of total (wet plus dry) mercury deposition patterns.

In 2002, Maryland issued a state-wide fish consumption advisory for lakes, reservoirs, and other impoundments due to high mercury levels in fish. This advisory is currently in effect. PPRP has been involved for many years in conducting complex modeling studies to estimate the quantity of mercury from Maryland and other regional sources that is deposited in water bodies throughout the state. The location of sources of mercury emissions close to Maryland, and the location of some of the water bodies and watersheds evaluated in PPRP's study, are shown in Figure 4-16.

*Figure 4-16    Location of Larger Watersheds (WS) and Mercury Sources within Maryland*




Source: ERM "Garrison, Mark, Anand Yegnan and Jenifer Flannery. "Mercury in Maryland: Modeling to Assess Impacts and Effects." Maryland DNR PPRP. June 2010.

As a part of the continuing effort to evaluate impacts of regional sources of mercury emissions on mercury loading to Maryland water bodies, PPRP conducted a study to determine the reduction in mercury loads to the state's water bodies due to implementation of Maryland HAA mercury controls. This analysis was based on the projected reductions in emissions from Maryland power plants, which was approximately 90 percent from 2007 base year levels. This analysis predicted that Maryland's HAA emission reductions would potentially reduce mercury deposition to these water bodies contributed by Maryland power plants by an average of more than 75 percent. The analyses also compared the reductions in loading to the total loading from regional sources of mercury and global background levels. The modeling analysis predicted that the reduction in emissions at Maryland power plants would potentially reduce the mercury load to water bodies by 1 to 28 percent, the lower estimate being for the western Maryland water bodies, which are predominantly influenced by sources from outside Maryland. An analysis of the reductions in load due to actual emissions reductions achieved is currently underway. PPRP is developing an updated mercury emissions inventory, and is working in cooperation with scientists from the National Oceanic and Atmospheric Administration (NOAA) to this analysis.

## 4.1.4 Recent and Developing National and Air Regulatory Drivers Affecting Power Plants

Since power plants are a major source of air emissions, both federal and state policies and regulations continue to target power plants for additional pollutant control. These regulations not only address criteria pollutants and HAPs, but also GHGs and climate change. Recently, the federal Clean Power Plan (CPP) has established limitations on $CO_2$ for both existing and new power plants. The CPP is summarized in detail in Section 5.2.3 of this CEIR. Other recent key regulations are addressed in this section.

### *Recent Maryland $NO_x$ Regulation*

In April 2015, MDE petitioned the Administrative, Executive, and Legislative Review (AELR) Committee of the Maryland General Assembly requesting "emergency status" to reduce $NO_x$ emissions during the 2015 summertime ozone season. This emergency action was approved May 1, 2015 and was projected to reduce $NO_x$ emission by 10 tons on the worst "ozone days" each summer. Emergency regulations were effective for 180 days (in this case through October 28, 2015); therefore, a permanent rule was adopted in August 2015. On December 10, 2015, a final version of the emergency action was promulgated; the rule establishes $NO_x$ emission requirements beyond 2015 that will reduce ozone formation in the summer.

### *Utility Mercury and Air Toxics Standard (MATS)*

On December 21, 2011, EPA promulgated a Maximum Achievable Control Technology (MACT) standard referred to as the Mercury and Air Toxics Standard, or the "Utility MATS." MATS is intended to reduce emissions of HAPs from power plants. The rule established emission standards for new and existing fossil-fueled electric utility steam generating units with generating capacities greater than 25 MW. The rule is intended to reduce emissions of heavy metals (mercury, arsenic, chromium, nickel), acid gases (hydrogen chloride (HCl) and hydrogen fluoride (HF)), and organic HAPs (formaldehyde, benzene, and acetaldehyde) from coal- and oil-fired power plants. Subsequent to promulgation of the Utility MATS, in a 5–4 decision announced on June 29, 2015, the U.S. Supreme Court overturned MATS, ruling that the EPA did not properly consider the costs of emissions reductions in crafting the regulations; the Court did not take issue with the standard itself. On November 20, 2015, the EPA proposed a supplemental finding that included a consideration of the costs and benefits of the rule, concluding that taking "cost of control" into account does not change its previous determination that MATS is "appropriate and necessary" to regulate HAP emissions from coal- and oil- fired generating units. In December 2015, the Court of Appeals for the DC Circuit issued a ruling that allows EPA to enforce MATS while EPA addresses the issues raised by the U.S. Supreme Court in its June 2015 decision.  EPA's final supplemental finding was published in the Federal Register on April 25, 2016.  At this time, MATS remains in place, and the EPA's final supplemental finding completes its response to the U.S. Supreme Court; however, further litigation is expected.

For new and existing coal-fired generating units, the Utility MATS establishes numerical emission limits for mercury, PM (as a surrogate for toxic non-mercury metals), and HCl or SO2 (as surrogates for toxic acid gases). For new and existing oil-fired generating units, the rule establishes numerical emission limits for PM (surrogate for all toxic metals), HCl, and HF. Existing sources were required to meet emission limitations and implement work practice standards by April 16, 2015, but about 200 plants were granted extensions to install pollution control equipment; new affected sources are subject to the standards at start-up.

For affected power plant sources in Maryland, it is possible that add-on pollution control systems, such as wet FGD systems installed for HAA compliance, may be sufficient for compliance with the Utility MATS mercury and organic and metal HAPs standards. Both H.A. Wagner and C.P. Crane installed dry sorbent injection (DSI) systems in 2015 to meet the HCl limit.

## *4.2 Impacts to Water Resources*

### 4.2.1 Generating Facilities

All steam electric power plants in Maryland are located in the Chesapeake Bay watershed. Power plants are significant users of water in Maryland, and their operation can affect aquatic ecosystems as well as the availability of water for other users. This section describes the surface and ground water withdrawals, consumption and discharges in Maryland from power plant operations. It also describes potential resource impacts and methods for minimizing any adverse impacts. The effects of transmission lines on aquatic resources are discussed in Section 4.2.2.

Other than a small segment of western Maryland and small estuarine water bodies of the Atlantic Shore, the bulk of Maryland's drainage system feeds the Chesapeake Bay. All of Maryland's primary rivers drain into the Chesapeake Bay: Potomac, Patuxent, Patapsco, Susquehanna, Chester, Choptank, Nanticoke, Blackwater, and Pocomoke Rivers. Together, these rivers and the Bay extend over a large geographic area and encompass a broad range of aquatic habitat types, including marine, estuarine, and freshwater rivers lakes.

#### *Surface Water Withdrawals and Consumption*

Most electricity produced in Maryland is generated by one of four types of generating technologies: steam-driven turbines, combustion turbines, combined cycle facilities (a combination of steam and combustion turbine units), and hydroelectric facilities. Power plants utilizing steam have significant water withdrawals because of the need to cool and condense the recirculating steam. Typically, a power plant will obtain cooling water from a surface water body. The other, much smaller water needs of the power plant, such as boiler makeup water, are typically met by on-site wells or municipal water systems.

Table 4-2 lists all major steam-generating power plants in Maryland (excluding self-generators) and quantifies their water withdrawals and consumption for 2013 and 2014. Cooling water withdrawals at steam electric facilities represent the majority of surface water usage in Maryland. In 2014, combined water withdrawal for all steam generating power plants in Maryland is estimated at approximately 5.05 billion gallons per day. All other non-power plant users in the state have a combined appropriation of less than 4 billion gallons per day. By comparison, the Potomac River has an average discharge of roughly 7 billion gallons per day, and the Susquehanna River discharges an average of about 23 billion gallons per day (actual daily flows in both the Susquehanna and the Potomac fluctuate greatly, both seasonally and from year to year).

### *Table 4-2 Surface Water Appropriations and Use at Maryland Power Plants with Steam Cycles*

| Power Plant | Surface Water Appropriation (average, mgd) | 2013 Actual Surface Withdrawal (average, mgd) | 2014 Actual Surface Withdrawal (average, mgd) | Estimated Consumption (mgd) | Water Source |
|---|---|---|---|---|---|
| **Once-Through Cooling** | | | | | |
| Calvert Cliffs | 3,500 | 3,286 | 3,019 | 17.2 | Chesapeake Bay |
| Chalk Point (a) | 720 | 560 | 265 | 1.7 | Patuxent River |
| C.P. Crane | 475 | 196 | 87 | 1.0 | Seneca Creek |
| Dickerson | 401 | 142 | 150 | 0.6 | Potomac River (non-tidal) |
| H.A. Wagner | 940 | 342 | 306 | 1.9 | Patapsco River |
| Morgantown | 1,503 | 942 | 1,195 | 2.3 | Potomac River |
| Riverside | 40 | 3.51 | 3.48 | 0.0 | Patapsco River |
| Wheelabrator | 50 | 37.4 | 14.4 | 0.1 | Gwynns Falls |
| SUBTOTAL | 7,629 | 5,508 | 5,040 | 24.7 | |
| **Closed-Cycle Cooling** | | | | | |
| AES Warrior Run (b) | 0.021 | 1.6 | 1.5 | 1.0 | City of Cumberland |
| Brandon Shores | 35 | 11.8 | 8.1 | 6.7 | Patapsco River (Wagner discharge) |
| Montgomery Co. Resource Recovery Facility | 1.342 | 0.73 | 0.34 | 0.41 | Potomac River (Dickerson Station's discharge canal) |
| Panda Brandywine | N/A | 0.74 | 0.86 | 0.54 | Mattawoman WWTP |
| Vienna | 2 | 0.002 | 0.001 | 0.00 | Nanticoke River |
| SUBTOTAL | 38 | 14.8 | 10.8 | 8.6 | |
| **TOTAL** | **7,667** | **5,523** | **5,051** | **33.3** | |

Source: MDE WMA
mgd = million gallons per day
(a) Chalk Point has two units on once-through cooling and two on closed-cycle cooling. The appropriation of 720 mgd covers all four steam units; data on each cooling system individually are not available.
(b) AES Warrior Run purchases its water from the City of Cumberland. The surface water appropriation of 0.021 mgd is for backup surface water withdrawals only.

Four steam power plants in Maryland – AES Warrior Run, Brandon Shores, Panda Brandywine, and Vienna – use closed-cycle cooling (cooling towers) exclusively instead of once-through cooling. (Chalk Point has multiple steam boilers: two that use once-through cooling and two that use closed-cycle cooling.) Closed-cycle systems recycle cooling water and withdraw less than one-tenth of the water required for once-through cooling; however, depending on plant design and operating parameters, 50 to 80 percent of the water evaporates from the cooling tower and does not return to the source, thus representing a consumptive use. Closed-cycle cooling systems consume 1.5 to 2 times more water per MWh than once-through systems.

Nuclear power plants also fall within the steam generating category; however, they use nuclear reactions instead of fossil fuel combustion to create thermal energy. The typical nuclear power plant operating today requires 10 to 30 percent more cooling water, on a per-MWh basis, compared to a fossil fuel plant. Nuclear stations generally operate at a lower steam temperature and pressure compared to fossil fuel-fired generating plants, which causes a somewhat lower efficiency in the conversion of thermal energy to mechanical and, ultimately, electrical energy. Consequently, more waste heat is created per MWh generated than would occur in a fossil fuel plant, and more cooling water is needed to absorb that waste heat.

Maryland has one nuclear power plant, Calvert Cliffs, which withdraws an average of 3.2 billion gallons per day from the Bay. This is the largest single appropriation of water in Maryland, and 13 times larger than the municipal supply for the Baltimore City metropolitan area of 250 million gallons per day (mgd). While the majority of this water is returned to the Bay, an estimated 17 mgd of Bay water is lost to evaporation as a result of the heated discharge (see Table 4-2).

While the quantity of water withdrawn from a source is fairly straightforward to determine and well-documented by individual facilities, calculating the net or consumptive use is a more complex analysis. By definition, consumptive use is water that is withdrawn but not returned directly to the surface or ground water source and is unavailable to other users. In water-limited or highly regulated systems (rivers with multiple dams and reservoirs), consumptive use is a critical factor in determining allocation and under what conditions competing uses have to be curtailed or prioritized.

For power plants with closed-cycle cooling systems, the evaporative losses to the atmosphere can be calculated as the difference between water withdrawn and water discharged. However, most steam plants in Maryland use once-through cooling, in which cooling water is continuously drawn from a water source, used, and then continuously returned to (usually) the same source. While water losses within the cooling system are negligible, the release of heated water results in elevated evaporative losses in the receiving waters – and these losses are not easily measured. PPRP's assessment of consumptive use is largely based on work conducted in the 1980s by the Interstate Commission on the Potomac River Basin (ICPRB), which calculated in-stream evaporative losses caused by heated discharges from 14 Maryland power plants. The ICPRB found that, on average, in-stream losses were equivalent to about 0.6 percent of a plant's total discharge volume during the summer and 0.5 percent during the winter.

When assessing the significance of water withdrawal impacts, the nature of the source water body is a key factor. In estuaries such as the Chesapeake Bay, and the tidal portions of Bay tributaries, the quantity of water "lost" is less important because tidal influx continually replaces the water withdrawn. In these estuarine environments, the ecological impacts of water withdrawals can be significant, but consumptive loss is not a concern.

## U.S. Geological Survey Water Use Report

The U.S. Geological Survey (USGS) develops water use reports for the United States every five years. The latest USGS water use report, published in November 2014, details national water usage data for the year 2010, as well as trends in water use from 1950 through 2010. USGS estimates that, in 2010, 161 billion gallons per day was withdrawn from surface freshwater sources for thermoelectric power generation in the US. Maryland accounts for about 3% of that withdrawal volume. The report does not include consumptive use data; however, USGS researchers are actively working on development of more accurate estimates of water consumption associated with power plant cooling systems.

In addition to cooling systems, air pollution control systems at power plants can also require substantial amounts of water. As a result of the Healthy Air Act, Maryland's four largest coal-fired power plants – Brandon Shores, Chalk Point, Dickerson, and Morgantown – have begun operating wet flue gas desulfurization (FGD) systems. Typically, about 85 percent of the water used in these systems is consumptively lost through evaporation out of the stack. Operation of the FGD systems at Maryland's coal-fired power plants results in an additional evaporative loss of approximately 8 mgd combined. This additional loss is not significant in the tidal estuarine environments at Brandon Shores, Chalk Point, and Morgantown. NRG, the operator of the Dickerson plant, is required to provide on-site water storage to minimize the potential impacts of its FGD system's water use on other users of the Potomac River (see discussion of low-flow issues in the next section.

### *Low-Flow Issues*

Consumptive users of water in the nontidal portion of the Potomac River must comply with Maryland's consumptive use regulations for the Potomac River Basin (COMAR 26.17.07). The intent of this regulation is to ensure that during low-flow periods, upstream users allow sufficient water to continue downstream to supply water demands in the Washington, D.C., metropolitan area.

The consumptive use regulations require users consuming more than 1 mgd of water from the Potomac River to maintain low-flow augmentation storage, and release water from this storage to offset their consumption during low-flow periods. Alternatively, users can comply with the rules by reducing consumptive use to less than 1 mgd during low-flow periods. The consumptive use regulations specify the amount of augmentation storage that must be secured to avoid the potential for curtailment of water withdrawals during low-flow periods.

A power plant developer can build ponds or tanks to store cooling water, which could carry the facility through a short-term drought. However, it is typically not feasible for plant developers to construct on-site storage that could supply enough water to support operations through a prolonged period of withdrawal restrictions. Plants that propose to withdraw cooling water from nontidal waters of the Potomac, therefore, accept the risk that severe drought conditions may require them to curtail their operations. It is recognized that severe drought conditions correlate quite well with conditions of heavy electricity consumption, but the goal of providing on-site water storage is to reduce the risk of curtailment, not entirely eliminate it. An example of this approach is the CPCN issued to Mirant (now NRG) for construction of the FGD system at Dickerson, which includes a requirement to construct an on-site pond capable of storing 4.5 million gallons to serve the facility during low-flow periods.

Similar regulations and policies have been established by the Susquehanna River Basin Commission (SRBC), which was created in 1970 to coordinate the water resource efforts of the Susquehanna River Basin Compact between the states of Maryland, New York, and Pennsylvania. The SRBC's consumptive use regulation requires users of surface or ground water within the basin to provide mitigation during low flow events, protecting both aquatic resources and other water users. Alternatively, users are allowed to pay a fee to the SRBC in lieu of conducting physical mitigation. The SRBC uses such fees to undertake large-scale storage projects that will offset consumptive water use by those paying the fee.

In 2012, the SRBC revised its Low Flow Protection Policy, incorporating low flow thresholds based on monthly or seasonal variability within the water body rather than annual flow thresholds. This provides a more realistic representation of stream conditions and a more appropriate basis to establish protective measures.

Old Dominion Electric Cooperative (ODEC) received its SRBC approval in March 2014 for a new cooling water withdrawal on the Susquehanna to supply Wildcat Point, a new combined cycle facility in Cecil County adjacent to ODEC's existing Rock Springs power plant (See Section 3.1.2). The 1,000 MW Wildcat Point facility will withdraw a maximum of 8.7 mgd of water from Conowingo Pond, of which a maximum of 7.9 mgd will be consumptive use (evaporated in the cooling towers). The Wildcat Point facility is under construction and scheduled to begin operating in Summer 2017.

## New Effluent Guidelines for Coal-fired Power Plant Discharges

The U.S. EPA first promulgated the Steam Electric Power Generating Effluent Guidelines and Standards (40 CFR Part 423) in 1974, and it recently amended these regulations with a final rule published in November 2015. This rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, including aggressive limits for selenium and mercury. It establishes new or additional requirements for wastewater streams from the following processes and byproducts associated with steam electric power generation: flue gas desulfurization (FGD), fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

As the NPDES permits for Maryland's coal-fired power plants come up for renewal, MDE is incorporating the new effluent guidelines to set new limits that are achievable using best available technology. PPRP provided technical assistance to MDE in 2014, when the EPA regulations were still in the proposed rulemaking stage, to identify the status and capabilities of effluent control methods.

### *Cooling System Alternatives and Advances*

With increasing pressures to minimize water withdrawals, power plant developers are finding more efficient means of cooling. Once-through cooling, the original standard for power plants, is not a viable option for new power plants, particularly in light of EPA's current regulations for new facilities under the Clean Water Act (CWA) Section 316(b), designed to reduce ecological effects of cooling water withdrawals. Closed-cycle cooling towers have become standard on new steam generating power plants, reducing water withdrawals substantially compared to once-through cooling systems. As noted previously though, their consumptive use is somewhat higher.

Environmental regulations to protect the Chesapeake Bay Critical Area and other aquatic make it more difficult to site facilities adjacent to large water bodies, as was common during most of the 20th century. The reuse of effluent from wastewater treatment plants (WWTP) is becoming an acceptable and viable water supply option for power plants to be located close to sources of reclaimed wastewater for cooling water supply, rather than relying on direct surface water withdrawals. The Panda Brandywine combined cycle facility, located in Prince George's County, currently utilizes about 0.5 to 1 mgd of treated effluent from the Mattawoman WWTP for its cooling water needs. In 2010, Constellation began using treated effluent from Anne Arundel County's Cox Creek WWTP to supply the FGD system now in operation at the Brandon Shores power plant. Other currently proposed plants that intend to use reclaimed wastewater for cooling water include CPV Maryland's proposed gas-fired power plant in Charles County and Mattawoman Energy Center's proposed natural gas combined cycle plant in Prince George's County (discussed further below). Construction of the CPV Maryland facility began at the end of 2014, and is still ongoing.

Effluent reuse has been established as an alternative that can be economically attractive and technically viable for sites located near large WWTPs. With respect to environmental impacts, effluent reuse still represents a consumptive loss of water resources, since the treated effluent that is used and evaporated in the cooling towers would otherwise be discharged to surface water. However, overall aquatic impacts are reduced because effluent reuse does not involve direct withdrawals from a surface body.

## New MDE Guidelines for Use of Reclaimed Water

Under §9-303.1(a) of the Annotated Code of Maryland, MDE is directed to encourage use of reclaimed water as an alternative to discharging treated sewage effluent to surface waters of the State. Two power plants in Maryland – Panda Brandywine and Brandon Shores – have been utilizing high-quality reclaimed wastewater for many years, avoiding the need for large volume surface water withdrawals to provide cooling water and, in the case of Brandon Shores, makeup water for air pollution control systems.

In 2015, MDE finalized new guidelines for commercial, residential, and industrial applications of highly treated effluent, designated as Class IV reclaimed water. The new guidelines pertain to the production and distribution of reclaimed water, design of systems, and standards for monitoring. The most notable implications are:

- Establishment of minimum water quality thresholds,
- Requirement that a WWTP obtain a construction permit from MDE before supplying Class IV reclaimed water, and
- Physical infrastructure requirements (e.g., pipe color, installation process).

WWTPs providing Class IV reclaimed water to industrial users must now meet these new guidelines. The standards are generally consistent with conditions that PPRP and MDE have recommended in past CPCN licensing cases, and that the PSC has included when approving new or modified facilities that use reclaimed water for cooling.

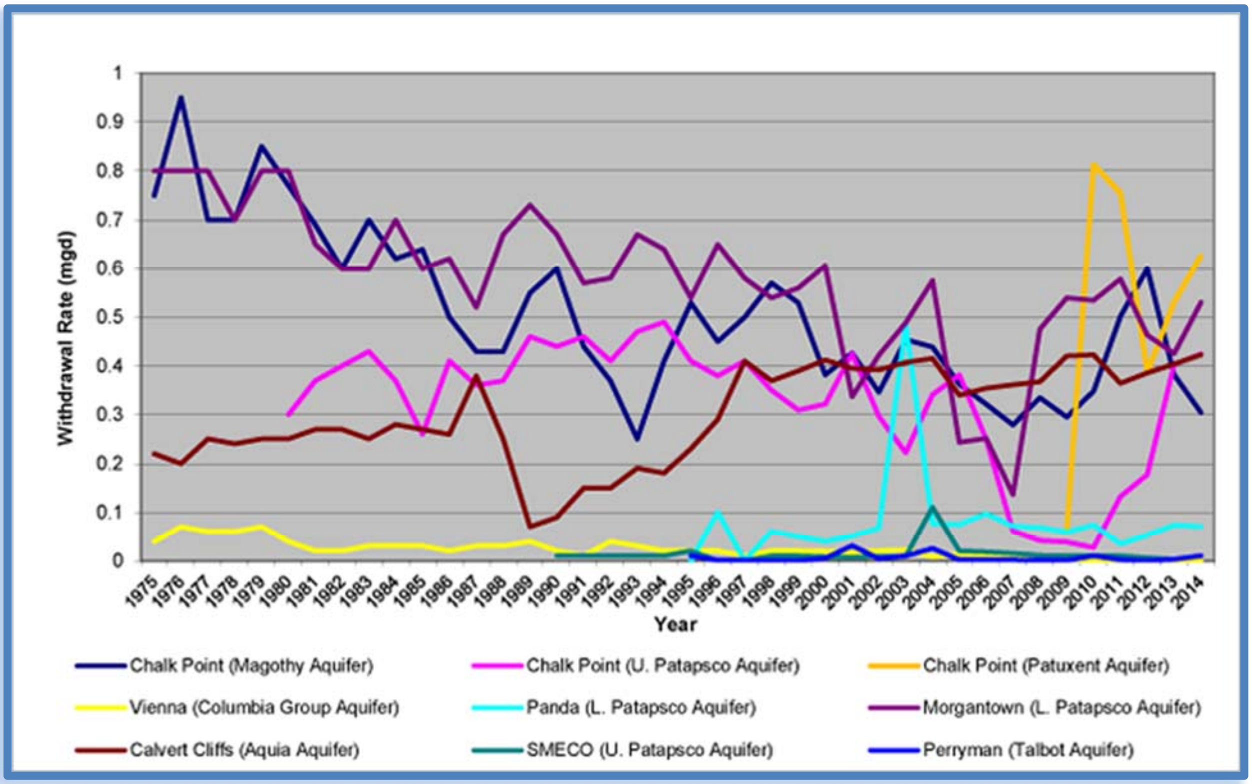
Dry cooling systems are also making significant inroads to the power industry, although there are not yet any major power plants in Maryland with dry cooling. Because of their large size, parasitic power use, required land, and capital outlay, dry cooling towers are more expensive to construct and operate compared to conventional wet cooling systems. However, with increasing constraints on siting and water appropriations, dry cooling is becoming a more attractive option in comparison. The proposed design for the Keys Energy Center combined-cycle facility in Prince George's County incorporates the use of dry cooling.

### *Ground Water Withdrawals*

The use of ground water for process cooling is severely restricted in Maryland, but some of Maryland's power plants are significant users of ground water for other purposes. Ground water is used for boiler feedwater in coal-fired power plants, inlet air cooling, emissions control in gas- and oil-fired combustion turbines, and potable water throughout the power plants. High-volume ground water withdrawals have the potential to lower the water table of an area, thus reducing the amount of water available for other users. Excessive withdrawals from Coastal Plain aquifers can also cause intrusion of salt water into the aquifer. Although large volumes of ground water are available in the Coastal Plain aquifers, withdrawals must be managed over the long term to ensure adequate ground water supplies for the future.

The impact of these withdrawals has been a key issue in southern Maryland, where there is a significant reliance on ground water for public water supply. Currently, five power plants withdraw ground water from southern Maryland coastal plain aquifers for plant operations: Exelon's Calvert Cliffs Nuclear Power Plant, NRG's Chalk Point and Morgantown power plants, Southern Maryland Electric Cooperative's (SMECO's) combustion turbine facility (located at the Chalk Point plant), and Panda Brandywine's combined cycle power plant. These five plants have historically withdrawn ground water from three aquifers in Southern Maryland: the Aquia, the Magothy, and the Patapsco. NRG's Chalk Point power plant began withdrawing ground water from the deeper Patuxent Aquifer in 2010. Two additional power plants utilize ground water: Perryman, located in Harford County northeast of Baltimore, and Vienna, located in Dorchester County on the Eastern Shore. Figure 4-17 shows the ground water withdrawal rates expressed as daily averages from 1975 to 2014 for each of these power plants. The withdrawal rates and associated appropriation limits are also listed in Table 4-3. As noted in Table 4-3, power plants typically withdraw ground water at rates well below their appropriation permit limits. The average withdrawal for all seven power plants in 2014 was 2.4 million gallons per day (mgd) compared to a combined daily appropriation limit of 3.8 mgd. The amount of ground water withdrawn by power plants has fluctuated between about 0.9 and 2.4 mgd over the past 40 years.

*Figure 4-17 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants*



## *Table 4-3 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants (in mgd)*

| | Chalk Point (Magothy Aquifer) | Chalk Point (U. Patapsco Group Aquifer) | Chalk Point (Patuxent Aquifer) See Note (a) | Vienna (Columbia Aquifer) | Panda (L. Patapsco Aquifer) | Morgan-town (L. Patapsco Aquifer) | Calvert Cliffs (Aquia Aquifer) | SMECO (U. Patapsco Aquifer) | Perry-man (Talbot Aquifer) | Total Average Daily With-drawal |
|---|---|---|---|---|---|---|---|---|---|---|
| **Current Appropri-ation Limit** | **0.66** | **0.66** | **1.02** | **0.05** | **0.064 See Note (b)** | **0.82** | **0.45** | **0.02** | **0.1** | **3.8** |
| 1975 | 0.75 | | | 0.04 | | 0.8 | 0.22 | | | 1.8 |
| 1976 | 0.95 | | | 0.07 | | 0.8 | 0.2 | | | 2.0 |
| 1977 | 0.7 | | | 0.06 | | 0.8 | 0.25 | | | 1.8 |
| 1978 | 0.7 | | | 0.06 | | 0.7 | 0.24 | | | 1.7 |
| 1979 | 0.85 | | | 0.07 | | 0.8 | 0.25 | | | 2.0 |
| 1980 | 0.77 | 0.3 | | 0.04 | | 0.8 | 0.25 | | | 2.2 |
| 1981 | 0.69 | 0.37 | | 0.02 | | 0.65 | 0.27 | | | 2.0 |
| 1982 | 0.6 | 0.4 | | 0.02 | | 0.6 | 0.27 | | | 1.9 |
| 1983 | 0.7 | 0.43 | | 0.03 | | 0.6 | 0.25 | | | 2.0 |
| 1984 | 0.62 | 0.37 | | 0.03 | | 0.7 | 0.28 | | | 2.0 |
| 1985 | 0.64 | 0.26 | | 0.03 | | 0.6 | 0.27 | | | 1.8 |
| 1986 | 0.5 | 0.41 | | 0.02 | | 0.62 | 0.26 | | | 1.8 |
| 1987 | 0.43 | 0.36 | | 0.03 | | 0.52 | 0.38 | | | 1.7 |
| 1988 | 0.43 | 0.37 | | 0.03 | | 0.67 | 0.25 | | | 1.8 |
| 1989 | 0.55 | 0.46 | | 0.04 | | 0.73 | 0.07 | | | 1.9 |
| 1990 | 0.6 | 0.44 | | 0.02 | | 0.67 | 0.09 | 0.01 | | 1.8 |
| 1991 | 0.44 | 0.46 | | 0.01 | | 0.57 | 0.15 | 0.01 | | 1.6 |
| 1992 | 0.37 | 0.41 | | 0.04 | | 0.58 | 0.15 | 0.01 | | 1.6 |
| 1993 | 0.25 | 0.47 | | 0.03 | | 0.67 | 0.19 | 0.01 | | 1.6 |
| 1994 | 0.41 | 0.49 | | 0.02 | | 0.64 | 0.18 | 0.01 | | 1.8 |
| 1995 | 0.53 | 0.41 | | 0.02 | 0 | 0.54 | 0.23 | 0.02 | 0.01 | 1.8 |
| 1996 | 0.45 | 0.38 | | 0.02 | 0.1 | 0.65 | 0.29 | 0 | 0.001 | 1.9 |
| 1997 | 0.5 | 0.41 | | 0.01 | N/A | 0.58 | 0.41 | 0 | 0.001 | 1.9 |
| 1998 | 0.57 | 0.35 | | 0.02 | 0.06 | 0.54 | 0.37 | 0.01 | 0 | 1.9 |
| 1999 | 0.53 | 0.31 | | 0.02 | 0.05 | 0.56 | 0.39 | 0.01 | 0 | 1.9 |
| 2000 | 0.382 | 0.322 | | 0.019 | 0.04 | 0.606 | 0.412 | 0.008 | 0.005 | 1.8 |
| 2001 | 0.427 | 0.426 | | 0.017 | 0.051 | 0.337 | 0.395 | 0.007 | 0.031 | 1.7 |
| 2002 | 0.346 | 0.296 | | 0.02 | 0.067 | 0.423 | 0.392 | 0.009 | 0.004 | 1.6 |

| | Chalk Point (Magothy Aquifer) | Chalk Point (U. Patapsco Group Aquifer) | Chalk Point (Patuxent Aquifer) See Note (a) | Vienna (Columbia Aquifer) | Panda (L. Patapsco Aquifer) | Morgan-town (L. Patapsco Aquifer) | Calvert Cliffs (Aquia Aquifer) | SMECO (U. Patapsco Aquifer) | Perry-man (Talbot Aquifer) | Total Average Daily With-drawal |
|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 0.454 | 0.222 | | 0.022 See Note (c) | 0.486 | 0.489 | 0.407 | 0.009 | 0.01 | 2.1 |
| 2004 | 0.439 | 0.341 | | 0.008 See Note (d) | 0.076 | 0.575 | 0.415 | 0.011 | 0.025 | 2.0 |
| 2005 | 0.362 | 0.382 | | 0.013 | 0.074 | 0.243 | 0.34 | 0.02 | 0.002 | 1.4 |
| 2006 | 0.322 | 0.249 | | 0.009 | 0.097 | 0.251 | 0.354 | 0.018 | 0.002 | 1.3 |
| 2007 | 0.279 | 0.061 | | 0.009 | 0.072 | 0.136 | 0.362 | 0.015 | 0.002 | 0.9 |
| 2008 | 0.335 | 0.042 | | 0.008 | 0.068 | 0.476 | 0.368 | 0.011 | 0.001 | 1.3 |
| 2009 | 0.295 | 0.039 | 0.059 | 0.005 | 0.059 | 0.540 | 0.421 | 0.010 | 0.001 | 1.4 |
| 2010 | 0.348 | 0.027 | 0.813 | 0.000 | 0.073 | 0.535 | 0.423 | 0.010 | 0.010 | 2.2 |
| 2011 | 0.502 | 0.132 | 0.755 | 0.000 | 0.035 | 0.578 | 0.364 | 0.010 | 0.002 | 2.4 |
| 2012 | 0.600 | 0.177 | 0.387 | 0.001 | 0.053 | 0.463 | 0.386 | 0.006 | 0.000 | 2.1 |
| 2013 | 0.382 | 0.403 | 0.532 | 0.000 | 0.073 | 0.426 | 0.404 | 0.003 | 0.003 | 2.2 |
| 2014 | 0.304 | 0.425 | 0.626 | 0.000 | 0.070 | 0.531 | 0.423 | 0.010 | 0.010 | 2.4 |

Source: U.S. Geological Survey, MDE WMA

Note (a): Well was installed in 2007. Routine withdrawal did not occur until approximately 2009.

Note (b): Panda was granted a higher appropriation during construction of its pipeline for conveying treated effluent.

Note (c): No report was submitted to MDE for the period July-December 2003. The amount shown was estimated using the total volume withdrawn of 4,131,683 gallons reported for the period January-June 2003.

Note (d): No report was submitted to MDE for the period January-June 2004. The amount shown was estimated using the total volume withdrawn of 1,505,770 gallons reported for the period July through December 2004

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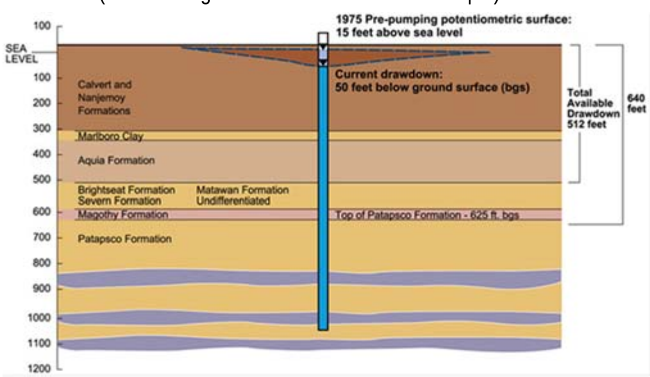
## Evaluating Drawdown Impacts

Long-term monitoring data show how pumping from a ground water aquifer affects the water level over time. MDE regulations define "available drawdown" in an aquifer as 80 percent of its historic pre-pumping level. The significance of the current drawdown can then be estimated by comparing current drawdown to the total available drawdown (see drawing below for an illustrated example).




Three government agencies – the Maryland Geological Survey (MGS), the USGS, and PPRP – jointly operate a ground water monitoring program to measure the water levels in the Coastal Plain aquifers of Southern Maryland to ensure the long-term availability of ground water. MDE Water Management Administration (WMA), the permitting authority for all ground water appropriations, uses the data from this joint monitoring program to assess the significance of impacts to aquifers when reviewing additional appropriation requests.

Long-term monitoring indicates a steady decline in water levels in the Aquia, Magothy, Patapsco and Patuxent aquifers. However, these declines are not solely due to withdrawal by power plants, and are considered acceptable by MDE WMA when compared to the amount of water available in the aquifers. The amount of water available is expressed as the aquifer's "available drawdown," which is defined in MDE regulations as 80 percent of the distance from the historic pre-pumping water level to the top of the pumped aquifer.

While power plants have contributed to the decline in the water levels in these aquifers, increased withdrawals from municipal well fields in southern Maryland have caused most of the recent declines. To minimize impacts to municipal supplies, MDE WMA has required industrial users to utilize the deeper aquifers for new withdrawals.

Water quantity impacts to each of the coastal plain aquifers are summarized below.

- **Aquia Aquifer at Calvert Cliffs –** Water levels in the Aquia Aquifer at Calvert Cliffs declined approximately 75 feet from 1982 to 2013, with most of the decline occurring post 1990. This acceleration in water level decline is due to withdrawal from municipal well fields at Lexington Park in St. Mary's County and Solomons Island in Calvert County. The water levels at Lexington Park and Solomons Island have declined nearly 113 feet and 96 feet, respectively, since 1982. The impacts from the water level decline are considered acceptable given the estimated 315 feet of available drawdown in the Aquia Aquifer at Calvert Cliffs based on MDE's available drawdown criteria described above.
- **Magothy Aquifer at Chalk Point –** MDE WMA has required industrial users of the Magothy Aquifer to use deeper aquifers like the Patapsco to allay concerns over water level declines in the Magothy. As a result, the Chalk Point power plant reduced its ground water withdrawal from the Magothy from 1990 to 2013 by about 40 percent compared to its withdrawals prior to 1980. This

reduction has resulted in a commensurate decrease in the rate of water level decline at the facility during this same period. However, water levels continue to decline in the aquifer due to its extensive continued use in Annapolis and Waldorf. The drawdown at Chalk Point between 1975 and 2013 has been approximately 42 feet, and a total of about 82 feet since pumping at Chalk Point began in 1964. Prior to pumping in 1962, the elevation of the potentiometric head in the Magothy Formation was 28 feet above mean sea level; thus the available drawdown is 80 percent of 600 feet plus 28 feet, approximately equivalent to 500 feet. Consequently, the total drawdown of 82 feet is small compared to the estimated total available drawdown of approximately 500 feet for the Magothy Formation in the vicinity of Chalk Point.

- **Upper Patapsco Aquifer at Chalk Point –** The water level surface in the Upper Patapsco Aquifer has declined 43 feet at Chalk Point since 1990. This decline will not impact the approximately 512 feet of available drawdown for the Upper Patapsco Aquifer at Chalk Point.
- **Lower Patapsco Aquifer at Morgantown –** The water level surface of the Lower Patapsco Aquifer in the vicinity of the Morgantown power plant has declined up to 29 feet since 1990. Water levels in the vicinity of the Morgantown power plant have increased about 5 feet since 2009.
- **Patuxent Aquifer at Chalk Point –** The water level surface of the Patuxent Aquifer has declined approximately 40 feet as a result of withdrawal at the Chalk Point power plant. Water levels in the immediate vicinity of the power plant have declined approximately 70 feet between 2009 and 2013, as a result of the use of the Patuxent Aquifer beginning in 2009.

### *Contaminated Ground Water Impacts*

In several recent licensing cases, PPRP has worked with MDE to address issues related to ground water contamination. These instances of contamination were not caused by power generation or transmission activities; however, the applicants in these licensing cases had to take measures to avoid exacerbating the negative impacts. PPRP has conducted in-depth evaluations in each of these cases and developed CPCN conditions to establish requirements for the applicants.

#### ***Perryman***

Ground water quality in the vicinity of the proposed Perryman 6 Project facility has been impacted by a release of fuel to the subsurface. The source of the contamination was a leaking No. 2 fuel oil line immediately west of combustion unit No. 4. Results of initial investigations identified an area roughly equivalent to five acres of free phase oil within the property boundaries. In an effort to mitigate the plume migration, skimmers were installed and adsorbents were used to recover as much oil as possible.

Currently, ground water monitoring is conducted as part of an active MDE Oil Control Program case that includes monitoring of oil and water level measurements and dissolved phase petroleum-related contaminants. Recent monitoring results indicate that the residual dissolved petroleum plume extends towards the west and is elongated in a northeast-southwest direction. Based on current total petroleum hydrocarbon diesel range organic concentrations measured in monitoring wells, the current area of the plume is approximately 2.5 to 3.0 acres. The results of investigations conducted in 2011 and 2012 indicate that the majority of the remaining liquid phase hydrocarbon is present at residual, immobile saturation, and is therefore trapped in isolated pores in discontinuous pockets by capillary forces.

The withdrawal of ground water is required for the operation of the Perryman plant. However, pumping ground water from the Upper Aquifer has the potential to cause impacts to the ground water quality if the reduction in the water table elevation or an alteration in the ground water flow directions disperses the oil plume. The results of the steady-state Non-Steady or Steady State Coupled (NSSCOU) aquifer model were used to evaluate the potential for these water quality impacts to be realized. The steady-state NSSCOU model results indicated that drawdown ranging from 0.1 feet to 0.15 feet could occur in the area of the oil plume. This slight drop in the water table would not alter the ground water flow direction, indicating that the pumping would not disperse the oil plume. Therefore, the model results indicate that lowering the water table will not alter the extent of the oil plume.

***Mattawoman***

The planned generator lead line for Mattawoman will traverse the Brandywine DRMO Superfund site, which is owned by Joint Base Andrews (JBA). Chlorinated VOCs are present in ground water at the DRMO Superfund site and were observed to be migrating offsite into a residential area. JBA is currently operating a groundwater extraction and treatment system at the DRMO Superfund site to capture and treat a chlorinated VOC plume that is migrating offsite.

JBA raised concern that dewatering activities at the Mattawoman site will influence groundwater flow at the DRMO site and adversely impact plume capture/migration and their ongoing remediation. As a part of the CPCN review process, Mattawoman conducted a dewatering evaluation to determine potential affects to the DRMO remediation system caused by construction dewatering at the proposed Mattawoman site. PPRP also conducted an independent analysis to evaluate the findings of “no significant impact” to the DRMO system from Mattawoman construction activities.

Licensing conditions imposed on Mattawoman were created to assure protection of human health during transmission pole installation for the generator lead line. Likewise, the licensing conditions also specified requirements to reduce/minimize further releases of contaminated soil or ground water to non-impacted areas such that the surrounding community would not be affected.

### *PEPCO Burtonsville to Takoma Park Transmission Rebuild Project*

PEPCO filed an application for the rebuild of an existing 230 kV transmission line originating at the Burtonsville substation and terminating at the Takoma substation. In its application, PEPCO acknowledged that there are three areas along the right-of-way (ROW) that could contain petroleum-contaminated soil or areas where hazardous substances may be present in soil or groundwater. The presence of oil-contaminated soil or hazardous substances is the result of releases caused by entities other than PEPCO whereby such substances have migrated onto the PEPCO ROW.

However, to ensure the safety of its workers, PEPCO committed to conduct investigations to determine the presence of soil and/or ground water contamination at the structure locations to the depths of proposed excavations prior to initiation of construction and to use the results to the investigation to determine the course of action to mitigate potential risks from contamination during construction.

#### Dewatering for Pipeline Construction

Dewatering of saturated materials during the construction of power plants, including pipelines, may be required when construction occurs in areas with a high water table, such as areas in the coastal plain of Maryland. A complete understanding of the influence that dewatering may have on the aquifer is necessary to avoid significant impacts to surrounding surface water resources, such as streams and ponds, and nearby ground water users. PPRP has conducted analyses in recent licensing cases to ensure that proposed pipelines associated with generating facilities will not deplete ground water resources or affect nearby water users.

The information needed to estimate the rate of dewatering in areas where pipes are placed below the water table, particularly in areas adjacent to or under streams, includes the following:

1. The estimated length of pipeline segments that will be installed beneath the water table;
2. An estimate of the depth that the excavations will extend below the water table (i.e., saturated thickness); and
3. Duration of pipeline construction and average construction duration of each segment.

PPRP uses this information to conduct a hydrogeologic analysis of the site, and estimate water table drawdown associated with the construction dewatering. PPRP determines the extent of the impacts to nearby ground water users, subject to ground water appropriation applicability under State regulations, in close coordination with MDE Water Management Administration.

This dewatering approach was applied to the Mattawoman Energy Center project. An 8-mile gas and a 10-mile reclaimed water pipeline were proposed for installation as part of the Mattawoman natural gas-fired power plant. Mattawoman calculated the duration and rate of dewatering for the first mile of the reclaimed water pipeline. The mile-long pipeline route was segregated into four segments, with the boundaries of each segment corresponding to major stream crossings. These segments were then evaluated using the methodology described above to determine if dewatering would be necessary for each segment, and if dewatering was deemed necessary, the amount of dewatering that would occur for each segment. Based on Mattawoman's calculations (confirmed by PPRP), all four segments needed an appropriation approval through a CPCN amendment. In February 2016, the Public Service Commission granted the CPCN amendment to Mattawoman to modify the ground water appropriation permit to accommodate construction dewatering for the first mile of reclaimed water pipeline.

License conditions were imposed on PEPCO to address concerns regarding worker health and safety and management and disposal of excavated materials impacted with hazardous substances, and ensure PEPCO delivers on the commitments set forth in the CPCN application. To achieve the license conditions, PEPCO was required to conduct necessary analytical testing of the soil and groundwater near the structure locations that could be affected by subsurface contamination. PEPCO was also required to prepare plans for soil and groundwater management to include plans for health and safety, excavation, containment and disposal. The License Conditions also require that PEPCO compare the results of the analytical data collected as part of the investigation to MDE's Cleanup Standards for Soil and Groundwater. Analytical data for soil must be compared to residential cleanup levels to ensure protection of residents living adjacent to the Project ROW. Should analytical data for soil exceed the MDE standards for residential soil, PEPCO must adhere to proper disposal of impacted soil at a licensed solid waste facility in accordance with MDE's solid and hazardous waste laws and regulations. Impacted soil may not remain within the Project ROW. If groundwater is determined to contain hazardous substances exceeding MDE's standards, procedures may be developed and implemented to ensure that impacted groundwater is either treated or disposed of in accordance with all applicable local, State, and federal laws and regulations.

### *Impacts to Aquatic Biota*

Electric power generation facilities have the potential to impact the state's water resources from water withdrawal, consumption and discharge during plant operations. Impacts on rivers and estuaries from surface water withdrawal and consumption may include a reduction in river flow volumes due to evaporative water loss in the plant's cooling system, as well as mortality of aquatic organisms as a result of entrainment in the cooling system, and impingement of larger organisms on cooling system intake screens as mentioned above. Elevated temperatures of receiving waters from a plant's discharge may also have an effect on aquatic resources. Impacts to fish in streams include the potential loss of habitat due to lower water levels or altered water temperature particularly during low flow periods if a plant's use of cooling water significantly affects downstream flow. Water usage and the resulting environmental impacts have been monitored by various agencies and organizations. These issues have been a major responsibility of PPRP since it was established in 1972. In systems where multiple sources of potential impacts can affect water quality and aquatic habitats, the combined effects may compound or intensify the effects of the individual sources, and accumulate in downstream areas (see Section 4.2.1 – Cumulative Effects on Biological Sources).

In addition to minimizing impacts, several power plants have instituted cooperative aquatic enhancement measures at their facilities, such as constructing and operating game fish hatcheries in cooperation with the Maryland Department of Natural Resources (DNR). Other power plants have established funds to remove fish migration obstructions caused by low-head dams no longer in use. The types of impacts identified by PPRP, along with the steps taken to minimize and mitigate these impacts are discussed in greater detail below. The impacts associated with cooling water withdrawals in the state are expected to be re-evaluated for regulatory compliance in the next several years because of EPA's revised Section 316(b) regulations of the CWA for existing power plants.

### *Cooling Water Systems*

Withdrawal Impacts

Cooling water withdrawals can cause adverse ecological impacts in three ways:

- Entrainment – drawing in of plankton and larval and/or juvenile fish through plant cooling systems;
- Impingement – trapping larger organisms on barriers such as intake screens or nets; and
- Entrapment – accumulation of fish and crabs (brought in with cooling water) in the intake region.

In the 1970s and early 1980s, PPRP evaluated impacts to aquatic organisms at eleven major power plants. The studies were used to evaluate the relative impacts of power plant operations on the aquatic environment, with special emphasis on the Chesapeake Bay (see sidebar on impingement and entrainment studies). Results of the studies showed that while power plant operations affect ecosystem elements, the cumulative impacts to Maryland's aquatic resources are not ecologically significant.

## Summary of Impingement and Entrainment Studies

Power Plants in Maryland with once-through cooling (all units are once through unless otherwise indicated; capacity values only include the units listed and not other units at the site that don't use cooling water).

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| R.P. Smith [now decommissioned] | 2 - Steam (Coal) | 114 | Potomac River (nontidal) | Ichthyoplankton losses due to entrainment would not significantly alter finfish populations or recreational fisheries in the vicinity of R.P. Smith. The estimated economic impacts due to the potential entrainment mortalities estimated at $400 (1981 $) due primarily to channel catfish losses. The overall projected ecological impact estimated at less than 0.1% of system net primary production.<br>Impingement losses to finfish populations (dominant species impinged: golden redhorse) are small and do not significantly alter finfish communities or recreational fisheries. Annual impingement losses were valued at $90 (1981 $; MMEC 1981).<br>Facility planned to meet the Phase II 316(b) regulations for impingement mortality by reducing the through-screen velocity to less than 0.5 feet per second. |

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| BRESCO | 1 - Steam (MSW) | 56 | Baltimore Harbor (tidal Patapsco) | No empirical data existed to estimate entrainment rates or address possible entrainment impacts on spawning and nursery areas in the vicinity of this facility but the potential for impacts was low based on historical distribution data. However, with a decline in pollutant loadings, spawning and nursery activities were expected to become important in the future.<br><br>Total estimated annual impingement was 80,178 finfish and invertebrates with a value of $14,702 (1987 $), with blue crabs and Atlantic menhaden accounting for 97% of this value. Blue crab, Atlantic menhaden, grass shrimp, mummichog, and Atlantic silverside composed 95% of the impingement catch at the facility (Holland et al. 1988).<br><br>No additional studies have been conducted since that time. |
| Vienna | 1 - Steam (FO6) | 153 | Nanticoke (tidal) | The profile-wire screen intake structure used for the Vienna Power Station was projected to reduce entrainment and impingement effects to levels that did not pose significant adverse environmental impacts to the affected ecosystems (DP&L, 1982).<br><br>No additional studies have been conducted since that time. |
| Calvert Cliffs | 2 - Steam (Nuclear) | 1675 | Chesapeake Bay | Calvert Cliffs was not a spawning area for species of commercial or recreational value and losses of ichthyoplankton due to entrainment did not significantly alter finfish communities in this region of the Chesapeake Bay; overall potential economic loss due to entrainment estimated at $200 annually (1980 $); overall ecological effect 0.1% of net primary productivity. Primary species entrained included bay anchovy, hogchoker, and naked goby. Ecological and economic projections suggest entrainment impacts were very limited in magnitude and spatial extent.<br><br>Numbers of fish impinged are high but estimated impingement losses were relatively low due to a high survival rate of 2 of the 4 dominant species. Dominant species impinged included bay anchovy, hogchoker, Atlantic menhaden, and spot (MMEC 1980).<br><br>From 1991 through 1995, impingement sampling was conducted weekly, four to five days per week. The estimated average annual monetary value of impingement mortality, summed over all species reported impinged at CCNPP, based on impingement from 1991-1995, is $21,458 (2007 dollars), with a standard error of $2,230 (AKRF, 2008)<br><br>Entrainment studies conducted from 1978-1980 were compared with 2006-2007 studies and some of their findings are summarized as follows: 1) All the taxa collected in 1978-1980 were also collected in 2006-2007 but composition was different; 2) The biggest difference was that hogchoker eggs, which dominated previous sampling, comprised only 0.3 percent of the total entrained in 2006 and 14.1 percent in 2007. Bay anchovy eggs ranked first |

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| | | | | both years in the recent study, comprising 64.2 percent in 2006 and 49.7 percent in 2007, but were ranked second in the past studies; 3) Density numbers were very high for hogchoker in 1978-1980 but much lower in 2007-2007; 4) Bay anchovy eggs were similar or lower in the past and much lower in the recent study. (EA, 2008). |
| Brandon Shores | 2 - Steam (Coal) (cooling towers) | 1296 | Baltimore Harbor (tidal Patapsco) | No impact assessment needed since cooling tower make-up water is withdrawn from the Wagner discharge canal; now considered part of the Wagner NPDES permit. |
| C.P. Crane | 2 - Steam (Coal) | 385 | Saltpeter and Seneca Creeks, adjacent to Gunpowder River, tributary to upper Chesapeake Bay (tidal) | Overall potential economic loss due to entrainment estimated at $300 annually (1983 $); overall ecological effect 15% of net productivity in Seneca, Saltpeter and Dundee Creeks;<br><br>1.7% of the Gunpowder-Middle River estuary and 0.04% of the upper Chesapeake Bay. Dominant species found in near-field ichthyoplankton were white perch, yellow perch, tidewater silverside, naked goby, and bay anchovy.<br><br>Impingement numbers appeared to be low and constituted only a small percentage of the total annual mortality of local stocks. Annual valuation of impingement losses ranged from $10,500 to $38,315 (1980 $). Atlantic menhaden, white perch, bay anchovy, spot, yellow perch, hogchokers, and gizzard shad were the most prominent finfish collected in impingement samples (Jacobs 1983).<br><br>Estimated total impingement of fish and invertebrates at observed cooling water flows at Crane Unit 1 was 48,620 in 2006 (March-December) and 17,678 in 2007 (January-October) (EA, 2008). The lost monetary value ($57,781 annually) under observed cooling water flow conditions was 43 percent less than for the maximum design flow calculation baseline over the 2-year study period.<br><br>Based on 2006-2007 sampling, the monetary value of the entrainment loss was estimated as the product of the estimated number of juvenile equivalents times the value per juvenile fish; that value was $28,439 annually (EA, 2008). |
| Riverside | 1 - Steam (NG) | 78 | Baltimore Harbor (tidal Patapsco) | Analysis of entrainment effects on the fish community not possible due to lack of an estimate of population size. The area of the Patapsco River in the vicinity of the plant was judged to be of minor importance as a spawning and nursery area as compared with other areas of the Chesapeake Bay. Total annual estimated impingement catch was 85,597 fish and shellfish with a value of $10,930 (1980 $; EA, 1980).<br><br>No additional studies have been conducted; plant scheduled to close June 2016. |

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| H.A. Wagner | 4 - Steam (1 - NG, 2 - Coal, 1 - FO6) | 1006 | Baltimore Harbor (tidal Patapsco) | Entrainment effects were potentially large, with estimated proportions of adult populations lost of 18% or more for at least one species; up to 49% of the local population of bay anchovy and 27% of silversides could be lost due to entrainment. The economic value of entrainment losses was insignificant but 3.3 to 5.3 % of net system production may be lost due to entrainment. As a result of these findings, ANSP (1994) conducted an entrainment impact study which found entrainment to be 37% to 75% lower for bay anchovy and 82% to 90% lower for naked goby, based on detailed field densities. Nevertheless, the annual losses from entrainment at Wagner could be valued at $109,000. Although losses are high, retrofitting the facility with wedge-wire screens or cooling towers would be disproportionate with the effect.<br><br>Impingement losses of finfish have been valued at $71,859 annually and blue crab losses at $16,686 (1988 $). The two most prominent species impinged were spot and Atlantic menhaden (Shaughnessy, 1990).<br><br>During the March 2006 through March 2007 study period a total of 232,174 (± 46,057 at 80 % confidence interval) fish and invertebrates was estimated to have been impinged at Wagner based on actual flow data (EA, 2007). Estimate of annual monetary value of impingement mortality for species identified in state regulations is $43,269 ± $7,679 (AKRF, 2008).<br><br>During the March 2006 through the March 2007 study period a total of 206,583,952 individuals (fish eggs, larvae, juveniles, adults) were estimated to have been entrained at Wagner based on actual flow data (EA, 2007). Comparisons with 1994 analyses indicate that conditions have not changed in a way that would suggest that these impacts from entrainment are greater than estimated in the 1994 analysis (AKRF, 2008). |

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| Chalk Point | 2 - Steam (Coal) (once-through) | 682 | | Species potentially affect included bay anchovy, silversides, naked goby, and hogchokers; overall potential economic losses to recreationally and commercially important species due to entrainment estimated at <$3,000 annually (1985 $); overall calculated ecological loss ("unutilized" energy) estimated at 8% for these species. Loss of bay anchovy in the estuary due to entrainment was approximately 14 to 51% (most probably 20 to 30%) annually (Versar, 1989), which was a significant adverse impact. PEPCO (Loos and Perry, 1989) calculated the value of the entrainment losses at $150,000 per year (1989 $) based on its loss estimates. PEPCO also calculated the cost of BTA alternatives (cooling towers and wedgewire screens) as ranging from $10,000,000 to $288,000,000 (1989 $). According to PEPCO, the alternatives evaluated varied in effectiveness in reducing entrainment from almost none to 100%. Impingement losses estimated at $180,600 annually (1983 $; MMES, 1985).<br><br>A mitigation plan was developed as a result of a number of factors, including the fact that there was a substantial difference between the cost of requiring BTA (such as cooling towers) and the environmental benefits. There was also substantial uncertainty about the magnitude of benefits and the nature of the impacted species. Chalk Point's NPDES permits prior to 2001 required PEPCO to spend $200,000 per year on striped bass aquiculture or other species as requested by the Maryland Department of Natural Resources (DNR), and $50,000 per year for aquaculture of yellow perch or other species as agreed upon by DNR. This permit condition contemplated the production of 200,000 striped bass and 50,000 yellow perch per year. The permit also required PEPCO to provide $100,000 per year to the state for environmental education or for projects to remove obstructions to anadromous fish.<br><br>A barrier net was installed and has been in operation for over 20 years. Studies to quantify the barrier net performance estimate an impingement reduction in excess of 80% (EPRI, 2010).<br><br>An analysis of some more recent ichthyoplankton data collected during five sampling events in April and May of 2005 determined some changes for potential entrainment effects for anadromous and semianadromous spawners that include white perch, striped bass, herring species and yellow perch. The estimates suggest potential effects to some of these species, but due to numerous uncertainties, new studies would be required to produce reliable entrainment and fractional loss estimates (EPRI, 2010). A 2-year entrainment study is being conducted for 2015 and 2016. |
| Chalk Point | 2 - Steam (FO6, NG)(cooling towers) | 1224 | Patuxent River (tidal) | No impact assessment was needed since cooling tower make-up water is withdrawn from the Chalk Point once-through discharge canal. |

| Plant Name | No. of Units & Primary Fuel Type | Capacity (MW) | Water Body | Entrainment and Impingement Studies and Conclusions |
|---|---|---|---|---|
| Dickerson | 3 - Steam (Coal) | 546 | Potomac River (nontidal) | Species potentially affected included spottail and spotfin shiners, channel catfish and redbreast sunfish; overall potential economic loss due to entrainment estimated at $1,000 annually (1980 $); overall ecological effect 0.1% of net primary productivity. (Summers and Jacobs, 1981). Estimated monetary value for the total number of fish impinged in one year was $11,282 (1979 $). Predominant species impinged was spottail shiner (ANSP 1979).<br><br>The 2005-2006 annual impingement estimate was considerably lower than the 1978 estimate while the overall seasonal pattern in impingement was similar between years (EPRI, 2008). Estimated annual impingement monetary value was estimated as about $200 based on this study. For the 2005-2006 studies, it appears that the entrainment impact (i.e. equivalent adult channel catfish loss) remained the same but impingement impact was greatly reduced. Entrainment studies will occur again in 2016. |
| Morgan-town | 2 - Steam (Coal) | 1164 | Potomac River (tidal) | Species potentially affected included silversides, bay anchovies, naked goby; overall potential economic loss due to entrainment estimated at 0.1% or $5,200 annually (1979 $); overall calculated ecological loss (“unutilized” energy) estimated at 0.35%. (Polgar et al. 1979). Principal fish species impinged were Atlantic menhaden, white perch, and spot. Estimated mean losses and death due to impingement was 1,191,989 individuals valued at $144,066 (1977 $; ANSP, 1977).<br><br>A one year impingement study was conducted from September 2006 to August 2007. This study determined the current annual impingement estimate to be 373,919 fish and blue crabs based on actual cooling water flow. (EPRI, 2009). Impingement loss was estimated to be approximately $35,520 based on the best estimate of impingement survival. Entrainment sampling was conducted in 2006-2007 for one year and another year of studies will be conducted in 2016. |

Source: Historical information from the 1980s adapted from: PPRP-127 Maryland Power Plant Cooling Water Intake Regulations and Their Application in Evaluation of Impact, 2002. Recent information summarized from various Comprehensive Demonstration Studies

Although entrainment losses of aquatic organisms were measured, they did not reveal consistent depletions of populations. Even then, some power plants modified their operating procedures and one constructed on-site hatchery facilities for fish stocking operations. They also provided funding to remove blockages to migratory fish and developed improved intake technologies and other modifications to reduce entrainment or impingement. Section 316(b) of the federal Clean Water Act requires power plants to use cooling water intake structures (CWIS) that reflect the best technology available for minimizing adverse environmental impacts. After several decades, the U.S. EPA implemented a final rule on requirements for CWIS at existing facilities (see sidebar).

