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MARYLAND DEPARTMENT OF NATURAL RESOURCES

PPRP

Maryland Power Plants and the Environment

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

February 2022

MARYLAND POWER PLANT RESEARCH PROGRAM

Wes Moore, Governor ◊ **Aruna Miller, 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.

Joshua E. Kurtz, Secretary
Maryland Department of Natural Resources

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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 affect 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 natural 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.

The Maryland Power Plant Siting Act of 1971 directs PPRP 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 dnr.maryland.gov/pprp.

This twenty-first edition of CEIR (CEIR-21) is divided into the following chapters:

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1.1 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 during its 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 Chesapeake Bay with a temperature increase of up to 12°F. This and other issues prompted the creation of PPRP to ensure a comprehensive, integrated, objective evaluation based on sound science to investigate environmental and economic issues.

Today, PPRP continues this role by coordinating a 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 groundwater, air, land and socioeconomics for proposed power generation facilities and transmission lines.

1.2 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 applicant that is planning to construct or modify a generating facility or a transmission line must receive a permit, the Certificate of Public Convenience and Necessity (CPCN),[1] from the PSC before the start of construction. The applicant must provide notification of the CPCN application to each county or municipality in which the proposed facility or transmission line is located. 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).

The PSC, or a delegated Public Utility Law Judge (PULJ), reviews applications for a CPCN in a formal adjudicatory process that includes written and oral testimony, cross-examination and the opportunity for public participation. Parties to a CPCN licensing case include the applicant, the PSC Staff, the Office of

[1] Not all projects are subject to CPCN review. Projects under 2 MW in capacity are excluded from the regulatory definition of a "generating station." Several types of projects can receive CPCN exemptions from the PSC. These include: (1) land-based wind projects, under 70 MW in capacity, whose energy is solely on the wholesale market, pursuant to an agreement with the local electric company; (2) projects under 70 MW in capacity that export less than 20 percent of the energy generated on an annual basis; and (3) projects under 25 MW that use at least 10 percent of the energy generated annually on site. In addition, the Federal Energy Regulatory Commission (FERC) has licensing jurisdiction over non-federal hydroelectric projects located on navigable waters in the United States. Thus, Conowingo Dam's license is from FERC, while certain permits necessary for this license, such as the water quality certification, are issued by Maryland (see PUC Article 7-207.1).

People's Counsel (acting on behalf of the Maryland residential ratepayers) and PPRP (acting on behalf of DNR and six other state agencies). Other groups, such as federal agencies, county and municipal governments, and consumer and environmental organizations, as well as individuals with a specified interest, also have a right to participate as intervenors in these hearings. The broad authority of the PSC allows for comprehensive review of all pertinent issues related to power plant licensing.

The CPCN licensing process provides an opportunity for the PSC to examine all of the significant aspects and potential impacts of a proposed power facility or transmission line, including the cumulative effects, interrelations between various impacts, and county and municipality input. 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 on 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 (MEA).