## Clean Water Act Section 316(b)

EPA's implementation of Clean Water Act (CWA) Section 316(b) has resulted in updated assessments of the impacts of cooling water withdrawals. EPA's regulation included three phases of implementation: Phase I applied to new facilities constructed after January 2002 with cooling water intake; Phase II, effective September 2004, applied to existing power-producing facilities, with cooling water intake designed for greater than 50 mgd (the regulations would be applied at the time the facility renewed its National Pollutant Discharge Elimination System (NPDES) discharge permit); and Phase III applied to non-power producing facilities.

Maryland has eleven existing steam electric power plants with an NPDES permit and a cooling water intake and discharge. Of these, two plants were below the 50 mgd design threshold for Phase II facilities (Warrior Run and Vienna), one was classified as exempt from the new regulations (Wheelabrator/Baltimore RESCO), and the remaining eight (Calvert Cliffs, Chalk Point, C.P. Crane, Dickerson, Gould Street, Morgantown, Riverside, and Wagner-Brandon Shores) have conducted Phase II evaluations.

The Phase II regulations established specific performance standards for reduction of impingement and entrainment, and identified five compliance alternatives for using best technology available to minimize adverse environmental impact at facilities. However, as a result of a lawsuit by several environmental groups, states, and industry groups, the U.S. Court of Appeals made a ruling on Phase II, rejecting many of its provisions (Riverkeeper et al. v. USEPA, decided January 2007). A portion of this ruling with respect to the cost-benefit test was appealed to the U.S. Supreme Court. The court ruled in 2009 that the cost-benefit test is allowed; specifically, the court stated: "The EPA permissibly relied on cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations." EPA proposed a revised rule for public comment in 2011, addressing the other issues required by the Riverkeeper case and the U.S. Supreme Court ruling on cost-benefit testing. PPRP submitted comments on the proposed rule. The EPA finalized the standards in 2014.

The new rule includes the following requirements, which facilities in Maryland that withdraw at least 2 million gallons per day will need to address in the coming years:

- Facilities are required to choose one of seven options to reduce fish impingement.
- Facilities that withdraw at least 125 million gallons per day (mgd) must conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms.
- New units added to an existing facility are required to reduce both impingement and entrainment that achieves one of two alternatives under national entrainment standards.
- One year of impingement studies and 2 years of entrainment studies (for facilities withdrawing greater than 125 mgd) must be conducted within the last 10 years. Some facilities already conducted some or all of these studies while others need to conduct additional studies.
- All facilities subject to the new rule will need to conduct economic and engineering studies to comply with the new rule as their NPDES permits are renewed.

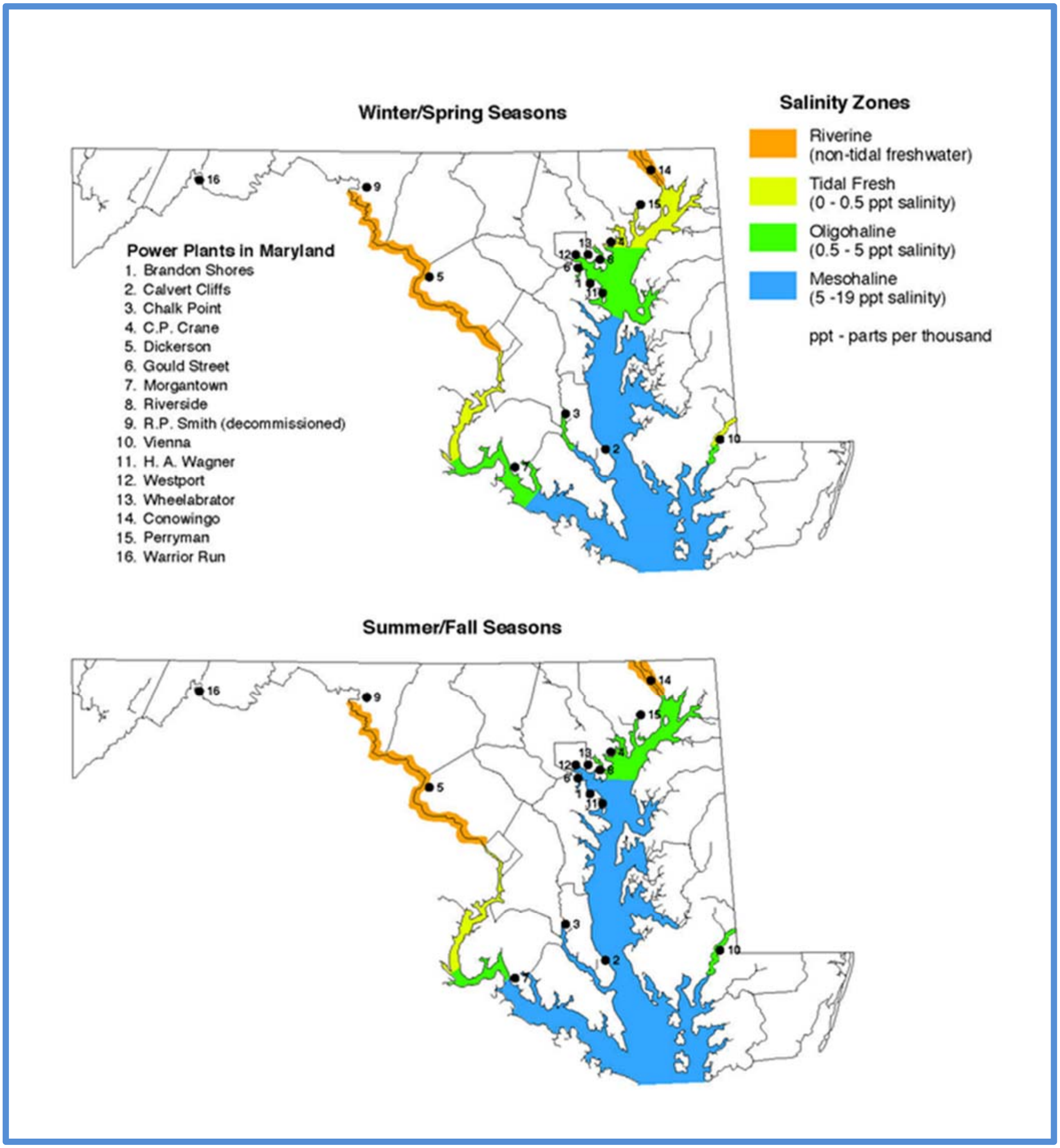
<u>Discharge Impacts</u>

Impacts to aquatic biota from power plant cooling water system discharges include elevated temperatures, discharge of chemicals used for biofouling treatment (e.g., chlorine), discharge of metals eroded from internal plant structures (e.g., copper), and, in the case of Maryland's only nuclear power plant, discharge of radiological materials (see Section 4.5 for more information). Each of these impacts is discussed below.

***Thermal Changes***

Biological impacts from heated effluents depend upon the magnitude and duration of the temperature difference between discharge water and receiving water. Small organisms that pass through a plant's cooling system experience the greatest temperature stress, both in magnitude and duration. Exposed organisms in the receiving waters are more likely to experience smaller increases in temperature of shorter duration due to dispersion of the thermal plume and mobility of most of the exposed aquatic biota (e.g., fish, blue crabs). PPRP and plant owners conducted studies to determine the effects of thermal discharges at each existing power plant in the state. Because different aquatic biota occupy different salinity regimes in Maryland waters, study results are presented here according to the habitats where power plants are located (see Figure 4-18). Below is a brief summary of the findings in those studies.

*Figure 4-18 Salinity Zones of the Maryland Chesapeake Bay*




**Mesohaline Habitat** – The largest power plants (by generating capacity) in the state discharge into mesohaline habitat (5-19 parts per thousand (ppt) salinity) during all or part of the year. PPRP studied thermal discharges from the Chalk Point, Morgantown, Calvert Cliffs, and H.A. Wagner power plants as part of extensive fieldwork in the 1970s and 1980s. Thermal plume dimensions for these power plants varied with season, tidal stage, wind velocity and direction, and plant operating levels.

The effects of thermal discharges from the power plants located in the mesohaline habitats of the Chesapeake Bay are localized and not considered significant. PPRP found no cumulative adverse impacts to the habitats of the Chesapeake Bay ecosystem. However, PPRP will continue to evaluate the habitats if additional power plant discharges are proposed; new technology would then be considered to reduce thermal discharges. More recently, PPRP studies have evaluated the potential effects of power plant discharges on diving ducks and their food resources.

**Tidal Fresh and Oligohaline Habitat –** Two plants, Vienna and C.P. Crane, discharge into tidal fresh (0-0.5 ppt) and oligohaline waters (0.5-5 ppt). Chalk Point also discharges into the oligohaline zone during part of the year. PPRP studies showed that the thermal plume at Vienna was small and its discharge effects were negligible. The thermal plume at C.P. Crane affected about 40 percent of the volume of the receiving water embayment. C.P. Crane effluents also resulted in a slight increase in nearfield salinity due to plant-induced changes in the nearby bay circulation pattern, but these factors did not affect nearfield dissolved oxygen.

In the early 2000s, MDE required studies at C.P. Crane to repeat some of the historical fishery surveys conducted in the late 1970s, as a condition for NPDES permit renewal. The purpose of the surveys was to demonstrate that the fish populations in the vicinity of the C. P. Crane power plant remain unaffected by its thermal discharge. The study showed that differences in the fish community apparent between the 2003-2005 results and the results of the 1979-1980 study reflect long-term changes in the upper Bay fish community and are not suggestive of a plant discharge effect. The results also suggest that the thermal discharge does not consistently affect the fish community’s composition or distribution.

Findings at the plants in these tidal fresh and oligohaline habitats were consistent with those at facilities in mesohaline areas. Thermal discharge effects were small and localized. PPRP studies found no evidence that fish movements were blocked by thermal plumes in the plants’ receiving waters in these particular habitats.

**Nontidal Freshwater Habitat –** Dickerson is the only Maryland power plant that uses once-through cooling and is located in nontidal riverine habitat. The thermal impact of power plant discharges on the Potomac River ecosystem was assessed in a long-term freshwater benthic study conducted by PPRP over an eight-year period in the 1980s. While this long-term study documented that the thermal discharges from Dickerson had an adverse impact on benthic communities in the immediate area of the discharges, these effects were localized. The affected percentage of the total river bottom is very small. To assess whether these localized impacts on benthic communities may be affecting fish populations within the river, the discharge permit for the Dickerson facility included a requirement for a multi-year study of growth and condition of several fish species in the vicinity of the plant. Based on data on fish condition collected over a 21-year period near the plant and at reference locations, there was no indication that fish near the plant were affected by the localized discharge effects on benthic communities.

### *Discharge of Chemical Contaminants*

Concerns regarding the impacts of copper and chlorine discharged from cooling water systems into sensitive waters of the Chesapeake Bay watershed in the late 1970s and early 1980s led to extensive studies by PPRP as well as others.

**Copper –** In the late 1970s and early 1980s, oysters in the vicinity of the Chalk Point, Calvert Cliffs, and Morgantown power plant discharges were found to be bioaccumulating copper that was present in the effluent discharge. The copper resulted from corrosion of the copper condenser tubes within the plants' cooling systems. While PPRP studies showed that oyster growth and survival were not adversely affected, the elevated levels of copper concentrations in oysters posed a potential risk to the health of individuals who might consume them. Power plants replaced the copper condenser tubes with titanium tubes where this problem was most significant, primarily in estuarine waters. The titanium tubes eliminated the metals corrosion, which also resulted in less maintenance on the condenser tubes. Currently, NPDES permitting for all power plant discharges includes an evaluation of maximum discharge levels for copper (as well as other metals) to protect human health and the environment.

**Chlorine –** This substance is sometimes used by power plants to control bio-fouling of condenser tubes in cooling water systems. While it may be an effective means of controlling biological organisms within the cooling system, it can also cause mortality in the aquatic biota of the receiving water body. Presently, the NPDES permits for all power plants in Maryland require that chlorine not be discharged into the state's waters for more than two hours in any one day from any one unit, and no more than one unit may discharge at any one time. An exception may be granted if a facility demonstrates that more chlorination is needed to control macroinvertebrates. Chlorinated discharge impacts are now considered resolved and no further action is needed.

### *Wastewater Discharges*

Wastewater discharged from coal ash ponds, air pollution control equipment, and other equipment at power plants can contaminate drinking water sources, impact fish and other wildlife, and create other detrimental environmental effects. Although air pollution controls have made great strides in reducing emissions from power plants, some of the equipment used to clean air emissions does so by "scrubbing" the boiler exhaust with water ("wet" flue gas desulfurization (FGD) systems), which then can pollute rivers and other receiving water bodies. Treatment technologies are available to remove these pollutants before they are discharged to waterways, but these systems have been installed at only a fraction of the power plants. Types of treatment systems for FGD systems include settling ponds, chemical precipitation, biological treatment, constructed wetlands, and zero-liquid discharge.

In 2009, EPA completed a multi-year study of power plant wastewater discharges and concluded that current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades. As part of this multi-year study, EPA measured the pollutants present in the wastewater and reviewed treatment technologies, focusing mostly on coal-fired power plants. Many of the toxic pollutants discharged from these power plants come from coal ash ponds and the FGD systems used to scrub $SO_2$ from air emissions. In 2009, EPA announced plans to revise the existing standards for water discharges from coal-fired power plants to reduce pollution and minimize its adverse effects. More information about EPA's study is provided in a report that was published later that year.

EPA issued a proposed rule to amend guidelines and standards for the steam electric power generating industry in 2013 and took final action in November 2015. Now that the new rule for electric power plants has been finalized, EPA and states are incorporating the new standards into wastewater discharge permits.

In addition to the contaminants covered under EPA's effluent guidelines, and as a result of the implementation of the Chesapeake Bay TMDL, all dischargers with NPDES permits, including industrial dischargers such as power plants, will have reduced limits on total nitrogen, total phosphorus, and sediment.

***Hydroelectric Facilities***

Maryland has only two large-scale hydroelectric projects (with capacities greater than 10 MW): Conowingo Dam (see discussion below) on the Susquehanna River and Deep Creek Lake in Western Maryland; however, five additional small-scale facilities also generate electricity within the state (see map and table in Section 2.1.5). Hydroelectric facilities may present special environmental concerns that are not encountered at steam electric power plants. Development and operation of hydroelectric facilities causes three main types of impacts:

**Changes in water quality –** Impoundments created for hydroelectric dams significantly alter river flow from free-flowing streams to deepwater flow. This alteration causes changes in natural water clarity, thermal stratification, and lower dissolved oxygen concentrations upstream of the dam, which, in turn, may result in low dissolved oxygen levels in the water discharged from the dam.

**Changes to flow regime –** Operating hydroelectric facilities in a peaking mode (in response to peak electrical demand) produces unnatural and frequently extreme water level fluctuations in impoundments as well as downstream from the dams. Additional small-scale projects may also divert some flow away from the natural streambed. Fluctuations in water level and flow may reduce fish abundance as well as important food sources essential to fish growth and survival. In addition, large hydroelectric dams allow suspended sediments to accumulate in the impoundment resulting in reduced storage, reduction in navigational waters, and changes in the timing and distribution of sediment and associated nutrients downstream of the dam.

**Direct adverse effects on fish populations –** Dams prevent the natural upstream and downstream movement of both resident and migratory fish species. Entrainment of fish attempting to move downstream past the dam may cause mortality due to the turbines. Factors that affect fish mortality include the type of turbine, the proportion of flow diverted through the turbine, and the size of fish.

<u>Susquehanna River Migratory Fish Restoration</u>

Historically, the Susquehanna River supported large spawning runs of migratory species such as American shad, river herring, striped bass, and American eel. The massive <u>diadromous</u> fish migrations extending as far upstream as Cooperstown, New York, were eliminated with the construction of four major hydroelectric facilities on the lower Susquehanna in the early 1900s (Maryland’s Conowingo Dam, and Holtwood, Safe Harbor, and York Haven dams in Pennsylvania).

By the year 2000, restoration programs had been operating for nearly 30 years, and fish passage devices had been installed at all four hydroelectric facilities, partially re-opening the Susquehanna River to migratory fish. This has created the potential for shad and other migratory fishes to move as far upstream as New York State, representing renewed access to well over 400 miles of historic habitat. However, fish passage has only been partially successful to date and additional studies are being conducted at several of the lower river projects to address these issues as part of relicensing.

Growth of the Susquehanna River shad stock in response to the restoration efforts and installation of fish passage devices has been problematic. Growth peaked in 2001, when nearly 200,000 American shad were passed over Conowingo Dam, but has since declined for reasons that are the subject of ongoing studies and potential mitigation measures (see Figure 4-19). The 2014 fish passage data indicate that only 24.2 % of what passed Conowingo passed Holtwood. The Holtwood numbers have historically been low, but better fish passage made in conjunction with recently added generation resulted in a large increase to over 63% of fish that had passed Conowingo in 2015 and 47% in 2016. Long-term (2000-2016), Safe Harbor has passed 76% of what passed Holtwood, but York Haven only passed 13% of what passed Safe Harbor. PPRP, working with dam owners and other state and federal agencies, is continuing efforts to enhance upstream migratory fish passage as well as safe downstream passage of juveniles through operational and/or engineering modifications.

Similar to shad, American eels likely occupied the majority of the Susquehanna Basin, but have been restricted from accessing the majority of the Susquehanna since the mainstem dam construction. Eel densities in the tributaries to the lower Susquehanna River below Conowingo Dam are higher than other Chesapeake Bay tributaries. Young eels may be attracted to the discharge of the Susquehanna River, but they are unable to migrate up the mainstem. The loss of eels, one of the most abundant fish in the watershed, has additional effects on the Susquehanna River ecosystem. The freshwater mussel, eastern elliptio (*Elliptio complanata*) is the most abundant mussel species in the mid-Atlantic, but its abundance in the Susquehanna River is lower than other regional watersheds (i.e., Delaware River). Freshwater mussels require a host, usually a fish, to complete their reproductive cycle. Eels serve as an important host species for eastern elliptio in the region and their disappearance from the watershed has likely played a significant role in the limited abundance, size, age, and recruitment of their populations.

Since 2009, the U.S. Fish and Wildlife Service (USFWS) has operated an eel ramp to capture juvenile eels below Conowingo Dam and move them upstream. The goal of this program is to move 1 million eels to designated locations within the watershed to not only restore mussels but to restore the ecological balance. Eels quickly bring balance back to the ecosystem by their predation on small fishes and crayfish.

The collected number of elvers (young eels) increased from 2009 through 2013 (Table 4-4); however, the past two years (2014-2015) have seen a decline in the number collected. The 58,444 elvers collected in 2015 was below the 11-year average of 76,040. This could be related to the unusual weather conditions in 2015, or this long-term trend could be related to natural variability in eel numbers.

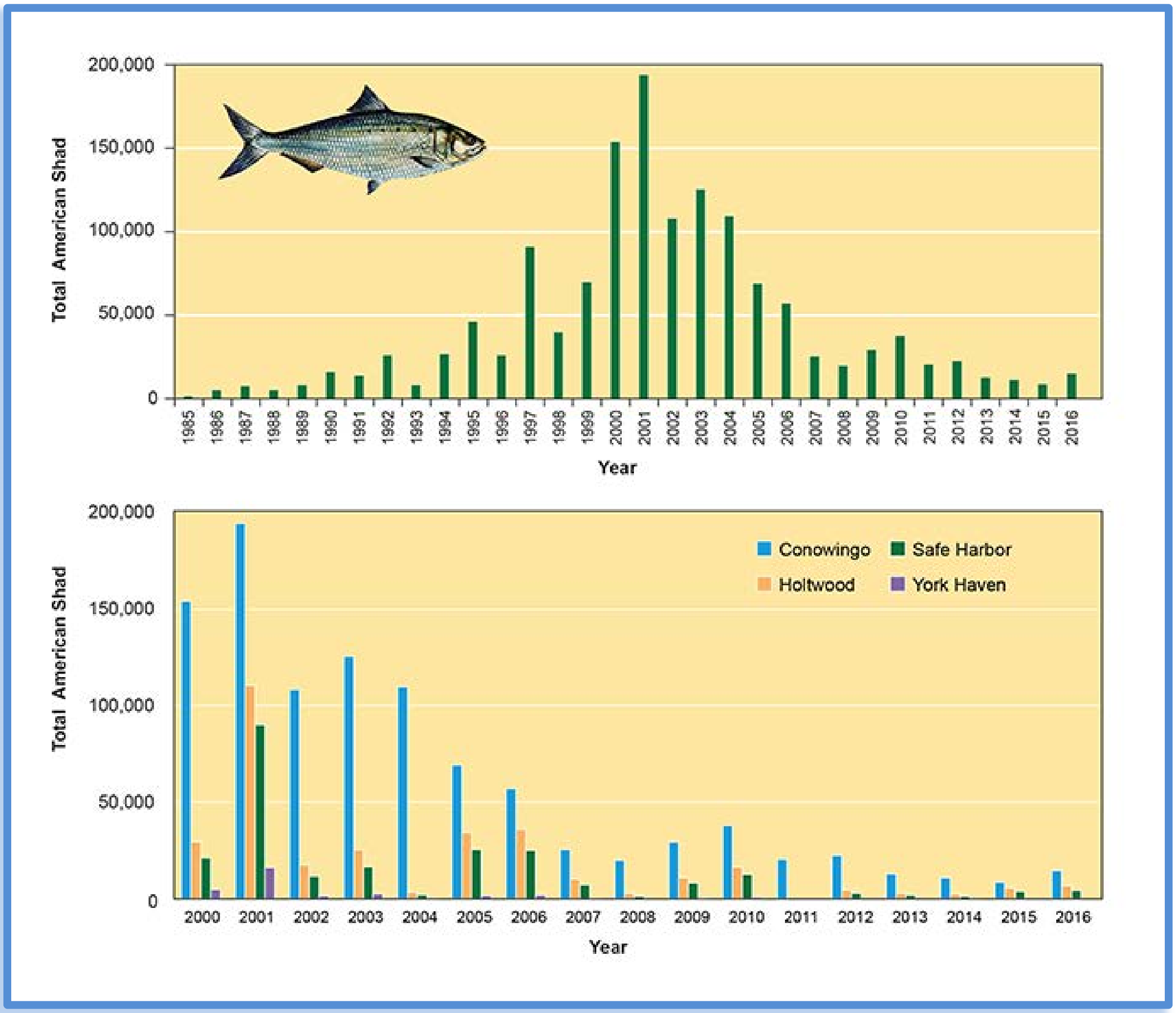
*Table 4-4 Total number of Elvers Collected, by Year, at Conowingo Dam, Maryland*

| Year | Total elvers collected |
|---|---|
| 2005 | 42 |
| 2006 | 19 |
| 2007 | 3,837 |
| 2008 | 42,058 |
| 2009 | 17,437 |
| 2010 | 23,856 |
| 2011 | 84,961 |
| 2012 | 127,013 |
| 2013 | 293,141 |
| 2014 | 185,628 |
| 2015 | 58,444 |

Source: USFWS, 2015. American Eel: Collection and Relocation Conowingo Dam, Susquehanna River, Maryland. 2015.

The FERC licenses for three of the five lower Susquehanna facilities (Conowingo, Muddy Run, and York Haven) expired at the end of 2014, and agency consultation on relicensing has been underway since 2009. Licenses have been renewed for York Haven and Muddy Run, but studies on sediment, fish passage, and downstream flow are continuing for the relicensing of Conowingo (see further discussion below). Holtwood and Safe Harbor project licenses expire in 2030.

*Figure 4-19 Number of American Shad Passed at Conowingo Dam from 1985 – 2016 and at Conowingo East, Holtwood, Safe Harbor, and York Haven Dams from 2000 – 2016*




Sources: http://www.fishandboat.com/Fish/PennsylvaniaFishes/Pages/SusquehannaShad.aspx

## Conowingo Hydroelectric Project Relicensing

The Conowingo Dam completed in 1928 created the 8,500 acre Conowingo Pond (reservoir); additional generating units added in the 1960s and upgrades in the recent decade resulted in the 573 MW Conowingo Hydroelectric Project. In addition to the types of impacts mentioned that are generally caused by hydroelectric facilities, impacts specific to Conowingo also include increased evaporation and sedimentation. The Conowingo Pond also supports other generating facilities nearby in Pennsylvania, including the 2,186 MW Peach Bottom Atomic Power Station, the 800 MW Muddy Run Pumped Storage Project and the 1,100 MW York Energy Center, as well as municipal water supply for Baltimore City and Chester, PA.

The federal license to operate the Conowingo Project (owned by Exelon) expired in August 2014, along with the licenses of two other hydroelectric projects in the lower Susquehanna River in Pennsylvania (Muddy Run, also owned by Exelon, and York Haven; licenses for these 2 projects have since been renewed for 40-year terms). Licenses for the other two lower Susquehanna River hydroelectric projects expire in 2030 (Holtwood and Safe Harbor). The Federal Energy Regulatory Commission (FERC) has the authority to issue the license for Conowingo, although with significant regulatory input from Maryland (with PPRP as the lead for the state) and other federal agencies. Studies and discussions have been taking place since 2009 between Exelon and various natural resource agencies and other interested parties. Relicensing participants include FERC, Exelon, Maryland (DNR and MDE), Pennsylvania (Fish and Boat Commission and Department of Environmental Protection), U.S. Fish and Wildlife Service, National Marine Fisheries Service, National Park Service, Susquehanna River Basin Commission, The Nature Conservancy, and the Lower Susquehanna Riverkeeper.

Exelon submitted to FERC a Final License Application in 2012 for continued operation of the Conowingo project. PPRP coordinated all Maryland agency reviews and provided input on various studies and the license application for FERC to consider as part of its review. Principal issues that were the subject of multi-year studies based on recommendations from PPRP include sediment and nutrient management, upstream and downstream fish passage (for migratory species such as American shad, river herring and American eel), flow and water level management, dissolved oxygen (DO) levels, debris management, land conservation and recreation. PPRP's goal is to develop appropriate protection, mitigation, and enhancement (PM&E) measures in consultation with MDE and other resource agencies, and ultimately to reach agreement on license conditions prior to issuance of a final license by FERC. Such a license will contain state-mandated license terms contained in the state's Water Quality Certification (WQC) for the project; a 3-year sediment/nutrient study funded by Exelon is underway to provide information for the WQC. Fishway prescriptions issued by the USFWS were also the subject of negotiations between the USFWS and Exelon. FERC issued a notice in 2013 declaring that the project is Ready for Environmental Analysis and subsequently prepared an Environmental Impact Statement in preparation for issuing a new license, pending issuance of the state's WQC and the USFWS fishway prescription. In the meantime, Conowingo will continue operating under existing requirements with annual licenses until a new one can be issued. A fishway prescription issued by the USFWS was the subject of extended negotiations between the USFWS and Exelon and was issued in May 2016. In that prescription, Exelon agreed to implement improvements to the existing fish passage facilities within three years of the renewal of its federal license. The initial items to be constructed include:

- Modifying the East Fish Lift to provide 900 cubic feet per second of attraction flow.
- Replacing the current 3,300-gallon hopper at the East Fish Lift with two 6,500-gallon hoppers.
- Reducing cycle time at each hopper at the East Fish Lift to be able to lift fish four times per hour.
- Completing modifications to the East Fish Lift structure to allow for trapping and sorting fish at the East Fish Lift facility and transporting them to the western side of the dam to a truck for transport upstream.
- Modifying the West Fish Lift to facilitate trap and transport.
- Constructing and maintaining structures, implementing measures, and/or operating the Project to provide American shad and river herring a zone of passage to the fish passage facilities.

- Evaluating potential trapping locations for American eel on the east side of Conowingo Dam including Octoraro Creek starting in May of the first calendar year after license issuance or immediately if license issuance occurs during the upstream American eel migration period.

In addition to these initial construction items, Exelon will trap and transport American shad and river herring from Conowingo to above the York Haven Hydroelectric Project beginning the first fish passage season after license issuance. Exelon also has committed to trap and transport American eels at the west side of Conowingo Dam.

Exelon will also conduct periodic efficiency tests of migratory fish passage through its improved facilities. If the project doesn't achieve specified passage goals, additional mitigation measures from a tiered list of items will be implemented to make further improvements in passage efficiency throughout the term of its license.

***Other Generation Facilities***

In March of 2013, the Maryland legislature passed a bill supporting offshore wind. Although no offshore wind energy projects have been constructed in the U.S., a number of large projects have been proposed, most in shallow waters (<30 m depth) off the Atlantic Coast. The development of large offshore wind farms will also require underwater transmission infrastructure, such as the proposed Atlantic Wind Connection (see Section 5.5.1 for detailed description of legislation and project), which has the potential to impact natural resources in this region. Effects on marine resources and on avian and bat populations from the construction and operation of these offshore generation facilities will need to be fully evaluated. Risks range from mortality due to collisions with turbines to exposure to chemicals resulting from accidental spills. Migratory routes, breeding and feeding areas could be affected. High fatalities of several species of bats have been recorded at land-based wind energy projects especially in the eastern U.S. Electric transmission from wind farms also creates electromagnetic (EMF) fields which are known to affect the behavior of some fish, such as eels, rays, and sharks.

*Impacts to Rare Threatened and Endangered Species*

The potential effects of the construction and operation of generation facilities on Maryland's rare, threatened and endangered species (RTE) need to be considered for every project. For example, the state-endangered Northern Map Turtle (*Graptemys geographica*) occurs only in the lower Susquehanna River in Hartford and Cecil Counties in Maryland, which is the eastern edge of its range. Impacts from habitat modification and human recreation are of special concern for Map Turtles in Maryland. Flows of the lower Susquehanna River are influenced by generation from the Conowingo Hydroelectric Dam and the river below the dam is heavily used for recreational activities. Given the potential impacts of the Conowingo Hydroelectric Dam and associated human recreational use of the river, the Maryland DNR funded a three-year study to examine the status, distribution, and ecology of Northern Map Turtles in Maryland. A full list of the State's RTE species can be found at http://dnr2.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx.

Federally listed threatened and endangered species that occur in the Chesapeake Bay and coastal waters of Maryland that could potentially be affected by offshore generation facilities include fish, whales, and sea turtles (see http://www.fws.gov/chesapeakebay/EndSppWeb/LISTS/specieslist-md.html for complete list). Except for sea turtle nesting habitat, principal responsibility for these species is vested with the National Oceanic and Atmospheric Administration Fisheries.

#### *Cumulative Effects on Biological Resources*

Although permit requirements and regulations may not require an assessment of cumulative effects, the health of the contiguous ecosystem is determined by the impact of multiple influences. PPRP has conducted aquatic impact assessment studies at all of Maryland's existing plants and has identified no measurable cumulative adverse impacts on water resources. MDE issues discharge permits, in accordance with the CWA, and uses aquatic impact assessment data to monitor continued performance of power plants to minimize these impacts. Cumulative effects of additional generation facilities such as offshore wind will need to be considered.

### 4.2.2 Transmission Lines

#### *Effects on Streams, Rivers, and Watersheds*

Construction of transmission line rights-of-way (ROW) across or alongside streams and rivers may result in temporary ecological impacts during construction as well as permanent habitat degradation. Constructing and maintaining transmission lines can also affect streams near the ROW both directly and indirectly. The primary direct effects are caused by construction or maintenance vehicles crossing or working within stream beds, floodplains, or bank areas, which may release sediment, construction debris, and contaminants into the stream. Vulnerable aquatic or riparian zone species may also be disturbed by noise, dust, and construction-caused changes in drainage patterns or soil. Tree removal during construction can result in immediate as well as long-term soil erosion that increases sediment loads in streams.

Large rivers may be too wide to avoid placing towers directly adjacent to the water, or within the river itself. For example, the 500 kV line crossing the lower Potomac River near Moss Point, shown in Figure 4-20, includes six towers in the river and a parallel set of towers has been proposed to support a second circuit. All of Maryland's major rivers, both tidal and nontidal, are crossed by transmission lines. At present, only one of these crossings — SMECO's transmission line between St. Mary's County and Calvert County near the mouth of the Patuxent River — is accomplished by a cable beneath the river. Potential impacts from transmission support structures placed in the riverbed include disturbance to fish and bottom dwelling organism habitat, redirection of water currents and erosion patterns, and potential hazards to navigation and commercial fishing. Above the waterline, the towers may provide nesting and roosting opportunities for some birds, while other birds may collide with the towers or the wires between them.

Special care must also be taken to protect and enhance first order streams. Any effects that propagate downstream, such as warmer water temperatures or increased sediment load, will also be detrimental downstream. In lower reaches of the watershed, the synergistic effects could cause a shift in water quality, initiate changes in aquatic species composition, or modify the configuration of the drainage channel. For this reason, protection of headwater streams – including small swales, creeks, vernal pools, wetlands, etc., that are the origins of most rivers – has been emphasized by State agencies. To minimize effects to streams, the State agencies typically recommend that towers be located as far from stream banks and their buffers as possible, and require vegetation and construction management practices that minimize the movement of disturbed soil and construction debris toward streams.

*Figure 4-20 Existing 500-kV Transmission Line Crossing of the Potomac River*

### General Impacts to Surface Waters

Construction and maintenance of transmission lines and their associated ROWs are known to affect freshwater streams through loss of vegetation and shading, bank erosion and sedimentation during construction, and herbicide contamination during maintenance activities. Long-term effects of increased water temperature due to clearing and runoff from maintenance treatments also elicit concern. These effects can be minimized with good practices. In areas where streams are already degraded, effective maintenance practices can assist restoration, particularly with landowner and community participation.

Removing trees in or adjacent to a transmission line ROW may be necessary to maintain adequate clearance between taller vegetation and transmission line conductors. It also allows equipment to access the ROW during construction and maintenance. Such clearing can affect streams in a variety of ways, but soil erosion is the most damaging. The root systems of trees are important for preventing erosion and slumping of the banks of rivers and streams. Soil erosion resulting from removing trees often produces increased sediment loads in streams, leading to changes in stream morphology and diminished water quality, which ultimately degrade the biological resources of the stream.

Removing vegetation from the riparian area reduces stream shading and decreases the amount of leaf litter, woody debris, and rootwads present in the stream system. This may result in increasing water temperatures and a reduction in habitat and food sources that threaten survival and reproduction of cold water species, including brook trout. No strong effect of a single transmission line ROW on average stream temperature has been documented, but protection of coolwater or coldwater habitat is advisable as a cautionary measure. In most cases, long-term effects can be minimized by placing transmission line towers sufficiently far from the stream that the wires span the stream and associated riparian area. This configuration is particularly effective at reducing impacts when natural vegetation is maintained in the riparian area. However, many ROWs that have been managed in traditional ways or that have towers or poles on the stream banks are entirely cleared to the edges of the stream.

Even following best practices, the construction and maintenance of transmission lines and their ROWs can inadvertently introduce contaminants into a stream ecosystem. Any spills that occur during the construction phase of the project (e.g., gasoline or oil from construction equipment) must be contained immediately and removed to the maximum extent possible. In order to manage the vegetation in the ROW after the construction phase is completed, pesticides and herbicides may be applied to the vegetation in the vicinity. Excessive application, wind-blown spray, and uncontrolled runoff of these chemicals may deposit them in streams and degrade water quality and, ultimately, damage the biological resources that are present. The PSC requires that EPA-approved substances that degrade quickly and that have minimal side effects be used for vegetation management. .

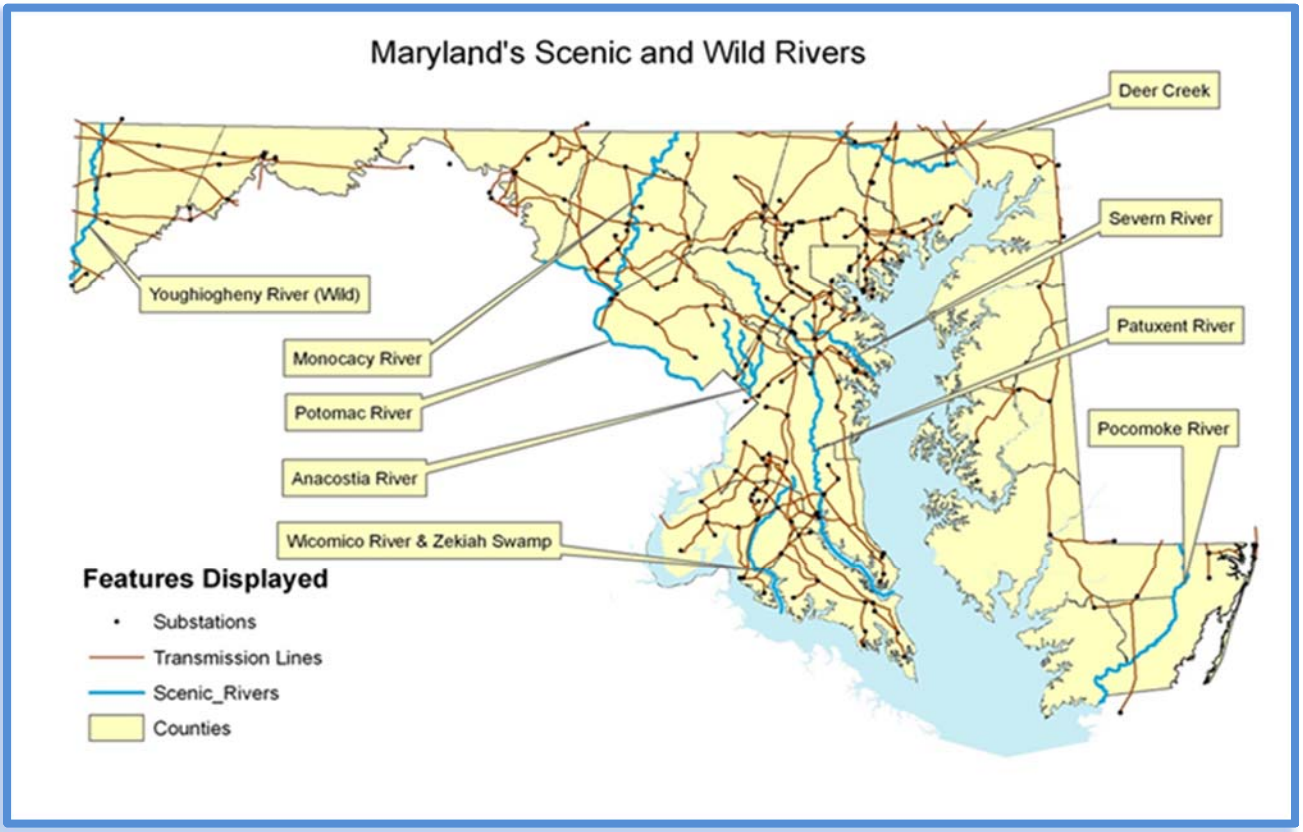
### *Impacts to High Quality Waters*

The State of Maryland recognizes some streams and rivers as having particular natural values that deserve additional regulatory protection. These high quality waters include Scenic Rivers and Tier II streams, both of which may be affected by transmission line ROWs. A map of the Scenic and Wild Rivers and transmission lines corridors in Maryland is illustrated in Figure 4-21. Reviews of the potential impacts of proposed transmission lines are conducted to ensure that impacts on these resources are avoided or minimized.

#### ***Scenic and Wild Rivers***

A Scenic River is defined as a “free-flowing river whose shoreline and related land are predominantly forested, agricultural, grassland, marshland, or swampland with a minimum of development for at least 2 miles of the river length.” The Wild and Scenic Rivers Act mandates the preparation of river resource management plans for any river designated scenic and/or wild by the General Assembly. These plans identify river-related resources, issues and existing conservation programs, and make recommendations on the recreational use of the river and protection of special riverine features. Each unit of State and local government, in recognizing the intent of the Act and the Scenic and Wild Rivers Program, is required to take whatever action is necessary to protect and enhance the qualities of a designated river and its tributaries. In many cases, a Scenic River will also have a Watershed Restoration Action Strategy (WRAS), which is a means of implementing the recommendations set forth in the river’s management plan.

*Figure 4-21 Scenic and Wild Rivers and transmission line corridors in Maryland*




Recent transmission projects that have crossed Maryland Scenic Rivers and their watersheds include the Mt. Storm-Doubs project (which crossed the Potomac River in Frederick County), the Monocacy-Ringgold-Catoctin project (the Monocacy River), the Bagley-Graceton and Conastone-Graceton rebuilds (Deer Creek), SMECO's Southern Maryland Reliability Loop project (the Patuxent River), and DPL's Piney Grove to Wattsville new 138 kV line (Pocomoke River). The review of these projects paid special attention to all river and stream crossings in the associated watersheds, especially concerning riparian loss and erosion leading to downstream sedimentation.

Frequently, transmission structures also significantly degrade the visual environment along the river, such as the current 69 kV line crossing the Pocomoke Scenic River. A number of Maryland's designated scenic rivers, including the Patuxent River, the Monocacy River, and portions of the Potomac River, have incurred viewshed impacts from existing transmission line crossings. Where possible, an underground crossing may eliminate or minimize such visual impacts (see Section 4.4.2 for additional details).

***Streams***

Particularly high quality streams are protected by Maryland's antidegradation policy that protects these waters from impacts that would degrade them to meet only the minimum standards (Tier I). The policy is laid out in three regulations: COMAR 26.08.02.04, which sets out the policy itself; COMAR 26.08.02.04-1, which provides for implementation of the antidegradation policy for Tier II (high quality) waters; and COMAR 26.08.02.04-2 which describes Tier III (Outstanding National Resource Waters or ONRW), the highest quality waters. There are Tier II streams in every county (23), though they are not evenly distributed throughout the state, and there are none located in Baltimore City. No Tier III waters have been defined in Maryland, to date.

A stream designated as Tier II is provided enhanced protection against degradation of water quality and habitat, including limiting sediment loads. Areas upstream of Tier II segments are also considered vital to the protection of the Tier II segment. All development that affects Tier II waters, including transmission line construction, is subject to review by MDE to eliminate any potential degradation resulting from the proposed activities.

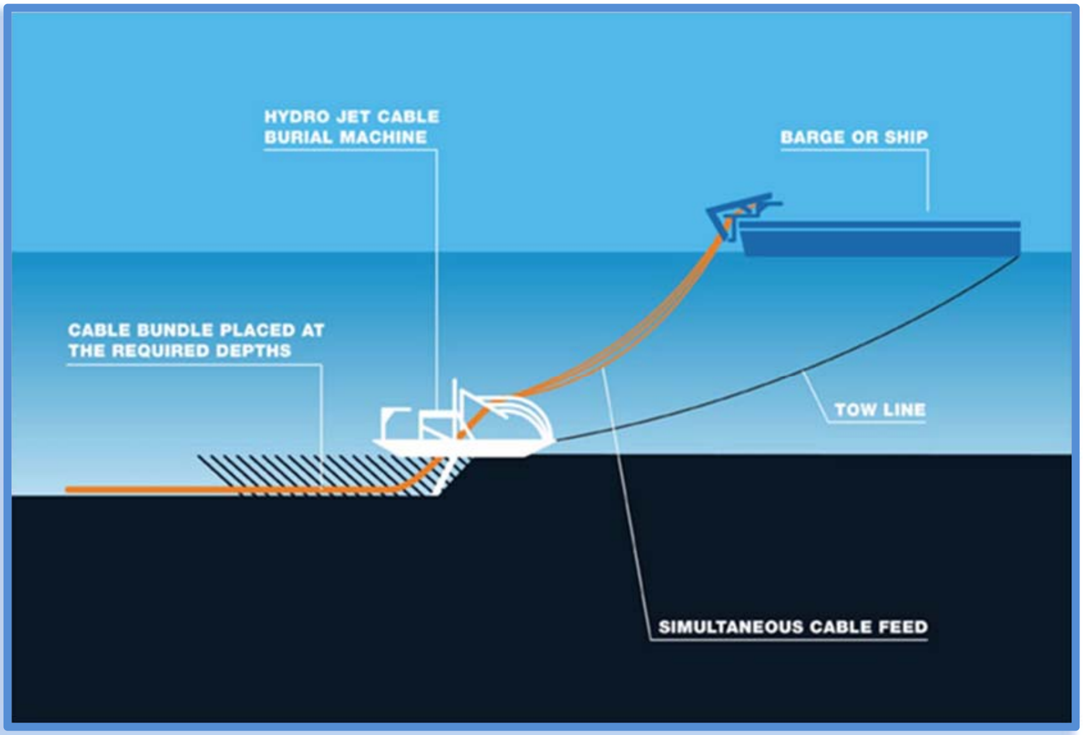
Recent transmission line projects that cross or are located in the vicinity of Tier II waters include the BGE Bagley-Graceton, Conastone-Graceton, and Bagley-Raphael Road rebuilds (several tributaries to Deer Creek and Little Gunpowder Falls); the BGE Northwest to Deer Park project (several tributaries to Liberty Reservoir); and the Delmarva Power Church to Townsend and Church to Wye Mills rebuilds (tributaries to the Chester River), and the Piney Grove to Wattsville upgrade (Nassawango Creek). In addition to the protection of water quality and habitat by stringent best management practices (BMPs) for sediment and erosion control, PPRP has recommended specific Integrated Vegetation Management (IVM) plans in areas upstream of Tier II waters in these cases. Relocating poles that are in sensitive areas such as wetlands or riparian buffers are also recommended if necessary.

### *Impacts to the Chesapeake Bay and Coastal Waters*

The prospect of offshore wind turbines and the need for more power on Maryland's Eastern Shore have resulted in past proposals for transmission across (under) large expanses of the Chesapeake Bay or the waters off of Maryland's Atlantic Coast. Recent technological advances have significantly improved the feasibility and cost effectiveness of long-distance submarine cable installations that would be required for such projects. Underwater cables have already been built in several areas of the United States, including Long Island Sound, Raritan Bay, and San Francisco Bay. Submarine cables offer visual and engineering advantages compared to overhead lines across water bodies. In any specific area, these advantages have to be compared with the impacts to the biological communities that inhabit the bottom, and the food chains that depend on them. A submarine transmission line would be expected to have multiple short-term, acute impacts caused by installation activities, and long-term impacts from construction disturbance, maintenance activities, and the operation of the electric power line once it is energized.

Underwater transmission cables usually are placed several feet deep in the bottom sediments. Under some circumstances, such as rocky hard bottom, the cable is just placed directly on the bottom. This latter technique affords the least protection from currents and man-made disturbance, such as being hooked by an anchor or damaged by commercial fishing operations. Installation of the cables can be accomplished by several methods, including horizontal directional drilling (HDD), the use of a jet plow, trench excavation, or a combination of these techniques. The HDD technique uses pressurized drilling muds, which may be released accidentally through weaknesses in the overburden, thereby contaminating sediments and increasing turbidity in the surrounding area. Jet plowing involves several steps to clear the area of debris prior to cable installation (e.g., grapnel dredging, pre-jet plowing), resulting in multiple sediment disturbances and the direct loss of benthic habitat along the cable corridor before the cable is even placed in the trench. During installation, which is depicted in Figure 4-22, a large jet plow sled is pulled along the cable corridor with high-pressure water jets fluidizing the sediment into which the cable sinks. Direct trench excavation creates the most impact due to removal and replacement of excavated materials. SMECO's Holland Cliff to Hewitt Road 230 kV Transmission Line Project included a crossing at the Patuxent River that was drilled under the riverbed using HDD. The crossing is parallel to and upriver from the Rt. 4 Bridge between Johnstown and Town Creek, Maryland, with end points at Point Patience and Patuxent Beach Road. A portion of the line also traverses the Navy Recreation Center (NRC) in Solomons through underground duct banks (concrete lined trenches used to place power cables underground, then covered with vegetation or pavement). Although the termination point is within the Chesapeake Bay Critical Area, a previously developed site was selected. The underground cable crossing is in an area of the river that is rich in biological resources including oysters, habitat for overwintering ducks, tidal wetlands, and submerged aquatic vegetation. SMECO completed the environmental studies required to comply with conditions of the CPCN concerning HDD beneath the Patuxent River. A sampling plan was required to establish the river bottom baseline conditions using geotechnical and biological surveys of the river bottom and included provisions for additional sampling if an inadvertent release of drilling fluids ("frac out") was suspected or confirmed during the HDD process. Pollution history and sampling data obtained by SMECO were used in formulating a Contingency Plan to help protect the living resources of the Patuxent River in the event of a frac-out. The HDD under the Patuxent River was successfully completed without incident in October and November of 2013.

*Figure 4-22 Illustration of an Underwater Cable Installation Using Jet Plow Technology*




Source: http://hudsonproject.com/project/description/

In Maryland, the laws that protect the "Critical Area" around the Chesapeake Bay and the Atlantic Coastal Bays require thorough environmental evaluations before building these types of underwater transmission lines. The Critical Area includes, in addition to the waters of the Chesapeake Bay and the Atlantic Coastal Bays and the submerged land below them, all land within 1,000 feet of either the mean high water line of tidal waters or the landward edge of tidal wetlands. The Critical Area Act (1984) authorizes State and local governments to assess impacts caused by construction disturbances, run-off, and activities within the 1,000-foot buffer zone. Any projects which may directly or indirectly affect the Critical Area in the state, including transmission line ROWs, are required to seek and obtain approval from the Critical Area Commission.

During project review, impacts evaluated include effects on turbidity, alterations of nutrient and dissolved oxygen concentrations, thermal changes, electromagnetic fields produced by the cables, salinity, and the creation of physical barriers on or in the bottom sediments. Continuously operated buried cables typically reach internal core temperatures of 90°C and may create zones of elevated sediment temperature above ambient conditions, depending on sediment thermal characteristics. Heat released during the operation of the cable could create a permanently warm area, affecting benthic habitats, spawning times of sessile species, and water mixing patterns. Long-term heating of the sediment could also create refuges for or increase the rate of growth of bacteria such as *Vibrio vulnificus* and *E. coli*. Oysters and other shellfish that ingest these bacteria pose a human health risk.

Aquatic habitats may be affected by re-suspension of sediments during construction or maintenance of the cables that may release contaminants or nutrients into the water column. Depending on the depth profile and tidal influences, disturbances that re-suspend sediments or contaminants could have effects well beyond the immediate physical footprint of the cable path, such as nearby oyster and clam beds. An underwater cable could therefore affect the benthic habitat and the species that depend upon it for food, spawning, or juvenile development - including oysters, softshell clams, crabs, resident and migratory fish, overwintering sea ducks, and many other sensitive species.

In light of these potential impacts, PPRP has conducted research studies along Maryland's Atlantic Coast to identify benthic and aquatic resources that would be at risk from transmission cables originating at offshore wind farms.

### *Impacts to Groundwater*

Transmission line structures have a small potential to affect ground water resources, particularly in areas where the water table is close to the surface. Potential impacts to ground water would occur mainly during the construction or installation of the structures, whether above ground or underground. The construction of new overhead transmission tower foundations or underground cable facilities may require drilling to depths that can penetrate shallow water tables or open access channels to deeper aquifers. For example, typical estimated drilling depths required for new structures for 230 kV transmission line projects (such as the recent SMECO Holland Cliffs to Hewitt Road or the Potomac Edison Monocacy-Ringgold-Catoctin projects) are approximately 40 feet below ground surface. In many areas of the state, potable water supplies are much deeper than this and would not be at risk. However, the depth to ground water is much less in areas such as the Eastern Shore where many upgrade projects are being conducted. As structure heights increase for higher voltage overhead transmission lines, the required drilling depths become deeper; therefore, the tower foundation and cable conduit drilling depths need to be compared carefully to the depth to ground water for many proposed transmission line projects in Maryland.

Alternatives to traditional overhead construction, such as underground and submarine cable installations, are becoming increasingly more common as the technology advances. Potential impacts associated with underground installations may include the redirection of ground water flow associated with the construction of underground duct banks and splice boxes or backfilling the trenches with material of differing porosity. Another potential effect could be an increase in ground water temperature due to the heating of an underground cable during its operation. The existence and magnitude of these impacts will be dependent upon several site-specific factors, including the project location, installation depth, construction technique employed, soil type, and depth to ground water.

### *Effects on Biological Resources*

Streams and water bodies found within Maryland provide habitat for a diverse assemblage of invertebrate and vertebrate species, ranging from coldwater to warmwater species, and from species that require high-quality habitat to those that are tolerant of impaired water quality conditions.

***Impacts to Wildlife***

As mentioned in previous sections, construction and maintenance of transmission lines and their associated ROWs affect freshwater streams through the loss of vegetation and shading, bank erosion and sedimentation during construction and herbicide contamination during maintenance activities. Many aquatic wildlife species may suffer, especially if Best Maintenance Practices are not followed. For example, the brook trout (*Salvelinus fontinalis*) is an aquatic species that was historically prevalent in Maryland waters. Decreases in water quality and habitat degradation have placed this species in decline in Maryland. The brook trout is a coldwater species, dependent on streams with maximum water temperatures of 22 . Removal of riparian vegetation at a brook trout stream, such as what would occur during the maintenance of a transmission line ROW, would decrease stream shading, thereby increasing the water temperature. This increase in the temperature could drive the brook trout out of a stream, leaving a habitat niche available for a non-native species such as the brown trout (*Salmo trutta*) to compete for resources.

***Impacts to Threatened and Endangered Species***

Threatened and endangered species are subject to the same impacts from the construction and maintenance of transmission line ROWs as other wildlife, but must be protected to the maximum extent possible. Aside from avoiding the area containing the habitat of the threatened or endangered species, time of year restrictions may be applied to activities within the ROW to avoid times when the species is breeding or especially active.

For example, the proposed rebuilding of Delmarva's Church to Steele transmission line would occur upstream of existing known populations of the state-listed endangered dwarf wedge mussel (*Alismidonta heterodon*). The dwarf wedge mussel is an extremely rare freshwater species found only in Maryland, New England, and North Carolina. It has very specific habitat requirements, including a stable, silt-free stream bed and well-oxygenated water free of pollutants. The mussel serves as an indicator species, as it is extremely intolerant to water quality pollution. The presence of this mussel in streams is indicative of extremely high water quality. The challenge to the project will be to protect the water quality through strict sediment and erosion control BMPs upstream of any known populations.

***Cumulative Effects on Biological Resources***

Because the health of an ecosystem depends on functional interactions between its components, impacts to multiple resources can have a cumulative effect much greater than a simple tally of the individual impacts would suggest. It is important to assess and address such multiple impacts. In addition to specific areas of multiple impacts, many small impacts to a single resource along a ROW can add up to a significant overall impact to that resource. It is also necessary to minimize such effects if they occur.

Cumulative effects can be assessed in several ways. The effect of multiple stresses on an ecosystem is usually measured against a standard for permissible impacts or a goal for restoration. For example, Maryland’s Wild and Scenic Rivers Act applies to the natural resources of State-designated Scenic Rivers and their tributaries (see Section 4.2.2 – Impacts to High Quality Waters), thus limiting any combination of activities within the watershed that would degrade the condition and quality of the designated river. Individual resources, on the other hand, are handled in terms of specific impact thresholds or goals.

Transmission lines that cross numerous streams and rivers within a single watershed may degrade the overall biological health of that watershed. Any local effects that propagate downstream, such as warmer water temperatures or increased sediment load, will accumulate in lower reaches of the watershed. The summed effects could cause a shift in water quality, initiate changes in aquatic species composition, or modify the configuration of the drainage channel. Evaluating the potential for such effects is always included in the reviews of proposed transmission line projects.

## *4.3 Impacts to Terrestrial Resources*

Maryland's physiographic diversity, geology, and climate have produced a variety of eco-regions that foster numerous, and sometimes unique, habitats ranging from ocean barrier islands in the east through salt marshes, fields and forests of the coastal plain, into rolling piedmont hills, and on to forested mountains with remnant alpine glades to the west. While human activities (agriculture, urban/suburban development, etc.) have altered all of these areas to some extent, the majority of the landscape continues to possess a wide variety of habitats that support diverse communities of flora and fauna. Many of these communities help define their regions, and may contain rare, threatened, or endangered species.

The State of Maryland implements a suite of regulations (COMAR Titles 08, 26, and 27) that afford protection to habitats and species in terrestrial and wetland environments:

- Waterway Construction;
- Water Quality and Water Pollution Control;
- Erosion and Sediment Control;
- Nontidal Wetlands;
- Tidal Wetlands;
- Forest Conservation;
- Threatened and Endangered Species; and
- Critical Area of the Chesapeake Bay and Atlantic Coastal Bays.

The construction and operation of power generation facilities can have significant effects on terrestrial environments, including wetlands. Power plant infrastructure, including production units, pipelines to transport water, oil, and natural gas, electrical transmission lines, and roadways and railways, can occupy extensive areas on the landscape. Notably, these facilities can:

- Physically alter or eliminate existing natural habitats;
- Disturb or result in the loss of wildlife species;
- Affect landscape ecology through atmospheric emission and deposition of PM and other air pollutants; and
- Degrade habitats by the permitted discharge of pollutants or from accidental spills.

New generation facilities may be constructed entirely within an area that is already developed or may require clearing a significant number of acres of natural habitat. Recent examples highlighting the scope of impacts to terrestrial resources include two projects under construction in Southern Maryland. The

Project Site for the Keys Energy Center (KEC) combined-cycle, natural gas-fired plant in Prince George‘s County is a 180-acre parcel of land formerly used for a sand and gravel mining operation. Approximately 30 acres of the parcel will be used for the permanent electric power generation and support facilities. The site is adjacent to PEPCO’s existing 500 kV transmission line right-of-way located on the western side of the property. The associated gas pipeline will be constructed on the vegetated side of the existing 500 kV transmission line for the gas pipeline, which requires clearing many acres of existing forested habitat. The gas pipeline route crosses sensitive areas such as wetlands and streams, including the headwater streams of Zekiah Swamp.

The Mattawoman Energy Center Project Site is a previously cleared 88-acre plot on Brandywine Road in Prince George’s County. Linear facilities associated with the Project include an approximately 10-mile-long reclaimed wastewater pipeline to bring treated effluent from Piscataway WWTP, an approximately 7.4-mile-long natural gas pipeline, and a 2.3 mile generation lead line extending from the power plant site north to PEPCO’s Burches Hill to Talbert 230 kV PEPCO transmission line. The proposed substation site is located on Cherry Tree Crossing Road, adjacent to the PEPCO 230 kV transmission line corridor, which contains approximately 8 acres of predominately upland forest. The gas pipeline will widen the existing gaps associated with the PEPCO/SMECO transmission line ROW, and will require clearing many acres of forest. A portion of the ROW, at the Mattawoman Creek crossing, runs directly adjacent to the proposed gas pipeline route for the Keys Energy Center. The last 1-mile segment of new ROW required for the gas pipeline runs parallel to Jordon Swamp.

Impacts from new generation projects on Maryland’s landscape in the future will also depend on the mode of power production. Power plants that use traditional resources such as coal and natural gas are generally confined to an intensively developed installation with the exception of the associated linear facilities that may be needed, whereas renewable energy projects using wind turbines or solar panel arrays may occupy hundreds of acres. There are more than 10 proposed solar generation facilities throughout the state that have recently undergone review by PPRP. Great Bay Solar is a recently approved project that will be constructed on approximately 1,000 acres near Princess Anne in Somerset County and involved coordination with Critical Area Commission. The facility will be constructed in two phases, with the capability to generate up to 150 MW of power upon the completion of the second phase. The Project is scheduled to begin operation by the end of 2016 and is anticipated to be in operation for a minimum of 25 years.

More than two thousand miles of electric power transmission line and natural gas pipeline rights-of-way are located throughout Maryland. Constructing and maintaining these rights-of-way creates long, mostly linear, corridors that are often quite different from the surrounding environment. These corridors can affect nearby areas, including terrestrial habitats and wetlands, in a variety of ways, either temporarily during construction or over the long term. To provide public review and to ensure that environmental and other concerns are addressed, CPCN applications are required for new corridor construction and for modifications in existing corridors.

Transmission line corridors may affect specific environmental features, alter the landscape over long distances, or change the way people use nearby residential, commercial, or agricultural land. For each right-of-way modification or construction proposal, PPRP reviews the potential impacts of the proposed project on streams, floodplains, wetlands, forests, rare species, historical and archeological sites, and surrounding land use. Quantitative comparisons of alternate routes are derived from digital maps, aerial photographs, and other data sets, and supplemented by field inspections. The purpose of these comparisons is to identify the types of impacts that may occur along each possible corridor and to find the route with the lowest overall impact. Where undesirable impacts cannot be avoided, recommendations may include compensating for the damage and/or maintaining certain conditions in the corridor after construction.

PPRP's role in the CPCN process is to facilitate compliance with Maryland's environmental regulations and natural resource management objectives. Environmental laws affecting Waterways Construction, Water Quality and Water Pollution Control, and Erosion and Sediment Control require best management practices (BMPs) to eliminate or minimize disturbance in and discharges to Maryland waters. These BMPs are uniformly included as conditions to a CPCN. However, a CPCN can also recommend specific conditions to avoid, minimize, or mitigate impacts on natural resources when the effects of the proposed project are particularly compelling. Under these circumstances, conditions placed on a CPCN to mitigate impacts to wetlands, forests, and sensitive species habitats may often be more stringent than requirements under the statutes.

### 4.3.1 Generating Facilities

#### *Effects on Wetlands*

Wetlands are important components of the environment, forming the interface between terrestrial and aquatic ecosystems. Wetland communities often consist of a diversity of plant species, a number of which may be species of concern. Wetlands also provide numerous values to society, including fish and wildlife habitat, flood protection, erosion control, and water quality maintenance. At the end of the 18th century, Maryland had nearly 1,650,000 acres of nontidal wetlands (24.4 percent of the surface area); 220 years later, in 2009, Maryland had only about 345,000 acres of nontidal wetlands (4.8 percent of its surface area), a reduction of approximately 80 percent. To address such losses, the State developed regulations under Maryland's 1991 Nontidal Wetlands Protection Act, with the goal of no net loss of nontidal wetlands. Under nontidal wetlands regulations, permanent impacts to nontidal wetlands must be mitigated at various ratios depending on the type of wetlands affected. For example, a ratio of 3:1 is applied to scrub/shrub and forested Wetlands of Special State Concern; a ratio of 2:1 is applied to other scrub/shrub and forested wetlands, and to herbaceous wetlands of special State concern; and a ratio of 1:1 is applied for emergent wetlands. Analogous to this, the 1994 Tidal Wetlands Regulations were developed to regulate activities in tidal wetlands, and mitigation ratio requirements are similar for State tidal wetlands. Temporary impacts and impacts to wetlands buffers do not usually have replacement mitigation requirements but may require compensatory or enhancement measures.

The CPCN process includes assessing potential wetlands impacts and developing appropriate mitigation equal to or greater than those required by these regulations. While wetlands are present at nearly all Maryland's power facilities, impacts to these wetlands can usually be avoided. Where especially valuable wetlands are present, the CPCN process can identify special conditions to ensure their protection. For example, the CPCN to construct the Competitive Power Ventures (CPV) generation facility in Charles County included the following conditions to protect the Zekiah Swamp Natural Environmental Area, a Nontidal Wetland of Special State Concern:

- Preparation of a protection plan that ensures the wetland recharge rates to Piney Branch Bog are maintained and do not exceed current conditions through the use of shallow infiltration beds and vegetated terraces; and
- Establishment of a permanent protection buffer with no vegetation clearing, earthworks, or other disturbances allowed within 300 feet of Piney Branch Bog.

Generation facilities such as the KEC and Mattawoman projects will require associated linear facilities including gas and water pipelines and transmission lead lines. Construction of gas and water linear facilities has the potential to affect streams and wetlands through vegetation removal or ground disturbance. Impacts to wetlands may be minimized through advanced construction techniques such as horizontal directional drilling (HDD). For example, PPRP has recommended CPCN license conditions for both KEC and Mattawoman that require HDD along natural gas pipeline corridors to avoid impacts to Wetlands of Special Concern.

### *Impacts to Forests and Maryland's Green Infrastructure*

The importance of forest resources is manifold. Forests provide habitat for wildlife including important game species such as white-tailed deer and wild turkey. On the ground, forests filter stormwater of nutrients and other pollutants, and prevent the erosion of the landscape; while in the air, they filter out air pollutants and perform the vital function of producing oxygen. As a forest grows to maturity, it sequesters carbon both as plant tissue and soil-forming materials from dropped leaves and branches. Forests are also important as commercial resources for providing construction materials and as a renewable fuel source. Nevertheless the historic losses of Maryland's forest resources have been compelling, which prompted enactment of the Forest Conservation Act (FCA) in 1991. With the exception of projects located in heavily forested Allegany and Garrett Counties, all construction developments of greater than 40,000 square feet must comply with the FCA.

Under the FCA, existing forest condition and character are integral parts of the development planning process, including power plant and transmission line siting, across the state. The FCA requires the applicant to submit both a Forest Stand Delineation defining the nature and character of the existing forest and a Forest Conservation Plan for protecting the most ecologically valuable areas of forest. Under the FCA, tree conservation, replanting, and other environmental parameters must be considered before any development disturbs forest resources. The Maryland Forest Preservation Act of 2013 amended the State's forest conservation policy to maintain a 40 percent tree canopy state-wide, in essence, a no-net-loss requirement. This legislation will help maintain and protect the state's forests, which is crucial to the health of local rivers, streams and the Chesapeake Bay. In addition to the no-net-loss requirements, this legislation adds a dual sustainability certification requirement for State Forests, and extends tax benefits to more Marylanders who work to increase tree cover on their property.

DNR has established land conservation strategies to preserve and restore the state's ecological health. One of DNR's programs, the Green Infrastructure (GI) Assessment, is designed to identify and map large areas of contiguous forest habitat hubs and narrower natural corridors that connect the hubs and allow movement among faunal and floral populations. The GI Network is important to the State because the size of forest patches correlates directly with the species of plants and animals that inhabit them and the diversity that the patch of forest can support.

## Maryland's Forest Conservation Act (FCA) and Solar Generation

Maryland's agricultural land is an attractive option for siting solar generation facilities. There are more than 10 proposed solar generation facilities currently under review by PPRP. The availability of large tracts of open land in rural communities, which generally does not require extensive site work (e.g., grading, or clearing), is ideal for solar generation development, particularly if located within close proximity to a power substation.

Maryland's Forest Conservation Act (FCA), specifically Maryland Code, Sections 5-1602(b)(5) and 5-1603 of the Natural Resources Article, establishes standards for land development that make the identification and protection of forests and other sensitive resources an integral part of the site planning process. The conversion of agricultural land for power generation, irrespective of the need for tree clearing, requires mitigation if a CPCN has not been issued. Generation projects must be permitted through the CPCN licensing process, and must minimize forest loss during site development. As such, PPRP recommends project-specific CPCN license conditions requiring generation project developers to consult with their respective counties to determine that county's requirements for any afforestation, reforestation or mitigation that may apply to the project.

Maryland's forest policies include a "no net loss of trees" standard as well as an overall percent cover goal. The Forest Conservation Act (1991), the Sustainable Forestry Act (2009), and the Forest Preservation Act (2013) all bear on actions that remove forests or develop nonforested land. Consistent with these Acts, the PSC has certain responsibilities with respect to forest conservation during the CPCN review, as specified in the Natural Resources Article, 5-1603 (f):

"After December 31, 1992, the Public Service Commission shall give due consideration to the need to minimize the loss of forest and the provisions for afforestation and reforestation set forth in this subtitle together with all applicable electrical safety codes, when reviewing applications for a certificate of public convenience and necessity issued pursuant to § 7-204, § 7-205, § 7-207, or § 7-208 of the Public Utilities Article."

Compliance with FCA mitigation standards for tree removal or for development of agricultural land generally meets the requirements of the PSC review. FCA provides a set of minimum standards that developers must follow when designing a new project. County and municipal governments are responsible for making sure these standards are met, but may choose to implement even more stringent criteria. New CPCNs issued for the construction of electric generating facilities require compliance with these requirements. Once a CPCN has been issued, certain FCA exemptions are available to utilities for subsequent maintenance activities. Generation project developers are required to consult with their respective counties and comply with the county's requirements for any afforestation, reforestation or mitigation that may apply to the project. PPRP also recently initiated its promotion of native Maryland pollinators and their habitats (see sidebar).

The CPCN process also considers the quality of the natural resources lost as the license conditions are developed. For example, the CPCN to construct the Rock Springs generating facility in Cecil County included restoration conditions to compensate for values of mature forest lost and some of the nitrogen deposition caused by the facility's emissions. Specifically, the applicant was required to plant 50 acres of young trees to replace 20 acres of mature forest. The reforestation was directed to riparian areas to increase the likelihood that deposited nitrogen would be intercepted before reaching Chesapeake Bay tributaries. At one reforestation site, 18 acres in size, 80 percent of the planted trees died by the summer of 2013. PPRP is re-evaluating the efficiency of such restoration projects.

## *Impacts to Biological Resources*

### ***Wildlife***

New generation facilities primarily affect wildlife by removing habitat during construction of the project. For example, the Cove Point LNG expansion project, once operational, will allow the facility to produce liquefied natural gas for exportation; however, it requires that 97 acres of forested area be cleared for construction laydown and staging areas. The loss of habitat from this area will affect forest interior dwelling species (FIDS) of birds, including the scarlet tanager, barred owl, pileated woodpecker, and eastern whip-poor-will. The loss of FIDS habitat will also affect properties adjacent to the area to be cleared. Wildlife will be affected by loss of habitat, and addition of light, noise, and activity during the construction period.

Wind energy projects can also have a substantial impact on wildlife during operations, especially to birds and bats. Depending on the number of wind turbines, usually installed in linear arrays, facilities can occupy large areas on the landscape when the turbines, service roads, and operations buildings are considered as a whole. A much greater area is often needed during the project construction phase as the large towers and turbine blades require broad lay-down areas during assembly. The loss of habitat can lead to the eradication or displacement of species in these areas.

All of the wind power facilities proposed for construction in Maryland have been in the predominantly forested habitats of Garrett and Allegany counties. The forests of western Maryland are considered to be a southern extension of the northern hardwood forests that extend more broadly to the north, and historically included pure stands of white pine, eastern hemlock, and red spruce. At present, however, logging, coal mining, and home construction have fragmented much of these forests. Where contiguous forest exists, wind power development within these forests could increase fragmentation. Fragmentation affects birds and bats as well as other terrestrial species through direct loss of forested habitat, the encroachment of species that can have direct (e.g., brown-headed cowbirds that parasitize songbird nests) or indirect (e.g., raccoons that can be disease vectors for rare mammals) detrimental effects, the potential disruption of corridors for daily movement or seasonal migration, and the failure of the resident species to adapt to the wind power facility.

PPRP and DNR's Wildlife & Heritage Service routinely review and comment on Bird and Bat Conservation Strategies (BBCSs) for wind power projects. BBCS (formerly known as Avian Protection Plans) are project-specific documents that outline a program to reduce the potential risks of bat and avian mortality that may result from the construction and/or operation of a project. The ultimate goal of a BBCS is to avoid impacts to avian and bat species to the greatest extent possible, including species protected under the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, and the Endangered Species Act, as well as the State Maryland Nongame and Endangered Species Conservation Act, and applicable County regulations.

A BBCS must be structured around careful project planning, siting, and construction, allowing power project developers to avoid impacts to birds and bats that could result from construction, operation, and decommissioning of projects. Appropriate power project design and construction measures must be implemented to avoid and minimize avian and bat impacts to the greatest extent practicable. The goal of avoidance and minimization measures for birds and bats is to eliminate aspects of a project that pose risks to these species.

Although raptor mortality rates at wind power projects in the Appalachian Mountains have been minimal to date, they have been elevated in some western states. Conversely, bat mortality rates at some wind power projects along the Appalachian Mountains have been among the highest reported. Birds and bats are typically treated separately in a BBCS document, therefore, with unique avoidance and minimization measures applied as appropriate. If monitoring indicates that avoidance and minimization measures are not effective, adaptive management measures have been implemented, including additional conservation measures, as needed.

In Maryland, land-based wind power facilities less than 70 MW can apply to the PSC for an exemption from having to obtain a CPCN. Although this exempts developers from the coordinated PPRP environmental review, they must still comply with federal and State regulations protecting threatened and endangered species.

## Promotion of Native Pollinators

Plants must rely on pollen vectors, from wind to insects to birds, to transport their pollen to another individual and attract the same species repeatedly to bring about successful pollination. Visitors must cause pollen transfer for plants to ultimately set seed and be successful. Pollinators contribute substantially to the success of our fruit, nut, and vegetables crops; however there has been a significant loss of pollinators, including honey bees, native bees, birds, bats, and butterflies, from the environment over the last few decades.

*Creating a Federal Strategy to Promote the Health of Honey Bees and Other Pollinators was proclaimed by the President in a memorandum issued on June 20, 2014. Migrating Monarch butterflies dropped to the lowest recorded population level in 2013-14. The loss of native bees, which also play a key role in pollination of crops, is much less studied, but many native bee species are believed to be in decline. Scientists believe that bee losses are likely caused by a combination of stressors, including poor bee nutrition, loss of forage lands, parasites, pathogens, lack of genetic diversity, and exposure to pesticides*.

PPRP recently initiated its promotion of native Maryland pollinators and their habitats. The promotion of pollinators is done through a cooperative agreement with applicants of new generation projects to investigate the feasibility of providing onsite ecologically-friendly, self-sustaining habitats for honeybees, bumblebees, other important insects, and other pollinators. These habitats would take the place of frequently mowed or crop areas (but never replace forested habitats) on a project site. The pollinator habitats consist of native herbaceous plants that are known to attract a variety of pollinator species (e.g., Bee Balm, Butterfly Milkweed, Black-eyed Susan, Joe-Pye Weed, etc.). These habitats are relatively maintenance-free, and once established, often only require an annual or semi-annual mowing. They generally require no application of herbicides or fertilizers, and are friendly to native birds and other wildlife. Pollinator habitat also can be managed in electric transmission rights-of-way with integrated vegetation management (IVM) as two distinct plant communities; grass and herbaceous plants within the wire zone (under and 20-feet outside conductors), and a shrub/scrub border zone from the wire zone to the ROW edge to develop meadow habitat and shrub habitat along the ROW border and in ravines.

### *Rare, Threatened and Endangered Species*

Rare, threatened and endangered (RTE) species, whether federal-listed under the Endangered Species Act or State-listed under Maryland's Threatened and Endangered Species regulations, are distributed throughout the state; however for the most part, these species are restricted to highly specific habitats. Generation projects proposed in Maryland must undergo environmental review by the DNR's Wildlife & Heritage Service (WHS) to identify any RTE species known to occur in the vicinity of the affected area. Any recommendations made by the WHS during the environmental review usually form the basis for conditions in the CPCN. Regardless of the kinds of habitat involved, State-listed threatened and endangered plants and wildlife are protected under State law. Table 4-5 lists the number of protected species by category that the CPCN process considers when evaluating potential adverse effects and developing protective recommended license conditions.

### *Table 4-5 Number of State-Listed Rare, Threatened, and Endangered Species by Category*

| Summary of State Listed Species* | | |
|---|---|---|
| **Category** | **Plants** | **Animals** |
| Endangered | 271 | 91 |
| Threatened | 74 | 19 |
| In Need of Conservation | n/a | 29 |
| Endangered Extirpated | 100 | 28 |
| Total | 445 | 167 |

* Summary of State Listed Species only includes species listed in COMAR 08.03.08
Source: Maryland DNR: http://dnr2.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx

Although few applications for power generating facilities affect listed threatened and endangered and rare species, a number of individual cases have considered potential impacts to Northern Long Eared Bat, Eastern Small-footed Bat, Bald Eagle, tiger beetles, Delmarva Fox Squirrel, Carpenter Frog, timber rattlesnake, and plant species such as Purple Pitcher Plant, New Jersey Rush, and Winterberry. During a recent visit to the proposed Dan's Mountain Solar site in Alleghany County, WHS personnel determined that four specific points along the eastern part of the site and directly bordering it likely provide habitats for two listed RTE species and one rare species in Maryland; these species include Allegheny Woodrat (*Neotoma magister*; State Endangered); Eastern Small-footed Bat (*Myotis leibii*; State Endangered); and Timber Rattlesnake (*Crotalus horridus*; not listed, but rare). In addition, Northern Long-eared Bat (*Myotis septentrionalis*) has been documented recently in the vicinity of the Dan's Mountain Solar project site. The Northern Long-eared Bat was recently listed as Threatened under both federal and Maryland Endangered Species Acts. These four species of concern could be affected by the development of the proposed solar facilities at this site. PPRP has drafted CPCN license conditions requiring the project developer to produce a binding Habitat Conservation Plan that will protect these four species. Further, given that forest clearing will be required to complete this solar project, PPRP recommended that Dan's Mountain Solar coordinate with the U.S. Fish and Wildlife Service regarding Northern Long Eared Bat.

Wind turbines can kill birds and bats that collide with them, or as recent research has shown, cause the death of bats through barotrauma, a fatal hemorrhaging of the lungs of bats from the rapid change in air pressure near the spinning turbine blade. After two decades of study at a number of wind power facilities in the U.S. and abroad, there is evidence that the numbers of bird fatalities are small at most locations. Two to three birds are killed annually per wind turbine on average. Studies at facilities constructed on eastern Appalachian ridges in West Virginia and Pennsylvania report similar rates of bird fatality. In contrast, the numbers of bats killed at these regional facilities are among the highest ever reported, and annual estimates range into the thousands for each project. It is currently believed that most of the bat fatalities occur during the late summer to fall migration period as bats move to their over-wintering habitat.

Until recently, wind turbines were not known to have killed any threatened or endangered species of bats. It has now been documented, however, that an Indiana bat was killed at a wind energy facility in Indiana. Western Maryland provides year-round habitat to the federally Endangered Indiana Bat, and the State-listed Endangered Eastern Small-footed Bat. Most records of these two species come from winter cave surveys when the bats are hibernating. Much less is known of their habits during the flying season as they disperse throughout the landscape; however, a recent radio-tracking study followed a single female Indiana bat from a Pennsylvania cave to Carroll County, Maryland. The seasonal and daily activity patterns of these rare species must be investigated further before concerns about the risks posed by proposed wind turbines can be adequately addressed and mitigation activities defined.

An even greater concern for populations of cave-hibernating bats, such as the Indiana Bat, the Northern Long Eared Bat, and the more common Little Brown Bat, has developed since White Nose Syndrome was found to be severely affecting bats in caves of the northeast. This fungal disease, first noted in 2006, has spread rapidly throughout eastern North America, causing up to 90 percent bat mortality in some caves. Bats succumb to White Nose Syndrome during winter hibernation periods after becoming sick and either dying within the cave or departing prematurely and perishing outside the cave during winter. The fate of these bat species, when considering the cumulative impacts of White Nose Syndrome and the growing wind energy industry, has yet to be determined. The U.S. Fish and Wildlife Service has recently published a 4(d) Rule for the Northern Long Eared Bat that identifies protections provided under the federal Endangered Species Act related to certain practices, and has designated a White Nose Syndrome Zone within which certain actions are considered, such as tree removal. Within the White Nose Syndrome Zone, Allegany County is designated as a county with known White Nose Syndrome infected hibernacula.

Listed species potentially affected by the proposed Dan's Mountain Wind project include Allegheny Woodrat (*Neotoma magister*; State Endangered); Eastern Small-footed Bat (*Myotis leibii*; State Endangered); and Timber Rattlesnake (*Crotalus horridus*; not listed, but rare). PPRP is developing CPCN licensing conditions in conjunction with WHS that will require mitigation elements for each of these species. Some elements of these conditions include:

- Stockpiling of large rock from project for small-footed bats, timber rattlesnake, and Allegheny woodrat.
- Creation/maintenance of rocky Allegheny woodrat habitats in the vicinity of the wind project without de-foresting.
- Creating standing dead snag trees away from rock outcrops for raccoon habitats (i.e., lure them away from Allegheny woodrat habitats, as they are vectors for parasite diseases).
- Trapping and removal of raccoons from the project area.

Planting of mast-producing trees as food source for Allegheny woodrats.

### *Cumulative Effects*

Potential cumulative effects of generation facilities are dependent on their location, size and the amount of habitat disturbed. The most noticeable impacts are associated with wind turbines, which can kill birds and bats through collisions. The cumulative impact of bird fatalities, at present, is not considered to be severe for any one species, as no single species appears to be disproportionately affected. In addition, operational (e.g., lighting that can attract birds) and design (e.g., guyed structures) circumstances that can contribute to higher fatalities are better understood and new wind power facilities are constructed with reduced lighting and no guy wires to minimize impacts. Birds considered most at risk are songbirds that migrate nocturnally. High fatality events for these species often coincide with nights that have a low cloud cover resulting in birds flying closer to ground level. Although the Migratory Bird Treaty Act prohibits the “take” of any birds, the U.S. Fish and Wildlife Service, in practice, only requires that good faith efforts be employed to avoid fatalities.

The cumulative impact to bat species is of greater concern. The high level of recorded bat fatalities has been distributed among only a few species, predominantly red and hoary bats. These two species undertake long distance seasonal migrations and typically roost in trees, whereas most other species have shorter seasonal movements to and from caves in which they over-winter. While the specific population characteristics of these species are uncertain, they are relatively long-lived and they produce few offspring annually, both characteristics that make them less able to sustain a high level of fatalities. Recent PPRP-funded studies of bat activity in western Maryland have recorded high numbers of these two species during spring monitoring. Another study examined population genetics indicated red bats appear to have a larger overall population size than hoary bats, and may be better able to absorb losses from wind energy facilities.

### 4.3.2 Transmission Lines

In general, overhead transmission line corridors range in size from approximately one hundred to several hundred feet wide, depending on the power-carrying capacity and the number of lines routed through the corridor. Due to their linear nature, transmission corridors invariably cross natural features such as streams; floodplains; forests; rare, threatened and endangered (RTE) species habitat; and historical and archeological sites. Siting new transmission lines or modifying existing lines requires careful planning and implementation to avoid impacts to these resources. Several new transmission lines have been proposed across Maryland recently in response to PJM’s transmission planning and federal studies that indicated that the northeastern U.S. is in critical need of increased transmission capacity and reliability. Furthermore, offshore wind power facilities proposed for near the Maryland coast would require both offshore transmission and additional large capacity transmission lines on the Eastern Shore. CPCN applications for interstate transmission projects like these raise many unique environmental and socioeconomic challenges, such as preserving natural habitats along the Atlantic Coast, shielding the views and vulnerable stream habitats of suburban central Maryland, protecting the sensitive bottom habitats of the Chesapeake Bay, or ensuring the security of power delivery to populations and facilities in Washington, D.C., Baltimore, Maryland, and other urban areas.

Currently there are numerous transmission line projects, located throughout the state, that are in various stages of review/approval. PPRP reviews the environmental impacts of proposed transmission line projects from a number of perspectives. The review considerations and typical impacts are summarized in the following subsections.

### *Impacts on Wetlands*

Wetlands are among Maryland's most valuable natural resources. Tidal wetlands are protected by the Critical Area Act, and non-tidal wetlands — including wetlands in utility rights-of-way — fall under the Non-tidal Wetlands Protection Act. Maryland's overall goal is no net loss of non-tidal wetlands acreage or function. To achieve this goal, the State requires that any unavoidable wetland losses be replaced at least acre for acre. Greater replacement ratios (up to 3:1) are specified for forested wetlands and Wetlands of Special State Concern. To construct a transmission line project in a wetland, the developer must obtain a Letter of Exemption, a State Programmatic General Permit, or an Individual Wetlands Permit that details project-specific conditions from MDE, or the U.S. Army Corps of Engineers or both. While new routes are usually planned so as to avoid wetlands, rights-of-way constructed prior to the Non-tidal Wetlands Protection Act were often less favorably sited, and many undesirable wetland impacts exist. For example, the Burtonsville to Takoma Park transmission line route in Prince George County, Maryland, would probably not be built today. It traverses sensitive wetlands and streams including Little Paint Branch Creek, which has one of the state's last brook trout populations.

Wetland impacts result when vegetation, soil, or water flow is altered by a transmission line right-of-way, either directly or indirectly. In the past, transmission line access roads within wetlands were often particularly damaging, because fill was used to raise the roadbed above the water table, changing both the natural drainage and the soil characteristics. Parts of the wetland that are isolated from their water source by the road or associated ditching can dry up. Conversely, parts of the wetland upstream (or up-flow) of the blockage often are permanently flooded. In addition, without proper management practices, invasive plants tend to colonize areas on and directly adjacent to a dry elevated road bed and compete with the adjacent wetland plants for sunlight and water. As a result of vigilant permitting oversight by MDE, U.S. Army Corps of Engineers, and DNR, and appropriate planning by the utilities, transmission line access roads are now rarely constructed in wetlands. The preferred access for pole placement and line maintenance near wetland areas is via access points on either side of the wetland, avoiding direct impacts. Where upland access is not possible, matting can often be placed over the wetland area to minimize damage from equipment and activities, without building permanent roads.

Indirect construction and maintenance impacts to wetlands are primarily caused by soil disturbance in uplands that allows runoff to convey loosened soil into streams and associated wetland areas. Construction activities can also disrupt nearby wetland habitat, especially during critical reproductive periods for the plants and animals that comprise the wetlands ecosystem. Impacts can often be minimized during construction by use of appropriate best management practices. After construction, impacts can be reduced by refraining from mowing or using other equipment within wetlands areas and using EPA-approved and appropriate herbicides to eliminate non-native invasive species in or near wetland areas. Overall, transmission line construction has the least impact on wetlands when poles are placed in uplands areas, well away from the wetland area, or lines are placed in horizontally-bored duct banks below the wetland.

### *Impacts on Forests and Maryland's Green Infrastructure*

Right-of-way management has historically used a simplistic paradigm of clearing all vegetation, reseeding with grasses, mowing frequently, and/or applying herbicides to kill shrubs and tree seedlings that invade the right-of-way. This approach allowed easy access to the transmission line, but was frequently detrimental to natural habitats as described in the preceding sections.

Over 40 years ago, the Working Committee on Utilities of the President's Council on Recreation and Natural Beauty prepared an extensive report on "actions required to assure that utility transmission and distribution lines and utility plant sites are compatible with environmental values." Most of the recommended alternative management practices for minimizing the impact of transmission lines remain valid today. Among the suggested practices that have been recommended to transmission line owners, but have been slow in implementation, are the following:

- Right-of-way clearing should be kept to the minimum width necessary to prevent interference from trees and other vegetation. Selective tree cutting and removal should be used, targeting only trees which could cause damage to the line.
- The right-of-way edges through forests or timber areas should be curved, undulating boundaries, not straight "walls" that create a "tunnel" effect.
- Small trees and plants should be used to feather the height of the right-of-way vegetation from grass and shrubbery near the center to larger trees at the edges.

Rights-of-way that are constructed through Green Infrastructure hubs and corridors split them into smaller, disconnected pieces (fragments) and diminish their ability to function as integrated habitat units. While the area of the removed forest may not be great, there may be severe consequences for the species that depend on the hub or corridor habitat. Invasive plants such as Japanese honeysuckle, Korean bush clover, Asiatic bittersweet, and wicker microstegium can grow prolifically in the cleared-edge habitats of transmission line rights-of-way and can spread into the forest interior, limiting the growth of native species. Careful vegetation management in the right-of-way can mitigate some of these effects.

For existing transmission line rights-of-way in Green Infrastructure areas, expansions of the right-of-way into the surrounding natural territories can be particularly harmful. Siting new transmission lines within Green Infrastructure network components is strongly discouraged unless it is not possible to bypass the Green Infrastructure system and align the new transmission line with pre-existing disturbed and degraded areas.

### *Impacts to Biological Resources*

#### ***Wildlife***

A large portion of the transmission line rights-of-way in Maryland are located in otherwise undeveloped areas that provide abundant wildlife habitat. Although many construction impacts are temporary, the long-term habitat alterations often continue to affect birds, terrestrial animals, amphibians, and fish.

A transmission line right-of-way through a forested area creates cleared areas with abrupt edges that are not desirable habitat for forest interior dwelling species (FIDS), and often provides a corridor for invasive species that compete with or prey upon native forest species. The effects of these changes are particularly severe near forested streams and wetlands. While there are lesser impacts in shrub-scrub and agricultural habitat areas, maintaining the right-of-way in a mowed state can still result in gaps between natural habitat patches. Such gaps can present an insurmountable barrier to some species, thereby isolating the populations. Even highly mobile species may not be able to maintain a coherent population under these circumstances, because individuals that attempt to cross the cleared area may be exposed to a high risk of predation.

Forest interior habitat may support many species, including but not limited to FID species of birds, terrestrial mammals, reptiles, amphibians, and plants. The forest interior habitat is uniquely productive and protected, and may form a core refuge for common forest species that also live in or near forest perimeters or non-interior areas. FID species, however, are particularly sensitive to the size of the remnant habitat patch. Interior habitat is defined as a contiguous zone of forest that is more than 300 feet inside of the edges of the forest area, and is dependent on the shape of the area as well as its total size. Long-term research by DNR indicates that interior habitat usable by some plant and animal species can exist in forest parcels as small as a couple of acres, but sufficient interior habitat to support resident breeding populations of FID birds generally requires several hundred acres. According to the Natural Heritage Program, the populations of many FID birds are declining in Maryland, often because of loss of suitable amounts of habitat. Thus, the effect on FID species of a transmission line corridor that splits or reshapes the edges of a large forest parcel may be significant, and the impact can be particularly damaging in patches smaller than 100 acres or in riparian areas.

Another potential impact of transmission lines is bird collisions and electrocutions. Eagle nests have occasionally been found on transmission line towers (see Figure 4-23). The U.S. Fish and Wildlife Service and the Avian Power Line Interaction Committee have cooperatively developed guidelines to help prevent injuries to birds that contact power lines. The State uses the voluntary guidelines, as updated in October 2012, to help utilities develop Avian Protection Plans that meet the specific needs of their facilities, protect birds from electrocution and collisions, and reduce the likelihood of power outages caused by bird collisions.

*Figure 4-23 Eagle's Nest in a Transmission Tower*

***Threatened and Endangered Species***

Most rare, threatened, or endangered species are composed of small populations that occupy localized environmental niches. Avoiding anthropogenic effects in these locations is the critical step in protecting the species, since even small disturbances may place the remaining population at risk. New transmission line corridors are usually an undesirable disturbance, although the habitats created by existing transmission line rights-of-way sometimes create an ideal niche for a threatened or endangered species.

For example, the state endangered Eastern tiger salamander (*Ambystoma tigrinum*) was noted in the proposed Church to Townsend transmission line project. Tiger salamander eggs were found by a DNR Wildlife Ecologist in a ditch perpendicular to the right-of-way in the vicinity of Millington Wildlife Management Area. This was the largest tiger salamander breeding output found in Maryland since 1997. In addition, several more egg masses were found in two other locations in or near the right-of-way. As part of the licensing process, PPRP included a license condition specific to the protection of the tiger salamander that includes the maintenance of a 500-foot buffer around all known tiger salamander ponds and wetlands, as well as a timing restriction on construction and maintenance activities within that buffer area. Other species found in eastern shore ROWs can include the white fringed orchid (*Platanthera blephariglottis*), sometimes in large patches that are subject to catastrophic disturbance during construction in these ROWs. PPRP reviews each case carefully, and in several recent cases has required the presence of an on-site third-party environmental monitor during construction activities to help avoid or minimize impacts.

The Maryland DNR Wildlife and Heritage Service (WHS), Natural Heritage Program, maintains a database of all known populations of the State's designated rare, threatened, and endangered plant and animal species, with particular attention to those that require special habitat protection to support viable populations. The route of every proposed new or modified transmission line is compared to this database to identify all possible impacts to known populations and also to identify habitat that may be suitable for any rare, threatened, or endangered species. If appropriate habitat is available, certain species could be present without documentation because adequate surveys have not yet been conducted. When habitats and potential habitats are identified in the vicinity of a proposed project, PPRP and WHS work together to make specific recommendations for each species. These include field surveys and protecting or mitigating impacts to any populations present, including avoiding disturbances during breeding seasons or migrations, controlling hydrology impacts during and after construction, controlling and monitoring sediment disturbance, and restricting actions or operations that will disturb or injure individuals of a vulnerable population.

### *Cumulative Effects*

Impacts impacts imposed by transmission line rights-of-way can be distributed over the landscape and affect many types of terrestrial natural resources. Small impacts to a resource, such as a forest or a watershed, at several locations can add up to a significant overall impact. At sensitive locations, such as stream and wetland crossings, small impacts to several different resources (e.g., forest, wetland, and stream riparian areas) can disrupt the overall integrity of the ecosystem. These additive impacts of the right-of-way are called cumulative effects, and are a serious concern where ecosystems are near a critical threshold or are already degraded. Because the health of an ecosystem depends on functional interactions between its components, cumulative impacts can have a result much greater than a simple tally of the individual impacts would suggest.

Cumulative effects can be assessed in several ways. The effect of multiple stresses on an ecosystem is usually evaluated in a context that defines a standard for permissible impacts or a goal for restoration. For example, Maryland’s Green Infrastructure network defines areas where natural conditions should be maintained or restored, while the Critical Area Law restricts development in all sensitive habitats around Chesapeake Bay and its tidal tributaries. Individual resources, on the other hand, are handled in terms of specific impact thresholds or goals. For example, Maryland has set a “no net loss” standard for forests under the Forest Conservation Act and for freshwater wetlands under the Non-Tidal Wetlands Protection Act.

Forest clearing in a right-of-way provides an example of the nature of cumulative effects. One proposed project will require expanding the cleared width along roughly 30 miles of an existing right-of-way in southern Maryland. Although the width of additional clearing is only 100 feet and may not have large local consequences, over the length of the line it totals to hundreds of acres of forest loss. The permanent removal of this much forest would be a significant regional environmental cost of the transmission line right-of-way.

Another transmission line right-of-way in southern Maryland, which was recently evaluated in response to a CPCN application to upgrade the capacity of the line, illustrates the multiplicity of impacts that must be considered. The right-of-way crosses in excess of 20 streams, at least 14 acres of Chesapeake Bay Critical Area, requires at least 20 poles in or near wetlands, fragments forest-interior-dwelling species habitat along its entire length, and affects a total of 179 acres of Green Infrastructure hubs or corridors. These statistics alone speak to the large and measurable cumulative effects that transmission line rights-of-way can have on some of Maryland's most critical natural resources.

### *Vegetation Management*

In existing transmission line rights-of-way, past maintenance activities will have shifted the vegetation toward low-profile species, such as grasses, ferns, herbaceous plants or forbs, shrubs, and tree saplings. Figure 4-24 shows an example of typical transmission line vegetation management practices in Maryland. Many of the species present in the right-of-way may be non-native species that were planted after the initial clearing to prevent soil erosion, or weedy and invasive species that have taken advantage of disturbed habitat in the corridor. In a few places where clearing to maintain the right-of-way has not been frequent, taller vegetation may be present, but generally the right-of-way will be open, with sparse vegetation cover and a different assemblage of plant and animal species than is present in the adjacent areas. The bordering ecosystems (within 100-300 feet of the right-of-way boundaries) can also be degraded to some degree when the vegetative community within the right-of-way has been significantly disturbed or altered by construction and maintenance, such as in forested areas.

***Figure 4-24 An Example of Typical Transmission Line Vegetation Management in Frederick County, Maryland***

Source: K. Sillett, Versar Inc

Trees in or near transmission line rights-of-way have historically presented special maintenance problems. While it is environmentally desirable to remove as few trees as possible, fallen trees and branches can have a major impact on reliability. In 2014, 22% of the total outages throughout Maryland were caused by contact with vegetation. There are fewer tree fall events that cause outages of larger transmission lines; however, DNR has joined with the Maryland Electric Reliability Tree Trimming (MERTT) Council, which typically focuses on lower-voltage lines, to develop a clear picture of trees that cause power outages in Maryland. Utility foresters are identifying each instance of a tree-caused power outage and recording the location, type of tree, and other details. DNR is assembling the data from utilities throughout the state into a common database, and analyzing the data to provide the PSC with accurate information on the causes of such outages. The results will be used by MERTT Council members and DNR to evaluate current data collected following the implementation of new vegetation management standards, known as RM 43. These standards dictate how close tree branches can grow to power lines, typically within a 4-year vegetation management cycle. They also allow utility companies to identify and remove hazardous trees near power lines.

### *NERC Regulations*

Improperly maintained vegetation in a transmission line right-of-way can disrupt the integrity of the system and cause power outages. The North American Electric Reliability Corporation (NERC), operating under the oversight of Federal Energy Regulatory Commission (FERC), develops and enforces reliability standards for transmission lines. Current best practices and requirements for reliability are codified in NERC Reliability Standard FAC-003-3 (Transmission Vegetation Management), which was approved by FERC on September 19, 2013 and is being phased in over time. The standard requires transmission owners to have a documented Transmission Vegetation Management Program (TVMP) for all transmission lines operated at 200 kV and above, as well as for designated sub-200 kV lines and generator interconnection facilities. The purpose of the TVMP is to improve the reliability of the electric transmission systems by preventing outages from vegetation within a right-of-way. The TVMP must identify and document clearances between vegetation and overhead conductors, taking into account voltage, sag under maximum load, and wind velocity on conductor sway. Minimum vegetation clearance distances (MVCD) are required for alternating current voltages. The calculated minimum distances to prevent spark-over between conductors and vegetation at various altitudes and operating voltages are specified in the standard. In addition to maintaining the MVCD, the transmission owner is also required to specify the methods that will be used to control vegetation and has the option of adopting the procedures and practices in the American National Standard for Tree Care Operations, Part 7 (ANSI A300). The TVMP must also include a schedule for annual right-of-way inspections.

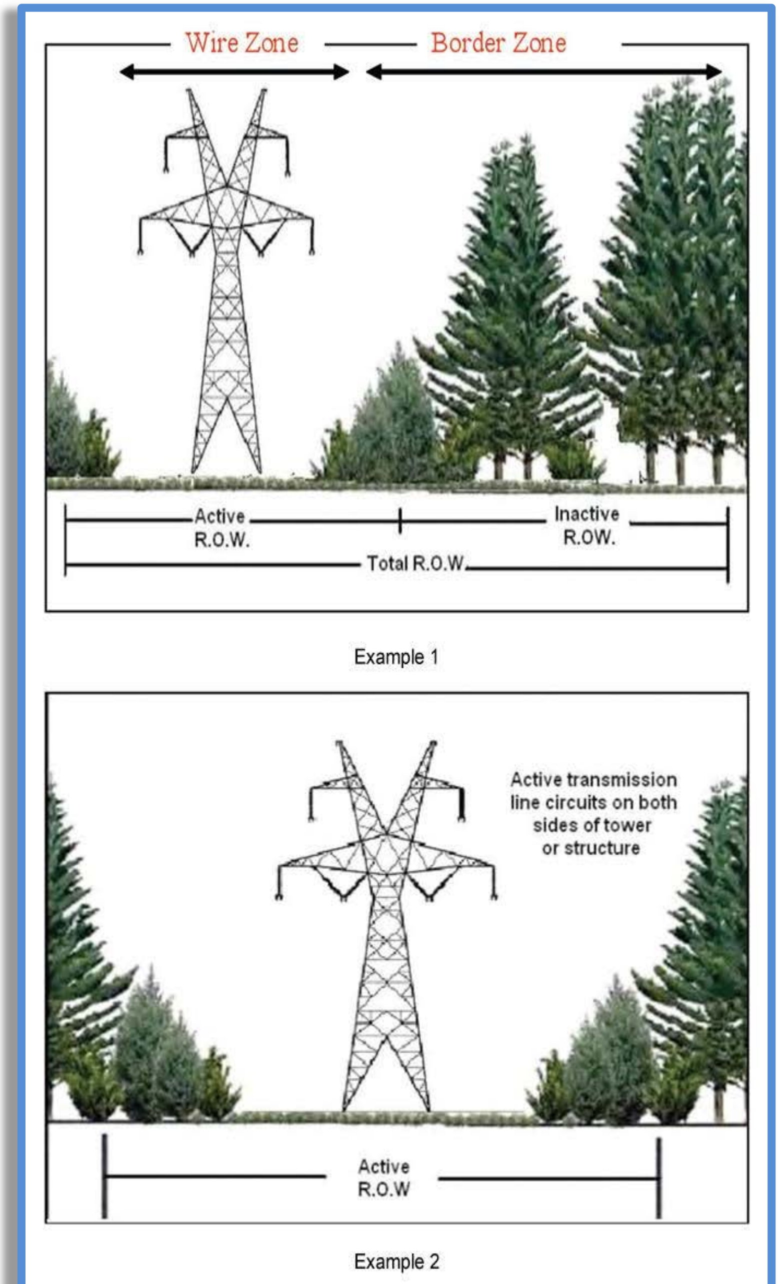
### *Current Practices*

Transmission companies are required to maintain rights-of-way in a condition that assures the reliable delivery of power in accordance with NERC standards. Although it has been common practice to achieve this goal by clearing and mowing the right-of-way, such vegetation management practices are not required and may cause unnecessary environmental damage, especially in sensitive areas and through forested habitat.

The alternatives suggested in the Guidelines of the Working Committee on Utilities, and other advanced techniques such as the Integrated Vegetation Management approach recommended by the International Society of Arboriculture, can be implemented as long as the required clearances are maintained. In general, most Maryland utilities use uniform, system-wide practices that may be more aggressive than NERC requirements. After forested land is cleared to create a transmission line right-of-way, a number of methods to maintain a low stature vegetative community within the right-of-way are generally used, including mechanical clearing, selective removal and pruning of problem trees with chainsaws, and application of herbicides. Mowing is the most common method of maintaining an open grassland habitat. Right-of-way corridors converted and maintained as open grassland habitat within forested habitats may not have much value for grassland breeding birds, and invasive and exotic species can be easily established in these areas. Clearing the entire right-of-way creates hard edges with no transition between habitats. Maintaining a scrub habitat, dominated by low-growing, bushy vegetation and young trees is preferable to mowing, particularly in forest habitats. It provides excellent habitat for wildlife including neotropical migratory birds, reptiles, amphibians and pollinators (see sidebar on Promotion of Native Pollinators).

Leaving the right-of-way in a natural state to the maximum extent possible is the best alternative for protecting wildlife in sensitive areas. Creating curved or wavy right-of-way boundaries and piling brush from the cleared right-of-way so that it provides wildlife habitat would help mitigate impacts from right-of-way clearings in forested areas. Feathered, or soft edges, as shown in Figure 4-25, can be used to provide a transition from forest to open grassland or meadow habitat. Establishing a transition on both sides of the corridor that bisects a forested area with a medium height “border zone” along the edges, and a lower vegetated “wire zone” in the center of the corridor, referred to as the “U effect,” also reduces the effects of fragmentation on wildlife. A transition zone of scrub-shrub habitat of at least 20 feet in height within the right-of-way is recommended for rights-of-way through forests, since long linear meadows do not have much value for grassland birds and these open areas tend to facilitate the establishment of exotic species.

*Figure 4-25 Transmission Line Vegetation Management using Feathering Technique*




Source: Examples adapted from NERC Standard FAC-003-2 Technical Reference, September 2009

### *Conditions and Compliance*

Most Maryland utilities indicate that they now use a combination of selective herbicide application and mechanical cutting rather than exclusively one or the other. To encourage the implementation of environmentally friendly maintenance in rights-of-way, PPRP has, through its membership in the Maryland Electric Reliability Tree Trimming Council, compiled information on innovative practices that reduce adverse effects on local wildlife and plant communities, such as reduced mowing frequencies. Several of Maryland's utilities have adopted maintenance programs to improve wildlife habitats in rights-of-way in limited areas. The introduction of desirable species into the right-of-way through "right tree/right place" plantings or wildlife habitat enhancement projects is often possible. Where implemented, such programs have created better, more stable habitats for wildlife, and have actually saved thousands of dollars in annual maintenance costs.

Some research indicates that planting "connecting corridors" in the right-of-way between otherwise separated forest patches could be beneficial for many forest species. Such corridors could consist of native low-growing trees and shrubs that do not grow tall enough to present a danger to the overhead transmission lines. The State agencies encourage utilities to identify opportunities to create such cross-right-of-way connections, particularly in areas where the right-of-way fragments habitat used by forest interior dwelling species or crosses riparian areas and wetlands. PPRP continues to research the benefits of innovative best management practices for power line rights-of-way vegetation management.

The Transmission Vegetation Management Programs of all applicants for CPCNs for new or modified transmission lines are reviewed by PPRP for compliance with the required standards and best management practices. As necessary, license conditions are recommended to the PSC for implementing such practices and for developing detailed vegetation management plans for sensitive locations along the ROW. PPRP maintains a database of these conditions, locations, and plans, and periodically inspects ROWs for compliance.

## *4.4 Socioeconomics and Land Use Issues*

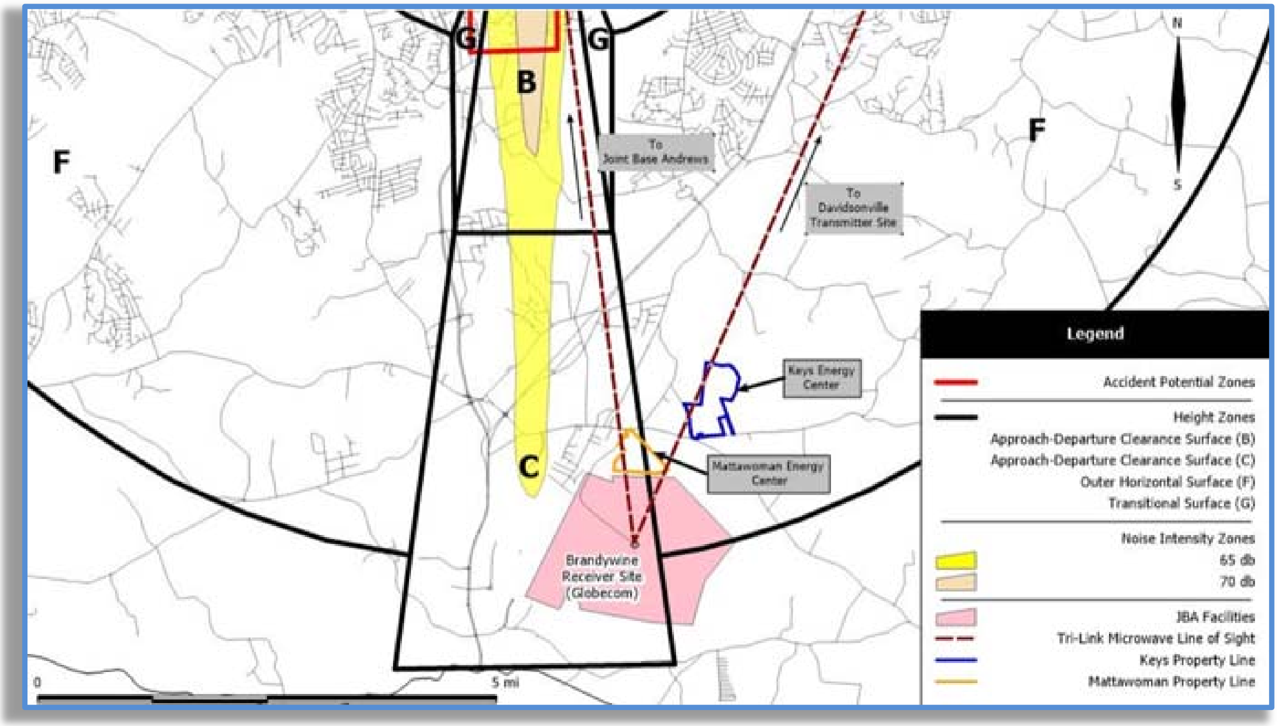
### 4.4.1 Generation Technologies and Socioeconomic Focus

Since CEIR-17, three natural gas generation facilities have been permitted in Maryland. In addition, Maryland's Renewable Portfolio Standard (RPS) has stimulated a large number of proposals for solar photovoltaic (PV) facilities, particularly on the Eastern Shore and in mid-Maryland. While producing both environmental and economic benefits, the licensing of these facilities has required PPRP to consider socioeconomic impacts in its environmental reviews unique either to the generation technology or its location.

#### *Natural Gas*

Two projects that have recently received CPCNs to construct and operate natural gas-fired generation plants in Prince George's County illustrate the uniqueness of land use issues that arose from their location. Located near Brandywine in southern Prince George's County, both the Keys Energy Center (KEC) and Mattawoman Energy Center (MEC) were sited in an area of concern to Joint Base Andrews (JBA) (formerly Andrews Air Force Base). The projects are also directly north of the Globecom Receiver Site, one part of the Andrews Tri-Link, a secure communications facility linking JBA and the Davidsonville Transmitter Site (see Figure 4-26).

*Figure 4-26 Interaction of Keys Energy Center and Mattawoman Energy Center with Joint Base Andrews*




With continuing population growth in Prince George's County, suburban encroachment upon these important military facilities has for years been of concern to the United States Air Force (USAF), prompting the Joint Base Andrews Naval Air Facility Washington Joint Land Use Study (JLUS). The study's outcome resulted in recommendations for promoting compatible land use policies around the facility and, in 2012 Prince George's County implemented an Interim Land Use Code (ILUC). The code governs development in areas impacted by height limitations, high noise levels, and high accident potential resulting from flight patterns at JBA for an interim period while long term regulations are being developed. ILUCs were established to prevent the intensification of existing land uses while the Military Installation Overlay Zone (MIOZ) is being developed as proposed in the JLUS and supported by recommendations in the Air Installation Compatibility Use Zone Study.

The KEC property is within the Outer Horizontal Surface zone (Zone F), one of six height zones around JBA. The Outer Horizontal Surface is defined as an imaginary surface located 500 feet above the established airfield elevation, and extends outward from the outer periphery of the conical surface (Zone E) for a horizontal distance of 30,000 feet. Part of the MEC property is also within the JBA Outer Horizontal Surface zone, with the rest within the Approach-Departure Clearance Surface (Zone C). The Approach-Departure Clearance Surface is symmetrically centered on the extended runway centerline, beginning as an inclined plane (glide angle) 200 feet beyond each end of the primary surface, and extending for 50,000 feet. The slope of the Approach-Departure Clearance Surface is 50:1 until it reaches an elevation of 500 feet above the established airfield elevation. It then continues horizontally at this elevation to its termination.

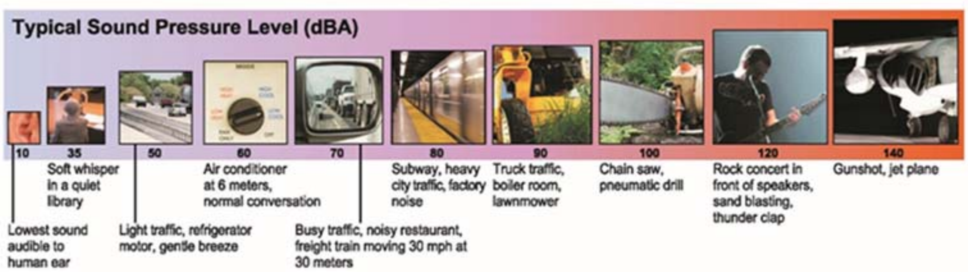
Prince George's County passed legislation in 2012 including a zoning bill (CB-3-2012) that established boundaries of the ILUC area and controls for uses closest to JBA, and a subdivision bill (CB-4-2012) to bring development rules into the subdivision ordinance. County ILUC regulations, for example, forbid the issuance of building permits for any structure exceeding the height of any imaginary surface. The tallest structures (combustion turbine stacks) of the KEC were initially proposed to be 175 feet above ground level (AGL), while those of the MEC (two combustion turbine stacks and the auxiliary boiler stack) were designed to be 100 feet AGL. After analyzing the locations of the structures relative to JBA's imaginary surfaces, PPRP was able to conclude the projects appeared to be compatible with the county's ILUC regulations.

## Evaluating Noise Impacts

Noise consists of vibrations in the air that gradually decrease, or attenuate, the farther they travel. For people who live or work near a power plant, the noise impacts, along with visual and traffic impacts, can be the most significant type of effect caused by the facility.

Noise, measured in decibels (dB), is made up of many components of different frequency (pitch) and loudness. Three decibels is approximately the smallest change in sound intensity that can be detected by the human ear. The sensitivity of the human ear varies according to the frequency of sound; consequently, a weighted noise scale is typically used when discussing noise impacts on nearby communities. This A-weighted decibel (dBA) scale weights the various components of noise based on the response of the human ear. The ear perceives middle frequencies better than low or high frequencies; therefore, noise composed predominantly of the middle frequencies is assigned a higher loudness value on the dBA scale.

**Ranges of Typical Sound Levels for Common Sounds**




The State of Maryland has adopted noise pollution standards, found in COMAR 26.02.03, which are derived from federal noise guidelines. The State regulations establish maximum allowable noise levels by zoning designation and time period (day vs. night). Compliance with noise standards is enforced at the county level, and some counties and municipalities in Maryland have more specific noise ordinances, including Montgomery County, Charles County, and Baltimore City.

As sound waves radiate outward from a noise source, they lose intensity; thus, the sound decreases with distance. Ensuring adequate buffer distances is an effective method of controlling noise impacts. Structures such as berms and walls may also be constructed to provide noise control, and have been used in transportation applications for many years. Vegetative buffers may be used in conjunction with such structures for additional noise abatement.

PPRP evaluates potential noise impacts as part of the CPCN licensing review for proposed power plants. All generating technologies have some type of noise emissions associated with them; even solar power emits a noticeable "electrical hum" from the inverters, but this is only audible at very short distances. In the past few years, noise impacts have been a particular concern during licensing cases for the Cove Point liquefaction project, and for the Keys and Mattawoman natural gas-fired plants, located in close proximity to each other in southern Prince George's County. PPRP evaluated the potential for specific residences to be affected by noise from both of those facilities, and concluded that there was no significant cumulative effect.

However, the USAF was also concerned with microwave and high frequency communications interference, radio frequency interference with the Andrews Tri-Link, and potentially other conflicts that could impact missions affecting national security. Aircrews from JBA also use four landing zones at the Globecom Receiver Site to practice unimproved landing area operations and helicopter flight patterns overfly the Mattawoman site. In response to Keys' filing of a Notice of Proposed Construction or Alteration for the KEC, the FAA issued a Notice of Presumed Hazard. In particular, the Federal Aviation Administration (FAA) found that at the filed height (175') and location, the stacks would exceed obstruction standards or have an adverse physical or electromagnetic interference effect upon navigable airspace by blocking the JBA terminal Doppler weather radar low elevation scans. FAA's notice also indicated that if the stacks were reduced to a height no more than 141 feet AGL they would not exceed obstruction standards, and a favorable determination could be issued. Keys modified facility plans by reducing stack heights to 140 feet AGL and subsequently entered into a stipulated agreement with JBA to address remaining concerns. A similar agreement, which included a clause retaining JBA's rights to continue helicopter operations over the generating station, was later executed between Mattawoman and JBA. PPRP's consultation with JBA in both licensing cases was an important catalyst for the resolution of these issues.

### *Solar Photovoltaic*

#### ***Solar Project Decommissioning***

Solar photovoltaic (PV) generation facilities are land intensive. As a rule of thumb, a solar PV facility consumes 5-10 acres per MW capacity, depending upon the strength of the solar resource and other factors. With ever-increasing efficiencies in solar panel technology, the density is approximately 5 acres per MW currently. Since most existing and proposed solar facilities are sited on agricultural land, decommissioning has been an ongoing concern in PPRP's environmental reviews of these projects.

There are no nationwide or statewide standards for decommissioning at present. However, restoration of a site to its "original state" would appear to be a reasonable goal of a decommissioning plan. A model bylaw developed by the Massachusetts Executive Office of Environmental Affairs defines restoration as the physical removal of all large-scale ground-mounted solar photovoltaic installations, structures, equipment, security barriers and transmission lines from the site; disposal of all solid and hazardous waste in accordance with local, state, and federal waste disposal regulations; and stabilization or re-vegetation of the site. Physical removal of ground-mounted structures includes the removal of all or some of below-ground foundations and supports, although the landowner or operator may leave designated below-grade foundations in order to minimize erosion and disruption to vegetation.

Particularly for agricultural land, the abandonment of below ground structures is a concern. A review of decommissioning plans of proposed or existing solar facilities in North America revealed no consensus with respect to below-ground structures, with decommissioning ranging from complete removal without exception to removal to a depth of between two and four feet below grade.

PPRP interprets restoration of a site previously used for agriculture to an "original state" to mean being returned to an agriculturally productive state which allows for safe agricultural practices. With soil compaction being a recurring problem in agriculture, and the potential for deep tillage applications on decommissioned solar farms to restore the land to agricultural use, PPRP recommends removal of below ground structures and cabling to a depth of at least three feet in project decommissioning plans.

Another concern is whether land converted from agriculture to solar generating facilities will actually be returned to agriculture after the facility reaches the end of its useful life. Clearly, a viable option for solar generators is to refit the facilities with new solar panels, given the existing infrastructure in place to support solar generation (cabling, supports, inverters, etc.) and both increased efficiencies and declining prices for PV panels. If solar PV generation is not overtaken by another technology but instead continues to contribute to Maryland's generation capacity, it could be a very long time before the land is returned to agriculture or converted to another use.