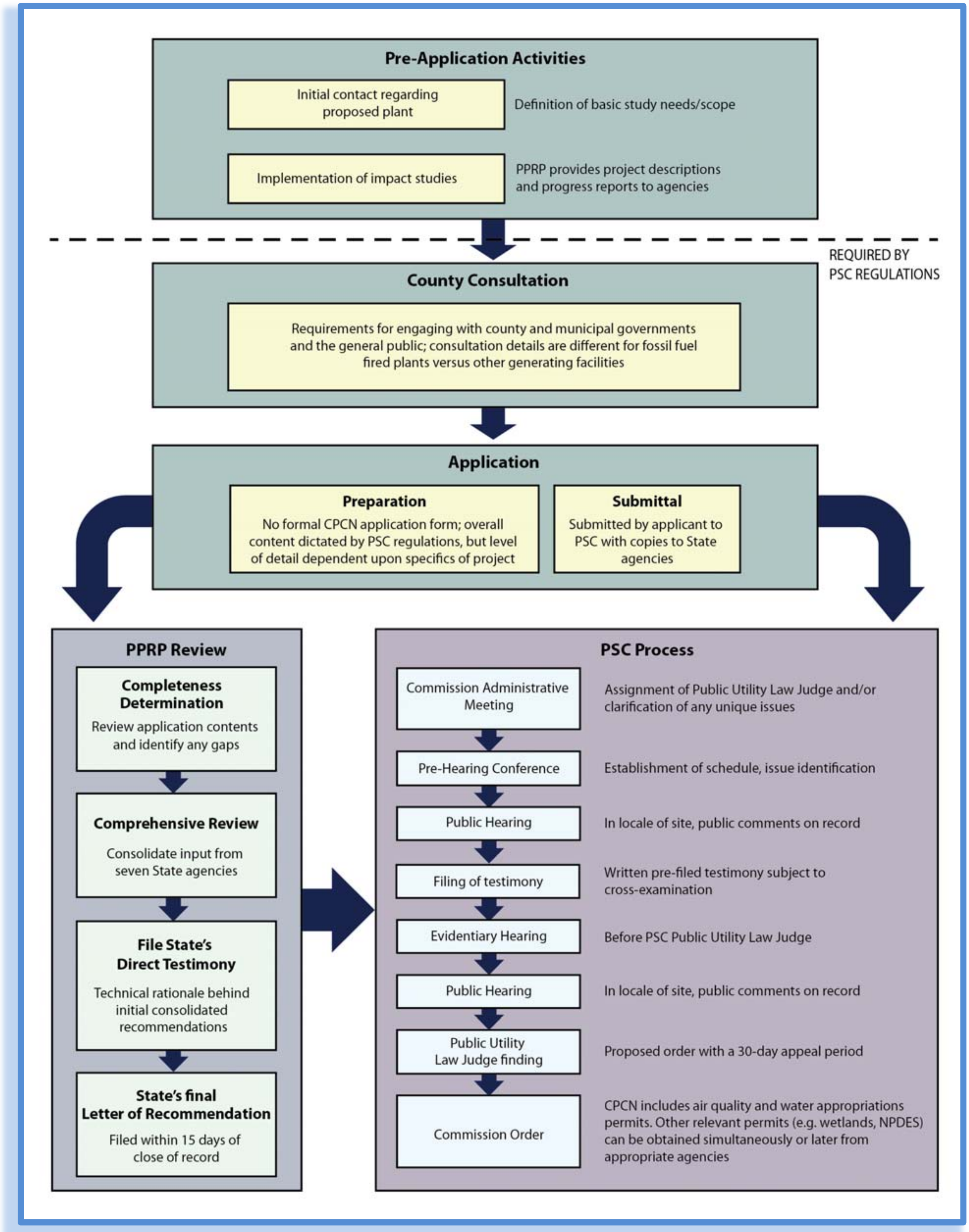
The Maryland Code, Natural Resources Article §3-306(b) requires the reviewing state agencies to forward to the PSC the results of their analysis and investigation of a CPCN application, "together with a recommendation that the certificate be granted, denied, or granted with any condition deemed necessary." For those projects that the reviewing state agencies recommend granting a CPCN, PPRP 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 innovative 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.

When multiple facilities are within proximity to each other or existing plants, or when proposed transmission lines span multiple regions and resource areas, PPRP considers cumulative impacts within the consolidated review process. In such cases, impacts to air, water, terrestrial, socioeconomic and other resources are evaluated and compared with any identified thresholds of acceptability. Additionally, the cumulative analysis identifies any license conditions that are necessary to address cumulative impacts.

In 2020, the PSC proposed to revise the regulations concerning the CPCN application process for generating stations and transmission lines. This action was taken largely in response to concerns that the process of reviewing and licensing solar facilities was causing delays that threaten Maryland's ability to meet its goal of 14.5 percent of purchased electricity coming from instate solar resources by the year 2030, established in the 2019 Clean Energy Jobs Act (see further discussion in Section 3.5.1). The regulatory revisions clarified aspects of the CPCN application requirements to help applicants, and the PSC, in determining when an application is considered complete. The new regulations also lay out requirements for CPCN applicants to demonstrate that they have coordinated with appropriate county and municipal governments. After the rulemaking process was complete, the PSC adopted the revisions on August 10, 2021. More discussion of the revisions is included in Section 2.2.

Figure 1-1 illustrates the elements of the CPCN licensing process.

Figure 1-1 CPCN Licensing Process



The primary steps in the CPCN licensing process are described below.

Pre-application. The PSC revised its CPCN regulations in 2021 to clarify several aspects of the CPCN application process. For proposed solar facilities, the applicant must contact any county or municipality in which a portion of the project is located, at least 90 days prior to submitting an application. The applicant must show the PSC a good-faith effort regarding their communication with the county or municipality prior to submission of the application to the PSC. Additionally, at least 45 days prior to the submittal of the application, the applicant must meet with PPRP to provide an overview of the proposed project. Through a diligent and thorough pre-application process, a prospective developer can limit the risk of submitting an incomplete CPCN application by making changes during the preliminary design phase to minimize negative 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 coordinates with other state agencies to evaluate the potential impacts of the proposed project on Maryland's resources, including water (surface and groundwater), air, land, ecology and socioeconomics (e.g., 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 new electric generation, there is no regulatory requirement to demonstrate need. The demonstration of need for new electric generation was eliminated when Maryland adopted retail electric competition, also known as electric restructuring, in 1999. Instead, the development of new electric generation is left to the competitive market; applicants seeking a CPCN for a generating unit do not have to show that the state has a need for the power.