Given the relative youth of most renewable energy technologies, there are only a few decommissioning examples, of which many are hydroelectric dams. However, the decommissioned Carrisa Plains (also known as Carrizo Plains) photovoltaic power plant is an interesting story. Constructed by ARCO Solar between 1983 and 1985 in central California, Carrisa Plains was then the largest photovoltaic array in the world, with 100,000 1' x 4' photovoltaic arrays producing 5.2 MWac at its peak. The facility occupied about 177 acres in San Luis Obispo County near San Bernardino. It followed ARCO's construction of the Lugo plant, a 1 MW pilot operation in Hesperia, California. Neither facility was able to compete with fossil fuel-based generation, and ARCO sold them to the Carrizo Solar Company for $2 million in 1990. However, by that time the Carrisa Plains plant was producing less than 3 MW of its original 5.2 MW rating, and was decommissioned shortly thereafter. The Carrizo Solar Company dismantled the facility in the late 1990s and the used panels were resold, some of which were subsequently used in domestic installations. The site was then stripped clean of structures and other electrical components, re-graded and returned to dry farming (Figure 4-27). Information about the extent to which the project site was restored to its former use is limited. State documentation indicates a cleanup of contaminated soils, and the site is reported to have had an underground storage tank containing diesel fuel, although no violations were reported. In 2009, it was unknown whether the underground storage tank was still present.

***Figure 4-27 Decommissioning of the Carrizo Plains Power Plant***

Source: The Center for Land Use Interpretation, http://clui.org/ludb/site/abandoned-solar-power-plant

The story does not end there, however. The site is now part of First Solar's 550 MW Topaz Solar Farm, constructed between 2011 and 2014, and occupying 9.5 square miles. That the site is hosting another solar PV facility should not be a surprise. Carrizo Plains is one of the sunniest places in California. Ironically, as part of a settlement with environmental groups, First Solar has committed to cease operations after 35 years (2047) and restore the area to its natural state, placing a conservation easement on the land and providing an endowment for managing the land in perpetuity. Figure 4-28 shows the site's land use transition from solar PV facility to dry farming to the Topaz Solar Farm.

***Figure 4-28 Carrisa Plains Land Transition 1989 - 2015***

1989 – Facility Operational
Source: USGS, National Aerial Photography Program (NAPP)

1994 – Carrisa Plains during Decommissioning
Source: Google Earth

2003 – Carrisa Plains Decommissioned Site
Source: Google Earth

2015 – Topaz Solar Farm on Carrisa Plains Site
Source: Google Earth

### *Fire-fighting Challenges at Solar Facilities*

Solar panels and associated electrical equipment are largely free of flammable materials. Although potential health hazards have been associated with toxic materials released during fires from cadmium telluride, copper indium diselenide and gallium arsenide photovoltaic modules, crystalline solar cells used in Maryland installations, which are primarily made of silicon, are not considered to be hazardous to the environment. Still, respiratory exposure to combustion products associated with PV components should be avoided. With respect to other components, some modern transformers use mineral oil as a coolant while others use dry-type cooling. The flashpoint of mineral oil is 335°F, significantly higher than the U.S. Occupational Safety and Health Administration (OSHA) standard, which defines a flammable liquid as any liquid having a flashpoint at or below 199.4 °F.

Post-construction, the risk of fire from ground-mounted photovoltaic systems is low if site preparation and maintenance has minimized potential fuels from under and around solar arrays. Fire prevention guidance for ground-mounted PV installations is contained within the National Fire Protection Association's NFPA 1 Fire Code Handbook and NFPA 70 National Electrical Code. PPRP's recommended license conditions for solar PV projects require developers to design, install and maintain the facility to meet the minimum standards set forth in NFPA 1 and NFPA 70.

Although the likelihood of fire is low, a challenge facing firefighters during fireground operations at PV facilities is the risk of electrical shock. This is because PV panels generate electricity when exposed to sunlight. Even at night, apparatus-mounted scene lighting may produce enough light to generate an electrical hazard. Under a continuous electrical load, any conduit or components between PV modules and disconnect switches will remain energized. Inverters may also provide voltage during daylight hours for several minutes on both sides of a disconnect, even when opened. The Fire Protection Research Foundation also recommends the use of respiratory protection during fireground operations involving PV systems.

While guidelines for fire operations at PV facilities have been published, PPRP is aware that most fire and rescue companies in rural Maryland, where most projects have been licensed, are all-volunteer organizations whose Standard Operating Procedures (SOPs) may not address fireground operations at PV facilities. Because of this, PPRP includes a license condition in its recommendations to the Public Service Commission to ensure that emergency response protocols are in place in the unlikely event of a fire or other emergency at the site unless conditions attached to the permitting of utility-scale solar energy systems by the host county adequately address fire safety issues associated with the project.

## 4.4.2 Scenic Quality in Electric Generation and Transmission Assessments

### *Solar Impact to Agricultural Land Use*

Utility-scale solar energy facilities exclude, until decommissioned, most other surface uses of the lands they occupy. This is in contrast to other renewables such as wind which typically maintain a small spatial footprint. As a result, siting guidance for PV systems typically emphasize the utilization of previously developed land such as abandoned industrial sites, fallow agricultural fields or former mining sites. However, because slope is an important consideration in PV facility siting and development costs are lower on previously cleared land, productive agricultural lands have been targeted by project developers in Maryland, particularly on the Eastern Shore. Combined with declining interest in family farming from one generation to another, rising costs and smaller profits for farmers, solar developers have found willing participants within the State's agricultural community in the conversion of farmlands to utility scale solar energy systems.

Agricultural lands have also been targeted for solar facilities in other states and countries. Starting in 2015, for example, the United Kingdom's Common Agricultural Policy eliminated subsidies for solar farms on agricultural lands through its Basic Payments Scheme even if the land between, under and around the panels are being grazed or is accessible for grazing. Closer to home, a farmland preservation clause was part of a 2012 bill signed into law by New Jersey Governor Christie that was primarily designed to address overbuilding of PV facilities in the state, which caused Solar Renewable Energy Credit (SREC) prices to plummet. Permits for utility-scale projects on farmland must go through additional review to be eligible to be part of the SREC program. In Maryland, on the basis of recommendations from a Renewable Energy Task Force convened in 2010, Kent County updated its zoning regulations to limit the area of use of utility scale solar facilities to 5 acres on property zoned Agricultural or Resource Conservation, essentially precluding grid connected solar farms from these districts. The Dorchester County Planning Commission recently considered, but subsequently rejected, a recommendation to amend its Zoning Ordinance to restrict utility scale solar energy systems to commercial and industrial properties within the county.

## Agriculture and Solar Farms

In other parts of the world, agriculture and solar farms coexist reasonably well. Throughout Europe and the United Kingdom (UK), small livestock (sheep, chickens) are grazed on utility-scale, ground-mounted solar farms, and other productive options such as beekeeping have been demonstrated, the latter which could complement PPRP's promotion of pollinator habitats at CPCN-licensed power projects. Through its "10 Commitments," which encourages continued agricultural activity and agri-environmental measures that support biodiversity on solar farms, the UK Solar Trade Association enjoys the support of Britain's National Farmers Union and other organizations concerned with agriculture and land management. Within the United States, loss of agricultural lands to solar farms and potential mitigation strategies have yet to gain visibility within domestic solar trade organizations, such as the Solar Energy Industries Association (SEIA), or from State and federal agricultural agencies, suggesting the adoption of similar coexistence practices is not likely to gain acceptance anytime soon.

Loss of productive agricultural lands from solar PV development appears to be less of a concern in United States due to its vast land area. Under the DOE's SunShot scenario, direct utility-scale PV land requirements for the U.S., much of which would be sited on non-agricultural lands in the Southwest, are projected to range from 667 thousand to 2.1 million acres in 2030, and from 1.4 to 4.4 million acres in 2050. As a point of reference, approximately 2.5 million acres are currently dedicated to golf courses nationwide. Acreage for other land uses associated with development, such as roads and airports consume even more.

Maryland's direct land requirements for an estimated 13.3 GW of installed PV capacity by 2050 in the SunShot scenario amount to 106,400 acres, approximately 1.7% of the State's total land area. PPRP estimates Maryland's Renewable Portfolio Standard, which requires that 2% of the State's energy – about 1,200 MW – come from solar, will displace about 9,600 acres of Maryland's land area (0.15%) from current uses. Compare this to losses in agricultural and forest lands in Maryland, which averaged 27,630 acres annually between 1973 and 2010, primarily to residential development. Furthermore, not all Maryland's projected solar capacity will necessarily be located on agricultural land.

The U.S. EPA's RE-Powering America's Land Program has identified 279 sites in Maryland totaling 103,000 acres comprising contaminated lands, former mines and landfills that could potentially host renewable energy projects. However, EPA's list ignores development considerations such as slope, and risk associated with constructing and operating facilities on federally regulated (i.e. RCRA and Superfund) sites. Removing sites with these constraints, up to 30,000 acres of Maryland's brownfields and closed landfills could be developed if other siting criteria are satisfied, particularly since MDE has a Voluntary Compliance Program for brownfields, which could potentially mitigate liability concerns. SmartDG+, an online screening tool sponsored by MEA and PPRP and designed for distributed generation and renewable energy projects between 1 and 10 MW, focuses on infrastructure proximity, land suitability, and other factors that could help developers and officials identify promising areas from this list.

Among recent solar siting projects reviewed by PPRP, the Great Bay Solar Farm, though expansive at 1,000 acres, would preempt normal agricultural activities from no more than about 1.5% of Somerset County's total 2012 acreage of land in farms, or about 2.75% of cropland acreage. Projected agricultural land losses to solar farms appear to be small relative to losses from other types of development, and may be reversible if facilities are decommissioned at the end of their useful lives. However, the direct loss of acreage is just one aspect of development pressure that is currently playing out in land use decisions across Maryland and the region. With land requirements in the range of 5 to 10 acres per MW, displacement of agriculture from regional economies, loss of prime farmlands and the security of the nation's food supply are increasingly seen as issues in utility-scale solar PV systems, a development that has begun to affect siting policy.

### *Solar Farms and Scenic Quality*

Related to the conversion of agricultural lands to solar PV facilities is scenic quality. While an important amenity for residents, it is equally so for the tourism industry, particularly for the attraction of recreational and heritage visitors to a region. Research has shown that degradation of views can affect tourist perceptions of scenic vistas and visitation levels. Therefore, scenic quality can indirectly affect the economic well-being of a region. Because of this, PPRP environmental reviews include assessments of impacts of generation and transmission line projects on the landscape.

Scenic quality is recognized in many of Maryland's programmatic designations. The Maryland Environmental Trust (MET), for example, accepts offers of conservation easement to protect natural, historic and scenic resources in the state. Maryland's Rural Legacy Program (RLP) provides "the focus and funding necessary to protect large, contiguous tracts of land rich in natural and cultural resources from sprawl development." Among its goals are "to establish greenbelts of forests and farms around rural communities in order to preserve their cultural heritage and sense of place." Administered by DNR, protection is enabled through easements and fee estates and through the program's support of Rural Legacy sponsors and local governments. The geographic framework for the RLP is the Rural Legacy Area (RLA), a "designated region rich in a multiple of agricultural, natural, forestry or cultural resources." The Maryland Heritage Areas Program preserves the State's historical, cultural, archeological, and natural resources for sustainable economic development through heritage tourism. This is accomplished through the local designation and state certification of Heritage Areas, defined by a distinct focus or theme that makes a place or region, including its natural landscapes, different from other areas of the state. SHA's Scenic Byways Program administers federal highway funds for encouraging the responsible management and preservation of the state's most scenic, cultural and historic roads and surrounding resources.

The degree to which these programmatic designations protect land from activities associated with electric generation and transmission varies. Generally, land placed in easement is protected from direct effects (i.e., pre-emption or conversion) by the terms of the Deed of Conservation Easement or similar document. The aesthetics of an easement property may be less protected from indirect effects, however. Furthermore, although easements, transferable development rights, and fee estates protect specific land parcels within RLAs, RLA designation, in itself, affords no land use protection. When carrying out activities in a Certified Heritage Area (CHA), a State agency must consult, cooperate, and, to the maximum extent feasible, coordinate their activities with the entity responsible for the management of each CHA; ensure that the activities are consistent with the CHA's management plan; and ensure that activities will not have an adverse effect on the resources of the Heritage Area unless there is no prudent and feasible alternative. While the SHA funds the development of community-based corridor management plans (CMP) to make scenic byways eligible for additional grants as well as a National Scenic Byway designation, and publishes guidelines for maintaining scenic quality along byways, there are no regulatory protections for scenic byways.

At the federal level, scenic quality is also recognized in the management plans for units of the National Park Service located in Maryland, such as the Appalachian Trail and the Chesapeake and Ohio National Historical Park; the National Register of Historic Places through its designation of historic landscapes and national historic landmarks; the National Heritage Area program; and the Federal Highway Administration's National Scenic Byway Program, among others. Local governments promote scenery through zoning overlays, such as the Antietam Overlay Zone in Washington County, and in various recreational initiatives, such as bicycle, hiking and water trails.

Federal involvement in scenic protection is in part governed by Section 106 of the National Historic Preservation Act, which requires federal agencies to take into account the effects of their undertakings on historic properties which may include historic landscapes. For National Historic Landmarks affected by undertakings, Section 110(f) of the Act goes further requiring agencies to "minimize harm" to the maximum extent possible. Since an undertaking includes not only projects funded by a federal agency, but also those requiring a federal permit, license or approval, power plants or transmission lines that traverse or otherwise occupy land under federal jurisdiction can be subject to Section 106 review.

In addition to oversight of National Register properties and National Historic Landmarks, the National Park Service (NPS) holds lands in both fee simple and easement, including scenic easements. Scenic easements are designed to limit development and provide a natural view shed to afford visual protection for visitors to national parks and to wild and scenic rivers through protective buffers. In Maryland, NPS currently holds 259 scenic easements in the C&O Canal NHP, most of which are in Washington and Montgomery counties. Outside park boundaries, the NPS acts to protect park resources by working cooperatively with federal, state and local agencies, and with adjacent landowners and other interested parties. National Heritage Area (NHA) and National Scenic Byway management plans carry no regulatory protections of scenic resources, but instead rely on leveraging existing land preservation programs to achieve their goals.

While many federal, state and local land preservation and heritage overlays contain scenic elements, landscapes are not uniform within them. Most views have low scenic value or are compromised by contrasting elements. Because of this, land preservation and heritage overlays are poor proxies for conducting scenic quality assessments. While comprehensive scenic resource assessments have been conducted for some regions of the state, Maryland has not conducted a statewide scenic landscape inventory. As a result, general planning decisions for power plant and transmission line siting, in addition to other growth policy decisions, are constrained by the lack of a scenic landscape data layer based on uniform visual resource assessment guidelines. PPRP visual impact assessments are therefore subjective, based on imperfect scenic resource data and multiple standards among scenic preservation interests for classifying visual resources and county land development regulations.

This is particularly true for solar PV facilities. Sitting no more than 10 feet above ground level, the physical structures associated with solar arrays have a low visual profile. For security and public safety, all facilities are surrounded by a 6-8 foot fence. Views of solar farms are therefore limited by their vertical dimensions. Still, without mitigation solar farms may be visible from surrounding residential properties or nearby public roads, which can detract from the agricultural landscapes that predominate around most of Maryland's solar facilities. The toolkit for mitigating visual impacts from solar facilities consists of setbacks and buffering. A setback is the distance from a nearest above-ground structure to a property line or public road right-of-way. In general, visual impact is reduced by a greater setback. A buffer is a visual screen between a viewing location and one or more above-ground structures. Usually, buffers are comprised of trees and shrubs, and may also incorporate a berm.

Setback and buffer requirements are typically codified in county zoning ordinances, and may apply to specific zoning districts or to specific land uses, such as solar facilities. In Maryland, setback and buffer regulations are not uniform across its counties, nor do all county zoning ordinances recognize utility-scale solar facilities as a specific land use. Such was the case in PPRP's review of the Great Bay Solar project in Somerset County, which would occupy land zoned AR – Agricultural Residential, I-2 – General Industrial, and R-1 – Low Density Residential. The county's zoning ordinance does not specifically address wind, solar, and other facilities, and therefore does not specify setback requirements specifically for solar energy systems. It does, however, require landscape or screening buffers for new principal commercial or industrial uses that abut a "primarily residential lot" within the AR, R-1, R-2, R-3 or MRC (Maritime-Residential-Commercial) district. Specific landscaping requirements are set out in §6.12 of the Somerset County Zoning Ordinance.

Drawing on its experience from other solar facility siting cases, PPRP concluded that Somerset County's setback requirements for new industrial uses were both inadequate for screening solar facilities from adjacent residences, and inconsistent with the region's goals for preserving and highlighting its natural and historic landscapes. PPRP noted, for example, Queen Anne's County requires a minimum 25-foot landscaped strip to provide screening from adjacent residential uses and public or private roads. Utility-scale solar energy systems in Dorchester County must be screened from the ground floor of any adjacent residential dwelling unit by a vegetated buffer of at least 50 feet wide, with specific requirements determined as part of the site plan review process. Setback and buffer requirements are similar in Charles County.

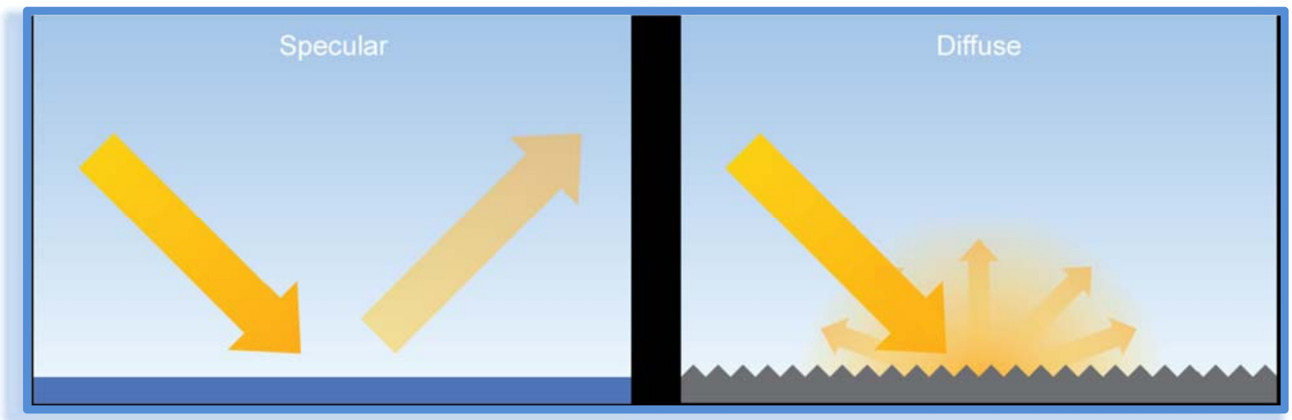
To mitigate visual impacts from the facility, PPRP recommended a license condition requiring Great Bay Solar to set back its facilities, defined as facilities within the perimeter fencing, at least 50 feet from any adjacent property line or public road. Where the project abuts a primarily residential property, or a public or private road, Great Bay Solar is required to design a landscape buffer within the setback and outside the fence line that will effectively screen, to a minimum 8 feet above ground level, views of the solar facility. Where it could be demonstrated that the landscaped buffer would serve no purpose, PPRP did permit the landscape screening requirements to be waived by Somerset County. PPRP has since recommended similar license conditions to other solar projects going through CPCN review where county setback and buffer requirements are inadequate.

### *Glare from Solar Farms*

Another visual impact issue is glare. Glare is light that reflects off a surface. It is sometimes referred to as glint when a surface reflects a momentary flash of bright light. For the most part, glint is simply a special case of glare, as both have the same impact upon receptors – a brief loss of vision or "flash blindness."

Glare is associated with solar PV panels through their interaction with sunlight. While a PV panel is designed to maximize absorption and minimize reflection to increase electricity production efficiency, some sunlight is invariably reflected off its surface. With an anti-reflective (A/R) coating, PV panels reflect as little as 2% of incoming sunlight, depending on the angle of the sun. The reflectivity of solar panels is similar to water, but significantly less than bare soil, vegetation, white concrete or snow. However, reflected light from a solar panel is predominantly specular, which is a more concentrated type of light that occurs when a surface is smooth or polished (Figure 4-29). Still water is another example of a surface that reflects specular light. Diffuse reflection occurs from light reflecting off a rough surface and produces less concentrated light. Many surfaces with higher reflectivity than solar panels produce diffuse reflections. This is important because, except under unusual circumstances, flash blindness can only occur from specular reflections.

***Figure 4-29 Specular and Diffuse Reflection***




Source: Technical Guidance for Evaluating Selected Solar Technologies on Airports. Federal Aviation Administration, Office of Airports, Office of Airport Planning and Programming. Washington, DC. November 2010.

Comprised of thousands of panels, a solar PV energy facility has the potential for being a significant source of glare. However, the potential for glare is related to a number of factors:

- The position of the sun in the sky relative to the array site, as a function of time of day and time of year.
- The intensity of the sunlight reaching the array, as a function of time of day and time of year.

- The characteristics of the solar array.
- The reflectivity of the panels as a function of angle of incidence of the direct sunlight onto the panels.
- The degree to which light reflected from the panels is specular reflection.
- The position of receptors that might be impacted by glare from the panels.

The position of the sun in the sky relative to a solar PV facility determines the sun's angle of reflection off the array, sometimes called the angle of incidence. In general, for southward facing arrays, the angle of reflection is lowest when the sun is shining at its highest point and highest just after sunrise and before sunset. The angle of reflection can be quite large (and glare closest to ground level) at sunrise and sunset for fixed arrays because the sun is more to the sides of the panels at these times. At Maryland latitudes, the sun reaches a maximum solar elevation of 75° at noon of the summer solstice and about 28° at noon on December 21.

Characteristics of the solar array include the facility's footprint, angle and direction of tilt of the panels, and whether the panels are fixed or tracking. Footprint relates to the facility's nameplate capacity. With respect to angle and tilt, many commercial solar arrays are positioned at a horizontal angle to the sun of 25° and azimuth of 180° true north (i.e., due south). Tracking allows solar panels to optimize contact with the sun. Single axis systems track the sun either horizontally, following the sun's lateral path from sunrise to sunset, or vertically, by changing the panel angle relative to the ground. Dual axis systems move both horizontally and vertically.

Virtually all light that passes through the front surface of a solar panel is trapped in layers below, so the only source of reflectance is the panel's front surface. While the specular reflectance of solar glass can be as low as one or two percent at near-normal incident angles, reflectance of solar PV glass can be more than 20 percent at large incidence angles (>60 percent), even with A/R coatings or surface texturing. The degree to which reflected light is specular is related to the texture of the reflecting surface. For solar panels, textured glass and anti-reflective coatings produce more diffuse reflections with lower solar intensities but larger glare sources.

The final factor affecting glare is the location of the viewer relative to the source. Broadly speaking, the impact of glare declines with increased distance from the source, but increases with the size and orientation of the reflective surface. Finally, one's light sensitivity can affect the perception of glare.

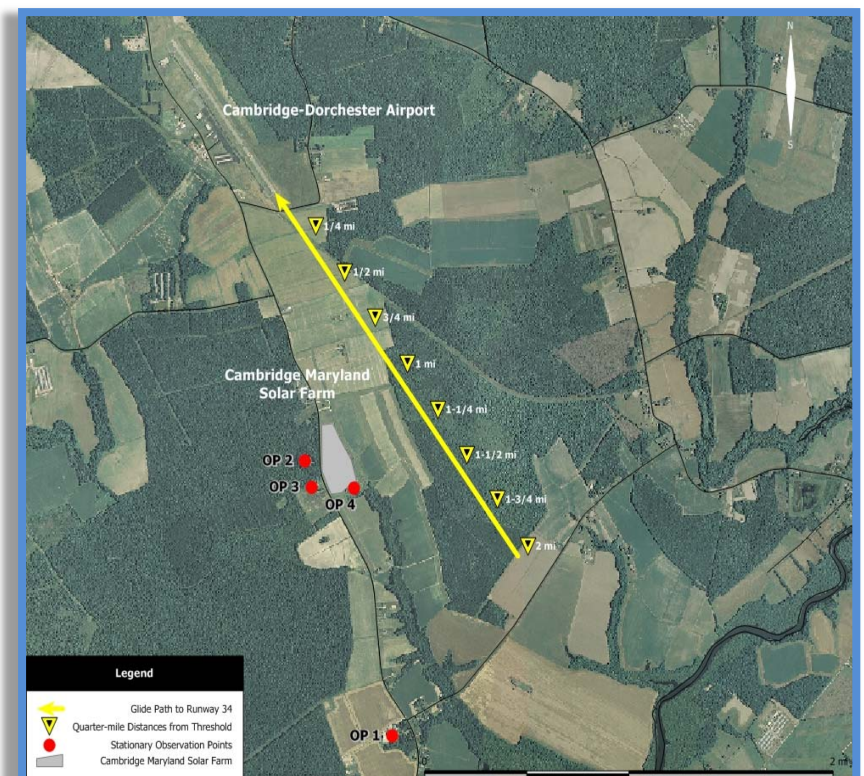
Potential receptors of glare from solar PV facilities include observers in nearby buildings, motor vehicles, scenic overlooks, and aircraft. Similar to glare from the sun, impacts from ocular discomfort can range from operational, particularly within the realm of motor vehicle and aviation safety, to nuisance, which may affect one's perception of the working or recreational environment.

Most regulatory activity addressing utility scale solar projects has been in aviation. However, some communities outside Maryland have begun to specifically address glare in their development standards for either rooftop or freestanding panels, although the language is subjective, typically requiring systems to be designed and sited to avoid glare on adjacent properties or roadways. None require a glare study or specify glare mitigation techniques or technologies. In Maryland some county and municipal zoning ordinances address light trespass onto adjoining properties. However, none explicitly addresses reflected glare from solar PV systems, nor is aesthetic guidance backed by regulation.

PPRP has undertaken glare studies in all recent solar PV licensing cases. It uses the Solar Glare Hazard Analysis Tool (SGHAT) to determine whether a proposed solar energy project would result in a potential glare impact. SGHAT is an interactive web-based tool from DOE's Sandia National Laboratories. It accepts input on the location and configuration of a proposed solar facility and observer locations, including air traffic control tower and aircraft glide paths. If glare is found, it predicts potential ocular hazards ranging from temporary after-image to retinal burn. SGHAT is not without its shortcomings. It considers terrain in its calculations, but not landscaping or other vegetative screening. As a result, PPRP considers predictions of glare by the model to be conservative, likely overstating the potential impact upon nearby receptors.

Still, the model has provided useful input into PPRP's environmental reviews. For the OneEnergy Cambridge Solar project, for example, PPRP's glare modeling predicted glare significant enough to cause a temporary after-image would be experienced on the Runway 34 glide path into the Cambridge-Dorchester Airport (Figure 4-30). This resulted in a license condition requiring OneEnergy, prior to construction, to file a Notice of Proposed Construction or Alteration to the Federal Aviation Administration (FAA) for a formal determination of the Project's effect on navigable airspace by aircraft. In many other cases, glare upon nearby residences and public roads has been predicted, but after examining proposed landscape plans and current vegetation around the site, PPRP has concluded the likelihood that reflective glare will trespass onto nearby properties is minimal. To be sure glare is not experienced by a project's neighbors, PPRP includes a license condition requiring the project developer to document and address complaints related to potential solar reflections.

***Figure 4-30 SGHAT Stationary Observation Points and Glide Path at Cambridge Maryland Solar Farm***

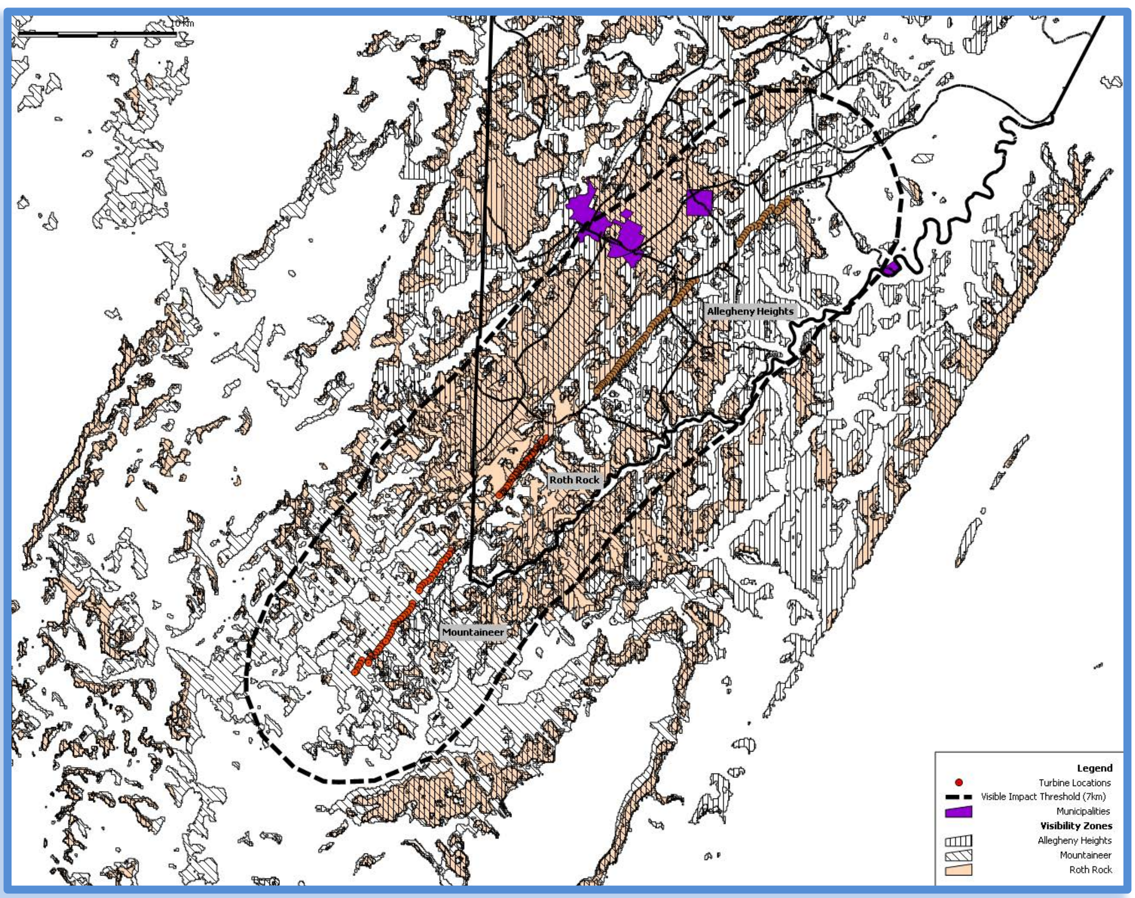


### *Visual Impact Analysis for Terrestrial Wind Power Projects*

Proposals develop terrestrial wind energy projects in Maryland have raised concern about visual impacts on the landscape. The placement of wind turbines 400 feet high or more would alter existing views from many perspectives. But the magnitude of visual effects is less certain due to uncertainties in the location of receptors, how they perceive a landscape and a number of other factors.

The visual footprint of a wind energy project can be estimated using a digital elevation model (essentially a digitized terrain relief map), turbine locations and heights, and geographic information system (GIS) analytics. The resulting graphic identifies every point on the ground visible by line of sight from the indicated height of one or more turbines (Figure 4-31). Reversing the perspective identifies locations (i.e., a visibility zone) from which one or more towers of an indicated height (or greater) are visible. Most GIS models are capable of estimating visibility zones. PPRP has utilized a wind farm analysis, design and optimization model in past wind energy licensing projects to compute visibility zones, wire-frame turbine views and 3D visualizations for its environmental reviews.

**Figure 4-31 Example of Visibility Zones**




Visibility zones computed from digital elevation models overstate the visibility of landscape alterations. In general, the theoretical distance from which an object is visible exceeds the actual distance because of atmospheric scattering of light. Furthermore, terrain is the sole determinant of line of sight computations that generate a visibility zone unless a vegetation layer is incorporated into the digital elevation model, not an easy task. Vegetation, particularly trees, fully or partially obscures views from within much of a visibility zone.

Visual impacts and visibility zones are not the same thing. Although visual impacts occur within a visibility zone, Bishop and Shang and Bishop, among others, have noted that visual impact thresholds are significantly less than distances from which an object in the landscape can be detected or recognized. Photo simulations, wireframe models, and 3D visualizations of wind turbines from selected locations help stakeholders visualize an alteration to the landscape, but they do not quantify visual impacts. Although their limitations are known, visibility models are useful in visual impact assessments because they identify view sheds, cultural resources, properties and other features that could potentially be adversely affected by landscape alterations.

## *4.5 Radiological Issues*

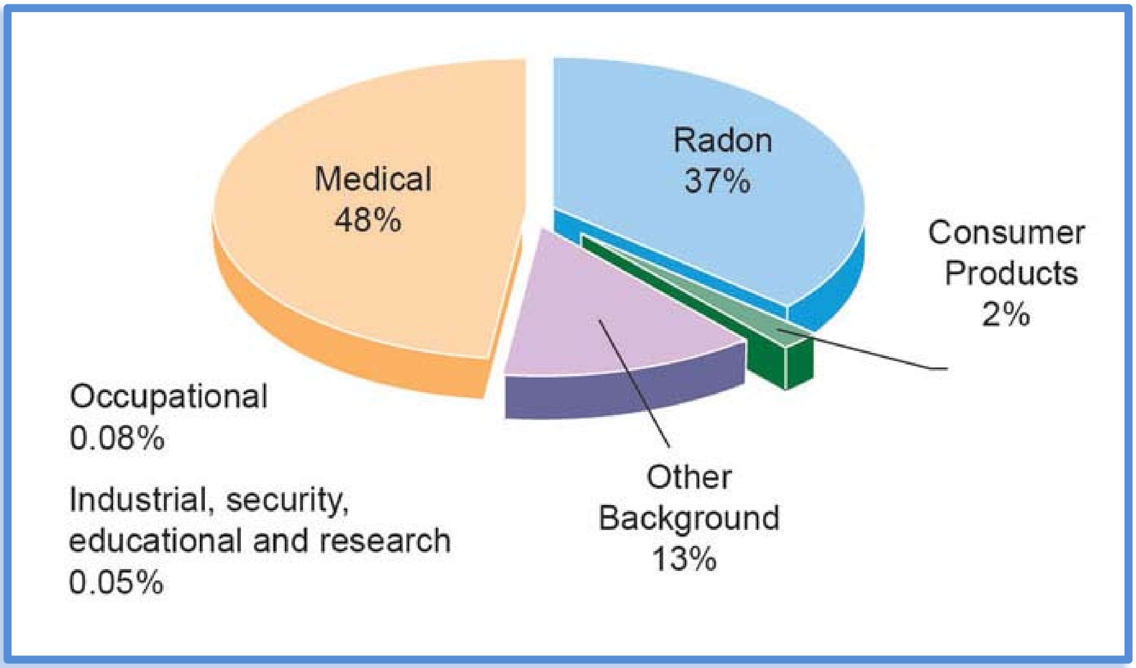
### 4.5.1 Pathways to Exposure

Production of nuclear power in the United States is licensed, monitored, and regulated by the U.S. Nuclear Regulatory Commission (NRC). Provisions in the operating licenses of each plant allow utilities to discharge very low levels of radioactive material to the environment. The kind and quantity of releases are strictly regulated and must fall within limits defined in federal law as protective of human health and the environment. The NRC regulates releases from nuclear power plants according to the principle that the exposure of the environment and humans to radiation be kept “as low as reasonably achievable.”

Pathways of exposure to radioactive material in the environment are similar to those for other pollutants. An aqueous (water) pathway dose can be received internally or externally by ingesting contaminated water and seafood, or by exposure to contaminated sediments and water. An atmospheric pathway dose can result from exposure to or inhalation of radioactive gas or airborne particles, or ingestion of radionuclides deposited on or assimilated by terrestrial vegetation and animals.

Nuclear power plants are minor contributors to radiation exposure in the United States. As Figure 4-32 illustrates, natural radiation sources (radon and other background sources) account for nearly 50 percent of the average radiation dose to humans. Of the remaining radiation dose to humans that arises from man-made sources, less than 0.05 percent is attributed to commercial nuclear power production.

***Figure 4-32 Annual Estimated Effective Dose Equivalent (mrem) to the General Population from Natural and Man-Made Sources***




Source: National Council on Radiation Protection and Measurements, Ionizing Radiation Exposure of the Population of the United States, NCRP Report No. 160, 2009

As noted above, nuclear power plants such as Calvert Cliffs and Peach Bottom routinely release small quantities of gaseous, particulate, and liquid radioactive material into the atmosphere and adjacent waterways used for cooling water (e.g., Chesapeake Bay). The level of radioactivity in the effluent at any given time depends on many factors, including plant operating conditions and conditions of the nuclear fuel.

Most of the releases to the environment consist of radioactive noble gases into the atmosphere and tritium to waterways, neither of which have environmental significance since they are easily dispersed or are chemically inert. Aqueous discharges, however, may contain varying concentrations of radionuclides (e.g., iodine and metals such as iron, cobalt, cesium, chromium, zinc, and manganese) that can be accumulated by biota or become trapped in bottom sediments. Over time, these radionuclides may potentially contribute to a radiation dose to humans by transport through the food chain. Total principal environmentally active radionuclide releases have declined over the past two decades due to improvements in coolant water filtration technology.

### 4.5.2 Nuclear Power Plants and Maryland

Figure 4-33 shows the locations of nuclear power plants in and near Maryland. Calvert Cliffs Nuclear Power Plant, in Calvert County, is the only nuclear power plant in the state of Maryland. The next closest plant, Peach Bottom Atomic Power Station, is on the Susquehanna River just north of the Pennsylvania/Maryland border. Both of these facilities release very low levels of radionuclides into Maryland's environment.

*Figure 4-33 Nuclear Power Plants In and Around Maryland*


## *Calvert Cliffs Nuclear Power Plant*

Exelon Generation Company, a subsidiary of Exelon Corporation, operates the Calvert Cliffs facility on the western shoreline of the Chesapeake Bay. Each of the two units are pressurized water reactors with a total generating capacity of approximately 830 MW. The units began service in May 1975 and April 1977.

## *Peach Bottom Atomic Power Station*

Exelon also operates Peach Bottom Atomic Power Station (PBAPS). PBAPS began operations in 1974 and is located on Conowingo Reservoir, 2.7 miles north of the Pennsylvania/Maryland border. The plant’s two operating units are boiling water reactors, each with a generating capacity of approximately 1,100 MW.

Besides these plants, there are nine additional nuclear generating sites within 100 miles of Maryland (see Table 4-6).

*Table 4-6 Out-of-State Nuclear Power Plants Near Maryland*

| Plant | Owner/Operator | Location | Generating Capacity (MWe) |
|---|---|---|---|
| Salem Nuclear Generating Station | PSEG Nuclear, LLC | Hancocks Bridge, NJ | 2,365 |
| Hope Creek Generating Station | PSEG Nuclear, LLC | Hancocks Bridge, NJ | 1,178 |
| Oyster Creek Nuclear Generating Station | Exelon Generation Co., LLC | Forked River, NJ | 645 |
| Three Mile Island Nuclear Station | Exelon Generation Co., LLC | Middletown, PA | 852 |
| Susquehanna Steam Electric Station | PPL Susquehanna, LLC | Salem Township, PA | 2,600 |
| Beaver Valley Power Station | FirstEnergy Nuclear Operating Co. | Shippingport, PA | 1,800 |
| Limerick Generating Station | Exelon Generation Co., LLC | Limerick, PA | 2,345 |
| North Anna Power Station | Virginia Electric & Power Co. | Louisa, VA | 1,892 |
| Surry Power Station | Virginia Electric & Power Co. | Surry, VA | 1,676 |

### 4.5.3 Monitoring Programs and Results

Because of the potential direct impact of nuclear power generation (specifically routine releases of radioactivity) on Maryland's natural resources, PPRP conducts monitoring in the vicinity of Calvert Cliffs and Peach Bottom to assess the radiological effects on the environment attributable to each of the power plants (Table 4-7). PPRP has monitored radionuclide levels in the environment surrounding Calvert Cliffs since 1975 and surrounding Peach Bottom since 1979 and publishes its environmental assessments biennially.

### *Table 4-7 Nuclear Power Plant Environmental Monitoring Elements*

| Matrix | No. Stations | Locations | Analytes | Collection Frequency |
|---|---|---|---|---|
| 1. Air Filter | 8 | Calvert County, Baltimore, Cecil County, Harford County, Eastern Shore | $\alpha$, $\beta$, $^{7}Be$, $^{137}Cs$ | continuous (exchanged weekly) |
| 2. Charcoal Filter | 8 | Calvert County, Baltimore, Cecil County, Harford County, Eastern Shore | $^{131}I$ | continuous (exchanged weekly) |
| 3. Potable Water | 7<br>1<br>1<br>1 | Calvert County<br>Baltimore City<br>Patuxent River<br>Potomac River | $\alpha$, $\beta$, $^{3}H$ | quarterly<br>monthly<br>quarterly<br>quarterly |
| 4. Raw Water | 1<br>1 | Patuxent River<br>Potomac River | $\alpha$, $\beta$, $^{3}H$ | monthly<br>monthly |
| 5. Precipitation | 1 | Baltimore City | $\alpha$, $\beta$, $^{3}H$, $^{7}Be$ | weekly |
| 6. Raw Milk | 1 | Cecil County | $^{89}Sr$, $^{90}Sr$, $^{131}I$, $^{140}Ba$, $^{137}Cs$, $^{40}K$ | quarterly |
| 7. Processed Milk | 1 | Baltimore City | $^{89}Sr$, $^{90}Sr$, $^{131}I$, $^{140}Ba$, $^{137}Cs$, $^{40}K$ | quarterly |
| 8. Sediment | 28 | Chesapeake Bay (near CCNPP) | $\gamma$ | quarterly |
| 9. Tray Oysters | 2 | Chesapeake Bay | $\gamma$ | quarterly |
| 10. Sediment | 19 | Chesapeake Bay & Susquehanna River (near PBAPS) | $\gamma$ | semi-annually |
| 11. Finfish | 1 | Susquehanna River | $\gamma$ | semi-annually |
| 12. Submerged Aquatic Vegetation (SAV) | 3 | Chesapeake Bay & Susquehanna River | $\gamma$ | semi-annually |

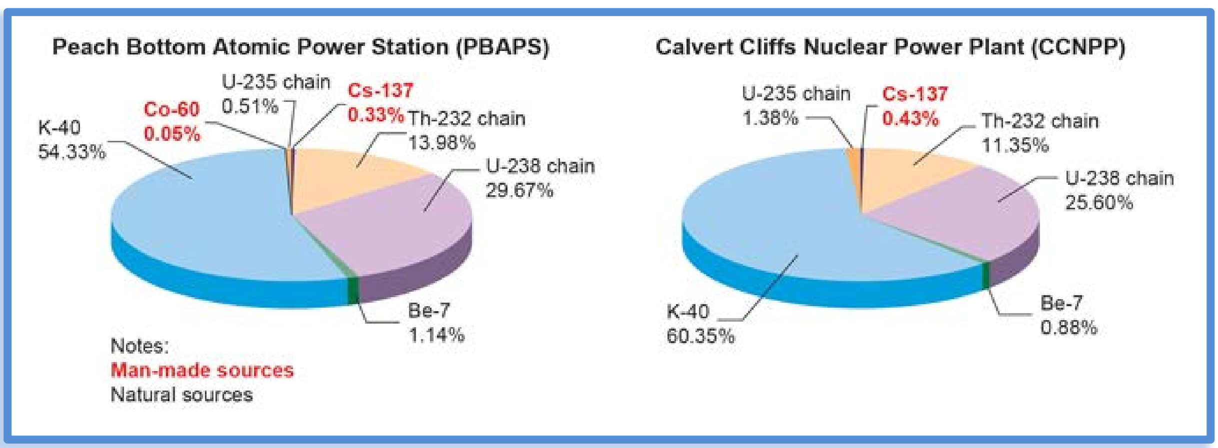
Monitoring by PPRP is conducted to satisfy NRC requirements to verify that any releases from normal plant operations result in potential doses to humans that are below regulatory limits. The monitoring also meets Maryland requirements to research the environmental effects of electric power generation and to maintain State oversight of environmental monitoring.

The most recently compiled results (for the years 2012 to 2014) from weekly air and annual vegetation monitoring conducted by Constellation Energy Nuclear Group (previous owner of Calvert Cliffs), Exelon Generation Company, and independently by PPRP indicate that releases of radioactivity to the atmosphere from the Calvert Cliffs plant were not detectable in air, precipitation, or vegetation.

Estuarine (e.g., Chesapeake Bay) and riverine (e.g., Susquehanna River) sediments are also useful indicators of environmental radionuclide concentrations because they serve as natural sinks for both stable and radioactive metals. PPRP collects sediment samples periodically from a network of transects in both study areas in the vicinity of Calvert Cliffs and Peach Bottom. No plant-related radionuclides, specifically $^{60}$Co, were detected in Bay sediments near Calvert Cliffs during the 2012-2014 reporting period (see Figure 4-34).

At Peach Bottom, plant-related $^{60}$Co was detected on twelve occasions (detection frequency of 10.5%) in sediments collected from Conowingo Reservoir and Susquehanna River, but not within the upper Chesapeake Bay. As shown in Figure 4-34, the quantity of $^{60}$Co in sediment samples, when detected, was proportionally far below the levels contributed by residual radioactive fallout and natural sources. Further, the detection frequency of $^{60}$Co in sediment samples from Peach Bottom during the 2012-2014 reporting period was lower than the average for historical samples (16.4% since 1996).

***Figure 4-34 Proportion of Natural vs. Man-Made Radionuclides in Sediment Samples near CCNPP and PBAPS***




Bay oysters are ideal indicators of environmental radionuclide concentrations because they do not move and readily ingest and concentrate metals. Oysters have been historically commercially harvested near Calvert Cliffs, and have the greatest potential for contributing to a human radiation dose through seafood consumption. The oysters are collected at scheduled time intervals and analyzed for radionuclide content in their tissues. Radiosilver (110mAg) has historically been the principal plant-related radionuclide accumulated by test oysters and oysters on natural beds. Since the fourth quarter of 2001, concentrations of 110mAg in oysters have fallen below analytical detection limits. The lack of detectible 110mAg reflects a downward trend in 110mAg releases, as well as other principal environmentally active radionuclide releases, from Calvert Cliffs.

Finfish are the primary pathway for Peach Bottom-related radionuclide releases to contribute to a human radiation dose because the reservoir contains a recreational fishery. Finfish are collected semi-annually by PPRP from the Conowingo Reservoir area near Peach Bottom. During 2012-2014, finfish samples contained no radionuclides attributable to PBAPS.

As part of its assessment program, PPRP estimates doses of radiation to individuals consuming seafood. The doses are calculated based on maximum or worst-case estimates of the amount of plant-related radioactive material potentially available in the seafood. Results indicate that radiation doses attributable to operations at Calvert Cliffs are well below federally mandated limits (see Table 4-8). As shown in Figure 4-32, the annual total body dose that originates from industrial releases of radionuclides, and subsequent consumption of seafood and drinking water, is small relative to other modes of dose accumulation.

*Table 4-8 Comparison of Radiation Doses to Humans and Applicable Regulatory Limits*

| Exposure Route | Maximum Dose Estimate (2012) | Maximum Dose Estimate (2013) | Maximum Dose Estimate (2014) | EPA Regulatory Limit (40CFR190 Subpart B) | NRC Regulatory Limit (10CFR50 Appendix I) |
|---|---|---|---|---|---|
| **Ingestion (mrem)** | | | | | |
| Oyster ingestion, whole body dose (from CCNPP) | <0.0024 (child)[a] | | | 25 | 3 |
| Oyster ingestion, other organ dose (from CCNPP) | <0.0133 (adult gastro-intestinal tract)[a] | | | 25 | 10 |
| Finfish ingestion, whole body dose (from PBAPS) | 0.0066 (adult)[a] | | | 25 | 3 |
| Finfish ingestion, other organ dose (from PBAPS) | 0.0105 (teen liver)[a] | | | 25 | 10 |
| **Inhalation (mrem)** | | | | | |
| Whole body dose (gaseous, from CCNPP) | 0.00029 (child)[b] | 0.00035 (child)[b] | 0.00032 (child)[b] | 25 | 3 |
| Other organ dose (gaseous, from CCNPP) | 0.00093 (child skin)[b] | 0.00053 (child skin)[b] | 0.00037 (child skin)[b] | 25 | 10 |
| Whole body dose (gaseous, from PBAPS) | 0.224 (any age class)[b] | 0.225 (any age class)[b] | 0.245 (any age class)[b] | 25 | 3 |
| Other organ dose (gaseous, from PBAPS) | 0.292 (any age class skin)[b] | 0.293 (any age class skin)[b] | 0.320 (any age class skin)[b] | 25 | 10 |

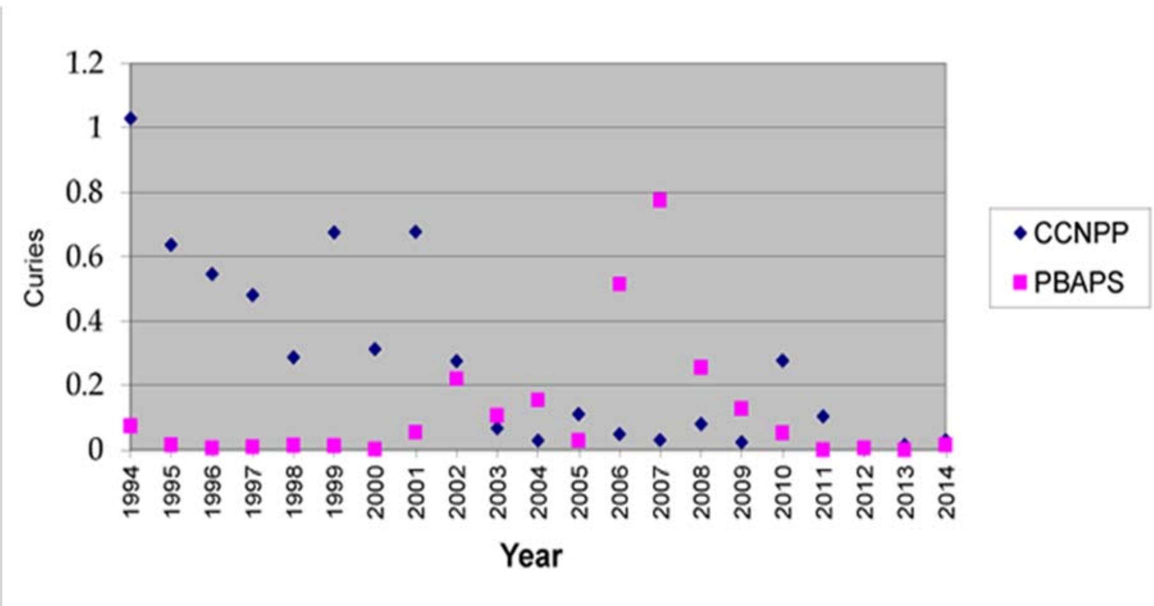
[a] Source: PPRP biennial reports
[b] Source: Annual Radiological Environmental Operating Reports for 2012, 2013 and 2014, Exelon Generation

Results of analyses of environmental samples collected in the vicinity of Calvert Cliffs and Peach Bottom can be found in the periodic environmental reports described above. A comparison of radionuclide concentrations in environmental samples collected in 2012 to 2014 with historical levels shows the following:

- *Plant-related radionuclides were not detected in seafood (i.e., oysters and finfish) during 2012 to 2014;*
- *Plant-related radionuclides were infrequently detected in sediments during 2012 to 2014;*
- *Although radionuclide concentrations fluctuate seasonally and annually, no long-term accumulation of plant-related radioactivity in local aquatic life and sediments is evident;*
- *The radioactivity introduced into the environment by Calvert Cliffs and Peach Bottom, when detected, is very small compared with background radioactivity in the environment from natural sources and weapons test fallout; and*
- *Radiation doses to humans due to atmospheric and aqueous releases are well within regulatory limits (see Table 4-8).*

In summary, environmental, biological, and human health effects from releases of radioactivity from Calvert Cliffs and Peach Bottom were not significant.

***Figure 4-35 Environmentally Significant* Annual Aqueous Releases, 1994-2014***




* Environmentally significant refers to radionuclides that are known to be assimilated by biological organisms and are discharged in detectable amounts. Aqueous releases of noble gases, tritium, and very short-lived radionuclides are not included because they do not bioaccumulate or they decay rapidly to stable forms.

## 4.5.4 Emergency Response

The State of Maryland, the NRC, and Exelon conduct emergency response exercises annually, and an in-depth, federally evaluated, ingestion pathway emergency response exercise every six years. The multi-agency exercises demonstrate and provide practice for Maryland's response measures using a simulated accident at Calvert Cliffs. The exercises encompass the implementation of protective actions for all phases (e.g., plume, ingestion pathway, recovery) of the simulated accident, depending on simulated conditions at Calvert Cliffs and simulated impacts to the surrounding environment. The protective actions affect farm operations, drinking water supplies, and human impacts. The exercises include taking simulated environmental samples in the area surrounding Calvert Cliffs and delivering them to the PPRP Radioecology Laboratory and the Department of Health and Mental Hygiene Radiation Chemistry Laboratory in Baltimore. The entire exercise is evaluated by representatives from the Federal Emergency Management Agency.

### 4.5.5 Radioactive Waste

In addition to the production of atmospheric and liquid effluent releases as a by-product of normal power generation operations, both Calvert Cliffs and Peach Bottom generate radioactive waste products which require disposal.

#### *Low-Level Radioactive Waste*

Low-level radioactive waste (LLRW) consists of materials such as contaminated gowns, toweling, glassware, resin, equipment, and reactor control rods that are used in the normal daily operation and maintenance of the power plant. Much of the waste is safety and testing equipment that have become contaminated through normal use. Resin is used to remove radioactivity from wastewater through an ion-exchange process. Depending on the waste type and radioactivity level, the waste is dried, compressed, and sealed into high-integrity containers, steel boxes, or 55-gallon drums. These containers may, in turn, be sealed into shipping casks or containers.  LLRW from Calvert Cliffs, similar to LLRW from other industries, is transported by truck to a licensed radioactive waste processing firm located in Tennessee.

### *High-Level Radioactive Waste (Irradiated Fuel)*

Used (spent) nuclear fuel from both Calvert Cliffs and Peach Bottom are presently stored at each site within spent fuel pools for the recently discharged fuel or, in the case of older fuel generated in earlier years of plant operation, at dry storage independent facilities located within the protected plant area. These Independent Spent Fuel Storage Installations (ISFSIs) were originally licensed by the NRC for 20 years, although recent regulatory changes now allow a plant operator to apply for a 40-year license period. ISFSI design and construction must conform to strict NRC specifications (10CFR72) that protect against unauthorized entry, earthquakes, and other natural phenomena such as floods and hurricanes. On-site storage facilities, such as the ISFSI, are currently the only long-term storage facilities for irradiated fuel available [see sidebar].

#### "Waste Confidence" and the "Continued Storage of Spent Nuclear Fuel Rule" for U.S. Power Plants

Nuclear "waste confidence" is a general regulatory term indicating that used (spent) nuclear fuel can be stored safely and with minimal environmental impacts at nuclear plant sites for some extended period of time (e.g., 60 years) after a plant's operating license expires.

In 2010, the NRC updated its *Waste Confidence Decision,* reiterating that used nuclear fuel generated at commercial nuclear power plants could continue to be stored using dry storage technology (i.e., ISFSIs).

In 2012, the D.C. Circuit Court of Appeals vacated the *Waste Confidence Decision*, concluding that the NRC's analysis supporting two waste confidence findings (repository availability and long-term interim on-site storage) was insufficient under the National Environmental Policy Act.

In response to the court's decision, the NRC issued the *Continued Storage of Spent Nuclear Fuel Rule* in 2014.This rule revised the previously vacated *Waste Confidence Decision* and changed the name of the rule in response to public comment to more accurately reflect its nature and content.

Specifically, the rule adopted the findings of a NRC prepared Generic Environmental Impact Statement, which concluded that used nuclear fuel can be stored for an indefinite period of time. In addition, the NRC found that a no repository scenario is highly unlikely and contrary to current law. The rule is currently under appeal in the D.C. Circuit Court.

Exelon's dry cask storage facility at Peach Bottom is estimated to have used over 70 percent of its currently available storage pad space. Peach Bottom's ISFSI license will expire in 2040.

It is also estimated that Calvert Cliffs has filled over 70 percent of its currently licensed storage capacity. In October 2014, following promulgation of the updated Continued Storage of Spent Nuclear Fuel Rule, the NRC granted the 40-year license renewal for Calvert Cliffs' ISFSI. This means that Calvert Cliffs' ISFSI license will expire in 2052.

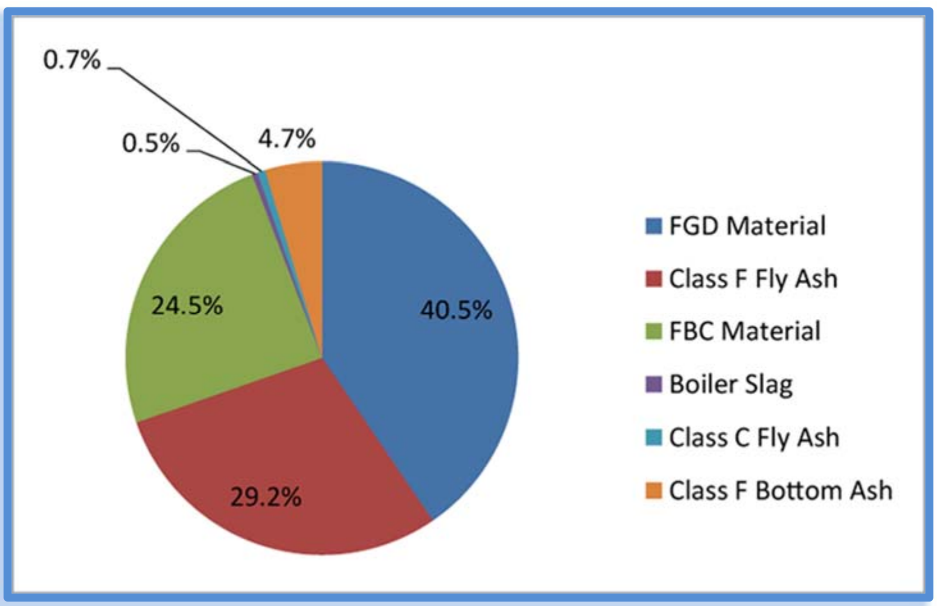
## *4.6 Power Plant Combustion By-Products*

The combustion of coal to produce electricity yields solid coal combustion by-products (CCBs), which in the past were often disposed of in landfills. Fortunately, CCBs can be used in innovative ways to reduce disposal and serve a wide variety of purposes. This section of the report focuses on the generation of CCBs at coal-fired power plants in Maryland and describes ongoing research efforts to promote beneficial use applications for CCBs. The ultimate goal is that all CCBs generated in Maryland will be used in environmentally beneficial or benign ways.

### 4.6.1 CCB Generation and Characteristics

In 2014, coal-fired power plants in Maryland generated an estimated 1.5 million tons of CCBs, as reported to the Maryland Department of the Environment (MDE). The term CCBs includes several solid materials with different physical and chemical characteristics. The types and percentages of CCBs generated in Maryland are shown in Figure 4-36.