PSC Process and PPRP Review. The PSC typically assigns a PULJ to the licensing case at a preliminary administrative meeting after an application for a CPCN has been received.[2] Within 45 days of assignment to a PULJ, PPRP must provide a summary of the completeness of the application. If the application is deemed complete by all parties, the PULJ then schedules a prehearing conference to establish an overall procedural schedule, including dates for evidentiary and public hearings. The adjudicatory process commences with a discovery phase. The applicant files direct testimony to summarize the impact analyses that have been completed and provide 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 analyses in direct testimony. PPRP's testimony, presented on behalf of the various state agencies, typically includes initial recommended license conditions along with supporting analyses (in the form of testimony and an independent project assessment report), 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 likewise subject to cross-examination. The PULJ also presides over public hearings to accept comments on a project from the general public.

[2] The PSC may also choose to conduct *en banc* hearings before all five Commissioners.

The PULJ takes into consideration the briefs filed by the applicant, the state and any other parties; reviews the recommended license conditions and public comments; 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 – Evolving Energy Topics in Maryland

Systems for generating electricity and providing it to customers have changed significantly over the past 20 years, and they continue to evolve. With the rise of digital technology, distributed generation and demands for decarbonization, the traditional electric utility framework and regulatory structures are being transformed. This chapter provides an overview of key energy topics and how they are affecting the state's electricity infrastructure.

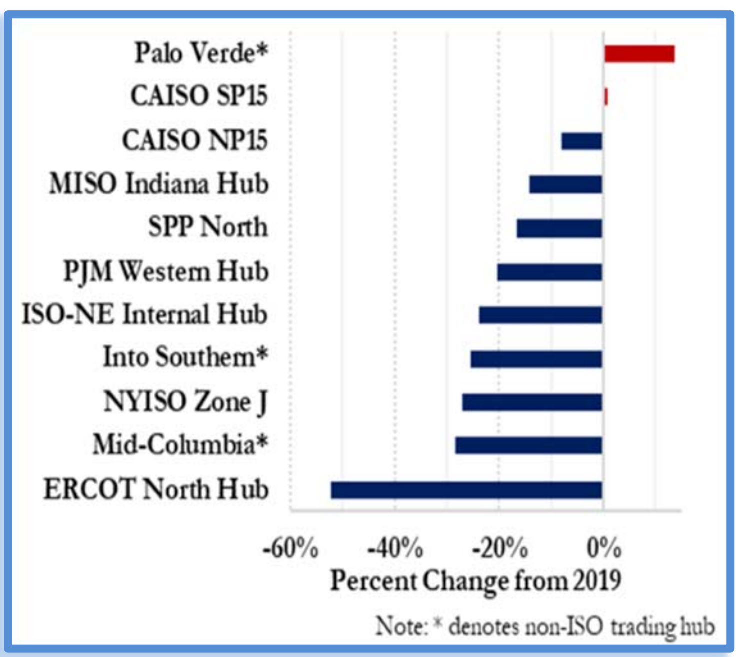
2.1 COVID-19 Impacts on Energy Usage in 2020

The emergence of the COVID-19 pandemic in 2020 presented unique challenges unlike any faced by the electric power industry in modern times. COVID-19 forced state regulatory bodies to adopt mitigation strategies to protect customers and utilities alike from unprecedented circumstances. The pandemic also curbed energy demand in 2020.

Electricity

In February 2020, a mild winter heating season was beginning to wind down, and with it the continued gradual decline of electricity prices nationwide. Coupled with the continued shift of the nation's generation fuel mix to natural gas and renewables, the mild winter weather was keeping energy prices low. By the end of March 2020, however, energy prices began a spring collapse, ushered on by the pandemic. Figure 2-1 visualizes this year-over-year (YOY) change in energy prices at key regional market hubs across the U.S.

Figure 2-1 Change in Annual Average Day-Ahead On-Peak Electricity Prices for Selected Nodes, 2019 to 2020

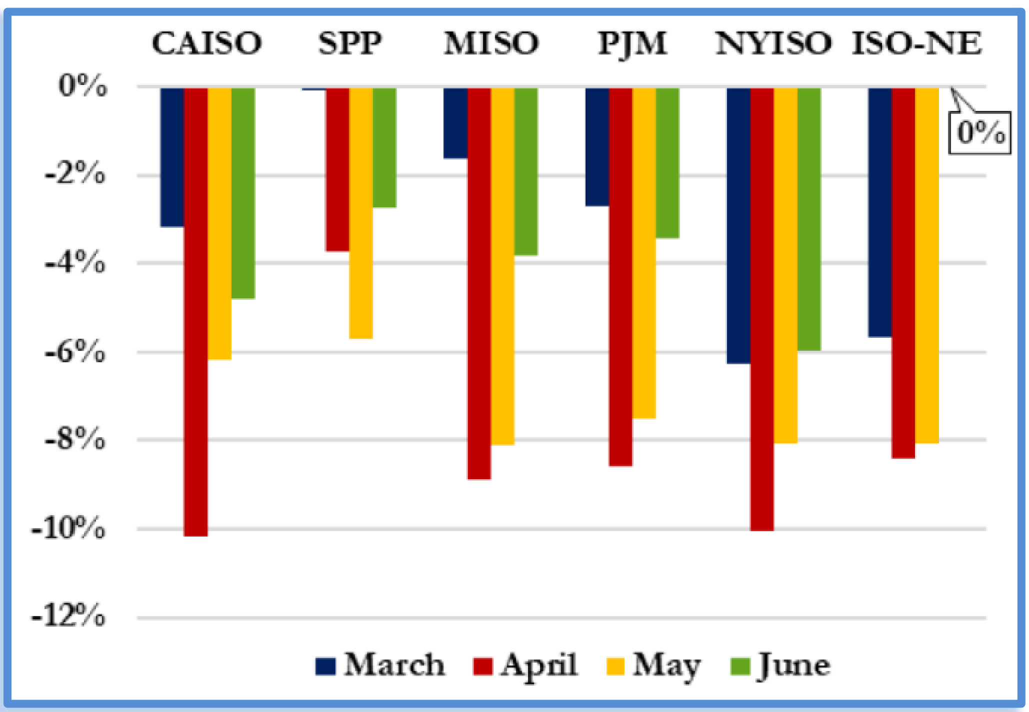


Source: Federal Energy Regulatory Commission State of the Market Reports 2020 Report.

The stay-at-home policies implemented by state governments changed typical energy consumption patterns. The U.S. Energy Information Administration's (EIA's) "Annual Energy Outlook" noted that the electric power sector experienced declines in electric power generation and power demand. Furthermore, working from home shifted the hourly consumption load curve and reduced morning and evening peaks, leaving a flatter, single-peaked load shape.

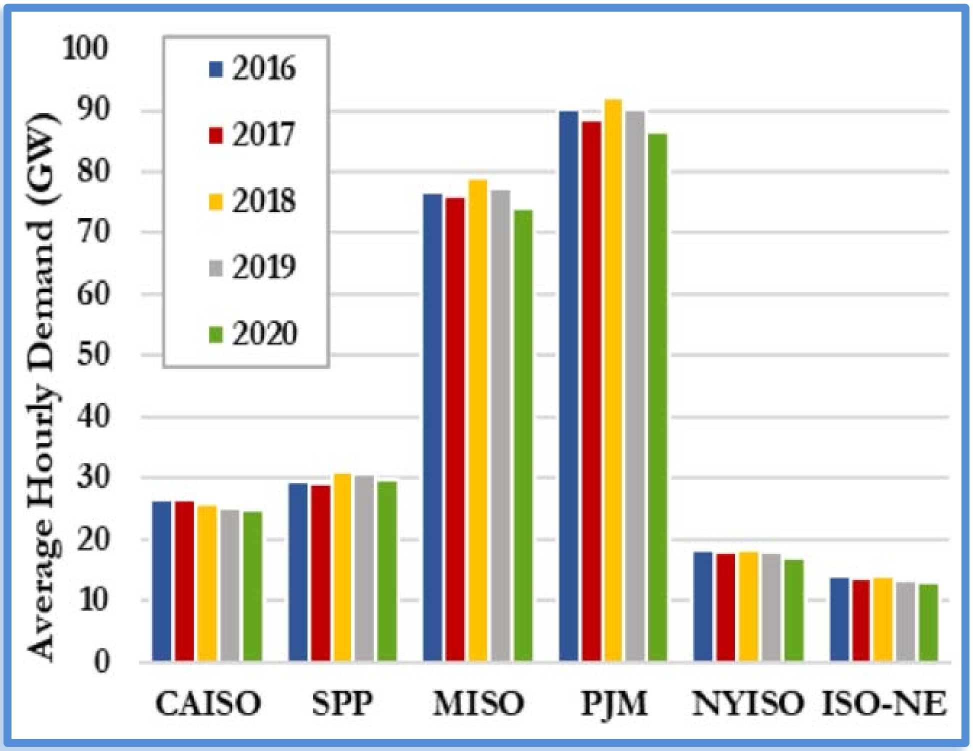
Figure 2-2 provides a visualization of just how profound the decreased consumption was across each of the nation's six major regional transmission organizations and independent system operators (RTOs/ISOs), relative to historical averages. In April 2020, five out of six RTO/ISOs registered more than an 8 percent decrease in weather-adjusted load compared to the historical average. Due to stay-at-home measures, residential load increased by about 1 percent as employers implemented work-from-home policies. The locational shift in day-to-day work was a large reason for the drop in commercial sector load, which totaled around 6 percent overall in 2020. The largest driver of a reduction in load was the industrial sector, which registered a YOY 8 percent reduction. In total, electricity demand in the U.S. recorded a 4 percent reduction over the historical three-year average, with declines observed in every region (see Figure 2-3).