***Figure 4-36 CCBs Produced in Maryland in 2014***




The exact chemical nature of CCBs depends upon the nature of the coal burned, the combustion process used, and any emission control processes used. Most power plants in Maryland burn bituminous coal from the eastern United States and produce predominantly Class F fly ash and bottom ash. Fly ash and bottom ash are distinguished by their physical characteristics. Fly ash is composed of very fine, and generally spherical, glassy particles that are fine enough to be transported from the furnace along with emission gases and are captured in electrostatic precipitators or baghouses. Bottom ash is composed of coarser, angular, and porous glassy particles that are heavier and thus fall to the bottom of the furnace, where they are collected. Boiler slag is a specialized type of bottom ash that collects in a molten form and is entirely glassy. There is little difference in the chemical makeup of fly ash and bottom ash. Class F ash is primarily composed of silicon, aluminum, and iron oxides, making it an excellent pozzolan material (meaning that it contributes to cementitious reactions when combined with water and free lime). It may also contain trace metals such as titanium, nickel, manganese, cobalt, arsenic, and mercury. For this reason, electric utilities are required to include all applicable constituents of their CCBs when reporting chemical releases to EPA's Toxics Release Inventory (TRI) program, which maintains a database listing the quantities of toxic chemicals released to the environment annually by various industries. When fly ash is used as pozzolan to produce solid material, its potential to leach trace elements is greatly reduced.

The composition of Class F fly ash and bottom ash is further altered by emission control technologies, like low $NO_x$ burners. These burners reduce the emission of smog-producing nitrogen oxides from power plant emissions, but they also tend to result in CCBs with higher levels of unburned carbon (also known as loss-on-ignition or LOI). High LOI material cannot be used by most cement manufacturers and ready-mix concrete industries. Maryland power plants have overcome this problem by adopting CCB beneficiation technologies. There are two fly ash beneficiation plants in Maryland, the STAR plant and the STET plant (formerly known as the STI plant) (Figure 4-37). These two plants use different technologies to reduce the level of unburned carbon in fly ash, making it highly desirable for the cement and concrete industries.

***Figure 4-37 STET and STAR Fly Ash Beneficiation Plants***

STET (Formerly STI) Facility STAR Facility

Alkaline CCBs are fly ash and bottom ash materials with high levels of calcium and high pH values. Class C fly ash and fluidized bed combustion (FBC) ash are two alkaline ashes produced in Maryland. The C.P. Crane plant uses sub-bituminous coal from the Powder River basin. This coal contains more calcium carbonate than eastern coals and results in Class C ash. The AES Warrior Run power plant near Cumberland uses fluidized bed combustion (FBC) technology in which coal and finely ground limestone are fed into the combustion chamber and mixed by forcing in air. The heat in the combustion chamber causes the limestone to decompose to an oxide that captures $SO_2$. FBC units can remove more than 95 percent of the sulfur produced from burning coal and the resulting FBC material by-products are similar to Class C ash. Alkaline CCBs often have self-cementing properties because they contain calcium oxide (free lime). However, they can also contain high levels of magnesium, which can interfere with some beneficial use applications.

The third category of CCBs produced in Maryland is flue gas desulfurization (FGD) materials. Like FBC processes, FGD uses limestone as a sorbent to control sulfur emissions. Unlike FBC processes, the sorbent is introduced, not with the coal, but into the exhaust system, producing a completely separate stream of residuals with a distinctive composition. FGD materials consist almost entirely of calcium sulfate, and are often referred to as synthetic gypsum. FGD scrubbers were installed at the Brandon Shores, Dickerson, Chalk Point, and Morgantown power plants in 2010.

If not managed in accordance with sound engineering principles, landfilled CCBs have the potential to adversely impact Maryland's terrestrial and aquatic resources. Careful planning and execution of the disposal and/or use of CCBs is necessary to minimize impact to the surrounding environment. The importance of sound engineering and proper placement of CCBs was highlighted at the BBSS Mine Reclamation Site. Between 1995 and 2007, Constellation Power disposed of 200,000 to 400,000 tons of CCBs, primarily unstabilized Class F fly ash, at a sand and gravel mine reclamation site in Anne Arundel County owned by BBSS, Inc. The site relied on a natural soil cover and its underlying geology to minimize the potential for leachate to impact the regional ground water system.

In 2006, MDE requested that PPRP provide assistance on an independent evaluation of the source of heavy metals and dissolved sulfate detected in residential wells near the site. A statistical comparison of residential and monitoring well water quality data indicated that fly ash placement in the Turner and Waugh Chapel Pits likely contributed to the deterioration of ground water quality nearby. The site continues to be an issue from the standpoint of contaminating local wells; EPA included the BBSS site in a list of documented damage cases related to CCBs, when it published final regulations on CCB disposal in 2015. Constellation and MDE entered into a Consent Decree in October 2007 with an approach to resolve the identified impacts.

### 4.6.2 Regulation of CCBs

The use and final disposition of CCBs is dependent on the creation and development of state and federal regulations that establish the requirements for beneficial use and disposal of CCBs. Figure 4-38 is a timeline that shows milestones in the CCB industry and corresponding regulatory developments; Figure 4-39 presents a more detailed regulatory timeline, broken down by state vs. federal actions.

#### *Maryland Regulations*

Historically, use and disposal of CCBs at the state level in Maryland was governed by the Pozzolan Act of 1974. In 2008, Maryland established more specific regulations for the disposal of CCBs and their use in mine reclamation. This regulation requires permitting of new CCB disposal facilities under the same regulations as industrial solid waste facilities. The regulation further extends the industrial solid waste landfill requirements to reclamation of non-coal mines. CCBs used for coal mine reclamation are required to be alkaline in nature.

In February 2010, Maryland proposed additional regulations for the beneficial uses and transportation of CCBs. The draft regulations require that beneficially used CCBs, and the products made from them, exhibit no significant leaching under specific test conditions. Although the required leaching procedure was not specified, the parameters that must be tested are identified in the draft regulation. The draft regulations specifically approved encapsulated beneficial uses of CCBs, including concrete, asphalt, wallboard, and filler in plastic. Other unconsolidated (unencapsulated) beneficial uses of CCBs, such as the use of bottom ash as aggregate beneath pavement, pipe bedding, and winter traction control, were permitted with more stringent restrictions. Maryland suspended development of its beneficial use regulations in 2010 after EPA announced that it would consider a federal rule governing CCB use disposal.

### *Federal Regulations*

Between 1980 and 2010, CCBs were excluded from the federal definition of "waste materials" by the Bevill Amendment to the Resource Conservation and Recovery Act (RCRA). EPA proposed the first federal regulations of CCB disposal in June 2010, and published the final rule in April 2015 after an extended period of comment and receipt of additional data. The final rule classifies CCBs (referred to as coal combustion residuals (CCRs) within the rule) as a non-hazardous waste, subject to RCRA Subtitle D requirements for disposal. These requirements are primarily enforced at the state level. The federal rule also established monitoring requirements for CCB landfills. The rule affirmed the use of CCBs in encapsulated applications (such as concrete and wallboard), but placed restrictions on the use of CCBs in unencapsulated land applications. The use of CCBs to reclaim sand and gravel pits was specifically deemed a "disposal" activity and thus subject to landfill requirements for construction and monitoring. The federal rule took effect in October 2015.

## 4.6.3 Disposition and Beneficial Use

### *Beneficial Use*

When properly engineered and correctly applied, CCBs can be utilized in manufacturing, civil engineering, mine restoration, and agricultural applications (see Table 4-9). The beneficial use of CCBs as raw materials in applications that are environmentally sound, technically safe, and commercially competitive leads to a reduction in disposal, which may contribute to reduced GHG emissions. The most direct contribution to reducing GHG emissions occurs when fly ash is used as a supplementary material in concrete and concrete products. By substituting fly ash in place of cement, the carbon emissions associated with cement production (an energy-intensive process) are avoided. Each ton of fly ash utilized represents approximately one ton of $CO_2$ avoided. A continued increase in the beneficial utilization of Maryland CCBs will likely lead to:

- Conservation and protection of the natural resources of the State;
- Reductions in the cost of producing electricity and cost for consumers;
- Substantial savings for end-users of CCBs; and
- Decreased need for landfill space.

### *Table 4-9 CCBs Produced in Maryland and Common Uses*

| CCB Type | Source in Md | Common Uses Across United States | Current Uses in Md |
|---|---|---|---|
| Class F Fly Ash | Brandon Shores, H.A. Wagner, Morgantown, Dickerson, Chalk Point | Concrete, cement, grout, road base, structural fill, soil stabilization | Concrete, cement, grout |
| Class C Fly Ash | C.P. Crane | Concrete, cement, grout, soil stabilization, coal mine reclamation, agriculture | Disposed |
| Class F Bottom Ash | Brandon Shores, H.A. Wagner, Morgantown, Dickerson, Chalk Point | Concrete, cement, grout, road base, structural fill, soil stabilization, traction control | Concrete, cement, grout |
| Boiler Slag | C.P. Crane | Abrasive grit, roofing shingles | Abrasive grit, roofing shingles |
| FBC Fly Ash/Bottom Ash | Warrior Run | Concrete, cement, grout, coal mine reclamation, agriculture | Coal mine reclamation |
| FGD Material | Brandon Shores, Morgantown, Dickerson, Chalk Point | Wallboard, concrete, cement, agriculture | Wallboard, cement |

Beneficial use of CCBs in Maryland has historically included predominantly large-scale fill applications as in highway embankments and mine reclamation. However, over time the use of CCBs in encapsulated forms, such as cement, concrete, wallboard, and roofing tile has become more prevalent. Such changes are driven by industry practice, technology, costs of natural materials, regulations and guidelines, public perception, and demands for sustainability in the commercial marketplace. Of the approximately 1.5 million tons of CCBs produced by Maryland power plants in 2014, just over 200,000 tons were placed in disposal sites. More than 350,000 tons of CCBs were used in concrete and cement, and another 500,000 tons were used in wallboard manufacture. Coal mine reclamation is the third largest use of CCBs in Maryland, with about 360,000 tons of alkaline CCBs being used to reclaim surface coal mines in Western Maryland. Other, smaller scale uses included agricultural amendments, and the manufacture of roofing tiles, blasting grit, and grouts. Figure 4-40 shows the locations of Maryland's 7 active coal-fired power plants (in addition to one plant that closed in 2012), and highlights some of the beneficial use sites and disposal sites across the state. Figure 4-41 highlights the quantity of CCBs generated and disposed by Maryland's coal-fired power plants annually.

## Use of CCBs in Highway Embankments

In an effort to assuage the environmental uncertainty associated with using CCBs as structural fill, PPRP has been monitoring water quality at two Maryland sites in which CCBs were used to construct highway embankments, namely the Route 213/301 overpass in Centerville on the Eastern Shore, and the Interstate 695 overpass near Baltimore. As with any fly ash beneficial use site, the potential exists for ground water quality degradation, primarily caused by elevated levels of sulfate and trace elements. Several design features provide mitigative controls to minimize adverse environmental impact compared to other CCB fill sites. These include the shallow fill thickness, the steep embankment slopes, and the presence of asphalt or concrete pavement.

The water quality data for these sites indicate that the potential for leachate to form in the fly ash is being realized, despite the fact that the majority of the fly ash used in the embankments is covered with impermeable pavement. The data further indicate that the leachate constituents, including calcium, sulfate, arsenic, sodium, and chloride, are being attenuated in the underlying native soils, possibly due to adsorption and precipitation reactions. Additionally, concentrations of arsenic, calcium, and sulfate are further attenuated in the underlying ground water at both sites. These findings suggest that overall, leachate from the fly ash has a negligible impact on ground water quality.

For future fly ash use for structural fill to be as environmentally effective as at these overpass study sites, proper design features tailored to the specific hydrogeologic conditions of the site must be incorporated. The benefits of fly ash utilization for embankment construction offset the minimal potential for environmental degradation.

Route 213 highway embankment site, Centerville

*Figure 4-40 Locations of CCB Generation, Use, and Disposal in Maryland*

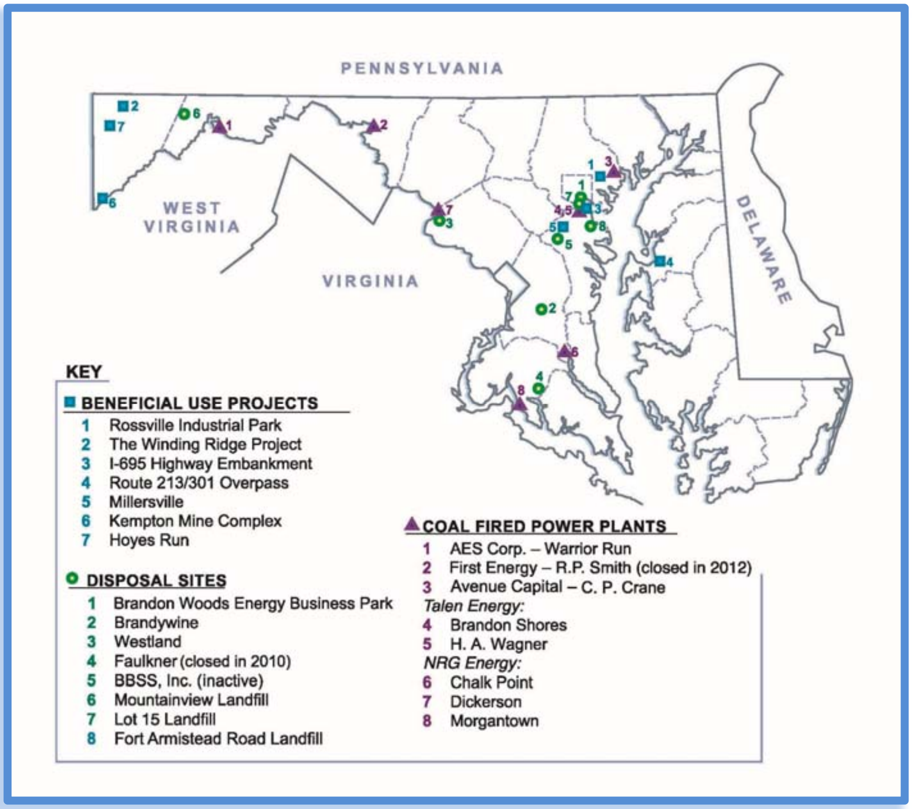
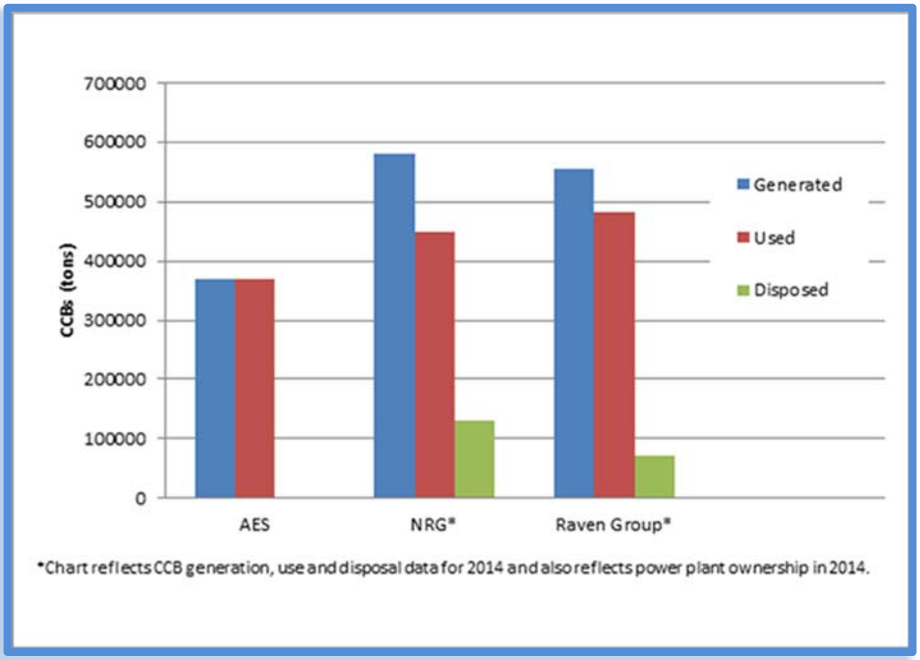


*Figure 4-41 CCB Generation and Disposal (2014 Data)*




Fly ash, bottom ash, boiler slag, and FGD material have different primary beneficial uses because each type of CCB has distinct physical and chemical properties suited to specific applications (see Table 4-9). Fly ash is used in the largest quantities and the widest range of applications among the CCBs because of its pozzolanic properties. In Maryland, sale of fly ash to the cement, grout, and ready-mix concrete industries is the predominant use of Class F fly ash. The relatively uniform spherical shape and particle distribution of fly ash improves properties of flowable fill and the fluidity of these cementitious materials. The manufacture of cement, concrete, and grout is also the primary beneficial use for bottom ash in Maryland. Nationwide, this material is also used as road base/sub base, structural fill, and snow and ice control. Boiler slag is taken up in more specialized applications, such as abrasive grit and roofing tiles. 100% of the boiler slag produced in Maryland is sold to these industries. Since the first FGD scrubbers were installed in Maryland in 2010, the majority of FGD material generated in Maryland has been marketed to wallboard manufacturers as a replacement for natural gypsum. This use accounted for more than 90% of the total FGD material produced in Maryland in 2014. The small percentage of FGD material that was disposed is primarily comprised of “off-spec gypsum” that could not be sold because it did not meet the standards required by industry for wallboard manufacturing.

### *Disposal*

The first permitted and lined CCB landfill in Maryland (the Millennium Landfill) began operation in 2011. This landfill is fully compliant with current state and federal CCB disposal regulations. However, prior to 2008, there were no regulations in Maryland governing the disposal of CCBs (see Section 4.6.2). CCBs were disposed in unlined landfills and were sometimes used as fill in applications that, under current state and federal regulations, constitute disposal. While high percentages of Maryland CCBs are currently going into beneficial uses and current disposal practices are more protective of ground water, these legacy ash disposal sites continue to have the potential to leach constituents into ground water.

One possible way to mitigate this impact is to "mine" the previously disposed CCBs for sale to the cement manufacturers and ready-mix concrete industries. The success of marketing freshly produced CCBs to cement manufacturers and ready-mix concrete industries has produced a demand for these materials within the industry. As older coal-fired power plants are retired, and in some cases, replaced by gas-fired generating units, cement manufacturers and ready-mix concrete industries are willing to consider, and pay for, previously disposed CCB materials. One successful example of this kind of project is described Section 4.6.4.

### 4.6.4 CCB Marketing Activities

Use of Class F fly ash and bottom ash in cement and concrete has resulted in the beneficial use of over 80 percent of these materials as they are currently produced. The high demand for freshly produced CCBs prompted industry interest in a partnership to excavate and use previously disposed CCBs in cement manufacturers and ready-mix concrete industries. In 2009, the Maryland Environmental Restoration Group (MERG) developed a partnership with FirstEnergy's R. Paul Smith Power Station in Williamsport, Maryland, to market its legacy ash pile, which had been accumulating since 1947 when the plant opened. Between fall 2009 and 2014, over 1 million tons of ash were mined from the pile. Although the plant was retired in late 2012, MERG continues to mine the ash pile, which is expected to be completely emptied of CCBs by 2020.

Maryland has a history of coal-fired power plants that stretches back to the late 1800s. For the majority of that time, CCBs were disposed in unlined fill sites that are now understood to have the potential to impact ground water. The success of the ash mining project at the R. Paul Smith disposal site could serve as a model to address other CCB pile and fill sites in Maryland by removing the CCB materials for sale to the concrete and cement industries. In addition, while CCB beneficiation facilities are not currently processing CCBs removed from former landfills, the potential exists for them to do so, further increasing the marketability of formerly disposed CCBs. Use of previously disposed CCBs in these kinds of manufacturing operations not only removes a potentially leachable material from the environment and converts it into a stable, monolithic solid, but also conserves natural materials that would otherwise be mined to support these manufacturing operations.

AES currently transports all of its FBC ash to surface mines for use as cover mixed with the site overburden. When used in this fashion, the alkaline components of the FBC are used to offset the acid mine drainage that can be produced by these mines. However, the mechanism by which FBC releases alkalinity is partial dissolution, a process that can potentially also release other constituents of the ash (such as heavy metals). PPRP currently supports monitoring of surface waters in the vicinity of these reclamation sites to track whether heavy metal releases are occurring.

Despite being underutilized currently, FBC ash generated at the AES Warrior Run power plant also holds marketing potential. This material contains levels of magnesium that make it unacceptable for use in cement manufacturers and ready-mix concrete industries. On the other hand, its free lime content makes it self-cementing when combined with water, which is useful for certain other applications. PPRP supports research and demonstration projects to develop methods of using this FBC ash and other CCBs to address the impacts of historic mining in Western Maryland (see Section 5.4).

# Chapter 5 - Looking Ahead

Maryland's definition of "sustainability" is the use of resources wisely today to ensure future generations have the same or better opportunities. Sustainable energy practices involve the efficient use of energy and associated resources. This chapter discusses a wide range of issues related to sustainable energy and how Maryland is seeking to craft a more sustainable energy future. It also addresses Maryland's sustainable energy efforts in the context of federal initiatives and technological advances.

## *5.1 Clean Energy Policies*

By law, Maryland encourages the development and use of clean energy technologies, as well as energy efficiency and conservation. The State continues to evaluate and implement policies that encourage energy innovation, energy efficiency, conservation, and renewable resource development.

### 5.1.1 Maryland RPS

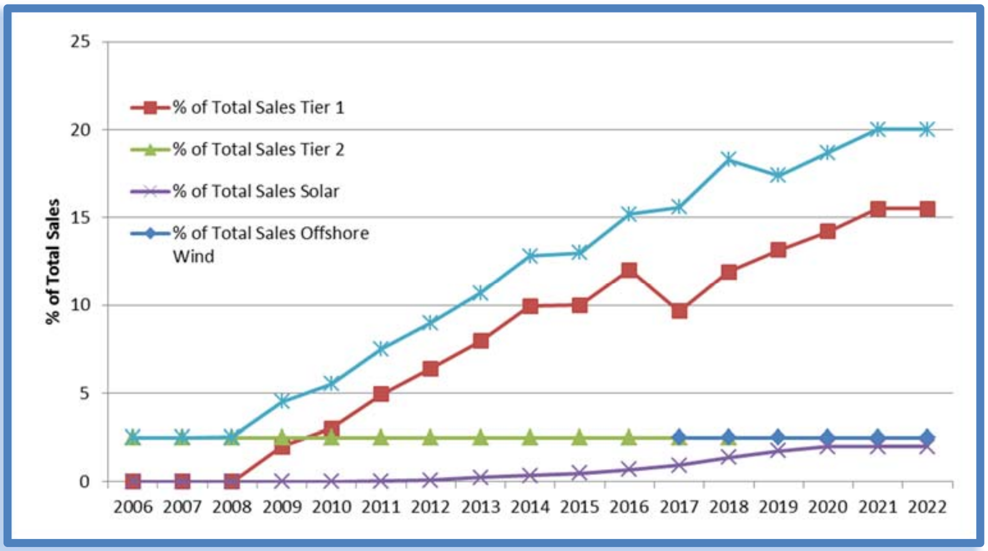
The Maryland Renewable Energy Portfolio Standard (RPS) was enacted in May 2004. The RPS requires retail electrical suppliers to provide a specified percentage of their electricity deliveries from Maryland-certified Tier 1 and Tier 2 renewable resources. Every megawatt-hour (MWh) generated by qualified renewable resources is eligible to be registered as one Maryland-certified Renewable Energy Credit (REC). Eligible RECs may come from a certified renewable energy facility that is either located within PJM or for the electricity the facility delivers into PJM from outside the PJM footprint. The 2004 RPS law was modified by legislation six times from 2007 through 2013 to effectuate change in qualifying resources, the percentage requirements, and other aspects of the statute. The current RPS law contains the following provisions:

- Tier 1 renewable resources include fuel cells that produce electricity from other Tier 1 renewable fuel resources, geothermal, hydroelectric facilities under 30 MW, methane, ocean, poultry litter-to-energy, qualifying biomass, solar, wind, waste-to-energy, and refuse-derived fuel. The Tier 1 requirement began at 2 percent and increases annually, in 2013 it was 7.95 percent, and will reach its 20 percent maximum in 2022.
- The solar energy set-aside requires that a specified percentage of energy supply must come from in-State solar facilities. This requirement increases annually to reach 2 percent in 2020, the 2 percent solar requirement is part of the Tier 1 overall 20 percent requirement.
- Existing hydroelectric facilities over 30 MW qualify to meet the Tier 2 standard. Tier 1 resources may also be used to meet the 2.5 percent Tier 2 standard. Tier 2 will sunset in 2018.
- The Maryland Offshore Wind Energy Act, which was passed in 2013, created a new set-aside for offshore wind facilities. Each year, the PSC will set the percentage of offshore energy to be mandated in the RPS based on the projected annual output from qualified and approved offshore wind projects. This percentage may not exceed 2.5 percent of total retail sales.

Figure 5-1 illustrates the renewable sources that are required for the RPS, shown as a percentage of total energy sales over time. If a supplier does not provide the required amount of renewable electricity to its customers, it must pay a non-compliance penalty, referred to as an alternative compliance payment

(ACP). These payments amount to $0.04 for each kilowatt-hour (kWh) short of the Tier 1 resource requirement (i.e., $40/MWh) and $0.015 for every kWh short of the Tier 2 requirement. The penalties for the solar energy set-aside started at $0.45/kWh in 2008, decreased to $0.40/kWh for 2009 through 2014; to $0.35/kWh in 2015 and 2016; to $0.20/kWh in 2017; and then will decrease by $0.05/kWh every other year to a level of $0.05/kWh in 2023.

***Figure 5-1 Maryland RPS Summary, 2006-2022***




Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2014, January 2016, http://www.psc.state.md.us/wp-content/uploads/2016-Renewable-Energy-Portfolio-Report.pdf (Download Adobe Acrobat Reader)

At the conclusion of 2015, there were 23,635 renewable energy facilities certified by the PSC, providing approximately 12,065 MW of renewable capacity in PJM (See Table 5-1).

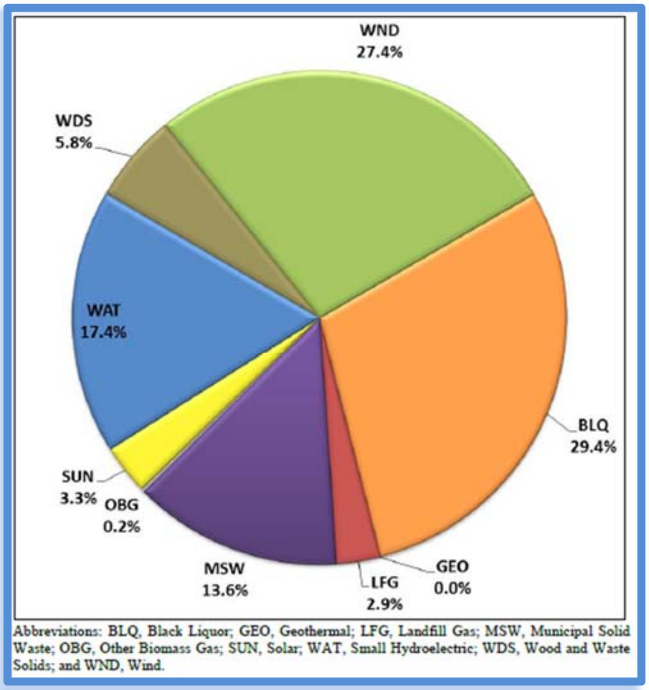
***Table 5-1 Maryland RPS Certified Capacity as of December 2015 (MW)***

| | Tier 1 | | | | | | | | | Tier 2 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| State | Solar | Wind | Hydro | Landfill Gas | Biomass | Black Liquor | Municipal Solid Waste | Wood Waste | Geothermal | Hydro | Total |
| Maryland | 412 | 190 | 20 | 33 | 69 | 65 | 268 | 4 | 1 | 474 | 1,536 |
| Delaware | - | - | - | 707 | - | - | - | - | - | - | 707 |
| Illinois | - | 2,535 | 20 | 117 | - | - | - | - | - | - | 2,672 |
| Indiana | - | 1,652 | 8 | - | - | - | - | - | - | - | 1,660 |
| Iowa | - | 145 | - | - | - | - | - | - | - | - | 145 |
| Kentucky | - | - | 2 | 16 | - | - | - | 5 | - | - | 23 |
| Michigan | - | - | 15 | - | - | - | - | - | - | - | 15 |
| Missouri | | 146 | - | - | - | - | - | - | - | - | 146 |
| New Jersey | - | 8 | 11 | 76 | - | - | - | - | - | - | 95 |
| New York | - | - | 153 | - | - | - | - | - | - | - | 153 |
| North Carolina | - | - | - | 6 | - | 152 | - | - | - | 568 | 726 |
| North Dakota | - | 180 | - | - | - | - | - | - | - | - | 180 |
| Ohio | - | 316 | - | 64 | 7 | 93 | - | 17 | - | 47 | 544 |
| Pennsylvania | - | 1,084 | 84 | 168 | 1 | 164 | - | - | - | 501 | 2,002 |
| Tennessee | - | - | - | - | - | 50 | - | - | - | 52 | 102 |
| Virginia | - | - | 60 | 128 | - | 288 | 63 | 130 | - | - | 669 |
| West Virginia | - | 517 | 55 | - | - | - | - | - | - | 117 | 689 |
| **TOTAL** | **412** | **6,773** | **428** | **1,315** | **77** | **812** | **331** | **156** | **1** | **1,759** | **12,064** |

Source: PJM Generator Attributes Tracking System (GATS), December 2015.
Note: The capacity values are based on the estimate of renewable energy capacity for each facility, which does not necessarily equal the total nameplate capacity at that facility.

As depicted in Figure 5-2, black liquor is the leading fuel source for compliance with the Maryland RPS, followed by wind, hydro, and municipal solid waste. Wood waste, solar, landfill gas, and other biomass gas make up the remaining fuels.

### *Figure 5-2 Tier 1 and Tier 2 Retired RECs by Fuel Source, 2014*




Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2014, January 2016, http://mgaleg.maryland.gov/webmga/frmStatutesText.aspx?article=gpu&section=7-701&ext=html&session=2015RS&tab=subject5

## Federal Production Tax Credit and Investment Tax Credit

The federal renewable electricity production tax credit (PTC) is a per-kWh tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times. The current credit amount is 2.3¢/kWh for wind, closed-loop biomass, and geothermal resources; and 1.1¢/kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and ocean energy resources. In December 2015, Congress extended the PTC for five years for wind power and one year for the other eligible technologies. Specifically for wind, the PTC is reduced by 20 percent in 2017; 40 percent in 2018 and 60 percent in 2019. Congress previously adopted language that allows an additional two years for projects that began construction or incurred five percent or more of project investment costs. Geothermal, biomass, landfill gas, municipal solid waste, qualified hydroelectric, and ocean energy projects that are under construction by December 31, 2018, will qualify for 10 years of production tax credits on electrical output. Wind will also have an additional two years to utilize the PTC from the time construction began or project investment costs were incurred, up until the end of 2021.

The Investment Tax Credit (ITC) provides a federal tax credit of 30 percent for investments in solar electric; heating and lighting technologies; fuel cells; and small wind and large wind plants, and a 10 percent federal tax credit for investments in geothermal heat pumps and electric systems; microturbines and combined heat and power systems. In December 2015, Congress extended the ITC, but at different tax credit rates and for different lengths of time by technology. Electric and non-electric solar systems are eligible for the 30 percent tax credit until the end of 2019. After that, the tax credit drops to 26 percent at the end of 2020, 22 percent in 2021, and 10 percent from 2022 onwards. The ITC for large wind systems also declines over time, beginning at 30 percent in 2016, 24 percent in 2017, 18 percent in 2018 and 12 percent in 2019 before expiring altogether. Geothermal heat pumps, microturbines, and combined heat and power systems can receive the 10 percent tax credit but only through 2016. Geothermal electric systems can receive the 10 percent tax credit without an expiration date. Finally, Congress adopted the two-year extension for utility-scale and commercial solar systems if they began construction or incurred project investment costs, but not for residential solar systems.

Source: U.S. Congress, Consolidated Appropriations Act of 2016, December 2015, https://www.gpo.gov/fdsys/pkg/BILLS-114hr2029enr/pdf/BILLS-114hr2029enr.pdf (Download Adobe Acrobat Reader)

The PSC is charged with ensuring compliance with the RPS and certifying eligible facilities. Eligible facilities must operate within the PJM footprint or a PJM-adjacent control area if the electricity is delivered into PJM, and must be classified as either a Tier 1 or Tier 2 facility. Retail electricity suppliers are required to submit annual compliance reports by April of the following year. Table 5-2 shows the aggregate supplier obligation, the RECs retired, and the ACPs submitted from 2006-2014. Each retired REC represents one MWh of renewable energy generated from a Tier 1 or Tier 2 facility.

In 2014, Maryland generated nearly 1.5 million MWh of renewable electricity from in-State Tier 1 resources and over 1.6 million MWh of renewable electricity from in-State Tier 2 resources, with a grand total of 3.1 million RECs producedwithin the State in 2014. About 25 percent of the RECs retired in Maryland in 2014 were from generating facilities located in-State. Overall, the cost of compliance with the 2014 RPS requirement was nearly $104 million, with ACPs accounting for approximately $66,000 (0.6 percent of the total).

### *Table 5-2 Maryland RPS Compliance, 2006-2014*

| RPS Compliance Year | | Tier 1 Solar | Tier 1 (non-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 | -- | $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 | -- | $12,623 | $23,751 | $36,374 |
| 2008 | RPS Obligation (MWh) | 2,934 | 1,183,439 | 1,479,305 | 2,665,678 |
| | Retired RECs (MWh) | 227 | 1,184,174 | 1,500,414 | 2,684,815 |
| | ACP Required | $1,218,739 | $9,020 | $8,175 | $1,235,934 |
| 2009 | RPS Obligation (MWh) | 6,125 | 1,228,521 | 1,535,655 | 2,770,301 |
| | Retired RECs (MWh) | 3,260 | 1,280,946 | 1,509,270 | 2,793,475 |
| | ACP Required | $1,147,600 | $395 | $270 | $1,148,265 |
| 2010 | RPS Obligation (MWh) | 15,985 | 1,920,070 | 1,601,723 | 3,539,778 |
| | Retired RECs (MWh) | 15,451 | 1,931,367 | 1,622,751 | 3,569,569 |
| | ACP Required | $217,600 | $20 | $0 | $217,620 |
| 2011 | RPS Obligation (MWh) | 28,037 | 3,079,851 | 1,553,942 | 4,661,830 |
| | Retired RECs (MWh) | 27,972 | 3,083,141 | 1,565,945 | 4,677,058 |
| | ACP Required | $41,200 | $48,200 | $9,120 | $98,520 |
| 2012 | RPS Obligation (MWh) | 56,130 | 3,901,558 | 1,522,179 | 5,479,867 |
| | Retired RECs (MWh) | 56,194 | 3,902,221 | 1,522,297 | 5,480,712 |
| | ACP Required | $4,400 | $0 | $1,050 | $5,450 |
| 2013 | RPS Obligation (MWh) | 133,713 | 4,858,404 | 1,521,981 | 6,514,098 |
| | Retired RECs (MWh) | 134,124 | 4,871,586 | 1,526,789 | 6,532,499 |
| | ACP Required | $2,440 | $40 | $0 | $2,440 |
| 2014 | RPS Obligation (MWh) | 203,827 | 6,062,635 | 1,520,966 | 7,787,428 |
| | Retired RECs (MWh) | 203,884 | 6,062,135 | 1,521,022 | 7,787,041 |
| | ACP Required | $15,600 | $46,600 | $3,765 | $65,965 |

Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2014, January 2016, http://www.psc.state.md.us/wp-content/uploads/2016-Renewable-Energy-Portfolio-Report.pdf.

## 5.1.2 EmPOWER Maryland

In July 2007, the Governor announced an energy initiative called EmPOWER Maryland with a goal of reducing Maryland's per capita energy consumption and peak demand by 15 percent by 2015. This initiative was codified by the EmPOWER Maryland Energy Efficiency Act of 2008 (EPM Act). The EPM Act seeks to achieve electric consumption and peak demand reductions as follows:

- Per capita electricity consumption: 5 percent reduction by the end of 2011 and 15 percent by the end of 2015, from 2007 levels; and
- Per capita peak demand: 5 percent reduction by the end of 2011, 10 percent by the end of 2013, and 15 percent by the end of 2015, from 2007 levels.

Under the EPM Act, utilities with more than 200,000 customers are responsible for the full 15 percent demand reduction and two-thirds of the consumption goal (i.e., a 10 percent reduction in consumption), with the remaining 5 percentage point reduction in per capita electricity consumption to be achieved through State-administered programs and changes to efficiency codes and standards. The utilities required to participate in EmPOWER Maryland include BGE, DPL, PE, Pepco, and SMECO.

As written, the EPM Act is inclusive of both electric and gas companies; however, the PSC has not established goals for gas energy efficiency programs. In 2014, Washington Gas Light (WGL) submitted a voluntary gas reduction program for the 2015-2017 program cycle. On December 23, 2014, the PSC approved WGL's residential and demand response programs which are designed to reduce gas consumption for heating and water heating in existing and new construction. As of early 2016, the PSC is in the process of considering the development of natural gas efficiency goals.

### *EmPOWER Maryland Energy Efficiency and Conservation Programs*

The EPM Act directed EmPOWER Maryland utilities to develop plans for all customer sectors—residential, commercial, and industrial. The PSC is directed to consider whether each program is cost-effective and adequate to achieve the EmPOWER Maryland goals, and also to assess the program's potential impacts on electricity rates, jobs, and the environment. The programs offered by the utilities include rebates for ENERGY STAR® products, energy audit and retrofit assistance, combined heat and power, and incentives for energy efficient new construction. In addition, all of the utilities have been directed by the PSC to include conservation programs targeting low-income consumers.

### *EmPOWER Maryland Peak Demand Reduction Programs*

The EPM Act directed utilities to reduce per capita peak demand by 15 percent from 2007 levels by the end of 2015. While energy efficiency programs can result in demand reduction, the majority of demand reduction comes from demand response and dynamic pricing programs (see Section 2.1.4 for more information on demand response). The EmPOWER Maryland utilities, with the exception of PE, implemented these types of programs to meet these goals.

In regard to demand response programs, BGE has implemented its Peak Rewards program, which is a voluntary program that cycles air conditioners, heat pumps, and water heaters for residential customers. Pepco and DPL are operating an Energy Wise Rewards program and SMECO is running CoolSentry; each offers residential and small commercial direct load control programs for air conditioner cycling.

Potomac Edison cites a lack of any cost-effective mechanism to meaningfully reduce peak demand. Each program offers various cycling levels, including 50 percent, 75 percent, and 100 percent. As the utilities have reached program saturation levels, the savings contributed by the demand response has plateaued. At the end of 2015, the four demand response programs were capable of providing a demand reduction of 738 MW.

The installation of advanced metering infrastructure (AMI) meters allows for utilities to implement a dynamic pricing program, which is used to lower summer peak demand (see Section 5.5.3 for more information on AMI meters). Dynamic pricing is a voluntary program for all customers with an AMI meter, regardless of whether they have central air conditioning. The day before an event, the utility will notify customers that the following day will be a dynamic pricing day. On the day of a dynamic pricing event, for each kWh that a customer reduces his or her usage from its baseline between the hours of 1:00 p.m. and 7:00 p.m., the customer will receive a bill credit of $1.25. BGE customers that participated in an event received, on average, a bill credit of $5 to $8 per event in 2015. In 2015, BGE, DPL, and Pepco customers reduced their loads by a total of 499 MW.

### *EmPOWER Maryland Reductions*

At the conclusion of 2015, the utilities had achieved 99 percent of their energy reduction goal and 100 percent of their demand reduction goal. The majority of energy savings from 2009-2015 were achieved through residential and commercial lighting programs.

### *Table 5-3 Energy Efficiency and Demand Response Reported Achievements*

| | 2015 Reported Reduction | 2015 Goal | Percentage of Goal |
|---|---|---|---|
| **BGE** | | | |
| Energy Reduction (MWh) | 2,638,975 | 3,593,750 | 73% |
| Demand Reduction (MW) | 1155.949 | 1267 | 91% |
| **Pepco** | | | |
| Energy Reduction (MWh) | 1,600,813 | 1,239,108 | 129% |
| Demand Reduction (MW) | 639.550 | 672 | 95% |
| **PE** | | | |
| Energy Reduction (MWh) | 529,519 | 415,228 | 128% |
| Demand Reduction (MW) | 82.344 | 21.000 | 392% |
| **DPL** | | | |
| Energy Reduction (MWh) | 382,605 | 143,453 | 267% |
| Demand Reduction (MW) | 146.701 | 18.000 | 815% |
| **SMECO** | | | |
| Energy Reduction (MWh) | 242,347 | 83870 | 289% |
| Demand Reduction (MW) | 92.437 | 139 | 67% |
| **Total** | | | |
| Energy Reduction (MWh) | 5,394,259 | 5,475,409 | 99% |
| Demand Reduction (MW) | 2116.981 | 2117.000 | 100% |

Source: Individual utility EmPOWER Maryland annual reports filed January 31, 2016.

## *EmPOWER Maryland Goals Beyond 2015*

On July 16, 2015, the PSC issued Order No. 87082 which established energy efficiency goals for the EmPOWER Maryland electric utilities beyond 2015. The PSC adopted an annual incremental gross energy savings reduction of 2 percent from a utility's weather-normalized gross retail sales baseline, which will be officially implemented beginning in the 2018-2020 program cycle. The 2016 weather-normalized gross retail sales will serve as the baseline for the 2018-2020 program cycle. The PSC did not set demand reduction goals, but stated that utilities should continue to use the demand reduction targets established through the approved 2015-2017 plans for program years 2016 and 2017. Table 5-4 depicts the utilities' demand reduction targets for 2016 and 2017. Currently, there are no established goals for natural gas or limited income programs.

In an effort to ramp up the utility plans to achieve the 2 percent goal in 2018, the PSC issued a 2017 goal. In 2017, utility plans that are not forecasted to achieve an energy savings equivalent to 2 percent of their respective weather-normalized 2013 gross retail sales must increase their 2017 forecasted energy savings 0.2 percent above the forecasted 2016 plan savings. For example, if a utility plan is forecasted to achieve a 1.3 percent reduction in 2016 from the 2013 weather-normalized retail sales baseline, then the goal for 2017 would be a 1.5 percent reduction from the 2013 baseline. However, if a utility is projecting 2 percent energy savings in 2017, it would use the 2017 plan as filed. The 2017 goals, formalized in PSC Order No. 87285, are depicted in Table 5-4.

### *Table 5-4 EmPOWER Maryland Energy Efficiency Goals and Demand Reduction Targets for 2016 and 2017*

| | Annual Energy Efficiency Goals (MWh) | | Annual Demand Reduction Targets (MW) | |
|---|---|---|---|---|
| | 2016 | 2017 | 2016 | 2017 |
| BGE | 565,933 | 631,138 | 811.97 | 834.495 |
| DPL | 66,931 | 76,060 | 110.828 | 115.292 |
| Potomac Edison | 73,434 | 88,557 | 10.8 | 11.6 |
| Pepco | 237,311 | 268,599 | 399.764 | 407.261 |
| SMECO | 75,900 | 78,284 | 63.528 | 64.258 |
| Total | 1,019,509 | 1,142,638 | 1,396.89 | 1,432.91 |

Source: MD PSC Commission Order No. 87285 and 2015-2017 EmPOWER Maryland Plans for each utility.

## 5.2 Greenhouse Gas Policies

The effect human activities have on the Earth's climate continues to receive global attention. There is evidence that the average global temperature is rising and that carbon dioxide ($CO_2$) and other greenhouse gases (GHGs) are present in the atmosphere at record high levels compared with both the recent and distant past. These atmospheric concentrations are potentially being caused or exacerbated by emissions of GHGs from human activities, such as fossil fuel combustion for electricity generation and transportation, industrial processes, and changes in land use, including deforestation.

### Climate Change Impact on the Power Industry and Resilience

The electricity sector is particularly vulnerable to the effects of extreme weather events. As global temperatures continue upward, sea levels will also rise and extreme weather events are likely to occur more frequently. Renewable energy investments are necessary in order to make our electricity systems more resilient and reliable.

Historic tide-gauge records indicate that Maryland's coastal waters have increased by 1 foot in the past 100 years and continue to increase, with a subsequent loss of approximately 580 acres of land per year along the Maryland coast. As sea levels rise, coastal floods reach higher lands, threatening the reliability of power plants in the affected regions. As sea level continues to rise, increasingly more electric facilities are put at risk. Seven generating stations in Maryland are sited less than nine feet above local high tide, and three facilities are sited less than five feet above high tide. According to MDE's GHG reduction plan published in December 2011, among U.S. states, Maryland is the third most vulnerable to sea level rise.

Another effect of climate change is more frequent heat waves. In Maryland, mean annual temperature increased from 1977 to 1999 by 2°F. In the late 20th century, there was an average of 30 days per year with maximum daily temperatures greater than 90°F. The number of days with the daily temperature greater than 90°F is expected to double by the end of the century. These trends suggest that extended heat waves in Maryland are likely to occur more frequently and last longer. Extreme heat creates periods of high energy demand due to increased use of air conditioning and cooling equipment, while at the same time, warmer ambient temperatures in surface water bodies can reduce efficiency at power plants that rely on cooling water.

To increase resilience of the electricity sector, certain measures can be taken. Burying transmission lines or elevating or relocating equipment can help reduce the risk of outages, but these options can be capital intensive and may not be a cost-effective, long-term solution. Renewable energy tends to be smaller-scale generation which reduces impact on the grid when upsets occur. Renewable resources are also less vulnerable to fuel supply risks, thus reducing vulnerability to the fuel supply chain and providing price stability for consumers. Further research and investment in renewable energy will improve Maryland's understanding of the impacts as well as the risks associated with implementing renewable technology in the power sector.

Some of the potential impacts associated with increased GHG levels in the atmosphere are global temperature increases, sea-level rise that may gradually inundate coastal areas and increase shoreline erosion, flooding from coastal storms, changes in precipitation patterns, increased risk of severe weather events and droughts, threats to biodiversity, and challenges for public health wellness.

Maryland has been working to reduce the State's impact on the climate. The Maryland Climate Change Commission (MCCC) was formed in 2007 to develop a state-wide Climate Action Plan, which was published in 2008. This plan contained 61 policy options, programs, and measures to reduce GHG emissions in Maryland and to help the State respond and adapt to the impacts of climate change. Maryland also implemented the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA), a key recommendation of the Climate Action Plan. The State continues to participate in the Regional Greenhouse Gas Initiative (RGGI) with the objective of reducing $CO_2$ emissions specifically from the electricity generation sector.

The latest regulatory development regarding GHGs is the federal Clean Power Plan. This and other key and local climate and GHG initiatives are discussed on the following pages.

### 5.2.1 Regional Greenhouse Gas Policies

In 2005, the governors of Delaware, Connecticut, Maine, New Hampshire, New Jersey, New York, and Vermont created the first cap-and-trade program for $CO_2$ in the United States, the Regional Greenhouse Gas Initiative (RGGI). Maryland, as required by the State's Healthy Air Act of 2006 (HAA), joined RGGI in 2007, the same year as Massachusetts and Rhode Island. Under the RGGI program, total $CO_2$ emissions from fossil fuel-fired electricity generating units with nameplate capacities of 25 MW or greater were capped initially from 2009 through 2014 at 188.1 million tons based on projected 2006-2007 emissions levels. The annual cap was reduced to 165 million tons following New Jersey's exit from the RGGI program at the end of 2011 and reduced again in 2014 to 91 million tons. Emission reductions of 2.5 percent per year are mandated from 2015 through 2020, for a total reduction of 10 percent. This phased approach was designed to provide regulatory certainty for electricity generators to begin planning for, and investing in, lower-carbon alternatives without creating dramatic electricity price impacts.

Table 5-5 lists the $CO_2$ budget allocations for each RGGI member state. There are 17 power plants in Maryland that are covered by RGGI. Maryland's 2016 RGGI budget allowance is 14.4 million tons of $CO_2$, or 22 percent of the 2016 budget for the region of 64.6 million tons. Contrary to what was expected when the $CO_2$ state apportionments were negotiated, emissions in the power sector have fallen over the last several years due to plant closures, the economic downturn, mild weather patterns, shifts to natural gas-fired generation, increased generation from renewable energy sources, and increases in conservation and demand response. At the conclusion of the second control period, the RGGI power sector recognized a 40 percent decline in emissions since 2005. Since 2005, emissions from Maryland's power sector have declined 52 percent, or by 19 million tons of $CO_2$.

A comprehensive program review was conducted in 2012 by RGGI member states via a regional stakeholder process. An updated RGGI Model Rule was published in February 2013, resulting in, among other program clarifications, a 45 percent reduction in the regional emissions cap to 91 million tons starting in 2014. Other revisions include the establishment of interim control period requirements, cost containment reserves to help alleviate spikes in allowance prices, and changes in the handling of offsets as described below. The 2016 Program Review by member states began in late 2015 and will continue throughout 2016.

It should be noted that of the thirteen states (plus the District of Columbia) that are included in whole or in part in the PJM footprint, only Maryland and Delaware are participants in RGGI. To some degree, therefore, "emissions leakage" may occur: reductions in emissions from plants covered in RGGI are offset by emissions from power plants not covered in RGGI. The reason for the potential emissions leakage is that the energy generated from covered plants in Maryland (and Delaware) is subject to the RGGI emissions cap while generation in PJM states not participating in RGGI (e.g., New Jersey) are not subject to the emissions cap. The extent of emissions leakage depends upon numerous factors including energy consumption levels, power plant running-cost differentials, the price of RGGI emission allowances, the level of the emissions caps, and transmission congestion.

### *Table 5-5 $CO_2$ Emissions from RGGI Sources*

| State | Annual Historic Emissions 2005 - 2008 (million tons of $CO_2$) | Annual RGGI Emissions (million tons of $CO_2$) | | |
|---|---|---|---|---|
| | | Compliance Period 1 2009-2011 | Compliance Period 2 2012 - 2014 | Compliance Period 3 2015 |
| Maryland | 32.38 - 37.26 | 25.57 - 27.96 | 18.68 -20.60 | 18.05 |
| Connecticut | 8.99 - 11.32 | 7.02 - 8.53 | 7.12 - 7.46 | 8.15 |
| Delaware | 7.56 - 8.30 | 3.71 - 4.30 | 3.93 - 4.84 | 3.52 |
| Massachusetts | 21.44 - 26.64 | 15.63 - 19.80 | 11.79 - 13.68 | 12.28 |
| Maine | 3.37 - 4.59 | 3.34 - 3.94 | 2.25 - 2.94 | 1.78 |
| New Hampshire | 7.10 - 8.97 | 5.53 - 5.90 | 3.57 - 4.64 | 3.82 |
| New Jersey | 20.60 - 22.07 | 16.36 - 19.68 | N/A (See Note A) | N/A (See Note A) |
| New York | 48.35 - 62.72 | 37.70 - 41.95 | 33.48 - 35.64 | 32.48 |
| Rhode Island | 2.69 - 3.29 | 3.42 - 3.95 | 2.77 - 3.74 | 3.08 |
| Vermont | 0.0026 - 0.0078 | 0.0020 - 0.0065 | 0.0023 - .000276 | 0.0012 |
| Original RGGI 10 State Total | 153.5 - 184.6 | 118.56 - 135.74 | N/A | N/A |
| Current RGGI 9 State Total | 132.9 - 162.5 | N/A | 86.53 - 92.73 | 83.16 |

Source: http://www.rggi.org/.
Notes:
(a) New Jersey withdrew from the RGGI program at the end of 2011.
NA – Complete emissions data are not available. Some facilities in Connecticut and Delaware are shown as having incomplete data in the RGGI emissions reporting database.

### *RGGI Allowance Auctions*

Each member state has its own independent $CO_2$ budget trading program. States sell their $CO_2$ allowances in regional auctions with each $CO_2$ allowance representing a limited authorization to emit one ton of $CO_2$. $CO_2$ allowances issued by any state are usable across all state programs, so that the individual state $CO_2$ budget trading programs, in aggregate, form one regional compliance market for $CO_2$ emissions. A power plant within a RGGI state must hold $CO_2$ allowances equal to its emissions to demonstrate compliance at the end of each three-year control period. During the program's first compliance period from 2009 to 2011, 206 of the 211 power plants subject to RGGI (over 97 percent)

## Allocation of the Maryland Strategic Energy Investment Fund

The RGGI member states have agreed that a minimum of 25 percent of the revenue from each state's emissions allowances are to be used for consumer benefit or strategic energy purposes. As of the March 2016 auction, Maryland has raised $467.3 million in RGGI proceeds. This revenue is directed to the Maryland Strategic Energy Investment Fund (SEIF), which is administered by MEA. The Maryland legislature has directed MEA to allocate the SEIF as follows:

- Up to 50 percent — Energy bill assistance for low-income residents;
- At least 20 percent — Energy efficiency, conservation, and demand response programs (of which half must be used on low and moderate income families);
- At least 20 percent — Clean energy and climate change programs, outreach, and education; and
- Up to 10 percent, but no more than $4 million -- Administration of the Fund.

met the program's compliance obligations. For the second compliance period from 2012 to 2014, 161 of the 167 power plants subject to RGGI requirements met their compliance obligations.

While any entity may apply to participate in the quarterly auctions, in the first 30 auctions 77 percent of the allowances have been purchased by electric generators or their affiliates. The reserve, or minimum, allowance price was initially set at $1.86 for the September 2008 auction and increases by 2.5 percent each year. For the December 2015 auction, the clearing price was $7.50, well above the established minimum. Allowance clearing prices have ranged from $1.86 to $7.50, as shown in Figure 5-3. In total, RGGI has resulted in $1.7 billion in revenues to the nine member states as of the December 2015 auction. Maryland has raised $474 million (see Table 5-6), the majority of which has been used for low-income energy assistance.

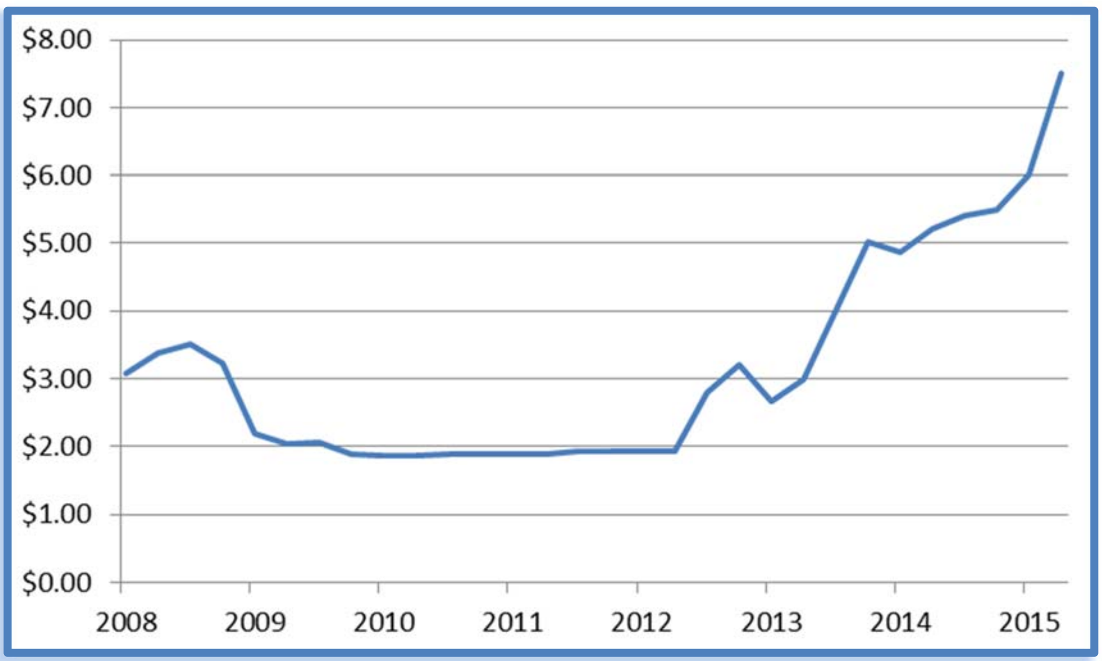
***Table 5-6 RGGI Allowance Auctions, 2008-2015***

| Auction Date | Auction Offering | Total RGGI Allowances Sold | Clearing Price | Maryland Allowances Sold | Maryland Revenues (million USD) |
|---|---|---|---|---|---|
| Sep-08 | Current | 12,565,387 | $3.07 | 5,331,781 | $16.37 |
| Dec-08 | Current | 31,505,898 | $3.38 | 5,331,781 | $18.02 |
| Mar-09 | Current | 31,513,765 | $3.51 | 5,331,783 | $19.93 |
| | Future | 2,175,513 | $3.05 | 399,884 | |
| Jun-09 | Current | 30,877,620 | $3.23 | 5,331,782 | $18.05 |
| | Future | 2,172,540 | $2.06 | 399,884 | |
| Sep-09 | Current | 28,408,945 | $2.19 | 5,331,782 | $12.42 |
| | Future | 2,172,540 | $1.87 | 399,884 | |
| Dec-09 | Current | 28,591,698 | $2.05 | 5,331,782 | $11.48 |
| | Future | 2,172,540 | $1.86 | 294,317 | |
| Mar-10 | Current | 40,612,408 | $2.07 | 7,878,873 | $16.99 |
| | Future | 2,137,992 | $1.86 | 368,169 | |
| Jun-10 | Current | 40,685,585 | $1.88 | 7,528,873 | $14.85 |
| | Future | 2,137,993 | $1.86 | 3,767,444 | |
| Sep-10 | Current | 45,595,968 | $1.86 | 5,681,334 | $10.99 |
| | Future | 2,137,992 | $1.86 | 231,008 | |
| Dec-10 | Current | 43,173,648 | $1.86 | 4,316,922 | $8.41 |
| | Future | 2,137,991 | $1.86 | 206,358 | |
| Mar-11 | Current | 41,995,813 | $1.89 | 7,528,873 | $14.94 |
| | Future | 2,144,710 | $1.89 | 376,444 | |
| Jun-11 | Current | 12,537,000 | $1.89 | 2,245,541 | $4.60 |
| | Future | 943,000 | $1.89 | 190,346 | |
| Sep-11 | Current | 7,487,000 | $1.89 | 1,336,077 | $2.53 |
| | Future | 0 | -- | 0 | |
| Dec-11 | Current | 27,293,000 | $1.89 | 5,669,520 | $10.72 |
| | Future | 0 | -- | 0 | |
| Mar-12 | Current | 21,559,000 | $1.93 | 4,410,931 | $8.51 |
| Jun-12 | Current | 20,941,000 | $1.93 | 4,458,850 | $8.61 |
| Sep-12 | Current | 24,589,000 | $1.93 | 6,222,230 | $12.01 |
| Dec-12 | Current | 19,774,000 | $1.93 | 5,011,529 | $9.67 |
| Mar-13 | Current | 37,835,405 | $2.80 | 9,579,963 | $26.82 |
| Jun-13 | Current | 38,782,076 | $3.21 | 9,579,963 | $30.75 |
| Sep-13 | Current | 38,409,043 | $2.67 | 8,739,921 | $23.34 |
| Dec-13 | Current | 38,329,378 | $3.00 | 8,739,920 | $26.22 |

| Auction Date | Auction Offering | Total RGGI Allowances Sold | Clearing Price | Maryland Allowances Sold | Maryland Revenues (million USD) |
|---|---|---|---|---|---|
| Mar-14 | Current | 23,491,350 | $4.00 | 4,842,487 | $19.37 |
| Jun-14 | Current | 19,062,384 | $5.02 | 3,725,941 | $18.70 |
| Sep-14 | Current | 17,998,687 | $4.88 | 3,725,942 | $18.18 |
| Dec-14 | Current | 18,198,685 | $5.21 | 3,725,942 | $19.41 |
| Mar-15 | Current | 15,272,670 | $5.41 | 3,051,680 | $16.51 |
| Jun-15 | Current | 15,507,571 | $5.50 | 3,053,288 | $16.79 |
| Sep-15 | Current | 23,374,294 | $6.02 | 5,323,721 | $32.05 |
| Dec-15 | Current | 15,374,274 | $7.50 | 3,053,288 | $22.90 |
| **Total** | | | | | **$473.77** |

Source: RGGI, Inc. website.

### *Figure 5-3 RGGI Allowance Clearing Prices, 2008-2015*




### *RGGI Offsets*

The RGGI program allows covered entities to use qualifying offset projects to reduce the total number of allowances they are required to secure. Offset projects or emission credit retirements will be awarded one $CO_2$ offset allowance for every ton of $CO_2$ reduced or sequestered. A source may cover up to 3.3 percent of its $CO_2$ emissions with offset project allowances. Currently, no offset projects have been awarded to offset allowances under RGGI.

Offset projects that currently qualify under the RGGI program are:

## Forestry Carbon Sequestration

Biological processes can capture and sequester carbon, providing an offset to carbon emissions from fossil fuel power generating facilities. Restoring or planting forests is one approach to enhancing these carbon sequestration services. One method suggested to protect or expand the natural sequestration services provided by such ecosystems is to create trading markets that place a value on carbon in a way that results in economic incentives and payments for removing carbon from the atmosphere and storing it in biomass.

To understand the requirements and potential of applying such an approach in Maryland, PPRP has been evaluating previously restored forest sites. Data have been collected at the ODEC Patapsco and Seneca Creek restoration sites to measure the carbon content of soils and vegetation, and estimate changes over time. These studies helped develop carbon measurement methodologies and establish baseline values for determining the rate of carbon storage by such systems.

A second initiative has been developing models that can use the field data to project the amount of carbon that will be sequestered over the lifetime of the project (which may be several decades). PPRP has adapted the Graz-Oak Ridge Carbon Accounting Model (GORCAM) for use in terrestrial and wetlands carbon sequestration projects in Maryland. The GORCAM model has been used to characterize the sequestration benefits of different management regimes in Maryland's state-owned forests and to estimate the range of results expected using different mixes of species in the DNR's carbon sequestration demonstration project.

At present, these investigations show that the low carbon prices in the experimental trading markets will not stimulate forestry offset projects in Maryland. However, sustainable forestry that selectively harvests high quality timber that can be converted into wood products with long lifetimes can be effective in increasing the amount of carbon removed from the atmosphere by biological processes and subsequently sequestered in stable forms for long periods.

1. Landfill Methane Capture and Destruction – applicable to municipal solid waste landfills that are not subject to New Source Performance Standards (NSPS).
2. Reduction in Emissions of Sulfur Hexafluoride (SF6) – preventing the release of SF6 to the atmosphere, through capture and storage, recycling, or destruction.
3. Sequestration of Carbon Due to Afforestation – sequestering carbon through the conversion of land that has been in a non-forested state for at least ten years to a forested condition.
4. Reduction or Avoidance of $CO_2$ Emissions from Natural Gas, Oil, or Propane End-use Combustion Due to End-use Energy Efficiency – reducing on-site combustion of natural gas, oil, or propane in existing or new commercial or residential buildings through energy efficiency.
5. Avoided Methane Emissions from Agricultural Manure Management Operations – destroying methane generated by anaerobic digesters and uncontrolled storage of manure or organic food.

The RGGI Model Rule issued in February 2013 details a new "sequestration of carbon due to reforestation, improved forest management or avoided conversion" offset category that may be adopted by states in lieu of the afforestation category described above. The new category accompanies an RGGI U.S. Forests Offset Protocol based mainly on a protocol by the California Air Resources Board.

### *Maryland Offset Projects*

In Maryland, two additional offset project categories are being pursued, specifically terrestrial sequestration through urban forestry and the restoration of salt marshes. Maryland is promoting the development of programs within urban communities to plant and grow trees, which reduces GHG emissions in two ways. First, $CO_2$ is removed from the atmosphere during the growing of the trees due to an increase in biomass. Second, GHG emissions are avoided through energy conservation, as the trees can provide shade with a natural cooling effect for residences and other buildings in the community. Several State agencies and community groups are interested in pursuing urban forestry projects as an alternative or supplement to other more traditional afforestation projects.

Salt marshes are prevalent in Maryland and are of critical importance for estuarine ecosystems, such as those associated with the Chesapeake Bay, by serving as habitats for wildlife and buffers to large storms. In addition, salt marsh soils have the capacity to sequester large amounts of $CO_2$ through organic and mineral accretion. Marsh decline, however, is becoming more prevalent throughout the region due to the increase in water levels. Raising the elevation of the marsh beds via supplementation of natural sediment (e.g., depositing clean dredged material) can restore the tidal fluctuations required to support the marsh systems and promote carbon storage. Over the last several years, Maryland's Power Plant Research Program (PPRP) has assisted with an effort by Restore America's Estuaries to develop a formal offset protocol for salt marsh systems (see sidebar).

Maryland has great potential for reducing GHG emissions through sequestering carbon in restored wetlands and marshlands around the Chesapeake Bay. Maryland's Department of Natural Resources (DNR) has identified three focus areas to promote wetland carbon sequestration with the potential to reduce the State's net emissions by an estimated 0.5 to 0.65 million metric tons $CO_2$ equivalent ($CO_2e$):

**Blackwater Tidal Marsh Sequestration Project –** PPRP, the U.S. Department of Energy (DOE), and several other partners are collaborating with the University of Maryland to restore up to 20,000 acres of tidal marshes using clean dredged material. Determinations of the carbon storage rate and the effect of management practices on the process, as well as the development of a sampling protocol for $CO_2$ validation in restored marshes, will lead to projects that produce carbon offsets. The restoration project is storing an estimated 24,550 metric tons of carbon each year, a rate above the national average. In addition, the restored marsh will provide habitat for native and migratory birds, terrestrial animals, and aquatic life.

**Dorchester County Wetlands Study –** PPRP conducted a study of wetlands in Dorchester County to demonstrate the potential carbon sequestration opportunities that may result from protecting and restoring wetlands. Areas for potential restoration were identified within Dorchester County's extensive coastal marshes. Satellite-derived net primary productivity of the wetlands was used to estimate gross sequestration, and net accumulation was estimated based on the current understanding of carbon dynamics in coastal wetlands.

**Sea Level Affection Marshes Model –** DNR utilized this model to identify areas known as wetland transition zones, or areas projected to convert into wetlands. These identified areas will become targets for wetland restoration and land conservation efforts to help maintain coastal wetlands into the future.

### 5.2.2 Maryland Climate Change Legislation

Over the last several years, Maryland has enacted several pieces of legislation that will help the State, both directly and indirectly, meet its climate change goals. These bills target emissions from power plants and vehicles, spur development of renewable energy, and set energy efficiency and conservation goals.

During the 2009 session, the legislature passed the GGRA via House Bill 315/Senate Bill 278. This law sets a state-wide GHG emissions reduction goal of 25 percent from a 2006 baseline by 2020. The GGRA also requires that Maryland prepare a plan to meet a longer-term goal of reducing its GHG emissions up to 90 percent by 2050, while promoting new "green" jobs, protecting existing jobs, and positively influencing the State's economy. A GGRA 2012 Plan (Plan) was designed to achieve the goals identified in the 2009 GGRA. The Plan describes 65 control measures for reducing GHG emissions, including reinforcement of Maryland's participation in RGGI and programs to support terrestrial and geological carbon storage. In addition to achieving GHG reductions, the Plan was designed to create jobs and improve Maryland's economy, and will also assist advancing other environmental priorities of the State, including restoration of the Chesapeake Bay, improving air quality, and other critical energy and national security issues. MDE released a GGRA Plan Update in October 2015 that will provide additional environmental benefits by helping the State further Chesapeake Bay restoration efforts, continuing improving air quality, and working to preserve agricultural and forest lands.

On May 12, 2015 the Maryland Climate Change Commission Act of 2015 was signed into law to expand the Maryland Climate Change Commission (MCCC) originally created in 2007. MDE worked with the MCCC on the 2015 GGRA Plan Update and will continue to work with MCCC to address climate change in Maryland. The MCCC has various workgroups to address climate change issues including mitigation; adaptation; science and technology; and education, communication, and outreach.

The Maryland Senate passed Senate Bill 323 on February 23, 2016, accelerating Maryland's efforts to reduce GHG emissions. The bill proposes a 25% reduction in statewide GHGs below 2006 levels by 2020, and a 40% reduction in statewide GHGs by 2030. This bill was passed by the House and signed by the Governor in April 2016.

### 5.2.3 Clean Power Plan

EPA recently launched the Clean Power Plan (CPP), a comprehensive program mandating reductions in GHG emissions from large existing sources, including power plants, and potential new sources of GHGs. The CPP is rooted in Section 111 of the Clean Air Act, which lays out distinct regulatory approaches for new and existing sources of emissions. Section 111(b) covers federal programs to address new, modified, and reconstructed sources by establishing emissions standards. Section 111(d) mandates a series of state-based programs covering existing sources; under Section 111(d), EPA establishes guidelines and the states then design programs that fit within those guidelines to achieve target emissions reductions.

#### *New Source Rule*

The New Source Rule under the CPP was published in the federal register on October 23, 2015. The regulations take the form of "New Source Performance Standards" (NSPS). Under the CPP, EPA is finalizing NSPS that for the first time will establish standards for emissions of $CO_2$ for newly constructed, modified, and reconstructed fossil fuel-fired generating units. This action establishes separate standards of performance for fossil fuel-fired electric utility steam generating units and fossil fuel-fired stationary combustion turbines. These standards also address related permitting and reporting issues.

The final rule sets separate standards for new power plants fueled by natural gas and coal. New natural gas power plants can emit no more than 1,000 pounds (lbs) of $CO_2$ per megawatt-hour (MWh) of electricity produced, which is achievable with the latest combined cycle technology. New coal power plants can emit no more than 1,400 lbs $CO_2$/MWh, which almost certainly requires the use of carbon capture, use and storage (CCUS) technology. CCUS is a technology that may capture up to 90% of the $CO_2$ emissions produced from the use of fossil fuels in electricity generation and industrial processes, preventing $CO_2$ from entering the atmosphere. Furthermore, the use of CCUS with renewable biomass is one of the few carbon abatement technologies that can be used in a "carbon-negative" mode, actually taking $CO_2$ out of the atmosphere.

CCUS is a multi-stage process in which potential $CO_2$ emissions are captured from a power plant instead of being vented into the atmosphere. CCUS consists of three parts; capturing $CO_2$, transporting $CO_2$, and securely storing $CO_2$ emissions underground in depleted oil and gas fields or deep saline aquifer formations. EPA has established certain regulatory requirements for demonstrating the permanent underground storage of $CO_2$. The requirement that new coal plants install CCUS technology will drastically reduce its emissions. Increased deployment of CCUS technology at power plants will very likely drive CCUS costs down and make it a more viable option at other new coal plants. Through experience and innovation, CCUS costs may come down enough to be viable on new natural gas power plants, or as retrofits on existing coal plants, to reduce carbon dioxide emissions from the power sector even further.

New natural gas plants can reach the final $CO_2$ standard by employing efficient generation technology. In older steam turbine plants, natural gas is combusted to heat water, which creates steam to turn a turbine and generate electricity. These plants have thermal efficiencies of 30-35 percent, meaning about one third of the chemical energy stored in natural gas is converted to electricity. In contrast, new combined cycle combustion turbines take advantage of the energy in natural gas to operate with a thermal efficiency above 60 percent.

New coal plants, on the other hand, cannot achieve the final standard through efficiency alone. The most efficient type of coal plants, using ultra-supercritical boilers or integrated gasification combined cycle technology, can currently achieve a $CO_2$ emission rate of around 1,700 lbs/MWh. Therefore, new coal plants can only meet a standard of 1,400 lbs $CO_2$/MWh through the use of CCUS, which can capture a significant portion of a power plant's potential emissions. Certain proposed CCUS power plants are aiming to capture nearly 90 percent of potential emissions, which translates into an emissions rate of potentially less than 500 lbs $CO_2$/MWh.

Even if EPA were not moving forward with this standard, very few new, greenfield coal plants are likely to be constructed in the U.S., in part because of the availability of affordable natural gas. The Energy Information Administration lists only four potential coal plants between now and 2018, compared with more than 200 expected natural gas plants.

The final CPP rule for new power plants would likely be layered on top of existing state programs. For example, a new plant operating in a RGGI territory, including Maryland, would have to achieve the final federal standard, and would also have to submit tradable emission allowances annually to comply with the requirements of RGGI.

The federal provisions of the CPP (Section 111(b)) vests relatively more authority in EPA, and is more straightforward than the state-based provisions (in Section 111(d)) described below. EPA is required to find emission reduction technologies that have been adequately demonstrated and use these to set federal, numerical performance standards that new power plants must meet. These standards are implemented by the states, as are most EPA air rules, but states do not have much flexibility to alter the standards set by EPA. On the other hand, under Section 111(d), states have greater flexibility in how they implement the EPA standard. For instance, as outlined below, the state-based program allows for the possibility of market-based mechanisms to reduce emissions system-wide, rather than focusing on individual power plants.

### *Existing Unit Rule*

The CPP under Section 111(d) of the Clean Air Act was released by the EPA on August 3, 2015 as a "Common sense approach to cut carbon pollution from power plants" and was published in the federal register on October 23, 2015. The CPP was developed to reduce $CO_2$ emissions from affected fossil fuel-fired (coal, oil, or natural gas) generating units by 32% from 2005 levels of $CO_2$ from "affected units" in the U.S. power sector. An affected unit is defined as one in operation or that had commenced construction on or before January 8, 2014, has a generating nameplate capacity above 25 MW capable of selling greater than 25 MW of electricity, and has a base load rating >250 MMBtu/hour heat input of fossil fuel; and any stationary combustion turbine that meets the definition of either a combined cycle or combined heat and power combustion turbine.

#### ***Best System of Emissions Reduction (BSER)***

In the CPP, EPA has determined the Best System of Emissions Reduction (BSER) that has been demonstrated for carbon emissions from a particular group of sources by examining technologies and measures already in use to reduce $CO_2$ from fossil fuel-fired power plants. Under the CPP, the BSER is a set of measures, or "building blocks" and guidelines to be used by states to develop state system plans that reflect the state's actual generation system and fuel mix. In determining the BSER, EPA considered the ranges of reductions that can be achieved at affected generating units at reasonable cost by application of the three building blocks, taking into account how quickly and to what extent the measures encompassed by the building blocks could be used to reduce emissions.

- Building Block 1: Improved efficiency at power plants.
  Power plants can make heat rate improvements to reduce the amount of $CO_2$ they emit per megawatt-hour of electricity generated by increasing the operational efficiency of existing fossil-fired power plants.

- Building Block 2: Shifting generation from higher emitting coal to lower emitting natural gas power plants.
  This building block reduces the carbon intensity of electricity generation by shifting electricity generation from higher emitting fossil fuel-fired steam power plants (generally coal-fired) to lower emitting natural gas-fired power plants.

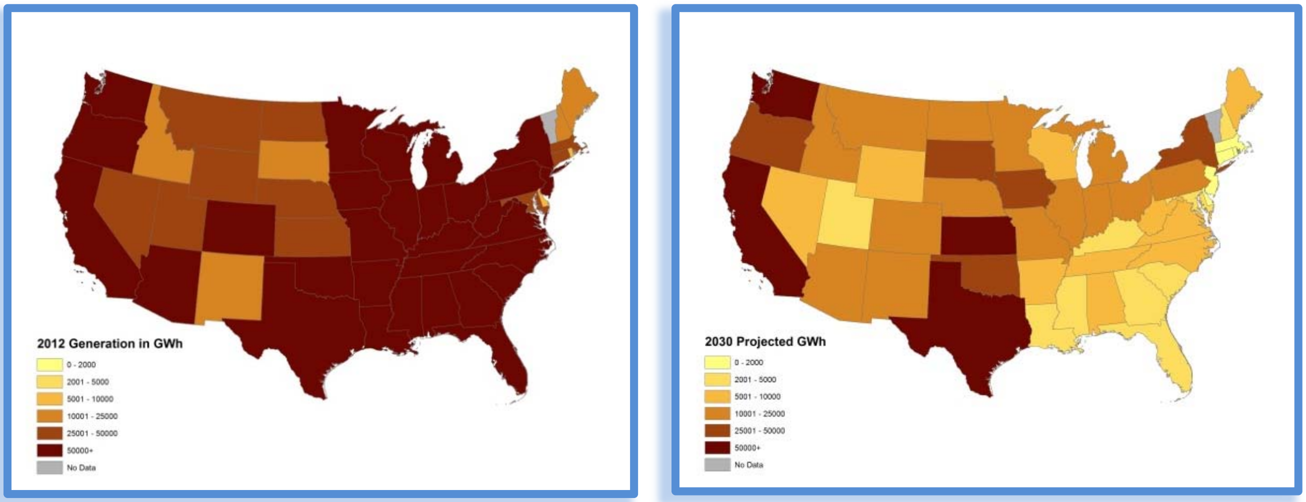
- Building Block 3: Shifting generation to zero-emitting renewable.
  The final BSER analysis does not include existing or under-construction nuclear power or existing utility-scale renewable energy generation as part of building block 3, but instead takes into account recent reductions in the cost of clean energy technology, as well as projections of continuing cost reductions. Generation from under-construction nuclear facilities and nuclear plant uprates can still be incorporated into state plans and count towards compliance. In fact, nuclear power competes well under a mass-based plan, as increased nuclear generation can mean that fossil fuel units are operating less and emitting fewer tons of $CO_2$.

A fourth Building Block, use of electricity more efficiently or demand-side energy efficiency, which was included in the draft CPP was removed from the final CPP BSER in terms of use for determining state reduction goals; however, the additional building block can be included in state implementation plans for carbon reductions if determined appropriate by any state. Ultimately the three building blocks have been used to determine state-specific reduction goals consistent with EPA's defined BSER; however, states do not need to utilize all of the building blocks in implementation plans if state-specific alternatives are available and can adequately show compliance with the CPP and the carbon reduction goals.

In assessing the BSER, EPA recognized that power plants operate through broad interconnected regional grids that determine the generation and distribution of power, and thus the Agency based its emission and reduction analysis on the three established regional electricity interconnects: the Western interconnection, the Eastern interconnection, and the Electricity Reliability Council of Texas interconnection. Maryland is located in the Eastern interconnection region. In determining state-specific goals, EPA made use of regional average emission factors paired with individual state-specific generation portfolios.

Building Block 3 includes increases in renewable energy for states to meet their GHG reduction targets. Figure 5-4 shows EPA's projections for renewable energy in 2030 compared to 2012 generation. As illustrated, the future for growth in renewable energy varies from state-to-state, depending in part on the status of existing renewable energy projects in these states.

### *Figure 5-4 Renewable Energy*




Source: EPA's Clean Power Plan Technical Support Document, 2014

While EPA's projections and proposed goal show Maryland and its power plants will need to continue to work to reduce $CO_2$ emissions and take additional action to reduce its goal in 2030, these rates are designed to be met as part of the grid and over time. In fact, Maryland's goal reflects the inherent flexibility in the way the power system operates and the variety of ways in which the electricity system can deliver a broad range of opportunities for compliance for power plants and states.

### *State Implementation Plan*

The CPP establishes state-specific interim and final goals for each state, based on the baseline average emission rates for the region and the states mix of power plants. States may meet either EPA's specified mass-based goals, which are an absolute tons of carbon emission reduction required or rate-based goals which are an intensity based emission rate expressed in terms of lbs of $CO_2$ per MWh of power generated. Whether rate-based or mass-based, there are many subtle elements or options that need to be considered to construct a workable, equitable, and economical implementation plan. These include consideration of options for allocation of allowances and offsets, renewable measures, load growth and accounting for energy efficiency.

States that use the mass-based goal must assure that carbon pollution reduction from existing units achieved under the CPP do not lead to increases in emissions from new sources. EPA is offering an option to simplify this requirement for states developing plans to achieve mass-based goals. If a state chooses this route, its state planning requirements are streamlined, avoiding the need to meet additional plan requirements and include additional elements.

States can use EPA's model trading rules or write their own plan that includes trading with other "trading ready" states, whether they are using a mass- or rate-based plan. Under current CPP guidelines, states electing to show compliance with a mass-based approach can only trade with other mass-based states. The same is true for those states choosing to take a rate-based approach. "Emissions banking and trading" provisions have been used extensively in mass-based emission budget trading programs. Banking programs generally reduce the overall cost of attaining more stringent emissions limitations. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which may be beneficial when there are social preferences or other reasons to achieve environmental improvements sooner rather than later. It is also beneficial when addressing pollutants that are long-lived in the atmosphere, such as $CO_2$, and where increasing atmospheric concentration of the pollutant leads to increasing adverse atmospheric impacts. If employed by a state, emission budget trading programs, including RGGI, must be submitted as part of the state Plan.

Other measures in the CPP encourage implementation of pollution reductions and increased investment in clean energy prior to mandatory reductions that begin in 2022, resulting in "glide paths" to compliance, rather than "cliffs." Mandatory reductions beginning in 2022 and the phase-in of BSER measures between 2022 and 2029 eliminate the "cliff" and enable states to chart their own individual emissions reduction trajectories or "glide paths." The glide path gradually steps down the amount of carbon pollution per megawatt-hour generated. The performance rates are phased in over the 2022-2029 period, which leads to a glide path of reductions separated into three "interim step periods": 2022-2024, 2025-2027, and 2028-2029. States may elect to set their own milestones for interim step periods as long as they meet the interim and final goals articulated in the emission guidelines. States must define their interim step milestones and demonstrate how they will achieve these milestones, as well as the overall interim and final goals.

All state goals fall in a range between 771 lb/MW-hr (states that have only natural gas plants) to 1,305 lb/MW-hr (states that have only coal/oil plants). A state's goal is based on how many of each of the two types of plants are found in the state. Maryland's 2030 rate-based goal is 1,287 lb/MW-hr, which is on the high end of the range; therefore, Maryland has one of the least stringent state goals, compared to other state goals in the final CPP. The step 1 interim goal for Maryland is 1,644 lb/MW-hr which provides a smoother glide path and less of a cliff at the beginning of the program.

Maryland's mass-based goal is 14.3 million tons by 2030, with a baseline of 20.1 million tons in 2012. In Maryland, the baseline data from 2012 through the limited allowable emissions results in a reduction of 37%. Under RGGI, Maryland's emissions will be reduced 17.5 million tons by 2020, a 25% reduction in annual GHG emissions by 2020, compared with 2006 levels. As of 2013, the State has reduced emissions by 9.7%. Maryland and its power plants will need to continue to work to reduce $CO_2$ emissions and take additional action to reach its goal in 2030; these goals seem achievable. The CPP ensures that states and power plants can rely on the electricity system's inherent flexibility and changes already underway in the power sector from socio-economic factors and other environmental and energy policy drivers. Figure 5-5 shows the expected $CO_2$ emission rate reduction in lbs/MWh and the emission mass reduction in million short tons for Maryland. Both the "glide path" and "cliff" are identified in Figure 5-5.

***Figure 5-5 Clean Power Plan CO2 Reductions by 2030***


Source: "Maryland." Clean Power Plan State-Specific Fact Sheets. EPA, 4 August 2015. Accessed 7 March 2016. https://www.epa.gov/cleanpowerplantoolbox/clean-power-plan-state-specific-fact-sheets

### *US Supreme Court Stay*

On February 9, 2016, the Supreme Court, in a 5-4 vote, stayed implementation of the CPP pending judicial review, in response to a legal challenge brought by a coalition of corporations and 27 states. The Court's order states that the stay will remain in place while the D.C. Circuit resolves the merits, and until the Supreme Court resolves any appeals. The D.C Circuit's decision is expected in either winter or early spring, which means the Supreme Court could hear a merits appeal sometime in the fall of 2017, with a slight chance it could even be the spring of 2017.

### *New Source Complements to Mass Goals*

In addition to the rate-based and mass-based goals that states may choose, an alternative to the mass-based goal—mass-based state goal with a new source complement measured in total short tons of $CO_2$—is available to implement the CPP standards. This includes the use of emission budget trading programs in a mass-based state plan for the RGGI participating states.

States face a trade-off in their decision to include or exclude new sources. Mass-base compliance plans that cover new units would limit emissions from covered existing units as well as new units in the same categories. Including new units creates a uniform market signal for new and existing sources, which maintains a level playing field and strengthens the environmental integrity of the policy. It also sets limits on fossil generation, potentially limiting a state's ability to meet load growth with fossil generation.

Expectations about future load growth and the resources used to meet that growth are a key consideration in the choice of whether to cover new sources. Depending on how a state's assumptions about future load growth and the resources needed to meet that growth compare with the EPA's assumptions in calculating the mass-based budgets, including new sources could be harder or easier to comply. For example, if no new units are built, the new source complement provides additional allowances that would reduce the stringency of the regulation. For states that participate in interstate trading, including Maryland, affected units in the state could end up with additional allowances to sell or needing to purchase additional allowances. Some states may perceive that covering new sources imposes risk by limiting total future emissions, but doing so will likely increase electricity markets' efficiency, states' flexibility in allowance allocation, and emissions integrity, and it may increase the supply of allowances for existing sources.

The new source complement for mass-based goals provides a slight increase in the existing mass-based goals for any new fossil-fuel power plants. The new source interim complement for Maryland is 170,930 tons of $CO_2$ and the final mass-based goal complement is 150,809 tons of $CO_2$. The addition of the new source complement mass-based goal increases the overall mass-based goal by only 1.1%. Figure 5-6 shows the interim and final mass-based emission limits for Maryland existing affected sources only and for existing and new affected sources that include the new source complement.

*Figure 5-6 Maryland New Source Complement Additions*

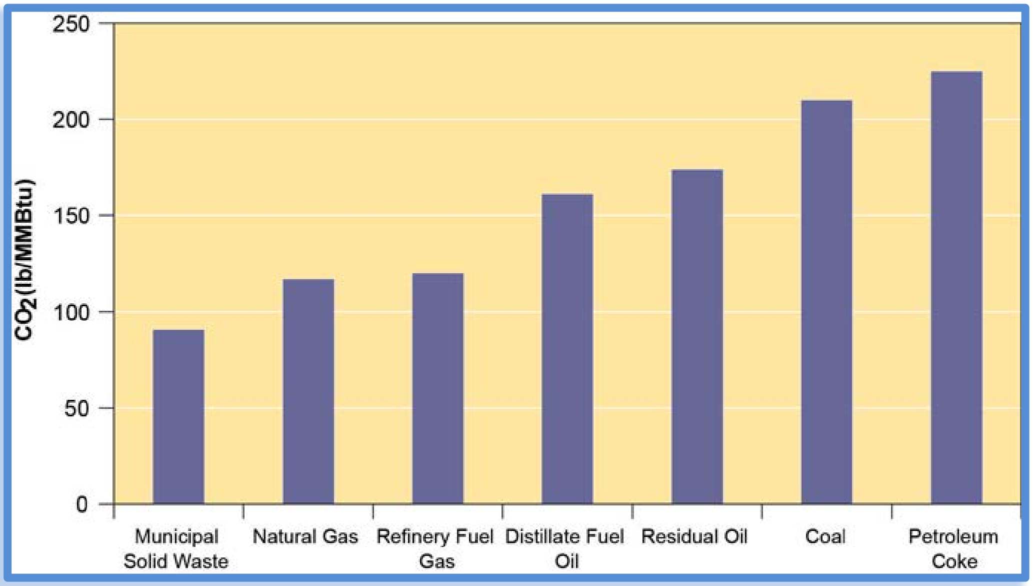

Source: Federal Register Vol. 80 No. 205 October 23, 2015, 40 CFR §60 subpart UUUU.

## 5.3 Fossil Fuel-Fired Generation and $CO_2$

### 5.3.1 Background

Coal is abundant in the U.S. and coal-fired electric generating units effective in meeting baseload, intermediate load, and peak demands given their high reliability. Historically, coal-fired power plants have supplied over half of Maryland's net electricity generation. Since 2012, however, this number has fallen to a little under half while natural gas-fired generation has increased. Energy conversion from traditional coal-fired power plants generates the highest levels of $CO_2$ emissions on a per-unit-of-energy basis of all the fossil fuels available, with the exception of petroleum coke. All fossil fuels contain substantial amounts of fuel-bound carbon that is oxidized into carbon monoxide (CO) and $CO_2$ during combustion. $CO_2$ emissions from conventional coal combustion technologies amount to approximately 1 ton per MWh of electricity generated, compared to 0.4 to 0.6 ton per MWh from natural gas-fired generation (e.g., combined cycle/simple cycle gas turbines). Figure 5-7 shows the approximate level of $CO_2$ formed when combusting various fossil fuels.

*Figure 5-7 CO2 Emissions from the Combustion of Fossil Fuels*




For coal to have an environmentally acceptable future, $CO_2$ emissions from new and existing coal-fired power plants will need to be mitigated to as low a level as feasible given regulatory drivers facing the electric utility industry in the upcoming years, especially EPA's Clean Power Plan (CPP) passed in August 2015. See Section 5.2.3 of the CEIR for more information on the CPP.

$CO_2$ mitigation for coal-derived power is a highly debated topic; however, there are several options that can be effective:

- *Improving generation efficiency (providing a reduction in overall $CO_2$ emissions per megawatt of electricity generated), either through the development of new plants or upgrades to existing facilities/equipment;*
- *Substituting a fraction of the coal consumed with a carbon-neutral fuel, such as biomass (biomass co-firing). Some modern coal-fired boiler designs are currently capable of co-firing up to 30 percent biomass; and*
- *Implementing $CO_2$ capture, utilization, and geological storage.*

Currently, three general methods are available to capture $CO_2$ from power plants and thus reduce $CO_2$ emissions:

- *Post-combustion capture, in which $CO_2$ is separated from flue gases typically using sorbent or solvent systems;*
- *Pre-combustion capture, in which $CO_2$ is captured prior to combustion and generally involves a shift reaction to convert synthesis gas to $CO_2$ and hydrogen; and*
- *Oxyfuel firing, in which the fuel is fired with an oxygen or oxygen/ $CO_2$ mixture, thus producing a $CO_2$-rich flue gas that facilitates capture.*

Located in Cumberland, Maryland, the AES Warrior Run power plant has been capturing a small portion of its $CO_2$ emissions for use in the food and beverage industry since 2000. This 180 MW circulating fluidized bed generating unit uses a post-combustion monoethylamine flue gas scrubber system to remove approximately 110,000 metric tons of $CO_2$ annually from a 2 to 3 percent slipstream of the plant's flue gas. The extracted $CO_2$ is then purified to a 99.99 percent purity level using carbon filters and molecular sieves. The $CO_2$ is stored under pressure in steel tanks until it can be shipped off-site via tanker trucks for beneficial use primarily in the food and beverage industry.

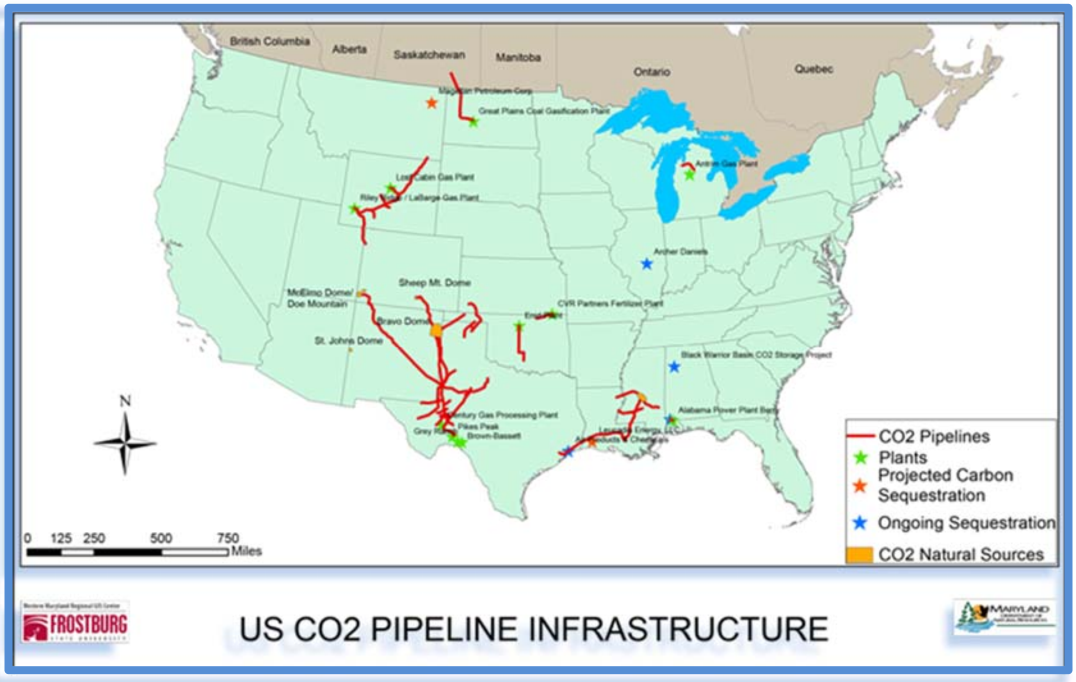
Several carbon capture demonstration projects are currently under various stages of development in the U.S., most of which are funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory. These projects incorporate the full range of existing carbon capture technologies, as well as test the viability of emerging innovative methods, such as cryogenic, phase-changing, and enzyme-based sorbent capture. A few commercial-scale industrial $CO_2$ capture projects are under construction or have commenced preliminary operations; however, most of the projects involving coal-fired power plants have not yet completed commercial-scale testing. The key barrier to carbon capture technology implementation for new and existing power plants is the substantial capital and operating costs. The beneficial use of captured $CO_2$ prior to storage to create value-added products or services may alleviate some of the economic burden.

### 5.3.2 Transporting $CO_2$

Typically, once $CO_2$ is captured, it must be highly pressurized and transported using one of several methods, including pipelines, trucks, and shipping vessels. The inherent limitations of trucking and shipping transport methods are volume constraints and intermittency, although they may demonstrate cost benefits over the construction of a $CO_2$ pipeline for small-scale applications.

To implement carbon capture on the scale necessary to reduce atmospheric $CO_2$ concentrations, the transportation of $CO_2$ from industrial sources to beneficial use or storage sites via pipeline networks must be greatly expanded beyond current capacities. The U.S. has a history of transporting $CO_2$ via pipelines that spans roughly 40 years due to the use of $CO_2$ in enhanced oil recovery projects. Around 50 million metric tons of $CO_2$ is transported in the U.S. each year through approximately 4,500 miles of pipelines, with approximately 75-80 percent of the $CO_2$ in these pipelines derived from natural (geologic) sources (Figure 5-8). If currently planned $CO_2$ capture facilities and pipelines are built, the portion of $CO_2$ from industrial sources could come close to matching natural sources by 2020.

***Figure 5-8 Existing CO2 Pipeline Network in North America***




While the transportation infrastructure for $CO_2$ is growing in certain regions of the country, there are no $CO_2$ pipelines in the Eastern U.S. Maryland has, however, an extensive network of natural gas pipelines (see Figure 2-3) that are concentrated in the central portion of the state, where the majority of Maryland's power plants and other large $CO_2$ emission sources are located. A conceptual $CO_2$ pipeline routing study was undertaken for PPRP by the Western Maryland Regional GIS Center at Frostburg State University which demonstrated potential locations of $CO_2$ pipelines that could directly connect large $CO_2$ sources with a backbone pipeline that would extend to potential geologic storage formations in Western Maryland or Southern Maryland. In addition to the point-to-point connections, the natural gas pipelines may offer opportunities for co-location to minimize the amount of new rights-of-way that must be obtained. Ultimately, the construction of $CO_2$ pipelines, which are physically similar to natural gas pipelines, is technically feasible in the state.

## 5.3.3 $CO_2$ Use and Storage

Even with multiple projects in the areas of carbon offsets, terrestrial sequestration, renewable energy, and switching from coal firing to natural gas, a need may still exist for geologic sequestration of Maryland power plant $CO_2$ to avoid continued releases of large $CO_2$ quantities to the atmosphere. While $CO_2$ is not a hazardous substance, it is an aggressive gas that carries certain risks. Geological sequestration must be approached carefully to achieve the permanent, safe storage of this industrial gas.

### *Storage of $CO_2$*

Carbon capture and storage technologies can be employed to reduce $CO_2$ emissions through either terrestrial or geologic sequestration. Terrestrial sequestration options include eroded and non-eroded cropland, marginal land, mineland, and wetlands and marshlands (see Section 5.2.1). Restoring these areas allows carbon to be sequestered in the soil and in plant matter as it grows. Geological sequestration, on the other hand, involves injecting $CO_2$ into underground formations for permanent storage. The primary types of geological reservoirs are depleted oil and gas fields, unmineable coal seams, and deep saline formations. A potential dual benefit of geological sequestration in oil and gas fields is that the pressurized $CO_2$ displaces residual oil and gas, allowing more of the resource to be extracted. A similar technique utilizes $CO_2$ injection into unmineable coal seams to displace and recover coal bed methane. Another potential sequestration option involves injecting $CO_2$ into (otherwise unused) deep saline reservoirs. Deep saline reservoir injection has two important advantages — potential storage capacity in the U.S. is very large and many reservoirs are close to major point sources of $CO_2$.

Sequestration of $CO_2$ in the subsurface can be achieved through either structural mechanisms (i.e., physical trapping) or adsorption storage (i.e., chemical reaction). The ultimate goal of long-term, permanent storage of $CO_2$ is more likely achieved through the chemical adsorption of $CO_2$, and the Maryland Geological Survey (MGS) is engaged in research aimed at identifying reactions that would keep $CO_2$ permanently locked in geologic formations. These reactions include capillary attraction in the small fractures created for gas production, physical adsorption of $CO_2$ known to occur on the surface of rocks containing organic material, and chemical adsorption of $CO_2$ known to occur on the surface of some rocks and with some brines. Unfortunately the first two reactions are not reliable in the long term since they are reversible when subject to pressure swings such as may occur in seismic events. Thus the only ultimately secure $CO_2$ storage is that achieved with chemical adsorption. Within a candidate geologic formation, the most promising strategy appears to be the use of the first two reactions (capillary attraction and physical adsorption) to saturate the formation with $CO_2$ and thus foster chemical adsorption, which is expected to occur over a longer period of time.

One additional promising means of storing (and using) Maryland $CO_2$ may be carbon mineralization using fly ash from power plants that does not meet the appropriate chemical specifications for use in industry. This process is an emerging technology that involves reacting coal ash from power plants with $CO_2$ in the flue gas of coal-fired power plants to ultimately create a solid that can be transported and stored permanently. MGS is evaluating this process for potential applicability to Maryland $CO_2$ sources.

### *Beneficial Use of $CO_2$*

The increasing global concern over $CO_2$ emissions coupled with the high costs associated with $CO_2$ capture and transport has resulted in a renewed emphasis on large-scale $CO_2$ use rather than just sequestration. In response to its demonstrated effectiveness in enhanced oil and gas recovery, the acceptance of $CO_2$ as a commodity has been encouraged. Many studies suggest regional $CO_2$ use as the best means by which to offset the expense of capture and transport.

A North American project that has proven to be a successful end-to-end CCUS operation is the Weyburn-Midale $CO_2$ Project. This project, which began its initial assessment phase in 2000, involves capturing $CO_2$ from the lignite-fired Dakota Gasification Company synfuels production plant located in North Dakota. The $CO_2$ is transported via pipeline 205 miles and then injected into the Weyburn oilfield in Canada. The $CO_2$ is utilized to increase oil and gas extraction from Weyburn, which previously had declining production rates.

In the US, most proposed and existing CCUS projects involving enhanced oil recovery (EOR) are located in the southern and western states, where mature oil fields are prevalent. A leading company in this industry, Denbury, has found success in developing $CO_2$ reserves for EOR, and has completed pipelines that enable it to extend its $CO_2$ reserves to the southeast Texas oil fields. In 2012, Denbury began using and storing its first anthropogenic sources of $CO_2$, which are expected to reach 50 million cubic feet per day in late 2016.

DOE is also funding extensive research and ongoing projects related to CCUS, especially in EOR applications. These projects include new IGCC facilities, a new oxy-combustion power plant, and the retrofit of existing facilities with post-combustion capture technology. The captured $CO_2$ will be transported mainly for use in EOR applications, with the primary projects in the US being:

- *The Summit Power Group's TCEP Project, which will capture and inject up to 2 million metric tons of $CO_2$ per year from a new IGCC facility into the West Texas Permian Basin, which is scheduled for ground breaking in spring 2016. The project schedule is currently being re-evaluated based on funding changes that were made in May 2016.;*
- *The Southern Company Kemper Project, which will inject up to 1.8 million metric tons of $CO_2$ per year from a new IGCC facility into Denbury Resources' Heidelberg oil field in Mississippi, which is scheduled for start-up in late 2016.; and*
- *NRG Energy's Parish Project, which will inject up to 1.4 million metric tons of $CO_2$ per year from the existing W.A. Parish Generating Station into a nearby mature oil field, located in Thompsons, Texas, for EOR and ultimately permanent storage, which is expected to begin at the end of 2016.*

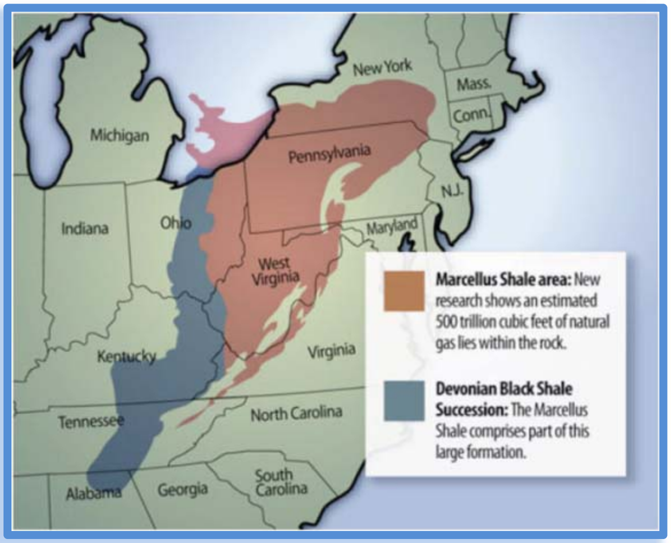
While the increasing trend in $CO_2$-EOR activity is promising, the single largest barrier to further expanded use of $CO_2$ in EOR is the lack of available, affordable $CO_2$ supplies. Of the total $CO_2$ currently used in EOR, about 25 percent (12 million metric tons) is anthropogenic in origin – i.e., produced by human activities, such as oil refining or fertilizer manufacturing. The rest is extracted from naturally occurring deposits. The $CO_2$ utilized in the oil recovery process is captured from the production well and recycled, so $CO_2$ emissions are negligible if injected $CO_2$ is stored in the reservoir when production is complete.

To date, there have been a limited number of global carbon capture, use, and storage (CCUS) projects that have transitioned from prototypes to successful full-scale ventures. One of the first of these projects is the Sleipner Project. Sleipner is a natural gas field located in the North Sea off the coast of Norway, and the gas produced from this field contains significant quantities of $CO_2$ that must be removed for the gas to be sold. Rather than discharge the $CO_2$ to the atmosphere and pay a significant tax on each ton of $CO_2$ released, the firm extracting the gas, Statoil, captures the $CO_2$ and injects it into a deep saline formation.

### *Applicability to Maryland*

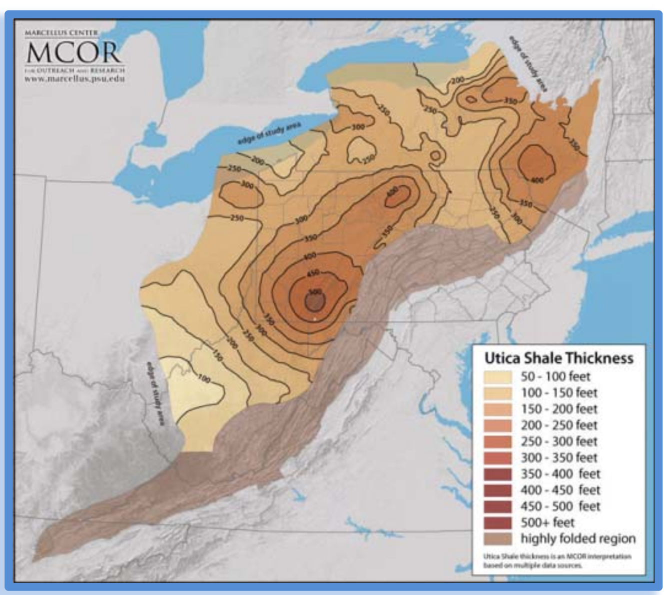
Long-term carbon storage potential is associated with deposits of so-called "unconventional" natural gas. Geologists have long known about the natural gas resources contained within these formations, but had not considered the gas economically recoverable until advances in drilling technology. Such resources exist in Western Maryland in the Marcellus Shale formation, a geologic feature in the Appalachian Range that stretches from West Virginia into central New York, and the Utica Shale formation (see Figures 5-9 and 5-10). In fact, there are many shale gas formations, including several others in the U.S., such as the Barnett and the Eagle Ford. Both the Marcellus and Utica organic shale formations provide the opportunity for permanent, irreversible $CO_2$ sequestration through adsorption in black, organic-rich shales – also called "sticky storage" – and this sorption of $CO_2$ may displace additional natural gas. Production wells, however, have not yet been drilled into the Marcellus Shale formation in Maryland. Pennsylvania, Ohio, and West Virginia have begun production of these formations.

### *Figure 5-9 Location of the Marcellus Shale Formation*




Source: "Marcellus Shale Safe Drilling Initiative Study"

### *Figure 5-10 Location of the Utica Shale Formation*




Source: "Marcellus Shale Safe Drilling Initiative Study"

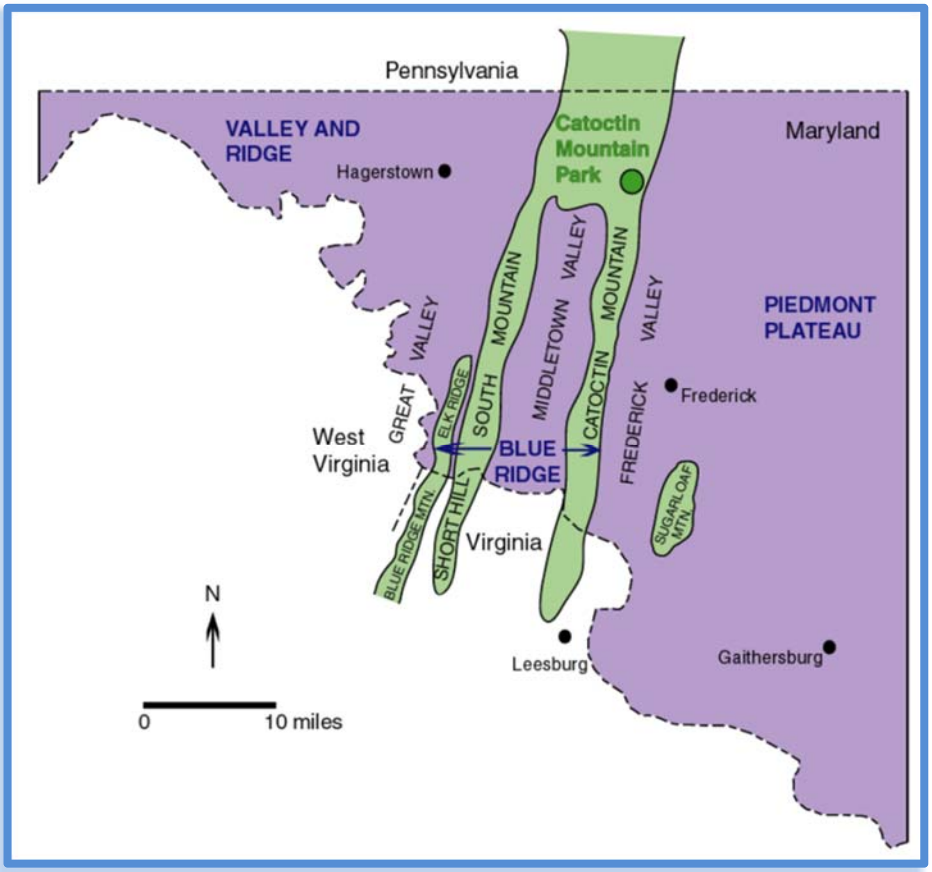
In December 2014, MDE and DNR issued a final report titled "Marcellus Shale Safe Drilling Initiative Study," which was undertaken following the Governor's issuance of an Executive Order to evaluate the impacts of shale gas production in Maryland. The final report provides that the risks associated with developing the Marcellus Shale can be managed to an acceptable level if the recommendations for rigorous best practices for all aspects of natural gas exploration and production are followed. in early 2017

Availability of vast reserves of economically viable, domestic unconventional gas, such as from the Marcellus, is changing the face of the electric generation fuel mix in the United States. Additional gas supply may spur power plants to switch from distillate oil to natural gas at existing combustion turbines, or install new high efficiency natural gas-fired combustion turbines to replace older coal- and oil-fired units. Whether through fuel switching or the development of new natural gas-fired units, the Maryland electric power industry has begun to experience a shift as natural gas resources displace coal resources throughout the PJM region. The U.S. Energy Information Administration predicts that by 2035, total domestic production of natural gas will grow by about 20 percent, with unconventional gas resources providing around 75 percent of total U.S. gas production.

To expand its involvement in regional sequestration opportunities, Maryland joined the Midwest Regional Carbon Sequestration Partnership (MRCSP) in 2004. The MRCSP was established by DOE to assess the technical potential, economic viability, and public acceptability of carbon sequestration within a nine-state region — Indiana, Kentucky, Maryland, Michigan, New York, New Jersey, Ohio, Pennsylvania, and West Virginia. The MGS represents Maryland in this Partnership, and DOE provides the funding for any $CO_2$ geological research done in Maryland. Through its Phase I and Phase II research, the MRCSP determined the estimated carbon sequestration capacity of black shales in the Appalachian Basin may range from 2.2 billion tons to 29.68 billion tons, respectively (2010), based on the assumed storage efficiencies of either saline aquifers (3 percent) or continuous coals (up to 40 percent). Phase III of the MRCSP work is currently underway and involves injecting one million mT of $CO_2$ over four years to assess potential storage capacity, validate computer models of subsurface geology, develop formation monitoring techniques, and to provide information to better understand similar rock formations throughout the region.

In addition to shales, basalt formations have also been identified as potentially effective $CO_2$ adsorption sites. Dense interior layers function to trap the injected $CO_2$. Laboratory studies show that within a matter of months, $CO_2$ chemically reacts with minerals in the basalt to begin forming calcium carbonate crystals. DOE estimates the US and portions of Canada have potential capacity in basalts to store as much as 5,700 years of $CO_2$. Figure 5-11 shows the location of the Catoctin Formation, comprised of a metabasalt breccia, which potentially could store $CO_2$ from Maryland's point sources.

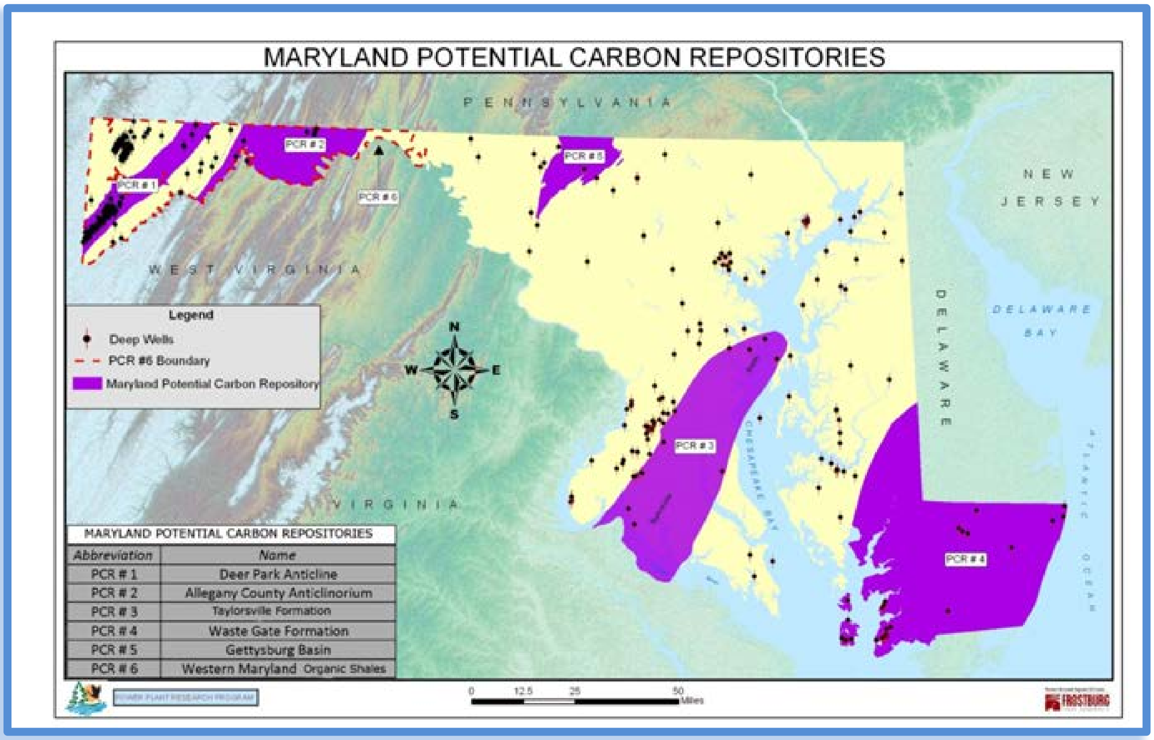
*Figure 5-11 Location of the Catoctin Formation, a regional basalt formation*




Source: "Marcellus Shale Safe Drilling Initiative Study"

PPRP has identified six additional potential carbon repositories in Maryland (see Figure 5-12). Some geologic and geochemical information is known about these sites from previous oil and gas or other drilling activities. The MGS is now collecting additional information on the $CO_2$ adsorption characteristics of these repositories to rank their potential to receive and permanently retain Maryland power plant $CO_2$. The Survey has a plan to study the adsorption storage of $CO_2$ in the exposed sedimentary basins of Maryland as a proxy for studying the $CO_2$ adsorption characteristics of the deeply buried sedimentary basins where the cost of obtaining core samples is very high. This may permit a reasonable estimate of the adsorption storage potential of the important Taylorsville Formation where large natural gas fired power plants will remain in use in the future and transportation of their $CO_2$ to the Appalachian Basin market may be an issue.

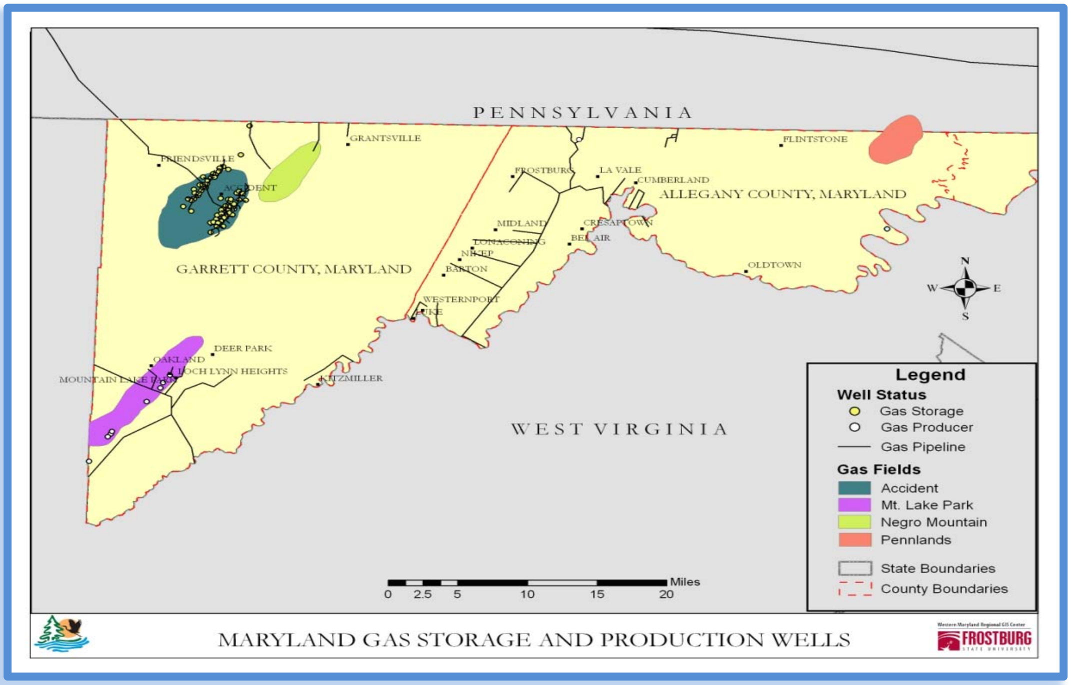
*Figure 5-12 Maryland Potential Carbon Repositories*




Source: "Marcellus Shale Safe Drilling Initiative Study"

In Maryland, the geology of the western portion of the state is particularly attractive for the possible storage and use of $CO_2$. Figure 5-13 shows the location of gas fields in Western Maryland that could potentially be used for enhanced recovery of gas and associated $CO_2$ storage, with the future potential economic use of the stored $CO_2$ in enhanced gas recovery. Maryland also has several coal beds in Western Maryland that could potentially be used for enhanced recovery of coalbed methane and associated $CO_2$ storage.