Figure 2-2 Percent Change in Weather-Adjusted Load in 2020 from Three-Year Historical Average



Source: Federal Energy Regulatory Commission State of the Market Reports 2020 Report.

Figure 2-3 Average Hourly Demand (2016-2020)



Source: Federal Energy Regulatory Commission State of the Market Reports 2020 Report.

Natural Gas

Similar to what occurred in the electric sector, COVID-19 reduced natural gas demand, which put further downward pressure on prices. The Henry Hub Index (the national pricing benchmark) recorded a 20 percent reduction in average annual spot prices, averaging $1.99 per million British thermal units (MMBtu) in 2020. In fact, according to data presented in PJM Interconnection LLC's (PJM's) "State of the Market Report" for 2020, all major natural gas trading hubs experienced a decrease in annual average spot prices relative to the five-year average. Despite slightly lower YOY production of natural gas in 2020 (around a 2 percent decrease overall), the large natural gas storage inventory built in 2019, combined with the mild 2019/2020 winter heating season, allowed the U.S. to remain above the five-year national gas inventory average in 2020.

Impacts of COVID-19 on Maryland's Utilities

In July 2020, the Maryland Public Service Commission (PSC) convened Public Conference 53 (PC53). The Commission asked a series of questions regarding:

- Changes in utility operations;
- Changes in customer usage and subsequent utility load projections;
- Revenue impacts and relevant customer payment behaviors;
- Impacts to utility programs; and
- Recommendations on actions the PSC could take related to COVID-19 impacts.

The Commission held virtual hearings on August 27, 28 and 31, 2020.[3] The Commission heard from Maryland's utilities that, as expected, some energy load shifting between residential, commercial and industrial classes (as more customers moved from office to home) was experienced. As previously discussed, the stay-at-home orders shifted load from commercial and industrial sectors to the residential sector. As such, most utilities saw either a modest drop in overall energy consumption, or a relatively minor drop as shifts in load from commercial and industrial customers to residential customers balanced out.

As PC53 continued, the focus of the hearings shifted to the topic of the growing customer debt and the upcoming expiration of the governor's moratorium on utility disconnections.

Utility Service Disconnection Moratoriums

By May 2020, utility regulators in all 50 states and the District of Columbia had enacted mandatory or voluntary service disconnection moratoriums, which allowed customers to continue receiving utility service, even if they were unable to pay their utility bills due to economic hardship. State regulators have only recently begun to grapple with cost recovery issues related to losses from unpaid customer utility bills. In fact, there are only a handful of states whose regulators have issued orders related to recovery, and Maryland is one of those.

One such order issued by the Maryland PSC in December 2020 involved Baltimore Gas and Electric Company (BGE). The PSC order approved recovery of the pandemic-associated regulatory assets for BGE over five years, with the unamortized balance included in rate base. These regulatory assets include lost revenues for late payment fees and service application/reconnection fees, as well as certain incremental operations and maintenance (O&M) costs (e.g., personal protection equipment, incremental cleaning services, overtime labor and vehicle cleaning, among other cost increases). The regulatory assets are calculated net of cost savings for travel, entertainment expenses and lower utility costs. The PSC approval allowed BGE to include the lost revenues for late payment fees and service application/reconnection fees in the regulatory assets but not in rate base (i.e., the utility is not allowed a return). Further, the PSC approved a methodology for calculating incremental write-offs for future disposition. In June 2021, the PSC allowed Potomac Electric Power Company (Pepco) to recover COVID-19 deferred balances over a five-year period but with no return on the unamortized balance.

[3] psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

2.2 Rulemaking 72 Impact on CPCNs

During 2021, the Maryland PSC conducted a formal rulemaking process to revise the regulations that govern CPCN applications (Code of Maryland Regulations [COMAR] 20.79). In its Notice of Intent announcing the rulemaking, the PSC stated that "some solar developers have expressed concern regarding delays due to zoning processes at the local level and the statutory due consideration that the Commission must give to local concerns." Rulemaking 72 (RM72) was intended to provide additional clarity on CPCN application requirements and thus make the CPCN application review process more efficient. The PSC recognized that process improvements will ultimately help the State of Maryland in meeting its renewable energy development goals under the Clean Energy Jobs Act of 2019, which requires that 14.5 percent of the state's energy must come from instate solar resources.