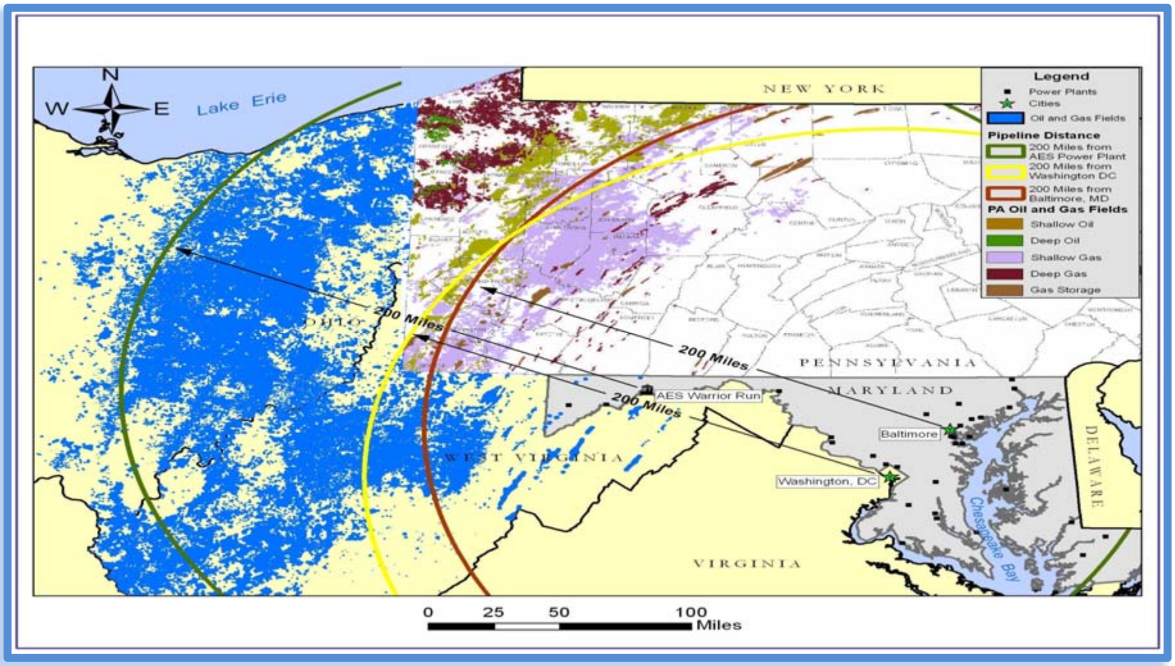
***Figure 5-13 Maryland Gas Storage and Production Wells***




Source: "Marcellus Shale Safe Drilling Initiative Study"

While Maryland is not an oil producing state and thus does not have EOR projects within its borders, potential exists for captured $CO_2$ to be transported elsewhere via pipeline for EOR projects. Precedent has been established for piping $CO_2$ across state lines, and as previously discussed, Maryland's current network of natural gas pipelines could hold potential for co-location of $CO_2$ pipelines in the state. Maryland could possibly consider pipelining its $CO_2$ to more regional EOR projects, such as those shown in Figure 5-14.

***Figure 5-14 Regional Oil and Gas Fields***




Source: "Marcellus Shale Safe Drilling Initiative Study"

If and when the $CO_2$ market in Maryland develops, several potential projects exist that could potentially utilize this $CO_2$. An example of a possible EOR project requiring $CO_2$ is the East Canton oil field located in Eastern Ohio, which the state of Ohio has identified as a potential $CO_2$ use candidate. According to the report, between 76 million and 279 million barrels of additional oil could be recovered from this oil field by $CO_2$ flooding. The field was discovered in 1947, has produced nearly 100 million barrels of oil, and still has more than 1 billion barrels of oil in place. It is Ohio's largest producing oil field. The $CO_2$ for this potential EOR project would need to come from anthropogenic sources such as steel mills, power plants, cement kilns, or landfills, according to the report. While a host of significant economic and environmental issues would warrant thorough investigation and evaluation prior to initiating a $CO_2$ pipeline project from Western Maryland power plants to Ohio, such a project could be worth considering if it were shown to be economically viable.

The risks associated with geological sequestration of $CO_2$ have been the subject of considerable study in the past decade and must be thoroughly evaluated when considering $CO_2$ storage. Multiple escape mechanisms exist and could be greatly aggravated by seismic activity too minor to be felt on the earth's surface. The significant risk of $CO_2$ escape underscores the importance of the permanent sequestration of $CO_2$ via adsorption.

Although the concept of $CO_2$ as a commodity has gained recognition, there are unresolved issues regarding CCUS projects. The issues of technology, infrastructure, and economics related to CCUS require continued research. Global policy issues involve the debate over CCUS as a worthwhile investment, and whether $CO_2$ used for economic gain, such as in EOR, would be considered eligible for carbon credits. Technological issues suggest the need for further study to ensure that carbon is permanently sequestered and that the potential for future leaks is minimized. Based on the premise that

Maryland can wait for a market to develop for Maryland-generated $CO_2$ to be sold to the EOR and EGR industries in the Appalachian Basin, PPRP $CO_2$ research is severely constrained. It is anticipated that fuel switching and other measures will greatly reduce $CO_2$ production in Maryland.

## *5.4 PPRP Demonstration Projects*

With 86 percent of the state's CCBs being beneficially used, Maryland is well above the national utilization rate of 45 percent, as reported by the American Coal Ash Association for 2014. PPRP has supported research and demonstration projects for more than 20 years regarding beneficial use of CCBs, particularly those applications that could use massive quantities of CCBs. A wide variety of bench-scale research projects and field-scale demonstration projects have been completed with significant focus being placed on uses of CCBs in underground mine reclamation, restoration of disturbed lands, and manufacturing.

### 5.4.1 Underground Mine Reclamation

A long history of coal mining in Western Maryland has left a legacy of environmental challenges including acid mine drainage (AMD) as well as land subsidence as aging mine tunnels weaken and collapse. Through demonstration projects such as the Winding Ridge Project and the Kempton Man Shaft project, PPRP demonstrated the feasibility of injecting grouts made from 100% CCBs into underground mines to reduce acid-producing reactions and to help restore natural ground water flow patterns.

Desktop research projects have characterized the broad extent of opportunities for such uses on a larger scale. PPRP sponsored a review of the Works Progress Administration (WPA) Maryland Mine Sealing Program of the 1930s that sought to mitigate AMD by sealing mine openings. The program was largely judged to be unsuccessful in mitigating AMD; however, the extent of the Mine Sealing Program and reasons for its failure to impact acid mine drainage were investigated as guidance for large-scale use of CCB grouts in mine applications. In addition, PPRP supported efforts of the Maryland Department of the Environment Abandoned Mine Lands Division (MDE AMLD) to address a mine blow out at the McDonald Mine that overwhelmed the doser treating its effluent (Figure 5-15).

***Figure 5-15 McDonald Mine Seep***


Photo on left shows the post-blow out mine discharge at the McDonald Mine. Photo on the right shows treatment system components added to help treat additional post-blowout discharge. (Cylindrical shape in background is the doser that was already present at the site.)

PPRP and MDE AMLD collaborated on investigations of how to bring the increased flow under control, manage the large volume of sediment being generated, and provide more effective treatment in the limited space available between the mine discharge and Georges Creek. Opportunities for CCB use in the form of grout and concrete were included in these investigations. PPRP further supported a benchtop weathering study of CCBs to demonstrate their stability in the presence of acidic waters typical of AMD.

## 5.4.2 Restoration of Disturbed Lands

Beyond historic mining practices, other factors may disrupt natural landscapes and flow patterns. Karst geology and the sinkholes associated with it can cause land subsidence and can severely damage buildings and infrastructure. Quarry activities can create artificial sinks for ground water that alter the natural direction of ground water flow and can exacerbate the development of solution channels that may already be present. CCB grouts have been shown to have sufficiently high strength and low permeability to help mitigate these problems when properly engineered and injected.

The Hoyes Run Project provided an excellent example of this use (Figure 5-16). Hoyes Run is a highly valued trout stream adjacent to the Key Stone Quarry in Garrett County, Maryland. During periods of low flow, its entire flow was lost to solution channels developed in a loss zone near the Quarry. Initial attempts to seal the channels using a conventional chemical grout were unsuccessful because these grouts expanded with such pressure that partings in the streambed increased causing even greater stream loss. A grout of fly ash and fine particle FBC material was developed to effectively fill the solution channels and seal the streambed without causing any problems so long as the channel entrances could be identified and isolated for grout injection. The grout proved to be highly effective at sealing the small openings and channels in the limestone bedrock. However, during a period of high rainfall and high flow rate in the stream, clay layers overlying the limestone bedrock were washed out and new areas of stream loss developed. Thus the project demonstrated the strength of the CCB grout seals, but also called attention to the need for thorough study and understanding of site specific geology in planning restoration projects.

***Figure 5-16 Hoyes Run Project***

**Photos During and Shortly After 2007 CCB-Grout Injection at Hoyes Run**. Stream flow was restored within hours of grout injection.

## 5.4.3 CCB Use in Industry and Manufacturing

PPRP has worked directly with industry partners to investigate the utility of CCBs in some specific products, such as pervious concrete (Figure 5-17). This material helps to protect surface water bodies by allowing storm water to infiltrate through pavement into underlying soil and ground water, rather than running off of traditional impervious pavements directly into storm sewers and surface water bodies.

***Figure 5-17 Pervious Concrete Test Cylinders Made with CCBs***

More broadly, PPRP has monitored and documented the rate at which CCBs are sold from power plants to industry, thus showing the “appetite” for these materials in industry. Although 86 percent of the CCBs generated in Maryland each year are being used without ever going to a disposal site, years of CCB disposal and filling operations in Maryland have left a large number of legacy CCB fill sites. By supporting research on the success of recovering and potentially beneficiating previously disposed CCBs (as at the R.Paul Smith CCB landfill, discussed in Section 4.6.4), the industry desire to make use of these materials may continue to be met, even if the generation of CCBs changes with changes in the power generation sector (i.e., decommissioning of coal fired power plants or switching from coal to natural gas as the preferred energy source). The use of previously landfilled ash has a secondary benefit of removing potentially leachable materials from the environment and converting them to stable, non-leachable monolithic materials.

## *5.5 Technology and Innovation*

As detailed in Chapter 2, historical methods of generation in Maryland have been mainly fossil fuel combustion-based, with some non-combustion methods, such as hydroelectric and nuclear generation. In recent years, however, there has been an emphasis within the State on the development of renewable energy sources (see Section 2.1.5 and Section 5.1).

Electricity in the United States is generally characterized by large centralized power stations (typically 300 MW to 3,000 MW) and is delivered to load centers and end-use customers by regional transmission and local distribution networks. Distributed generation (DG), however, provides an alternative to the traditional centralized power system. DG refers to small-scale energy generation (typically 1 kW to 10 MW) that is located close to the point of use. Home-based solar, wind, and geothermal installations are examples of DG that are gaining in popularity, as described in Section 2.1.3.

Technology advances and innovation lead to the increased use of efficient DG resources, including those fueled with renewable resources. Advances in transmission technologies and energy storage technologies, such as more efficient batteries and flywheels, will help improve the reliability of renewable energy sources. Finally, the smart grid concept, which embodies the idea of increasing the computerization of the electric grid, combined with the expectation of a growing fleet of plug-in electric vehicles (PEVs), are likely to have significant impacts on the electricity system.

### 5.5.1 Offshore Wind Energy

There are 13 countries with offshore wind power facilities—Denmark, Belgium, China, Germany, Finland, Ireland, Italy, Japan, Netherlands, Norway, South Korea, Sweden, and the United Kingdom. By June 2015, there was 8,990 MW of offshore wind installed capacity in these 13 countries. To date, no offshore wind facilities have been developed in United States waters. With Maryland's greatest wind energy potential located offshore, the possibility of developing a wind facility off the coast of Maryland has received growing attention in recent years.

The estimated capital costs of offshore wind vary widely depending on technical aspects of the specific project and the availability (or lack thereof) of parts through the supply chain. Additionally, because of the lack of U.S. experience, there is significant uncertainty surrounding the cost estimates. The DOE's National Renewable Energy Laboratory (NREL) estimates the installed capital costs for an offshore wind facility installed in 2014 at $5,925 per kW of capacity, which equates to installed costs of approximately $3 billion for a 500-MW facility. Comparatively, capital costs of land-based wind facilities are typically around $1,700 per kW—less than a third of the estimated installed cost of offshore wind.

There are several factors that contribute to the higher capital costs for offshore wind facilities. Performing work at sea is more complicated, and therefore more expensive, than performing work on land. Offshore wind turbines require more complex foundations and specialized installation vessels. Capital costs typically increase with greater water depths, and the developer may be required to purchase and install submarine transmission cables necessary to transmit the energy to shore. Capital costs for offshore wind facilities are also expected to increase when projects are sited farther from shore, because longer power cables would be required and project logistics become increasingly complex. Nevertheless, as offshore wind technology matures, prices are expected to decline. NREL projects that the capital costs of an offshore wind plant will range between $4,500/kW and $5,200/kW through 2020.

#### *Offshore Wind Energy Activities in Maryland*

***Maryland Offshore Wind Energy Act of 2013***

During the 2013 legislative session, the Maryland General Assembly passed, and Governor O'Malley signed, the Maryland Offshore Wind Energy Act of 2013 (Offshore Wind Act). The Offshore Wind Act creates a mechanism to incentivize the development of up to 500 MW of offshore wind capacity, at least ten nautical miles off of Maryland's coast. A project size of 200 MW would require the installation of an estimated 40 turbines off the coast of Ocean City. The Offshore Wind Act establishes a Maryland Offshore Wind Business Development Fund and Advisory Committee within the Maryland Energy Administration (MEA) to promote emerging businesses related to offshore wind and also establishes a Clean Energy Program Task Force.

The Offshore Wind Act creates a "carve-out" for energy derived from offshore wind within the State RPS. The carve-out requires that a specified portion of State electricity sales must come from offshore wind power facilities beginning in 2017 and for every following year, with the amount of offshore energy required in each year set by the PSC. The PSC would base the size of the carve-out on the projected annual creation of "offshore wind renewable energy credits" (ORECs) by qualified offshore wind projects, but not exceed 2.5 percent of total retail sales. The Offshore Wind Act establishes an application and review process for the PSC for proposed offshore wind projects and limits rate impacts to both residential and non-residential electric customers. The increase in the electric bills of residential customers owing to the offshore wind energy carve-out is limited to $1.50 per month; commercial customers are limited to a 1.5 percent bill increase.

Under Maryland's Offshore Wind Power Act, a "qualified offshore wind project" means a wind turbine electricity generation facility, including the associated transmission-related interconnection facilities and equipment, that:

- Is located on the outer continental shelf (OCS) of the Atlantic Ocean in an area that is designated for leasing by the U.S. Department of the Interior (DOI) after coordination and consultation with the State in accordance with the Energy Policy Act of 2005 and between ten and 30 miles off the coast of Maryland;
- Interconnects to the PJM grid at a point located on the Delmarva peninsula; and
- Is approved by the PSC, subject to specified requirements.

***Leasing in Federal Waters***

Under the Energy Policy Act of 2005, the DOI's Bureau of Ocean Energy Management (BOEM), formerly the Minerals Management Service, is the lead federal agency responsible for issuing leases in federal waters (greater than three nautical miles from shore) for ocean energy technologies. BOEM is responsible for issuing a lease on a competitive basis unless BOEM determines no competitive interest exists for such leases. In April 2010, BOEM established a Maryland/Federal Renewable Energy Task Force to provide input throughout the BOEM leasing process. The Task Force, comprised of officials from State and federal agencies as well as elected officials from Maryland's coastal communities, provided recommendations for siting offshore wind projects. In November 2010, BOEM accepted these recommendations, and issued a Request for Interest (RFI) for wind leases off Maryland's coast. An RFI is a formal invitation for submissions of interest in obtaining a commercial lease from BOEM, and it is the first major step in the leasing process under BOEM regulations. Eight offshore wind developers responded with development proposals and 12 stakeholders submitted comments. Based on the responses to the RFI, BOEM made a determination of competitive interest for a commercial lease off of Maryland's coastline.

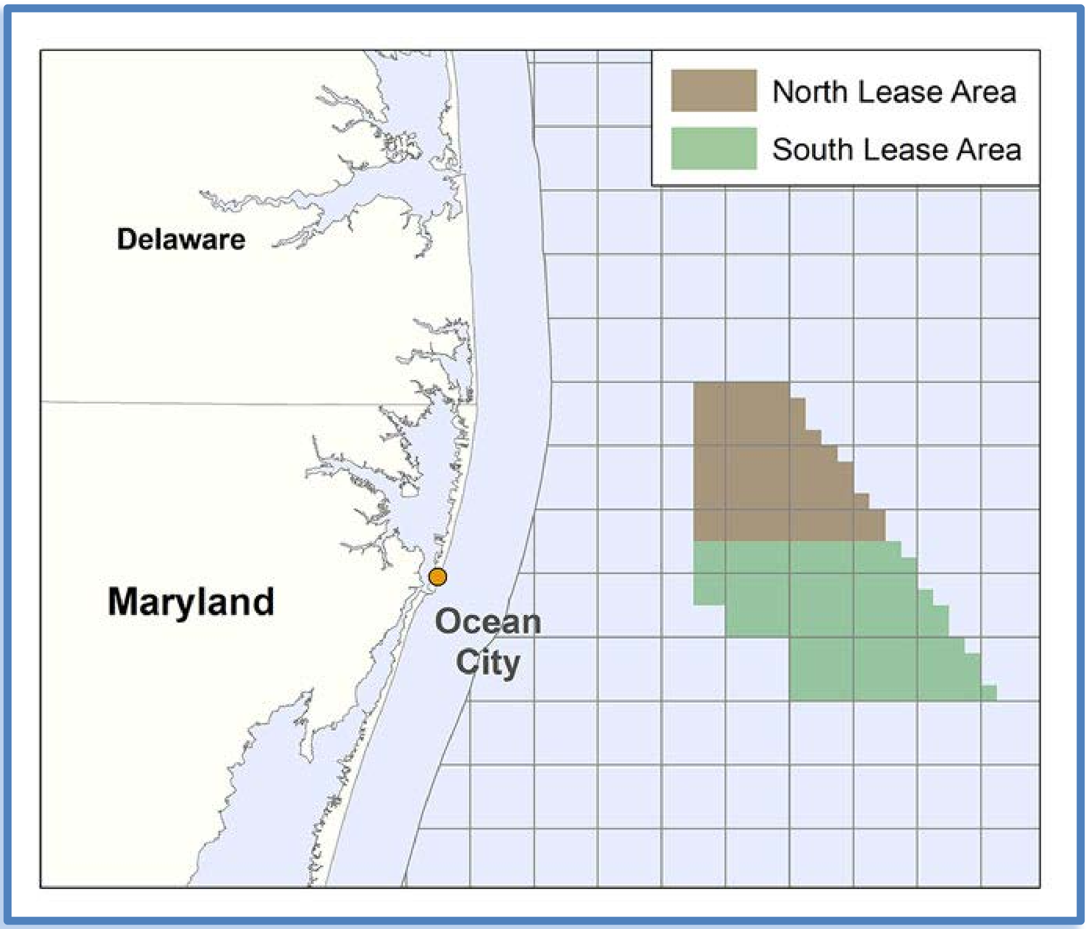
The next major step in the competitive leasing process for commercial renewable energy leases on the OCS is the publication of a Call for Information and Nominations (Call) in the Federal Register. Maryland's Call was published in February 2012, after BOEM released a regional environmental assessment (including the coastal areas of Delaware, Maryland, New Jersey, and Virginia) for siting activities on the OCS. Individual projects would require a more in-depth environmental analysis (likely an Environmental Impact Statement) before construction may begin on the OCS. The Call was intended to inform the public of the area under consideration for leasing; solicit comments from all interested parties on areas or subjects that should receive special attention or analysis; invite potential bidders to indicate areas and levels of interest; and invite public input regarding possible advantages and disadvantages of potential leasing and development to the region and the nation. The comment period for the Call closed on March 19, 2012, and BOEM received six nominations of interest and six comments.

In 2013, BOEM developed a Proposed Sale Notice (PSN) which describes proposed terms and conditions for a lease sale for two commercial wind energy leases in the Maryland Wind Energy Area (WEA). After publication of the PSN in the Federal Register on December 18, 2013 and the closing of a 60-day public comment period, BOEM published a Final Sale Notice. The Final Sale Notice stated that BOEM would hold a commercial lease sale (i.e., auction) on August 19, 2014 for the Maryland offshore WEA. The WEA covers approximately 80,000 acres, and its western edge is located about ten nautical miles from the Ocean City coastline, as shown in Figure 5-18. It was auctioned as two leases, referred to as the North Lease Area (32,737 acres) and the South Lease Area (46,970 acres). After the lease sale was held, the final step in the competitive leasing process was for BOEM to select the winning bidders and issue the commercial leases.

In August 2014, BOEM selected U.S. Wind, a subsidiary of the Italian company, Renexia, as the winner of BOEM's competitive lease auction. Thanks to the offshore wind carve-out in the Maryland RPS, the auction value was the highest of any of the offshore wind leasing auctions that the BOEM had held to that date and accounted for almost 60 percent of the total revenue the BOEM has realized from these auctions. Although the lease area could support nearly 1,000 MW of offshore wind capacity, U.S. Wind is considering a 500 MW project to minimize costs and to keep the project in areas with water depths of no more than 85 feet. In February 2016, U.S. Wind applied for ORECs from the Maryland PSC, triggering a process whereby other companies can apply to the PSC as well. Should the PSC approve U.S. Wind's application, the company hopes to begin construction on an initial 250 MW phase in 2018 and begin operation in 2020. The company currently plans to develop two interconnection points, each at 250 MW, with one located in Maryland and the second located in Delaware.

The PSC received a second application for ORECs, submitted by Skipjack Offshore Wind, a subsidiary of Deepwater Wind Holdings. In November 2016, the PSC announced that it had determined both applications are administratively complete and met minimum threshold criteria. The PSC initiated a docketed proceeding, Case No. 9431, to conduct a multi-part review to evaluate and compare the two applications. The review process calls for the PSC to make a decision on the applications within approximately six months.

*Figure 5-18 Map of the Maryland Wind Energy Area*




Source: U.S. Department of the Interior, Bureau of Ocean Energy Management, "Renewable Energy Programs, Maryland Activities," http://www.boem.gov/Maryland.

### *Permitting Issues*

Offshore wind power is new to the United States energy industry, and the regulatory and institutional structures for offshore wind energy are still emerging. Offshore wind energy facilities will require regulatory approval from both federal and state agencies, and in many cases local agencies as well.

Prior to construction, the developer's project must undergo an environmental and permitting review process. This process typically includes the following federal government reviews and approvals:

- A National Environmental Policy Act (NEPA) review, which calls for an Environmental Assessment (EA) and potentially a full Environmental Impact Statement (EIS).
- Demonstration of compliance with state coastal management programs as administered under the Coastal Zone Management Act.

## Exposure to Severe Weather

Nor'easters and hurricanes pose a significant risk to wind turbines off of the Northeast Atlantic Coast. Further, anticipated global temperature increases and elevated sea levels associated with climate change may impact the intensity of these storms.

A group of Carnegie Mellon University researchers found that turbines built along the Atlantic Coast may be vulnerable to hurricane-force extreme winds. The team found that the maximum wind speeds in severe storms can exceed the design limits of currently available wind turbines. In 2003, for example, seven wind turbines in Okinawa, Japan, were destroyed by typhoon Maemi and several turbines in China were damaged by typhoon Dujuan. The research team emphasized that developing reasonable safety measures, including improved design requirements and backup power for the motors that allow turbines to track the wind direction could mitigate serious hurricane damage.

Despite such findings, industry experts maintain that wind turbines off the coast of New Jersey or New York would have survived Superstorm Sandy in October 2012. Most offshore wind turbines are designed to withstand Category 3 hurricane conditions, which exceed the conditions imposed by Sandy. Additionally, the offshore wind industry is anticipating and preparing for the type of extreme weather challenges these facilities will be subject to during their 20+ year lifespans. Whether a particular turbine design can handle the load from extreme weather events in the Northeast remains unknown, and will be subject to further research.

- U.S. Army Corps of Engineers (USACE) permit for construction of any structures that might obstruct navigable waterways of the United States, as required by Section 10 of the Rivers and Harbors Act.
- USACE permit for dredging and backfilling that would be required for project construction, as required under sections 401 and 404 of the Clean Water Act.
- FERC approval for connection at the transmission interface.
- Notice to the Federal Aviation Administration (FAA) of any construction exceeding 200 feet in height.
- U.S. Coast Guard permission to establish aids to maritime navigation.
- BOEM approval of the Site Assessment Plan, the Construction and Operations Plan, and the Decommissioning Plan.

In addition to federal approval, it will be necessary for developers to obtain state and local regulatory approval. For example, a CPCN from the Maryland PSC would be necessary to transmit electricity to the existing electrical grid.

### *Offshore Wind Turbines Research and Development*

Over 60 percent of offshore wind resources in the U.S. are in deep waters, i.e., the water is so deep that the usual techniques of fixing large steel piles or lattice structures to the ocean floor are not possible. Utilizing floating foundations for offshore wind turbines could access these offshore wind resource areas, and could also lead to improved offshore wind industry standardization as the floating platforms are not as sensitive to differences in seabed conditions or water depth. That, in turn, translates into greater efficiencies in manufacturing and assembling offshore wind turbines and could lead to an offshore wind project being constructed on land and towed out to sea. Additionally, floating foundations result in reduced environmental impacts as pilings do not have to be installed and the ocean seabed is not disturbed.

Floating foundations will need to meet new design criteria encompassing weight and buoyance requirements and the heaving and pitching from ocean waves. The technology is at an early stage and much more design and testing needs to be completed before floating foundations are commercially feasible. Three types of floating wind concepts are under investigation: Ballast Stabilized, Mooring Line Stabilized and Buoyance Stabilized. Ballast Stabilized foundations (also known as spar buoy) rely on mooring lines with anchors that drag in the water. Mooring Line Stabilized (also known as tension leg platform) foundations uses suction pile anchors— essentially, upturned buckets that are embedded in marine sediment through negative pressure. Buoyance Stabilized (also known as semi-submersible) foundations are similar to Ballast Stabilized foundations except that they are semi-submersible and are on a floating platform. Figure 5-19 depicts these concepts.

***Figure 5-19 Floating Wind Turbine Concepts***


Source: National Renewable Energy Laboratory, artist Josh Bauer.

Several floating wind turbine prototypes are being tested around the world. Statoil’s Hywind test turbine was installed in 2009 off the coast of Norway and consists of a 2.3-MW wind turbine in about 700 feet of water. Principle Power has a 2-MW semi-submersible wind turbine, known as WindFloat, off the coast of Portugal that has been in the testing phase since 2011. The DOE provided $12 million to the University of Maine which resulted in a wind turbine installed on a semi-submersible platform in 2013. DOE also is funding a five-turbine, 25-MW offshore wind project to be installed off the coast of Oregon by Principle Power using its WindFloat technology. The project will not progress, though, until Principle Power finds a buyer for its generation.

## Block Island Offshore Wind

In December 2017, Block Island Wind Farm became America's first operational offshore wind farm. Deepwater Wind developed the 5-turbine 30 MW project approximately 3 miles from Block Island, which is off the coast of Rhode Island. Prior to the project, Block Island was fueled by a small diesel power plant and not connected to Rhode Island's mainland power. The offshore wind project resulted in Block Island being connected to the New England power grid and the closure of the island's diesel power plant.

*Environmental and Socioeconomic Risks*

Wind turbines can provide environmental benefits through the reduction of GHG emissions and conservation of water resources. However, as with all energy sources, there are environmental and socioeconomic risks associated with offshore wind energy. Studies suggest that the potential risks associated with offshore wind projects are typically site-specific. Research at European-installed projects and U.S. baseline studies are building the knowledge base and helping to inform decision-makers and the public. Outlined below are some of the primary stakeholder concerns regarding offshore wind power facilities:

- **Marine species populations:** Site-specific research is necessary to gain a better understanding of the potential impacts to populations of marine species including fishes, marine mammals and benthic organisms. European studies conducted to date suggest that the impacts of offshore wind facilities on marine populations are minimal, but U.S. studies may be required to replicate these results and address mitigation of any harmful effects. Offshore wind turbines can also act as artificial reefs, resulting in an increase in shellfish and the fish and marine animals that consume them.
- **Avian and bat populations:** Concerns exist regarding bird and bat mortality due to collisions with turbines; however, European studies suggest that birds are able to adapt to the turbines and avoid collisions. Some studies found a sharp decline in some bird species (Common Eiders and Black Scoters) but an increase in seagulls and cormorants. Another concern regarding avian populations is the possible fragmentation of their ecological habitat network (e.g., migration pathways, breeding, and feeding areas). Bats are known to traverse the offshore environment during migration, but the level of risk from offshore wind turbines is unknown.
- **Visual effects/property values:** Extensive studies to estimate the change in property values as a result of the presence of offshore wind turbines have not been conducted for coastal communities in the United States. Studies conducted for land-based wind projects, however, show minimal to no impact on real estate prices and property values as a result of the presence of wind turbines.
- **Tourism:** Coastal communities that are dependent on beach vacationers and the resulting local revenues and tax base have expressed concerns about the presence of offshore turbines, however, the evidence is ambiguous. Denmark currently attracts tourists with "Energytours" of offshore wind facilities.

- **Marine safety:** The possibility of a ship colliding with a turbine poses a potentially significant risk to the marine environment from fuel leaks from a disabled ship or to human safety should the turbine collapse. Measures will need to be taken to prevent collisions (e.g., navigation exclusion zones, distance requirements for routes, mapping on navigation charts, warning lights, etc.), however, a risk assessment for the Horns Rev II wind facility located off the coast of Denmark concluded that the likelihood of a ship-to-ship collision is “significantly higher” than the probability of a vessel colliding with a wind turbine. The U.S. Coast Guard created the Atlantic Coast Port Access Route Study (ACPARS) to study the impact of alternative energy facilities, including offshore wind, on shipping lanes and vessel traffic. The ACPARS issued an interim report in 2012 which stated that offshore projects would disrupt vessel traffic, increase the density of vessel traffic and raise the risk of collisions that could lead to the loss of property, loss of life, and environmental damage. The final report, released in February 2016, included (1) recommended marine planning guidelines; (2) determination of the appropriate width of navigation routes for alongshore towing operations near offshore wind turbines; (3) recommendations to modify designated wind energy development areas to increase boating safety.
- **Noise:** Construction of offshore wind turbines can result in high amounts of noise that, absent mitigation, could contribute to marine species avoiding the area and can result in tissue damage and even higher mortality rates for fish. Noise from the wind turbines is not thought to be of particular concern other than for Baleen whales, whose hearing is assumed to include low frequency sounds, and Right whales, who may respond to noise from wind turbines at close range.

## 5.5.2 Innovations in Transmission Technologies

New emerging transmission technologies are being developed to endure higher electrical and mechanical stresses and provide greater power transfer capacity and flexibility. Currently available technologies are already able to provide twice the capacity of similar traditional equipment with half the energy losses. Minimizing transmission losses effectively reduces energy demand and increases system efficiency.

### *High-Voltage Transmission Line Technologies*

Electricity can be transmitted several ways and at various voltages. The majority of current bulk power transmission systems in the U.S. consists of overhead AC transmission lines that are generally rated at 230 kV or higher. High-voltage direct current lines (HVDC) comprise only about 2 percent of the total installed high-voltage transmission line mileage (see Section 2.5.2). These direct current systems have been used mainly for large scale one-way bulk power transfers, such as undersea cables, or to transmit power over long distances. HVDC systems are capable of carrying significantly more power over longer distances with fewer losses than traditional AC systems. Ultra-HVDC systems are being installed outside the U.S. in overhead configurations that operate at 800 kV and can carry 6,000 MW of electricity.

HVDC transmission lines are especially effective for transmitting power from remote and renewable generation facilities like offshore wind, solar, and hydro. Several HVDC projects for renewable power transmission are currently planned or under construction in the US. In January 2016, Vermont's Public Service Board approved the New England Clean Power Link Transmission Line. This HVDC line will carry Canadian-generated hydro and wind power to the Northeastern US. The Clean Power Link has a 1,000 MW capacity and will run 150 miles from the US-Canadian border to Ludlow, Vermont. Another HVDC project of note is the TransWest Express Transmission Project. This project will carry renewable energy from Wyoming to the Southwestern US, and has been under development since 2005. ,

The technology with perhaps the greatest potential for future transmission grid improvements is high-temperature superconductors (HTS), which will typically be designed for underground installations. Advances in materials sciences are steadily increasing the temperature requirements for superconductivity, which function only in extreme cold. These HTS can potentially carry up to 100 times more power with few, if any, line losses as there is no electrical resistance in superconducting wires.

A nearly half-mile 138 kV HTS cable was energized in 2008 as part of the Long Island Power Authority grid. The current in the Long Island cable is carried through HTS wires, which exhibit zero resistance when cooled to about -321°F with liquid nitrogen. Several smaller scale demonstration projects are in progress worldwide, including the Hydra project in New York City, which is funded in part by the U.S. Department of Homeland Security.

### *Electricity Storage Technologies*

Electricity storage technologies might serve to support intermittent renewable resources such as wind and solar. Electricity storage devices currently in use include pumped hydroelectric power, compressed air facilities, batteries, and flywheels.

Pumped hydro is the most widespread energy storage system in use today. With an efficiency rate of more than 80 percent, pumped storage provides for approximately 20 GW of energy storage in the United States. Water is pumped into an upper reservoir when electricity prices are low, generally during night-time off-peak periods, then used to generate electricity for sale to the grid during peak hours. The Muddy Run pumped storage facility on the Susquehanna River in Pennsylvania has been in operation since 1966 and has a capacity of 1,070 MW.

Compressed air energy storage (CAES) makes use of natural and manmade (abandoned gas and oil wells) caverns to store compressed air and recover it for use in a turbine. Excess and inexpensive electricity is used to compress and pump high pressure air into an underground cavern. When electricity is needed, the air is released, mixed with natural gas, and combusted via a turbine to generate electricity.

Lithium-ion batteries and sodium sulfur batteries are already being used to provide 15 to 60 minutes of energy storage as regulation service. In 2011, AES began operation of its Laurel Mountain facility, which provides 32 MW of lithium-ion battery energy storage for a 98 MW windpower facility in West Virginia. AES plans to assemble a similar, much larger 400 MW facility for the Long Island Power Authority (LIPA) in New York. Some energy companies are also testing the use of batteries for grid management and energy storage.

A flow battery is a type of battery that uses liquid chemicals to store energy. Total energy storage is limited only by the size of tank used to hold the liquid. These systems are being targeted for peak shaving and utility-scale storage of solar and wind power. Prototype flow battery demonstration systems have been deployed throughout the world. The U.S. Department of Energy announced in April 2013 a breakthrough in flow batteries that utilizes a less expensive design with increased performance. UniEnergy Technologies has developed the largest capacity flow battery in North America and Europe; it entered service in June 2015. The 1 MW and 4 MWh vanadium-redox battery is located near Pullman, Washington, and is owned and operated by Avista Utilities.

Flywheel systems utilize large rotating masses and are a good fit for providing regulation services. This technology can be used as a short-term buffer to smooth local output fluctuations from a wind facility or PV array. Flywheels are commercially available for development as "regulation power plants" providing up to 20 MW of regulation capacity. A flywheel storage regulation power plant has been shown to be capable of providing full power within four seconds of receiving a control signal.

Rail cars are also becoming a viable alternative for energy storage. In 2014, the Southeastern Pennsylvania Transportation Authority (SEPTA) piloted a battery storage network program that captures and stores energy from braking subway cars. Constellation Energy (a subsidiary of Exelon) will partner with Viridian Energy to expand this pilot program to a 10 MW battery storage network at seven SEPTA stations in 2016. Similarly, a company called ARES recently developed a railcar test-system as an alternative to hydro-pumped storage in Southern California. The storage system moves weighted rail cars uphill when receiving excess energy from wind and solar generation, and releases the cars back down the hill to generate additional power during lulls in solar and wind production. ARES plans to build a 50 MW commercial-scale rail car storage system in Nevada with operations targeted for 2019.

In addition to traditional storage devices, the electricity grid itself can be considered a mechanism for storing electricity. For example, a home powered by a solar PV installation may ship (sell) excess electricity generated to the grid during daylight hours and utilize (buy) electricity from the grid during evening hours and overnight.

### 5.5.3 Smart Grid and Cybersecurity

Smart grid proponents believe that electric infrastructure will evolve over the next few decades into a highly automated and interconnected network similar to the internet. The smart grid involves a network of two-way communications connecting electric meters and "smart" devices containing microprocessor or computer technology to transformers and centralized electric grid operations centers. This two-way communication enables grid operators to better respond to moment-to-moment variations in the electric system through real-time balancing of generation and electric delivery. The desire to make the grid smarter, safer, more reliable, and more cost-effective is driving the growth of smart grid technologies in the U.S. The smart grid of the future will be largely automated and self-correcting, efficiently balancing the needs of energy suppliers and users, and largely self-balancing to ensure reliability in real-time.

#### *Advanced Metering Infrastructure (AMI) Initiatives*

At the heart of a "smarter" electric grid lies the deployment of advanced technology at end-user locations. On the metering and communications front, these technologies are referred to as Advanced Metering Infrastructure, or "AMI." AMI has multiple benefits: utilities can "see" electrical outages based on clusters of unresponsive meters, costs for all parties are lowered as meters indicate (either directly or implicitly) the need for maintenance, and the meters themselves can be read remotely via wireless communications. However, the greatest potential benefit from AMI deployment comes from the new rate structures they enable. AMI provides the necessary technology for the dissemination of high-resolution (≤ 1 hour) prices to customers, who can then make decisions to curtail or defer electricity usage based on the prices and their personal preferences. These dynamic rates are expected to lower energy and capacity prices as customers shift energy use away from typical peaks to save money.

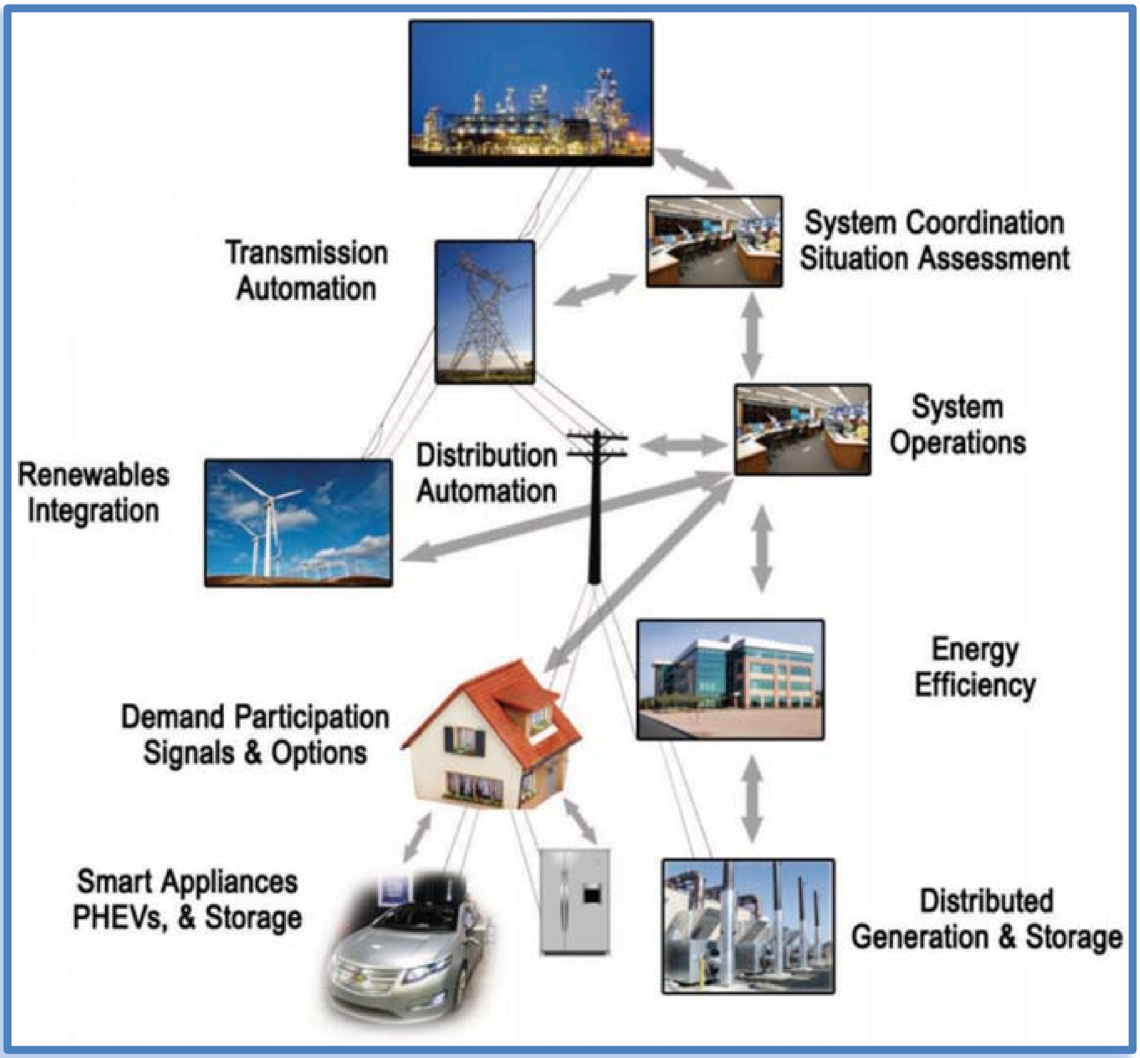
As of this writing, BGE, DPL, and Pepco have completed the installation of AMI meters in their respective service territories, and SMECO is in the process of implementing AMI. For customers who wish to opt-out of receiving the AMI meter, the PSC has established opt-out fees that vary by service territory. Until the AMI projects are proven cost-effective, each utility must defer incremental costs related to AMI in a regulatory asset. In November 2015, BGE filed a rate case in which it requested to transition the regulatory asset into base rates. In total, the BGE AMI project cost approximately $502 million, with $158 million of that cost offset by a DOE grant for smart meter deployment. BGE stated that its AMI project, which included dynamic pricing, would save customers $2.50 for every dollar invested. The savings comes from operational benefits, such as fewer truck rolls and market benefits from dynamic pricing events (see Section 5.1.2 for more information on dynamic pricing programs). DPL, Pepco, and SMECO have not filed to include AMI costs in rate base. At this time, PE has not filed plans to install AMI meters.

### *Smart Grid Integration*

AMI and smart grid are often used synonymously. However, while AMI is a necessary precondition for the realization of full smart grid benefits, the concept of smart grid extends far beyond remote and dynamic meter communications. A smart grid integrates advanced technologies and communication by consumer-based resources, distribution companies, and transmission systems (see Figure 5-20). Better integration of these traditional elements of the electrical system may one day serve to reduce utility and power plant operations and maintenance and capital costs by improving load factors, lowering system losses, and improving outage management performance.

On the consumer side, the smart grid will provide information, control, and options that enable consumers to engage in new energy markets and allow for better home energy management. For example, intelligent control systems reading temperatures, weather forecasts, and real-time power system statistics, coupled with a high degree of automation for end-user electrical control (e.g., price-responsive thermostats, water heaters, lighting), can dynamically match customer price points with electrical system needs.

*Figure 5-20 Smart Grid Integration*




## *Cybersecurity*

The increasingly digital and interconnected nature of the nation's electrical grid exposes these crucial systems to the threat of infiltration and attack. Addressing cybersecurity is critical to enhancing the security and reliability of the nation's electric grid. A resilient electric grid is a complex and critical component of the nation's infrastructure that is required in order to deliver essential services.

For the past several decades, a significant portion of generation dispatch has become automated or been outfitted for remote control using Supervisory Control and Data Acquisition (SCADA) systems. Through the SCADA infrastructure, system operators communicate instructions from a central control facility to the generating units via automated generator control (AGC). Owing to this level of automation, the grid has always faced some threat from cyber-attacks. In particular, the protection of nuclear plants and large hydroelectric dams, and the potential large-scale consequences of their sabotage, has always been one of the key cornerstones of generating system infrastructure protection.

However, the extension of grid intelligence beyond SCADA and AGC to the more robust network and ultimately more distributed smart grid increases these risks.

In February 2013, President Obama issued an Executive Order on "Improving Critical Infrastructure Cybersecurity'" in response to failed attempts at passing federal cybersecurity legislation in Congress. The Executive Order encourages information sharing between the federal government and private industry and puts voluntary cybersecurity standards in place for critical infrastructure. Two years later, the President issued an Executive Order on "Promoting Private Sector Cybersecurity Information Sharing" in an effort to allow private companies and the federal government to work together when responding to threats. Further strengthening those two efforts, in February 2016, the President directed his administration to implement a Cybersecurity National Action Plan (CNAP) to enhance cybersecurity awareness and projections through near-term actions and long-term strategy. The CNAP will benefit grid security through the establishment of a National Center for Cybersecurity Resilience, in which companies and sector-wide organizations can test system securities, such as replicating a cyber-attack on the electric grid.

Over the last several years, the FERC has adopted cybersecurity standards under the Critical Infrastructure Protection (CIP) standards. In early 2016, FERC Order 822 revised seven of NERC's CIP standards. In addition, it requires the NERC to develop modifications to: (1) protect transient electronic devices used at low-impact bulk electric system cyber systems; (2) protect communication network components between control centers; and (3) refine the definition for low-impact external routable connectivity.

In addition to these legislative and regulatory activities, most observers recognize that grid operators and equipment manufacturers play a pivotal role in making systems less vulnerable by adopting good security practices and building security into their products and systems. This topic will continue to be relevant to electricity reliability in Maryland and nationwide as smart grid technology is adopted throughout the nation.

The PSC recognized the risks associated with AMI meters, stating that "as our distribution systems become more automated, and private customer data is increasingly being used in electronic format, we are keenly aware of the risks and rewards related to smart meter infrastructure build-out in Maryland." The PSC approved BGE's, DPL's, and Pepco's respective Cybersecurity Plans filed in October 2012. In addition, the PSC approved a Cyber-security Reporting Plan, which establishes the protocols for reporting incidents and providing annual updates to the PSC and other parties, such as the Governor's office and the MEA. Additionally, the three utilities fund the PSC's access to a cyber-security consulting firm which serves at the discretion of the PSC. The firm provides independent advice to the PSC regarding the process and sufficiency of the AMI-related cyber-security.

### 5.5.4 Electrification

The United States is going through an electric renaissance as the country's generation portfolio shifts from coal plants to renewable resources. These types of changes, along with changes to how transportation is powered and how energy is supplied, are termed "electrification." Electrification is the production of an electrical charge and involves changing from one power source to another. Renewable energy, mentioned in Chapters 2.1.5 and 5.5.1, qualifies as electrification. In addition to the sources previously discussed, this Chapter will discuss the electrification of vehicles, energy storage, and microgrids.

### *Plug-In Electric Vehicles*

Over the next two decades, it is expected that increasing electrification of the transportation sector in the form of plug-in electric vehicles (PEVs) will have a significant effect on the electricity system. PEVs come in three major types:

- Hybrid Electric Vehicles (HEVs) have a small on-board electric motor and battery that is recharged by vehicle operation, generally while braking. The batteries in HEVs cannot be recharged externally. Conventional HEVs have been on sale for over 10 years and are fundamentally different from the other types of electric vehicles.
- A Plug-in Hybrid Electric Vehicle (PHEV) has an internal combustion engine that can take over when the battery runs down. PHEVs have larger batteries than traditional hybrid vehicles, allowing them to be operated in all-electric driving mode for short distances, while the internal combustion engine effectively provides for an unlimited driving range. Toyota makes a PHEV Prius.
- Battery Electric Vehicles (BEVs) have a battery that can be recharged through an external connection to an electricity source and runs only on the batteries. An example of a BEV is the Nissan Leaf. An Extended-Range Electric Vehicle (ER-EV) is essentially a BEV with a small internal combustion engine, which acts only as a generator to recharge the batteries for longer range. The engine does not power the wheels. An example of an ER-EV is the Chevrolet Volt.

Regardless of whether a consumer owns a BEV, PHEV, or ER-EV, driving habits are expected to remain unchanged, and therefore, battery charging requirements will be similar. The versatility offered by PHEV and ER-EV back-up engines is especially appealing to consumers concerned about the range limitations of all-electric vehicles, making consumer adoption of PHEVs and ER-EVs in significant numbers more likely. Additionally, once "range anxiety," as it has been termed, is no longer an issue due to the combustion engine back-up, consumers will not need to worry about charging their vehicles while away from home. Therefore, the majority of PEV charging will likely be on residential-level electric distribution systems.

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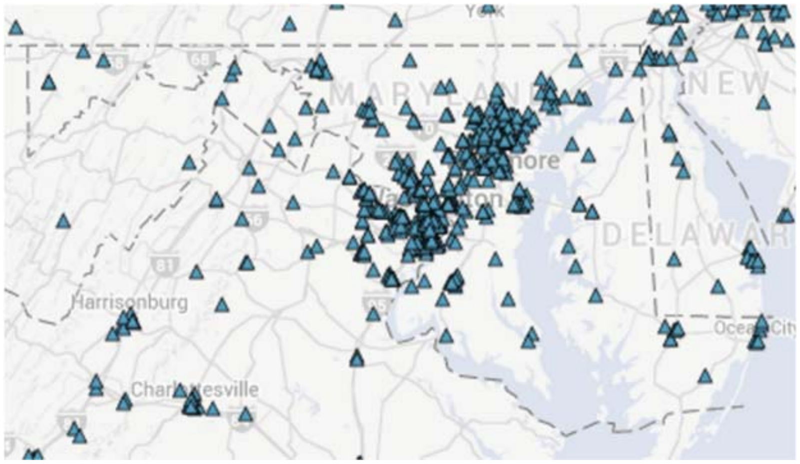
**Electric Vehicle Charging Stations in Maryland**

As of April 2016, there were 403 public electric vehicle charging stations throughout Maryland that offered a total of 904 charging outlets. The build-out of charging stations throughout the State has been assisted by the Maryland Energy Administration's Electric Vehicle Infrastructure Program's Fast Charger grants and the Maryland Transportation Authority's (MTA) inclusion of charging stations at Maryland rail stations such as MARC, Metro, and light rail.

## Map of Public Electric Vehicle Charging Stations




Source for graphic: Maryland EV. http://www.afdc.energy.gov/fuels/electricity_locations.html

In order to assess the environmental benefits of PEVs, it is necessary to compare emissions from electric vehicles to emissions from an internal combustion engine (ICE). When running on electricity, PEVs do not emit any pollutants through the tailpipe exhaust; however, there are emissions associated with the generation of electricity used to power the vehicle, unless of course, all the electricity comes from a clean resource, such as solar or wind.

Nonetheless, according to data from the EPA's Emissions & Generation Resource Integrated Database (eGRID), electricity generation in the region that encompasses Maryland, defined as the ReliabilityFirst Corporation, produces an average of about 516 grams/kWh of carbon dioxide equivalent ($CO_2e$). Therefore, assuming a BEV is driven 12,000 miles per year, which approximates the national average, its expected contribution to annual emissions in Maryland equates to about 2.10 metric tons of $CO_2e$.

According to an estimate from EPA, the average internal combustion engine passenger vehicle produces approximately 5.2 metric tons $CO_2$ on an annual basis. In addition to $CO_2$, automobiles produce methane and $N_2O$ from the tailpipe, as well as HFC emissions from leaking air conditioners. $CO_2$ accounts for about 95 percent of vehicle emissions, while the other three gases make up about 5 percent. When accounting for these additional GHGs, the EPA estimates that the average passenger vehicle produces about 5.5 metric tons $CO_2e$ per year—more than double the level of emissions associated with a BEV in Maryland.

Integrating PEV charging into the electric grid comes with both costs and benefits. As PEV charging will be mainly conducted at the distribution level, this is where impacts will first be seen. From a kW standpoint, a PEV represents approximately half the load of a typical home. However, charging can be managed and shifted to night-time hours when overall loads are lowest (i.e., during off-peak hours), especially with the increasing deployment of smart grid components and two-way communications. Additionally, AMI-enabled dynamic rate structures in Maryland can provide economic incentives for PEV owners to charge their vehicles during non-peak hours. Such incentives could allow a significant level of PEVs to charge simultaneously without requiring any upgrades to the existing generation and transmission systems.

Transmission system impacts will likely be minor until PEV penetration reaches a relatively high level (25 million PEVs in PJM would be about 45 percent of the total vehicle fleet). Transmission and generation are constructed to meet peak-level demands, and therefore, during non-peak periods, considerable amounts of transmission and generation capacity sit idle. Excess transmission and generation capacity is especially available during the lowest-load night-time periods. This means that with managed charging that shifts the majority of the PEV load to night-time hours, there is ample existing capacity to meet foreseeable PEV demand.

With managed charging, PEVs present many potential benefits to grid operations and also to PEV owners. For example, a fleet of PEV vehicles could provide additional reliability to the grid, while earning a stable stream of revenue for vehicle owners. Fleet vehicles are ideal candidates for providing large-scale services to the grid, because they have the advantage of predictable and schedulable usage. PEVs have the capability of both receiving and discharging electricity from their batteries, so the battery storage capacity of a large fleet can offer valuable services to a grid in the same manner as other electricity storage technologies.

### *Energy Storage*

Energy storage can take any of several common forms and can satisfy multiple functions. The types of available energy storage technologies include pumped hydroelectric, compressed air energy systems (CAES), flywheels, and various types of batteries, e.g., lead-acid batteries, lithium-ion batteries, and zinc-bromide batteries. Each of the different technologies carries with it different benefits, different economics, and different operational characteristics. Hence, the various technologies can be used to serve different end functions. The principal end uses of electric storage include:

- On-peak power supply –Storage technology can be relied upon to provide electric power at times of high demand. For example, pumped hydroelectric (or pumped storage) entails pumping water up into a reservoir during periods when the demand for electric power (and hence price) is low and using that water to generate electricity when demand (and price) is high.
- Electric grid support – Storage can help support the transmission system by correcting for transient voltage anomalies. Additionally, storage can be used to help relieve transmission congestion and to relieve pressure on the local distribution system when periods of high, localized demand occur. Use of storage in this way can postpone the need to upgrade electric distribution facilities to accommodate those periods of high demand that occur only infrequently.
- End-user cost management – An end-user can benefit from energy storage by storing electric power during periods when market prices are low and drawing on that power when market prices are higher.
- End-user reliability enhancement – Electric storage can be relied upon for power supply during times when the electric grid is not available.
- Intermittent renewable energy generation support – Electric storage can be used to reduce the intermittency of certain renewable electric generation technologies, such as wind and solar. For example, storage could be used to reduce the output fluctuations from a photovoltaic array due to passing clouds. Furthermore, storage can enhance the value of intermittent renewable energy production by effectively allowing generation produced in one-time period to be carried to a later time period when electricity prices are higher.

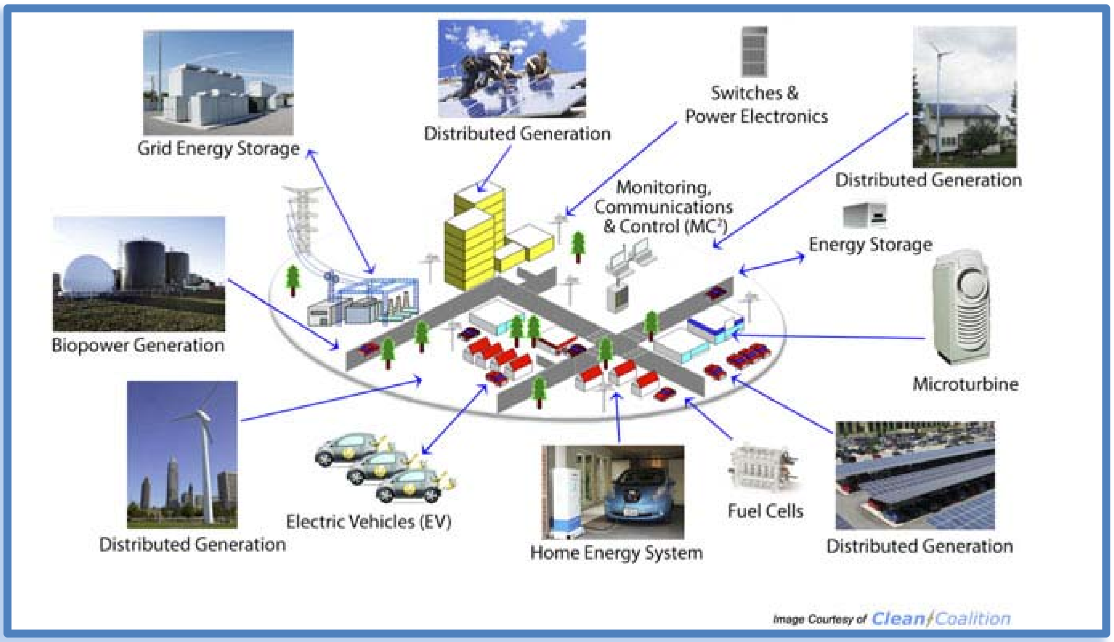
Presently, only pumped hydroelectric and CAES can be effectively used to provide bulk energy services since these technologies can be sized at 100 MW or more and are capable of providing electric power to the grid for periods measured in hours rather than in minutes or seconds. Bulk energy service refers to: (a) the ability to significantly shift large amounts of energy between the time of generation and the time of use, and (b) the provision of generation capacity. Battery systems and flywheels are better suited to providing transmission and distribution system grid support due to typical size and operational factors and can also be used to provide power quality and reliability at the end-use (retail) level.

The widespread use of storage technology has been adversely affected by the relatively high cost of storage. Decreases in the prices of storage devices, particularly lithium ion battery storage which has benefited from research and development related to plug-in electric vehicles, have been significant in recent years and prices are generally expected to continue to decline over time. Based on the potential uses of storage, electric storage can be viewed, to some degree, as a substitute for certain types of generation (e.g., peaking generation) and for certain marginal investments in the distribution and transmission infrastructure.

### *Microgrids*

A microgrid is defined as a group of interconnected loads and distributed energy resources, with clear electrical boundaries, that can be connected to the grid or disconnected from the grid to operate in an island-mode. Interest in the development of microgrids has grown significantly over the last five years due to major storms and resulting outages, which sometimes were of prolonged duration. The ability to island a microgrid during an outage is appealing, especially to critical community assets, such as hospitals, community centers, and emergency service complexes. Microgrids utiltize distributed energy resources (DERs) including, but not limited to wind, solar, energy storage, and combined heat and power as energy sources when islanding. The various types of generation that may power a microgrid are detailed in Figure 5-21.

*Figure 5-21 Distributed Generation Found in Microgrids*



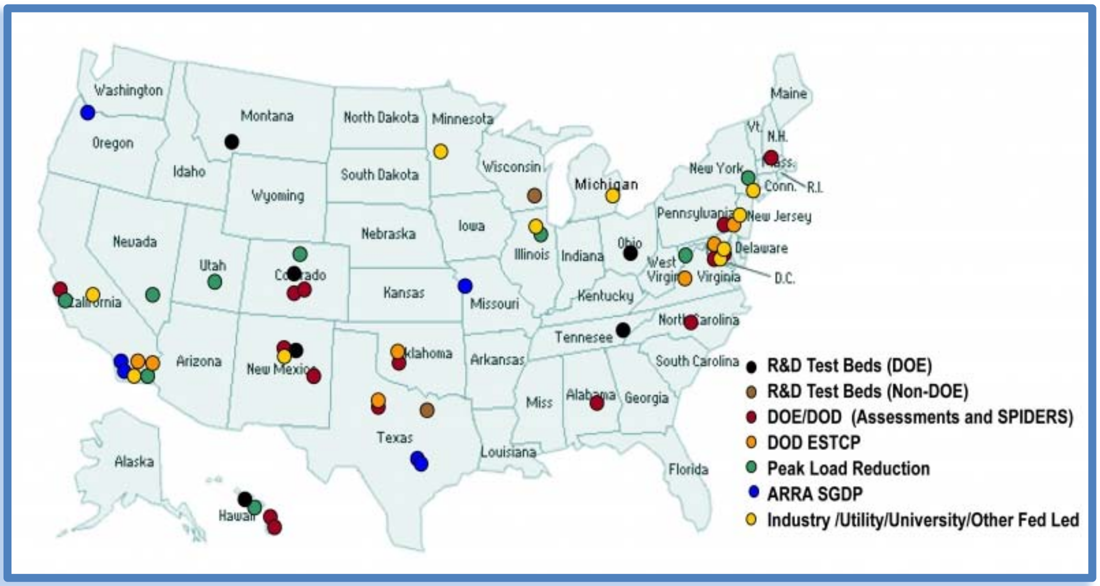

Source: "Microgrids 101," NYSERDA, http://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Microgrids-101.

As defined by the Lawrence Berkeley National Laboratory, there are four types of microgrids:

1. Customer microgrids (or true microgrids) are self-governed, and are usually downstream of a single point of common coupling, which allows for the customer to have control of its power system from its side of the meter.
2. Utility or community microgrids (or milligrids) vary from customer microgrids as it will involve a segment of the regulated grid, which require the microgrid to comply with utility regulations.
3. Virtual microgrids include distributed energy resources at multiple sites that can be coordinated to be operated as either a controlled island or multiple islands.
4. Remote power systems operate in island mode only, as they are not grid-connected but involve similar power systems as microgrids.

Research, development, and deployment of microgrid systems are occurring throughout the United States, as identified in Figure 5-22.

### *Figure 5-22 Microgrid Projects Throughout the United States*




Source:
1 "Microgrid Activities," Department of Energy, http://energy.gov/oe/services/technology-development/smart-grid/role-microgrids-helping-advance-nation-s-energy-syst-0
2 Definitions for map legend. SPIDERS – Smart Power Infrastructure Demonstration for Energy Reliability and Security. DOD ESTCP – Environmental Security Technology Certification Program. ARRA SGDP – American Recovery and Reinvestment Act Smart Grid Demonstration Program.

Campus-style microgrids have been in operation for several years in locations such as college campuses, hospitals, military installations, and federal facilities; however, these tend to be customer microgrids. In 2014, the Maryland Resiliency Through Microgrids Task Force was convened to focus on developing a roadmap, as well as removal of barriers, for the development of public purpose microgrids that incorporate critical community assets and cross public rights-of-way. In December 2015, in response to the Task Force's report, BGE filed for approval of its public purpose microgrid pilot program with the Maryland Public Service Commission. For its pilot program, BGE proposed two microgrid projects. The first project is a 3-MW microgrid in Edmonson Village in Baltimore City, which would incorporate a library and high school which could serve as shelters, and is projected to cost \$9.2 million. The second project is a 2-MW microgrid at King's Contrivance Village Center in Howard County, projected to cost approximately \$7 million. Both sites serve as mixed purpose use and the pilots would rely on natural gas as the preferred fuel source, as well as incorporate customer-owned renewable energy. The design and development of the microgrid pilot projects are expected to be completed within 12 to 18 months following PSC approval.

In July 2016, the PSC issued Order No. 87669 denying, without prejudice, BGE's proposal on the basis that the proposal was deficient and was not in the public's interest, specifically siting BGE's site selection process, cost recovery, and ratepayers. In its Order, the PSC recommended that BGE resubmit a microgrid pilot proposal for one or two public purpose microgrids.

# Appendix A – Permits and Approvals for Power Plants and Transmission Lines in Maryland

Under Maryland regulations, a person, developer, or electric company that is planning to construct or modify a generating facility or a transmission line greater than 69 kilovolts (kV) in Maryland must receive a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (PSC) prior to the start of construction. The approved CPCN constitutes permission to construct the facility and incorporates several, but not all, required construction and operation permits. The CPCN process was designed in 1971 to be a “one-stop shop” for power plant licensing and the broad authority of the PSC allows for the comprehensive review of all pertinent issues.

In the case of new or modified power plants, most of the air quality permits and approvals that are required for construction are incorporated into the CPCN, for example:

- Air quality Permits to Construct for power plants that are minor sources of air emissions, and
- Prevention of Significant Deterioration (PSD) and Nonattainment Area New Source Review (NA-NSR) permits for major new or modified power plant sources in Maryland.

As with all major source air 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 recommended license conditions during the CPCN process. Agencies that are authorized to issue Part 70 Title V operating permits are also authorized to issue Clean Air Act Title IV Acid Rain and Cross-State Air Pollution Rule (CSAPR) permits. In Maryland, the Maryland Department of the Environment (MDE) is the entity authorized to issue Part 70 Title V, Acid Rain, and CSAPR permits.

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 for use at the facility, 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 or modifications to existing facilities in Maryland. The shaded rows indicate those permits that are included within the CPCN. While there are several permits that are issued separately, PPRP evaluates the entire suite of environmental and socioeconomic impacts during the consolidated licensing review process (described in Chapter 1 of this report).

## *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 |
|---|---|---|---|
| Certificate of Public Convenience and Necessity (CPCN) | Incorporates several State and federal permits and approvals — those incorporated into CPCN are highlighted | Maryland Public Service Commission (PSC) | |
| **AIR QUALITY** | | | |
| Air Quality Permit to Construct[1] | Applies to any minor new, modified, or reconstructed sources of air pollution | PSC/Maryland Department of the Environment (MDE) | Constitutes a "minor New Source Review (NSR) construction permit" |
| Nonattainment Area New Source Review (NA-NSR)[1] | Required for new or modified major sources that emit VOCs or nitrogen oxides ($NO_x$); requirements and limitations are location-specific | PSC/MDE | Constitutes a "major NA-NSR" permit; requires Lowest Achievable Emission Rate (LAER), offsets, and alternatives analyses |
| Prevention of Significant Deterioration (PSD) [1] | Required for major new or modified sources in attainment areas | PSC/MDE | Constitutes a "major PSD" permit; requires air quality monitoring, Best Achievable Control Technology (BACT), ambient impact analyses (modeling), impact on surrounding Class I areas |
| Title V Operating Permit (federal) and Maryland Permit to Operate | Facility-wide permit to operate | MDE | |
| Title IV - Acid Rain Permit | Covers "affected" power plant generating units for minor sulfur dioxide ($SO_2$) emissions | MDE | Requires continuous emission monitoring, recording, and reporting; acquisition of $SO_2$ allowances |
| Clean Air Act (CAA) 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 $NO_x$ |
| Cross-State Air Pollution Rule (CSAPR) | The rule uses a cap and trade system to reduce $SO_2$ by 73 percent $NO_x$ by 54 percent from 2005 levels. | MDE | Applies to 28 eastern states and the District of Columbia |

| Subject | Description | Regulatory Entity Issuing Permit in Maryland | Comments |
|---|---|---|---|
| **WATER QUALITY AND USE** | | | |
| Waterway Construction | State-federal review and permitting for waterway impacts | MDE/ U.S. Army Corps of Engineers (USACE) | Waterway 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/ National Oceanic and Atmospheric Administration (NOAA) | State and federally coordinated program |
| Chesapeake Bay and Atlantic Coastal Bays Critical Areas | Protects Maryland's Critical Areas, which include all land within 1,000 feet of Maryland's tidal waters and tidal wetlands as well as the waters of the Chesapeake Bay, the Atlantic Coastal Bays, their tidal tributaries, and the lands underneath and the air space above these tidal areas. | DNR/County/ Municipality | Generally, enforced at the local or county level, but if a State Action is involved, such as granting a CPCN, the project must be reviewed by the full Critical Area Commission. |
| Scenic and Wild Rivers | Designates and protects the water quality and cultural and "natural values" of Maryland's wild and scenic rivers, including the impacts to the River mainstem and all tributaries thereof. | DNR | Maryland's Scenic and Wild River Act can be found in the Maryland Code, Section 8-401 et seq. of the Natural Resources Article |
| 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/ National Pollutant Discharge Elimination System (NPDES) Permit | Combined state and federal permit for industrial wastewater and possibly storm water discharge to state water; must meet applicable federal effluent guidelines, satisfy state water quality standards, and comply with CAA 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. |

| 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 | Section 401 of the Clean Water Act provides states with the power to either deny or impose restrictions on construction that might affect water quality. Generally, this has been applied to construction or operation of hydroelectric projects under jurisdiction of the Federal Energy Regulatory Commission | MDE | Wetland impact determination necessary |
| Surface Water Withdrawal Permit/Water Appropriation & Use Permit[1] | 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, State Historic Preservation Officer (SHPO) clearance, National Resource Conservation Program (NRCS) consultation, floodplain permitting, and road boring permits | County/ Municipality | |

| Subject | Description | Regulatory Entity Issuing Permit in Maryland | Comments |
|---|---|---|---|
| Tidal Wetland Permit | State-federal review and permitting for tidal wetland impacts | The Board of Public Works (BPW)/ PSC/MDE Water Management Administration (WMA)/USACE | Wetland impact determination necessary. BPW has the ultimate authority for issuing tidal wetlands permits and licenses. |
| Non-Tidal Wetlands Permit | State-federal review and permitting for non-tidal wetland impacts | MDE WMA/ USACE | Wetland impact determination necessary |
| Groundwater Withdrawal[1] | Requires submittal of an application to the WMA for any withdrawal of groundwater for use in a project (sanitary water, process water, cooling, etc.) | PSC/MDE WMA | An impact assessment must be conducted |
| 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 exceeds an average of 20,000 gallons per day for any consecutive 30-day period |
| **OTHER APPROVALS AND NOTIFICATIONS** | | | |
| Facility Response Plan | Prevents on-shore oil facilities from polluting navigable waters | 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 Wastewater Treatment Plant (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 | |

| Subject | Description | Regulatory Entity Issuing Permit in Maryland | Comments |
|---|---|---|---|
| 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 |
| 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 and facilities that have a total above ground capacity of 1,000 gallons of used oil |
| Local building permits during construction | Requirements under local ordinances to be filed as necessary with County | County / Municipality | Includes building permit and site plan approvals as applicable |
| Forest Conservation Act | Requirements to prepare Forest Stand Delineations and Forest Conservation Plans, and mitigation for impacts related to energy development. | DNR Forest Service (delegated to Counties) | Mitigation may be required for disturbance, whether or not trees are removed. |
| Phase II Cultural Resources Investigation | Research potential significant impacts to cultural resources on site | MHT | Coordinate with Maryland State Historic Preservation Officer if necessary |
| National Historic Preservation Act / Maryland Historical Trust Act | Protection of cultural/historic artifacts found during development | MHT | Coordinate with Maryland 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 Wildlife and Heritage Service (WHS) | WHS Natural Heritage and Biodiversity Conservation Programs; coordinate with US Fish & Wildlife Service and NOAA |
| 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 |

| Subject | Description | Regulatory Entity Issuing Permit in Maryland | Comments |
|---|---|---|---|
| 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 State Highway Administration (SHA)-owned Land | For projects that are proposed for location on property owned by SHA. | SHA | Longitudinal occupancy of an SHA ROW by electrical transmission lines greater than 98kV prohibited. |
| 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 | 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 | Any construction or alteration of more than 200 feet or a height greater than a defined imaginary surface extending outward and upward from an airport or heliport. |
| Patuxent River Naval Air Station Wind Turbine Restrictions | The Department of Defense (DOD) must be notified if a wind turbine will be within 56 miles of the Patuxent River Naval Air Station. | PSC/DOD | This regulation arose from concerns over wind turbine interference with radar signals |
| National Fire and Electrical Codes | For the construction and operation of electrical generation and transmission facilities. | National Fire Protection Association (NFPA) | Minimum standards defined in NFPA 1 (Fire Code) and NFPA 70 (National Electrical Code) |
| 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, or when FERC backup authority is invoked for siting an interstate transmission line. |

[1] Incorporated in 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 PSC. 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 RTO are bilateral transactions, wherein 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 (PPA), 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).

The primary purpose of financial trading is to protect against expected price volatility and to 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 (ICE) or the New York Mercantile Exchange (NYMEX) according to the specifications determined by the commodity exchange.

The electricity supply markets in PJM's wholesale electric market consist of four separately organized units, defined in greater detail as: 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 Market). These markets are competitive and suppliers and buyers submit bids and offers. Except for a small number of ancillary services that are provided at cost-based rates, 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). An LSE is any supplier, including regulated utilities providing standard offer service or default service, which 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 for buyers and sellers 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 in which 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 LMPs for any generation that exceeds their day-ahead scheduled quantities since 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 since 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*

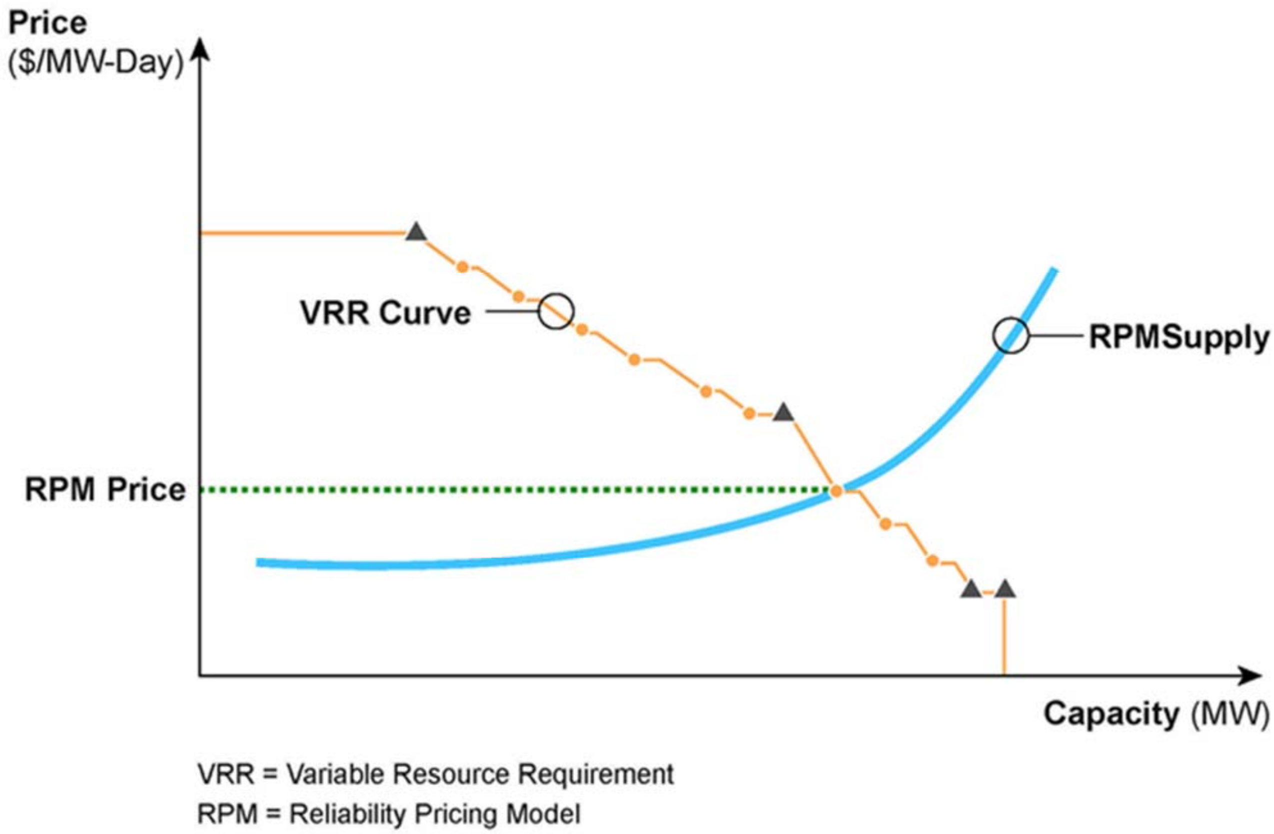
Capacity refers to the amount of electricity generation available at any given time. The capacity market is a forward market in which LSEs purchase supply-side and demand-side capacity resources. Each LSE is required to have available its share of the PJM system peak plus a planning reserve margin of an additional (approximate) 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.

The current PJM capacity market is based on PJM's Reliability Pricing Model (RPM), 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. 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 (CONE), i.e., the level of revenue that a power plant developer would require in order 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.

*Figure B-1 PJM Demand and Supply Curves*




Source: Adapted from *The Evolution of Demand Response in the PJM Wholesale Market*, PJM 2014

**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). 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.

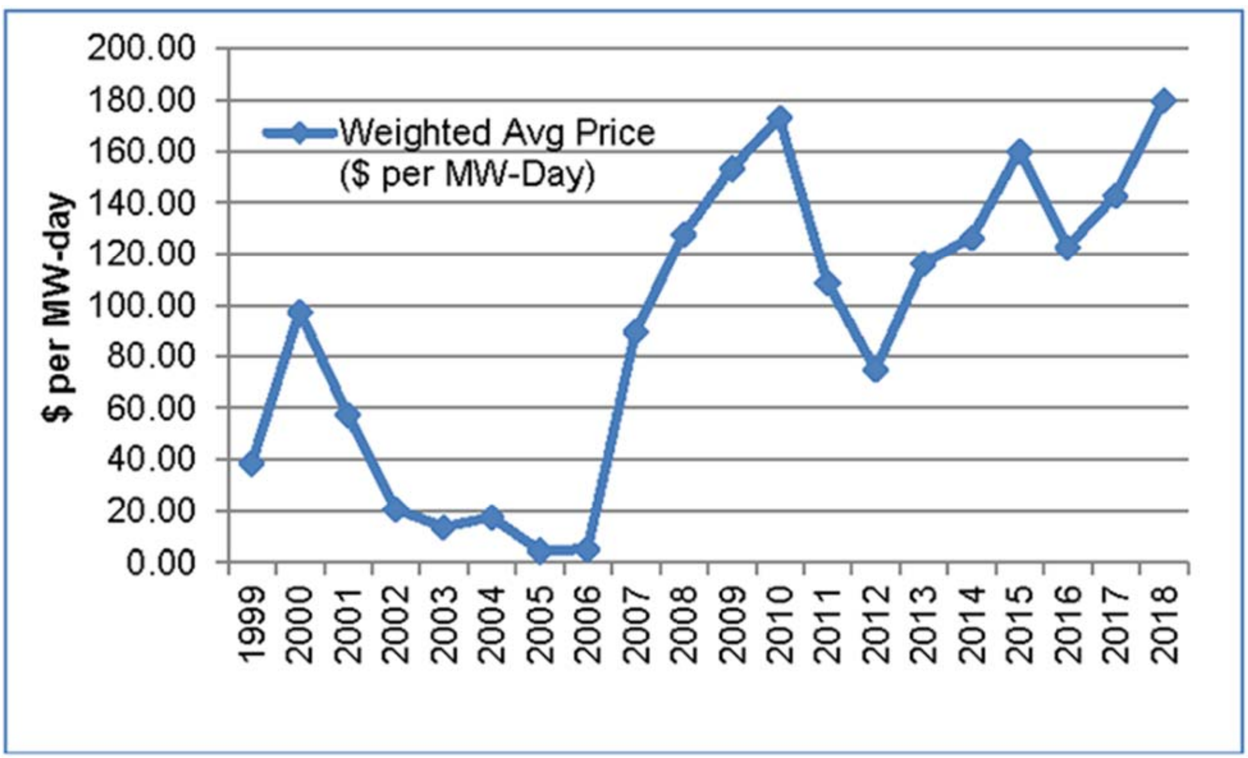
**The Supply Curve** – the supply curve is obtained by PJM through the capacity bids offered by the capacity owners. Eligible capacity includes existing and new capacity, demand-side resources (e.g., load response), and qualified transmission upgrades. The capacity offers from the auction are stacked (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 opted for the Firm Resource Requirement (FRR) alternative. 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 2013 through May 2014 was held in May 2010). 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 and supply curves. The capacity resources that clear the BRA receive the market-clearing price and assume the obligation to provide capacity in the relevant planning year. In the event that a party fails to meet its capacity commitment, PJM can impose 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-2 shows historical capacity prices along with RPM prices out to 2015 arising from the PJM auctions.

***Figure B-2 Average PJM Capacity Prices by Delivery Year, 1999-2018***




Source: Monitoring Analytics, 2015 State of the Market Report for PJM.

## *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 operating reserve energy. Cost-based services are provided by PJM and billed to participants according to a set rate based on revenue requirements.

An important element of PJM's ancillary services is regulation. Regulation service matches generation with short-term changes in load, maintaining desired frequency and voltage by increasing or decreasing the output of selected generators, load response units, or electricity storage systems as needed via automated control signals. Longer-term deviations from scheduled load are met by the operating reserves and generator responses to economic signals. PJM's regulating requirement is 525 effective MW during off-peak hours (midnight to 4:59 p.m.) and 700 effective MW during on-peak hours (5:00 p.m. – 11:59 p.m.). The PJM regulation market accepts bids from generators and fast-responding load resources and electricity storage systems. These entities enter an offer price for each hour and, if called upon, are paid the hourly market clearing price for regulation service.

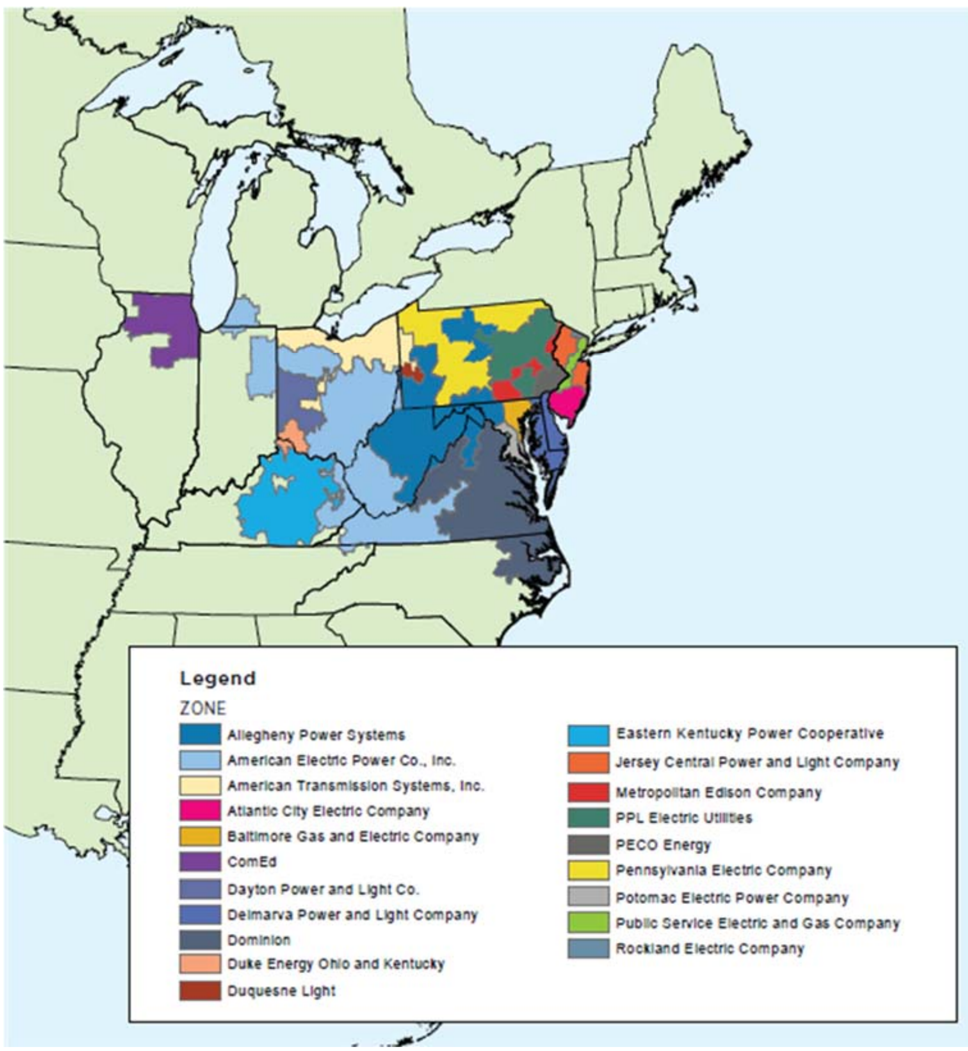
Operating reserves represent the generating capability that is standing by ready for service in the event of a disruption on the power system, such as the loss of a generator. These operating reserves, the standby generation made available to serve load in case there is an unplanned event, are not the same as the 15 percent planning reserve requirement, which is an annual capacity obligation based on PJM's independent load forecast and other system planning assumptions and scenarios. The 15 percent annual planning reserve requirement refers to the overall amount of extra capacity that must be maintained in the PJM system as a whole in order to keep the probability of a loss of load event below a specified level. In other words, the PJM system must always maintain a condition where overall generation ability exceeds peak demand by 15 percent. The operating reserves refer to the amount of generation kept in standby mode as part of daily system operations so it can be called upon in case of an emergency, such as a major generation unit tripping offline. Operating 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 upon to do so. Primary reserves are those resources available within ten 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 different zones (shown in Figure B-3), organized primarily according to the service territories (or aggregations of two or more 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-3 PJM Zones*




Source: PJM

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 a.m. to 11:00 p.m.; off-peak hours are the remaining evening, weekend, and holiday hours. Table B-1 provides the PJM average and median prices experienced over the 2015 calendar year.

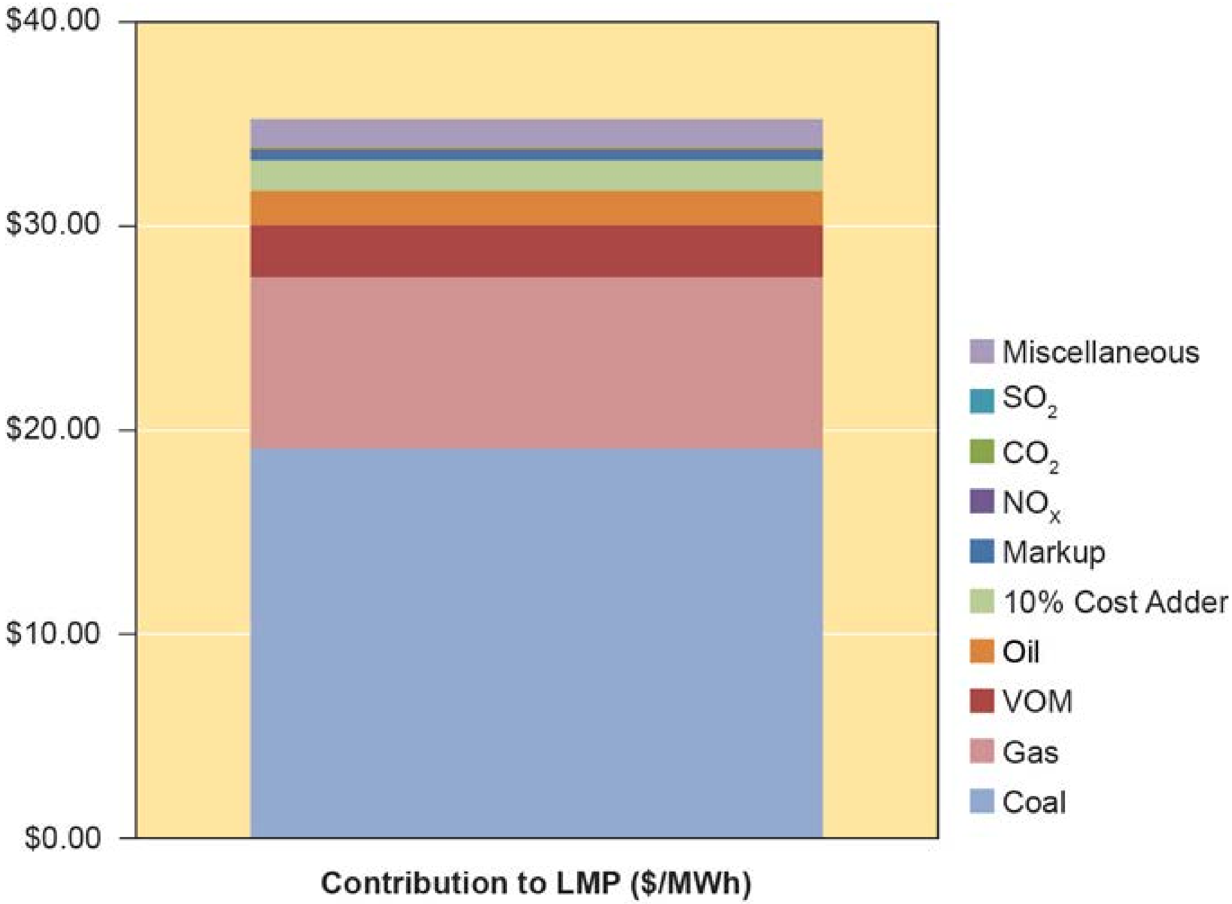
### *Table B-1 PJM Off-Peak and On-Peak Average LMPs for 2015*

| | Day Ahead ($/MWh) | | Real Time ($/MWh) | |
|---|---|---|---|---|
| | **Off-Peak** | **On-Peak** | **Off-Peak** | **On-Peak** |
| **Average** | $28.11 | $40.97 | $28.08 | $39.44 |
| **Median** | $24.51 | $33.69 | $23.62 | $29.95 |

Source: Monitoring Analytics, 2015 State of the Market Report for PJM.

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-4). 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 2015, the capital and fuel supply costs of coal-fired generators made up 43 percent of the annual average LMP, while gas-fired generators made up 27 percent. Variable operating and maintenance costs (VOM) contributed 7 percent of the LMP and PJM's Cost Adder contributed 8 percent overall. PJM allows generators to add a 10 percent cost adder to their bids to account for the uncertainty in the process of defining costs. In addition, the cost adder provides protection against unintended understatement of variable operating costs, which could be harmful to reliable grid operation because it could create an incentive for generators to restrict their generation offer parameters. Besides fuel costs, other factors contributing to price levels include environmental costs (such as cost of controls and emission allowances), non-fuel operating costs, and profit margins. Cost for compliance with $CO_2$, NOX, and $SO_2$ emissions regulations contributed approximately 2 percent to the total LMP. All generators, however, are paid the LMP in their zone; the PJM Market Monitor estimates these cost factors for informational purposes only.

*Figure B-4 Components of Load Weighted Annual Average LMP (2015)*




Source: Monitoring Analytics, 2015 State of the Market Report for PJM.

Average annual LMPs in PJM rose from the late 1990s to the late 2000s, more than doubling from 1998 to 2008 (see Table B-2). During the last decade, a large portion of the constructed new generating capacity has been natural gas-fired. Natural gas and petroleum prices 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. LMPs in 2009 and 2010 were much lower than in 2008, however, due mainly to reduced electricity demand as a result of the recession. In 2011 and 2012, LMPs were once again significantly lower than in 2008, and in 2012, LMPs were the lowest since 2002. After a slight uptick in 2013 and a sharp increase in 2014, LMPs once again fell back to their 2012 levels in 2015. This can be largely attributed to the low cost of natural gas. Natural gas prices have declined since the highs reached in 2008. Along with the lack of load growth since the Great Recession, due mostly to a weak economic recovery from the recession as well as increased penetration of energy efficiency and behind-the-meter renewable energy projects, this decline in the cost of natural gas has put downward pressure on market prices for electric power. Figure B-5 depicts fuel costs for electricity suppliers between 1996 and 2014.

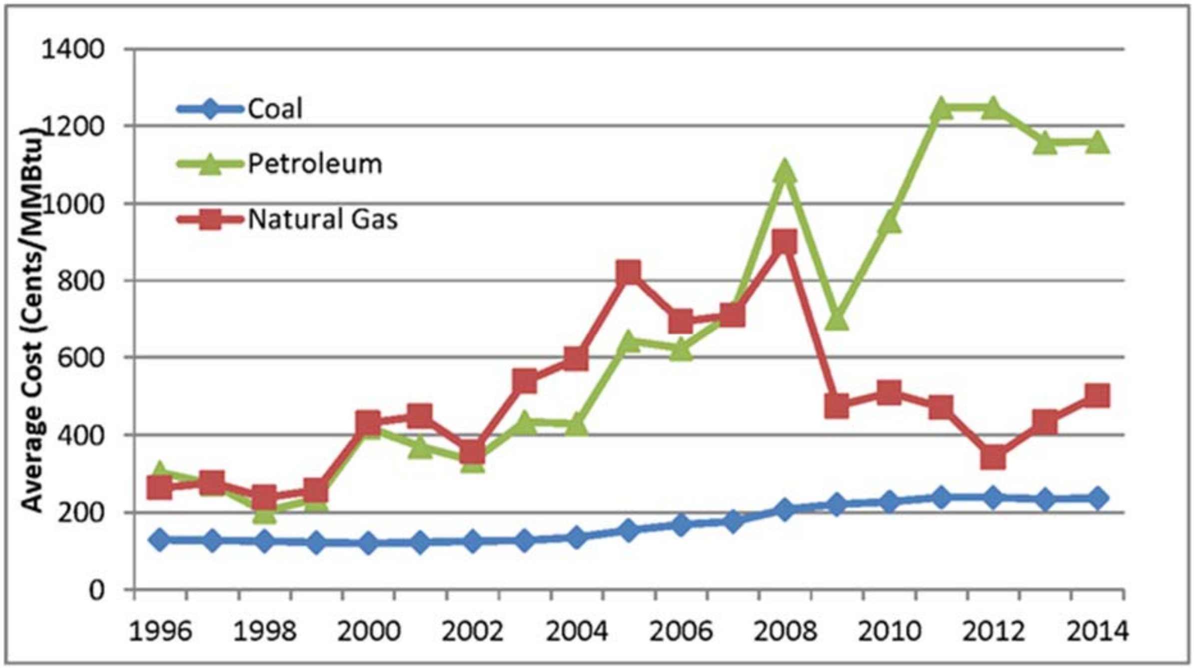
The cost of uranium fuel (not shown in Figure B-5) is only a small part of the overall operating and maintenance cost for a nuclear facility. However, the price of uranium has increased over the last decade, rising from a weighted average of $12.61 per pound in 2004 to $55.64 per pound in 2011, then dropping to $46.16 per pound in 2014. A pound of uranium provides approximately 171 MMBtu; therefore, the cost to the electric power industry was approximately 27 cents per MMBtu in 2014. While the cost of uranium fuel does have a small impact on operating costs, it has little to no influence on the dispatching of a nuclear facility since they are a base load power source.

### *Table B-2 PJM Real-Time Load-Weighted Day-Ahead Average LMP, 1998-2015*

| Year | LMP per MWh | Change from Previous Year | Percent Change |
|---|---|---|---|
| 1998 | 24.16 | NA | NA |
| 1999 | 34.07 | 9.91 | 41.00% |
| 2000 | 30.72 | ($3.35) | -9.80% |
| 2001 | 36.65 | 5.93 | 19.30% |
| 2002 | 31.60 | ($5.05) | -13.80% |
| 2003 | 41.23 | 9.63 | 30.50% |
| 2004 | 44.34 | 3.11 | 7.50% |
| 2005 | 63.46 | 19.12 | 43.10% |
| 2006 | 53.35 | ($10.11) | -15.90% |
| 2007 | 61.66 | 8.31 | 15.60% |
| 2008 | 71.13 | 9.47 | 15.40% |
| 2009 | 39.05 | ($32.08) | -45.10% |
| 2010 | 48.35 | 9.30 | 23.80% |
| 2011 | 45.94 | ($2.41) | -5.00% |
| 2012 | 35.23 | ($10.71) | -23.30% |
| 2013 | 38.66 | 3.43 | 9.70% |
| 2014 | 53.14 | 14.48 | 37.50% |
| 2015 | 36.16 | (16.98) | -32.00% |

Source: Monitoring Analytics, 2015 State of the Market Report for PJM.

*Figure B-5 Fuel Costs for the Electric Power Industry, 1996-2014*




Sources:

"Electric Power Annual 2014," U.S. Energy Information Administration, February 2016. http://www.eia.gov/electricity/annual/pdf/epa.pdf (Download Adobe Acrobat Reader). Table 7.1 "Electric Power Annual 2007," U.S. Energy Information Administration, January 2009, http://www.eia.gov/electricity/annual/archive/03482007.pdf, Table 4.5

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 different electricity prices in the transmission zones that comprise PJM (see Table B-3).

As seen below in Table B-3, the differences in LMPs in 2015 between the Western Region and Mid-Atlantic Region decreased compared to the differences in LMPs between the Western Region and Mid-Atlantic Region in 2014. This can be attributed to lower amounts of congestion in 2015 than in 2014. PJM reported a 28 percent decrease in total congestion costs in 2015 compared to 2014. In Table B-3, the PJM zones that impact Maryland are highlighted in brown. Additional information on congestion is provided in Chapter 2 of this CEIR.

### *Table B-3 Real-Time Annual Load-Weighted Average LMPs for 2014 and 2015*

| Zone | 2015 LMP | 2014 LMP |
|---|---|---|
| **Eastern PJM Zones** | | |
| AECO | $35.85 | $55.77 |
| **AP** | **$38.04** | **$52.94** |
| **BGE** | **$47.22** | **$67.78** |
| Dominion | $41.42 | $62.99 |
| **DPL** | **$42.27** | **$65.03** |
| JCPL | $35.65 | $56.07 |
| Met-Ed | $35.79 | $56.08 |
| PECO | $35.11 | $55.94 |
| PENELEC | $36.13 | $51.90 |
| **Pepco** | **$43.04** | **$65.61** |
| PPL | $35.95 | $56.97 |
| PSEG | $36.97 | $57.90 |
| RECO | $37.58 | $56.79 |
| **Western PJM Zones** | | |
| AEP | $33.90 | $47.81 |
| ATSI | $34.00 | $48.60 |
| ComEd | $29.85 | $42.04 |
| Day | $34.20 | $47.36 |
| DEOK | $33.28 | $45.00 |
| DLCO | $32.21 | $44.22 |
| EKPC | $32.93 | $47.88 |

Source: Monitoring Analytics, 2015 State of the Market Report for PJM.

# Appendix C – Determinants of Electricity Demand Growth in Maryland

## Introduction

This appendix provides an overview of the basic theoretical foundations upon which forecasts of electricity consumption and peak demand rest, and an analysis of the trends of the key economic and non-economic determinants of the demand for electricity. The Maryland data presented herein were 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. Economic variables include income, price of electricity, and employment; non-economic variables include population (which is itself influenced by income and employment) and weather. Historical information is required for estimation purposes, while projected data are necessary to forecast the demand for power using the statistical relationships between these variables and electricity consumption determined during the estimation process based on the historical data.

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 Appendix C, which examines economic and demographic trends for Maryland by region. For purposes of presentation, the State has been divided into six regions, as shown in Table C-1. 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 of Appendix C presents a brief summary.

***Table C-1 Principal Regions in Maryland***

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

# *Theoretical Foundations for Econometrically Modeling Electricity Demand*

"Econometric" forecast studies use the economic theory of demand as the organizing principle to 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.

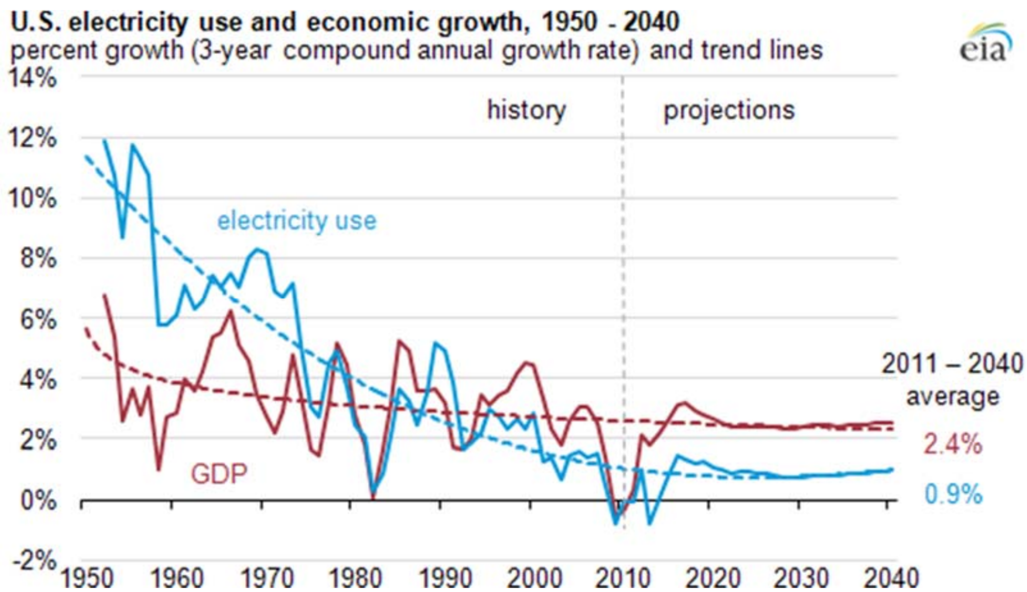
The residential demand for electricity is assumed to result from the exercise of choice by which the consumer maximizes his or her welfare subject to a budget constraint. Consumer demand for electricity is taken to be a function of its price, consumer income, weather, and the price of related commodities (i.e., substitutes and complements such as natural gas for home heating). 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. 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. Because no satisfactory time series of output data is available at a suitably disaggregated level, we use employment as a proxy for output. 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.

The growth in electricity use has historically been linked to the level of economic growth. The rate of growth of electricity use nationwide exceeded the rate of increase in gross domestic product (GDP) in the 1950’s by 5 percent. As shown in Figure C-1, the differential between the growth in real GDP and the growth in electric use has declined steadily from 1950 until the 1990’s when growth in electric use fell below GDP growth. Similar to the recession in the early 1980’s, the differential between GDP growth and growth in electric use during the Great Recession of the late 2000’s is minimal. The U.S. Energy Information Administration (EIA) reports in its *2015 Annual Energy Outlook* (AEO) that average electric use is projected to grow less than 1 percent per year from 2016 through 2040, compared to average real GDP growth of 2.5 percent over the same period. Over the next three decades, the EIA projects that electricity use will continue to grow, but the rate of growth will slow over time. The EIA does not expect growth in electricity use to equal or exceed real GDP growth for any sustained period of time because efficiency standards for lighting and other appliances will continue to put downward pressure on the growth in electricity consumption.

***Figure C-1 U.S. Electricity Use and Economic Growth, 1950-2040***



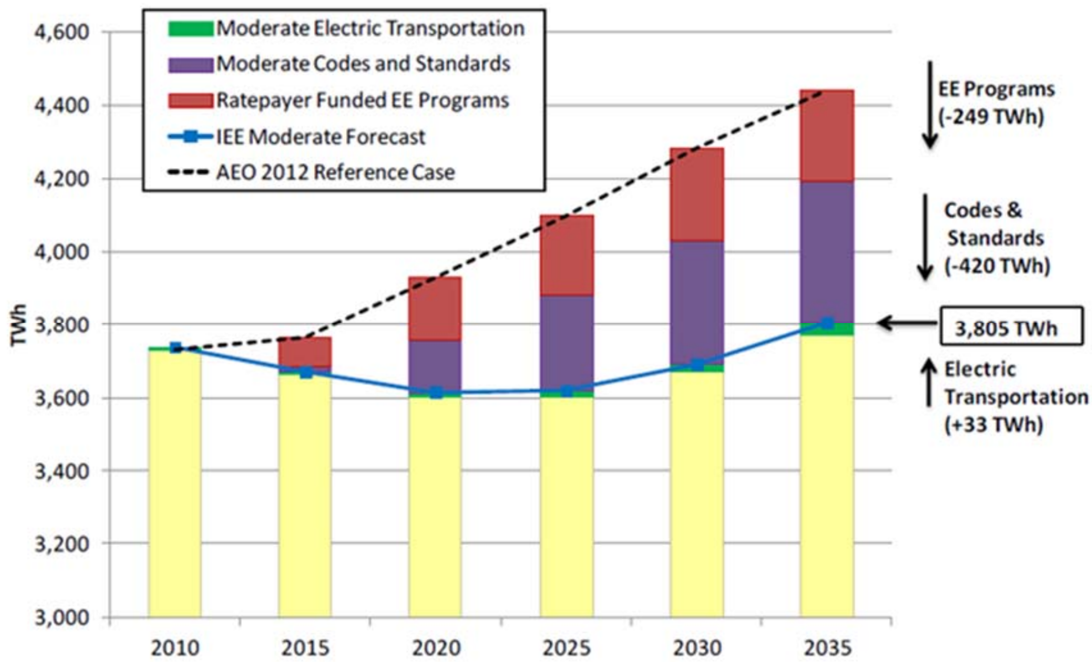

Source: U.S. Bureau of Economic Analysis; U.S. Energy Information Agency's Annual Energy Outlook for 2014 and 2015.

According to the Edison Foundation's Innovation Electricity Efficiency Institute (IEE), the major factors that are expected to affect growth in electricity use through mid-century are:

- Energy efficiency (EE) programs sponsored by electric utilities, and
- Government codes, standards and policies that impact appliance, equipment and building energy use.

The IEE projects that improvements in building energy codes, adoption of appliance/equipment energy standards and expansion of ratepayer-funded energy efficiency programs could result in declining electricity use through 2020 after which time economic growth and the potential growth in use of electric vehicles could result in modest electric growth through 2035. This effect is illustrated in Figure C-2.

***Figure C-2 Projected U.S. Electric Energy Use 2010 – 2035***




Source: Innovation Electricity Efficiency, an Institute of The Edison Foundation. "Factors Affecting Electricity Consumption in the U.S. (2010 – 2035).

## 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; for example, consumers will re-evaluate the intensity of use of a more constrained budget if there is a decline in income. This can be manifested in higher air-conditioning settings or use of lower-wattage lamps for electricity requirements. Second, an income change will induce changes in the stock of electricity-consuming appliances as it impacts consumers purchasing energy efficient devices. As income changes, therefore, the demand for electricity will rise or fall. Previous PPRP forecast studies have demonstrated a positive and, typically, statistically significant relationship between income and the residential demand for electricity.

Real (i.e., inflation adjusted) per capita income can be used as an explanatory variable for residential per-customer electricity consumption. Real per capita income figures are reported in Table C-2 for the Maryland regions defined in Table C-1. Table C-2 summarizes historical and projected data as well as average annual growth rates for the period 2000 through 2025. As shown by the historical data, the rate of income growth has remained constant or has slowed for all regions in Maryland. For the State as a whole, growth in real per capita income declined to 0.73 percent per year between 2005 and 2010, compared to an average annual growth rate of 2.23 percent between 2000 and 2005. All regions of the State, with the exception of Southern Maryland (owing to its proximity to Washington, D.C. and federal government employment opportunities, which drive up wages and the in-migration of relatively high-income households), saw considerable decreases in the rate at which income grew during the 2005-2010 time period relative to 2000-2005. The Upper Eastern Shore region saw a decline in inflation-adjusted income between 2005 and 2010. This slowing was a product of the severe economic downturn and associated job losses affecting numerous Marylanders who lost their incomes, and economic conditions placed downward pressure on wages as the competition for available jobs became more intense.

From 2010 to 2015, the rate of real per capita income growth increased relative to the 2005-2010 period. A forecast by the Maryland Department of Planning for 2015-2020 shows that as the nation (and Maryland) emerges from the recession and the economy once again begins to grow, income will follow the economy's upward trajectory. Income growth is projected to once again slow (but is not negative) between 2015 and 2020 as the economy returns to steady-state rates of growth lower than those expected during the rebound period that follows the recession.

***Table C-2 Historical and Projected Per Capita Income for Maryland, 2000-2025***

| Region | Per Capita Income (2009 $) | | | | | | Annualized Growth | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 | '00-'05 | '05-'10 | '10-'15 | '15-'20 | '20-'25 |
| Maryland | $42,501 | $47,467 | $49,221 | $52,000 | $56,854 | $60,112 | 2.23% | 0.73% | 1.10% | 1.80% | 1.12% |
| Baltimore | $41,240 | $46,709 | $48,850 | $52,498 | $57,965 | $61,589 | 2.52% | 0.90% | 1.45% | 2.00% | 1.22% |
| Washington Suburban | $48,357 | $53,167 | $54,395 | $56,155 | $60,675 | $63,808 | 1.91% | 0.46% | 0.64% | 1.56% | 1.01% |
| Southern Maryland | $37,765 | $41,536 | $44,827 | $46,626 | $51,162 | $54,298 | 1.92% | 1.54% | 0.79% | 1.87% | 1.20% |
| Western Maryland | $28,638 | $32,391 | $34,428 | $36,452 | $40,332 | $42,947 | 2.49% | 1.23% | 1.15% | 2.04% | 1.26% |
| Upper Eastern Shore | $37,822 | $42,076 | $42,110 | $46,155 | $50,940 | $54,017 | 2.15% | 0.02% | 1.85% | 1.99% | 1.18% |
| Lower Eastern Shore | $30,646 | $34,698 | $35,873 | $37,824 | $41,320 | $43,592 | 2.51% | 0.67% | 1.06% | 1.78% | 1.08% |

Source: Prepared by the Maryland Department of Planning, Planning Data Services, January 2015. Historical data, 1970-2010, from the U.S. Bureau of Economic Analysis.

# *Employment Trends*

Non-residential demand from commercial and industrial electricity consumers is largely driven by their economic output (e.g., customers served, quantities manufactured, etc.). Higher output implies some additional use of electricity. Output data at the county level are not available on a consistent basis, hence, a proxy for output needs to be used. Non-farm employment has typically been relied upon for this purpose.

By virtue of the necessity to have adequate numbers of employees to achieve a desired level of output, it is a sound alternative and it is not subject to data consistency problems. Employment data at the regional level are reported in Table C-3.

***Table C-3 Historical and Projected Employment for Maryland, 2000–2025***

| Region | Total Jobs (thousands) | | | | | | Annualized Growth | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 | '00-'05 | '05-'10 | '10-'15 | '15-'20 | '20-'25 |
| Maryland | 3,065 | 3,309 | 3,345 | 3,552 | 3,752 | 3,881 | 1.54% | 0.22% | 1.21% | 1.10% | 0.68% |
| Baltimore | 1,514 | 1,609 | 1,627 | 1,754 | 1,846 | 1,900 | 1.21% | 0.22% | 1.52% | 1.04% | 0.58% |
| Washington Suburban | 1,088 | 1,183 | 1,197 | 1,252 | 1,324 | 1,372 | 1.68% | 0.24% | 0.91% | 1.12% | 0.71% |
| Southern Maryland | 124 | 147 | 156 | 162 | 174 | 184 | 3.43% | 1.15% | 0.84% | 1.39% | 1.16% |
| Western Maryland | 130 | 137 | 136 | 143 | 149 | 156 | 1.08% | -0.20% | 0.96% | 0.87% | 0.87% |
| Upper Eastern Shore | 99 | 114 | 115 | 123 | 133 | 140 | 2.90% | 0.26% | 1.36% | 1.51% | 1.03% |
| Lower Eastern Shore | 110 | 119 | 114 | 118 | 126 | 130 | 1.70% | -0.85% | 0.62% | 1.26% | 0.63% |

Source: Historical data from the U.S. Bureau of Economic Analysis, Tables CA25 and CA25N.
Projections from 2015 to 2040 prepared by the Maryland Department of Planning, Planning Data Services, January 2015.

As shown in Table C-3, while every region of the State has seen consistently positive employment growth over the past two decades, the Lower Eastern Shore and Western Maryland were the hardest hit by the recession. Growth between 2010 and 2020 is projected to be most rapid in the Southern Maryland and Upper Eastern Shore regions and slowest in Western Maryland and the Lower Eastern Shore. The City of Baltimore emerged from a recent trend of employment growth lower than the State average (2000-2005) to have a rate of employment slightly higher than the State as a whole from 2010-2015. Overall employment trends for the State tend to track those in the Baltimore and Washington, D.C. suburban regions as these areas contain the largest number of jobs. Both the Baltimore and Washington, D.C. suburban regions, and subsequently the State of Maryland in aggregate, are projected to see similar growth rates through 2025.

The economic downturn in the late 2000's continued to greatly affect employment, as well as energy consumption, and considerably slowed the employment growth rates between 2005 and 2010. Maryland's unemployment rate rose from 3.4 percent in 2007 to 7.8 percent in 2010. However, Maryland has still fared better than the United States as a whole. The nationwide unemployment rate in 2010 was 9.6 percent. As with real per capita income, the anticipated growth rebound out of the recession has considerably increased the forecast of job creation through 2025 relative to the recent, much less robust growth between 2005 and 2010. Now out of the recession, the national unemployment rate was down to 5.3% in 2015; Maryland's unemployment rate was 5.2% the same year.

Recent forecasts of economic indicators (income and employment) have tended to be overly optimistic as the United States begins to emerge from the recent recession, as evidenced by the actual levels of growth in real GDP that the U.S. has experienced in the past few years. Should GDP forecasts continue to underperform, then Maryland PSC 10-Year Plan forecasts will, by virtue of relying on overly optimistic expectations for economic indicators, predict growth in electricity consumption that does not appear as quickly as expected, other factors equal.

## *Population Trends*

Population is an important causal variable because population trends determine (in large part) the number of residential customers. Both the number of households and household size play a role in influencing electricity demand. The number of households affects the number of residential customers purchasing electricity, and changes in average household size can affect usage per customer. Larger numbers of customers mean higher demand, and smaller household sizes (for a given total population) will typically result in higher demand. While smaller households use less electricity in absolute terms, the relationship between size and usage does not scale linearly, as household electricity uses (such as heating and lighting) decline at rates lower than the decline in number of household members. Population growth and the rate of household formation are closely related, and both affect the residential use of electricity. However, household size has seen a slow but steady decline (in Maryland and the United States as a whole) as cultural and societal norms change over time. Deferred marriage and the decision to limit or forgo child-rearing have steadily lowered the size of the average household. Accordingly, increases in population lead to increases in the number of households (and hence residential customers), although these rates of change need not coincide due to changes in the size of households. Population and household data are reported in Tables C-4 and C-5.

Population data at regional and State levels are reported in Table C-4. The table summarizes historical and projected data, as well as average annual rates of growth for the period 2000-2025. The rates of growth in population have been positive since 2000 for every region of Maryland. Between 2000 and 2010, population growth in Maryland was on average 0.87 percent per year. The growth in population for the State is projected to slow through 2025. While following these trends generally, Southern Maryland and the Upper Eastern Shore have seen much more rapid population growth than that in the rest of the State. 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. Baltimore’s growth rates are expected to be the lowest during the 2015-2025 period.

***Table C-4 Historical and Projected Population for Maryland, 2000-2025***

| Region | Total Population (thousands) | | | | | Annual Rate of Growth | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2005 | 2010 | 2015 | 2020 | 2025 | '05-'10 | '10-'15 | '15-'20 | '20-'25 |
| Maryland | 5,296 | 5,774 | 6,010 | 6,225 | 6,430 | 0.87% | 0.81% | 0.70% | 0.65% |
| Baltimore | 2,512 | 2,663 | 2,746 | 2,828 | 2,886 | 0.58% | 0.62% | 0.59% | 0.41% |
| Washington Suburban | 1,870 | 2,069 | 2,182 | 2,247 | 2,326 | 1.01% | 1.07% | 0.59% | 0.69% |
| Southern Maryland | 281 | 340 | 363 | 395 | 426 | 1.93% | 1.27% | 1.73% | 1.53% |
| Western Maryland | 237 | 252 | 256 | 266 | 277 | 0.65% | 0.26% | 0.78% | 0.81% |
| Upper Eastern Shore | 209 | 240 | 247 | 261 | 277 | 1.38% | 0.61% | 1.04% | 1.24% |
| Lower Eastern Shore | 187 | 209 | 216 | 228 | 238 | 1.15% | 0.63% | 1.07% | 0.89% |

Source: Projections for the Baltimore region based on Round 8A from the Baltimore Metropolitan Council of Government's Cooperative Forecasting Committee. Projections for the Washington suburban region based on Round 8.3 of the Metropolitan Washington Council of Governments Cooperative Forecasting Committee. Aggregated data prepared by the Maryland Department of Planning, July 2014.

Household data for the State are shown in Table C-5. The table shows a summary of historical and projected data, as well as average annual rates of growth for the period 2000-2025. Household growth rates differ from population growths due to population demographics and differences in household size. Because of this, household growth captures certain variables, such as the establishment of new households by young adults or the movement of childless couples into the region, which a raw population statistic fails to convey. On average, areas with high household sizes will see higher increases in electricity demand from household growth. Inspecting the rate of change in household size can convey the type of households being added. For example, Southern Maryland is expected to see the highest growth rates in both population and housing in the State. However, it will also see the most rapid decline in household size, suggesting that the households being added may be smaller, and subsequently elicit different changes in electricity demand.

Since 2000, household size in each of the six Maryland regions has been declining or flat, and the decline is forecast to continue through 2025. For the State, average household size was level at 2.61 people during the period 2000-2015. Household size is expected to decline to 2.54 people by 2025.

***Table C-5 Historical and Projected Number of Households and Average Size of Households in Maryland, 2000-2025***

| Region | Number of Households (thousands) | | | | | Average Annual Rate of Growth | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2005 | 2010 | 2015 | 2020 | 2025 | '05-'10 | '10-'15 | '15-'20 | '20-'25 |
| Maryland | 1,981 | 2,156 | 2,248 | 2,360 | 2,470 | 0.85% | 0.83% | 0.98% | 0.91% |
| Baltimore | 959 | 1,021 | 1,057 | 1,102 | 1,141 | 0.63% | 0.70% | 0.84% | 0.69% |
| Washington Suburban | 681 | 746 | 783 | 819 | 858 | 0.91% | 0.97% | 0.92% | 0.94% |
| Southern Maryland | 98 | 120 | 129 | 143 | 157 | 2.05% | 1.45% | 2.10% | 1.88% |
| Western Maryland | 91 | 97 | 99 | 104 | 109 | 0.68% | 0.42% | 0.93% | 0.97% |
| Upper Eastern Shore | 80 | 91 | 96 | 102 | 110 | 1.39% | 0.91% | 1.33% | 1.50% |
| Lower Eastern Shore | 73 | 82 | 85 | 90 | 95 | 1.14% | 0.74% | 1.22% | 1.11% |
| | Household Size | | | | | Average Annual Rate of Growth | | | |
| Maryland | 2.61 | 2.61 | 2.61 | 2.57 | 2.54 | 0.00% | 0.00% | -0.31% | -0.23% |
| Baltimore | 2.55 | 2.54 | 2.53 | 2.5 | 2.46 | -0.08% | -0.08% | -0.24% | -0.32% |
| Washington Suburban | 2.7 | 2.73 | 2.74 | 2.7 | 2.66 | 0.22% | 0.07% | -0.29% | -0.30% |
| Southern Maryland | 2.83 | 2.8 | 2.78 | 2.73 | 2.68 | -0.21% | -0.14% | -0.36% | -0.37% |
| Western Maryland | 2.44 | 2.43 | 2.41 | 2.39 | 2.37 | -0.08% | -0.17% | -0.17% | -0.17% |
| Upper Eastern Shore | 2.58 | 2.58 | 2.54 | 2.5 | 2.47 | 0.00% | -0.31% | -0.32% | -0.24% |
| Lower Eastern Shore | 2.43 | 2.42 | 2.4 | 2.38 | 2.35 | -0.08% | -0.17% | -0.17% | -0.25% |

Source: Historical data from the U.S. Census. Forecasts prepared by the Maryland Department of Planning, July 2014.

# Summary

This appendix provides a review of the theoretical and demographic foundations used for modeling the demand for electricity econometrically. 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 electricity demand should continue to grow in Maryland.