RM72 provided an opportunity for a broad group of stakeholders to make suggestions, and review and comment on draft regulatory language. County governments, solar power developers, non-governmental organizations, PPRP and individuals submitted comments and participated in the process.

As a result of the rulemaking process, the COMAR regulations now include the following elements:

- Pre-application requirements for proposed new generating facilities that are fueled by fossil fuels (coal, oil, natural gas). These requirements include public notifications, informational meetings and designation of a community liaison officer. Applicants must also evaluate environmental justice considerations and determine potential impacts to low-income communities.

- Pre-application requirements for other proposed generating facilities such as solar or other renewables. These requirements include specific materials that need to be provided to any county or municipality where the project would be located. An applicant must meet with PPRP prior to submitting a CPCN application, and must request a meeting with the affected county (and municipality if relevant).

- More detailed description of the information and impact evaluations required in an application. The regulations provide additional descriptive guidance for the level of detail that an applicant must include regarding environmental information, natural resources and socioeconomics. This portion of the regulations serves as a checklist for determining whether an application is complete. This completeness determination must be made within 45 days after the PSC assigns a Public Utility Law Judge (PULJ) to the case, and the PSC must issue a decision on the CPCN within 365 days after the application is deemed complete (for a new generating facility), or 150 days after completeness (for a facility modification).

2.3 Decommissioning

Decommissioning refers to the process of permanently removing a facility from operation. In the power industry, plant decommissioning can include removing some or all of the physical components; however, some power plant structures may remain in place, especially if they may have value for future reuse or redevelopment. As the number of renewable energy projects in Maryland grows, there has been an increased focus on plans for decommissioning these facilities in the event a facility becomes non-operational.

New generation projects are subject to increased scrutiny regarding long-term planning and end-of-life concerns, including decommissioning and subsequent land availability. The increased attention can be attributed, in part, to development pressure and sensitivity to land use issues in the state. Moreover, utility-scale renewable energy in the form of wind and solar requires significantly larger amounts of land to generate the same amount of power as a traditional fossil fuel or nuclear power plant. Recent closures of coal-fired power plants that are no longer economically viable have also raised awareness of the end-of-life issues associated with power plants. The subsections below provide an overview of power plant decommissioning.

2.3.1 Renewable Energy Facilities

Solar energy generation capacity operating in Maryland increased from 0.1 megawatts (MW) in 2007 to 1,432 MW in 2020. More than half of this capacity is distributed solar on commercial, industrial and residential sites (either rooftop or ground-mounted), which does not require a CPCN from the PSC. As of September 2021, the PSC has granted CPCNs to 39 solar projects representing 1,024 MW of capacity; of this total, 179 MW have been constructed and placed in operation. The first wind energy facilities in Maryland were constructed in the 2000s and capacity has essentially stopped, as no new wind turbine construction has occurred in Maryland since 2015 (see Section 3.1.5 for more details on the status of solar and wind energy in the state).

Technical Issues Associated with Renewable Energy Decommissioning

Anticipated impacts from decommissioning renewable energy facilities in Maryland are dependent upon a number of factors relating to past and future use of underlying lands, their location, and the extent to which the surrounding economic landscape changes over their operational life. Few utility-scale solar and wind projects have reached the end of their 20- to 30-year lifespan in the U.S., and none in Maryland. The projects that have come to their end-of-life horizons, particularly wind facilities, have more often been repowered than decommissioned. Repowering utility-scale photovoltaic (PV) facilities is also becoming an attractive option for the solar industry.

At the end of a utility-scale solar or wind power plant lifespan, components are expected to be decommissioned or the facility could be replaced or repowered. The reclamation phase includes removing the power generating equipment and all infrastructure, recontouring the site and access roads, replacing or supplementing soil, and revegetation to suit the original land use. This process can cause transportation impacts similar to construction-related impacts. Passenger vehicle traffic will be generated by a “de-construction” labor force, while trucks will be used to transport excavation equipment and cranes for dismantling project components and site restoration.

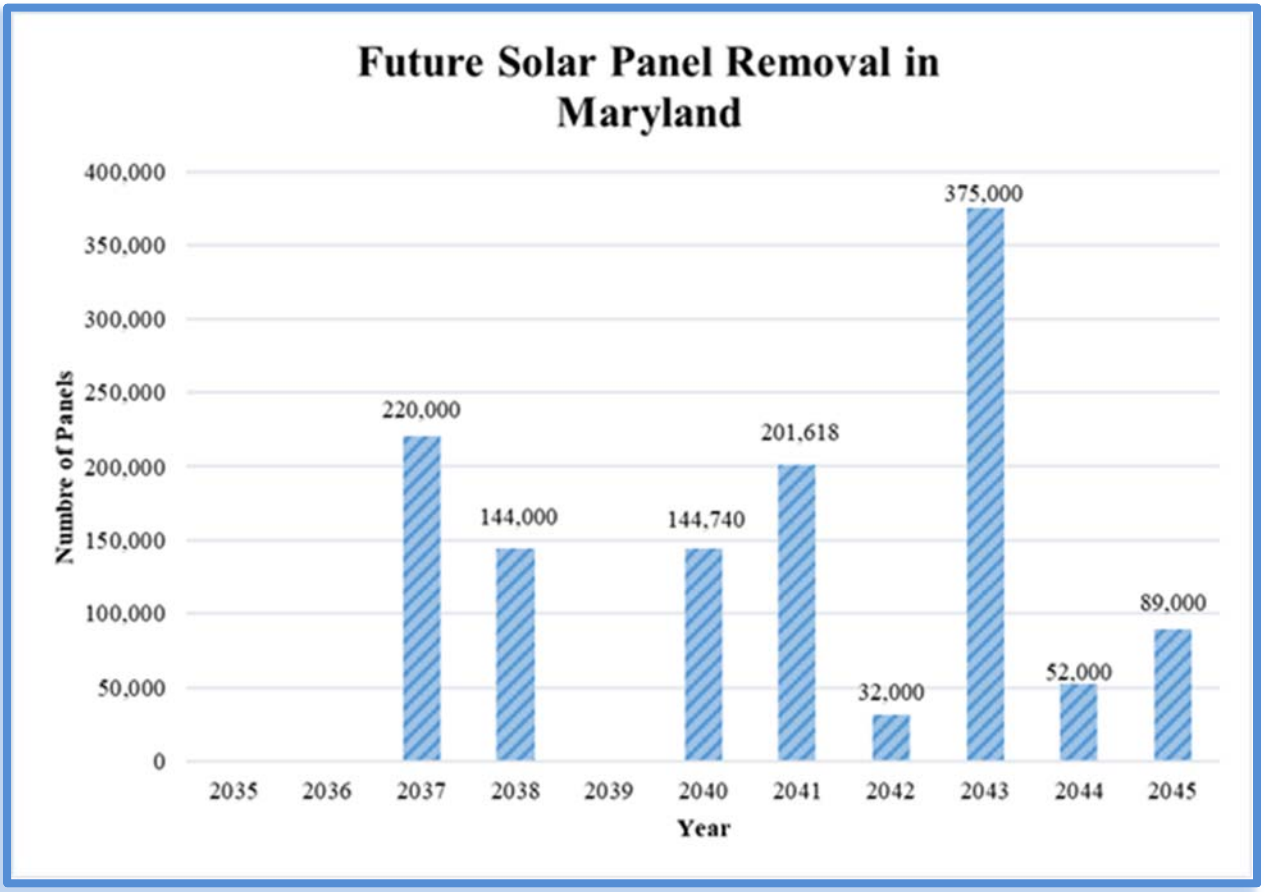
The goal of reclamation is to develop a fully functioning ecosystem after disturbance. For solar, the restoration requirements may be dependent on the post-decommissioned use of the site. For a site previously used for agriculture, restoration of a site to its condition prior to development typically means being returned to an agriculturally productive state that allows for agricultural practices. This requires complete removal of below-ground structures and cabling. Decommissioning the site for the resumption of agricultural production may also have to address soil compaction caused by equipment used to construct the facility. In some cases, restoration for agricultural use may not be the best option if farming the property is no longer financially or otherwise feasible, as may occur when an area's agricultural economy changes or is overtaken by development. The landowner or operator may choose to leave designated below-grade foundations to avoid soil disturbance and erosion during decommissioning. This suggests that some flexibility needs to be built into decommissioning plans since future uses of land under solar projects are uncertain.

While the area of potential effect of a wind energy project is visually extensive, its physical footprint is relatively small compared to solar. On agricultural parcels, land use impacts are similar to transmission line structures. Similar to solar projects, decommissioning a wind energy project involves the removal of all physical material and equipment, including underground cables. Concrete wind turbine foundations, which are as deep as 15 feet below the surface, may be only partially removed. Access roads, operations and maintenance buildings and other facilities, such as substations and interconnections, are also removed. Wind turbine blades are difficult and expensive to transport and are typically cut into sections that can be hauled to landfills or recycling centers in standard trailers. While we have not yet seen wind power facilities in Maryland being decommissioned or repowered, it is expected that many wind turbines may undergo repowering to extend their useful life in the future. The repowering of a wind project also results in the need to recycle or dispose of wind turbine blades and the nacelle, since these items are usually replaced.

Many common components of renewable energy systems, such as the copper and aluminum found in cables, or the steel found in array supports and turbine towers can be recycled and/or disposed of locally. However, components of both solar and wind energy systems present a disposal challenge. Solar panels contain trace amounts of potentially hazardous waste and though some panels are refurbished or repurposed, others end up in a landfill as there is no solar PV-specific waste law in the United States that requires the recycling of end-of-life panels. Though there are a few national recycling programs for these panels, the transport of retired solar PV components needs to be a cost and logistical consideration in solar decommissioning plans.

Figure 2-4 illustrates the significance of the waste management issue presented by future solar decommissioning from utility-scale solar facilities. Assuming that utility-scale solar facilities currently in operation are dismantled after 25 years, about 25,000 tons of solar panels will need to be recycled or disposed of by 2045. Adding in smaller solar facilities that do not require CPCNs could approximately double the number of panels that will reach the end of their design life within that time frame. By comparison, total solid waste generated in Maryland every year is more than 9 million tons.

Figure 2-4 Projected End of Lifetime for Utility-Scale Solar Panels in Maryland



Wind turbine blades are a concern in the decommissioning of utility-scale wind energy projects. Blades are comprised of resin and fiberglass that produce dust and toxic gases when sectionalized onsite. However, this allows blades to be transported on standard-length trailers. Even when the turbine blades are reduced in size, most municipal landfills do not have the capacity or equipment to process them. Because of their composition, wind turbine blades cannot be easily recycled or repurposed. Recycling options in the U.S. include a start-up company that produces thermoplastic fiberglass pellets and construction panels from turbine blades, ultimately serving a variety of industrial applications. Like solar PV, wind project decommissioning faces logistical challenges with transporting turbine blades to a limited number of facilities that can accept them. That being said, the recycling of these materials is at an early stage and the market will change significantly over time.

Economics of Decommissioning

States and counties across the U.S. are experimenting with a variety of approaches to ensure that there is sufficient funding to decommission a solar project when the time comes, although letters of credit and bonds appear to be the most popular options. The estimated costs of decommissioning solar projects vary widely, in large part because of the volatility of salvage values that can at least partly offset decommissioning costs. Because of the wide variation in decommissioning costs and salvage value, it is not possible for Maryland to ensure that decommissioning plans filed today or in the near future will include accurate cost and benefit forecasts. However, the state can assess whether these forecasts have been prepared by a responsible party and appear to be reasonable.

CPCN conditions now require periodic updates from solar project developers to include decommissioning and salvage cost estimates, and usually require updates every five years. As long as a project's approval is conditioned upon these forecasts (and any associated financial assurances) being updated regularly, today's decommissioning plans can be updated over time with better data, well before the decommissioning plan is executed.

2.3.2 Fossil Fuel Plants

Power plants fueled by coal, and to a lesser extent oil, produced the majority of the state's electricity from the 1960s through the beginning of the 21st century. As natural gas has become a less expensive fuel and solar and wind energy has become more cost-competitive, generating plants that burn coal and oil are operating for fewer hours. The R.P. Smith facility in Williamsport was the first coal-fired plant in Maryland to be decommissioned, in 2012. GenOn decommissioned its Maryland coal-fired units at Chalk Point (in Prince George's County) in June 2021, after having completed the retirement of these units and the Dickerson units (in Montgomery County) on August 13, 2020. Table 2-1 lists the announced or projected decommissioning schedule for the remaining coal-fired plants in the state.

Table 2-1 Projected Operational End Dates for Coal-fired Power Plants in Maryland

Plant Name	Projected Decommissioning
Morgantown	2022
Brandon Shores	2025
Herbert A. Wagner	2025
Warrior Run	2035

For power plants fueled by fossil fuels (as well as biomass and waste-to-energy facilities), there are no regulatory requirements for owners and operators to have plans in place during operation that address future decommissioning activities. Decommissioning of a fossil fuel-fired generating station must be done in accordance with Clean Air Act requirements to ensure that dust, particulates and other air pollutants are controlled. Decommissioning and reuse of a power plant site requires site investigation and proper management of any contaminated soils and waste materials, including off-site disposal if necessary. The actual decommissioning would be regulated according to relevant requirements for site remediation and land redevelopment, depending upon the use intended for the site after decommissioning. Because of the infrastructure in place at former power plant sites, such as access to roads, rail, water and workforce resources, these sites are attractive for subsequent industrial redevelopment.

2.3.3 Nuclear

Nuclear power stations are subject to extensive federal regulations addressing decommissioning. In 1974, the Energy Reorganization Act established the U.S. Nuclear Regulatory Commission (NRC), which regulates all aspects of power reactors, including decontamination and decommissioning. The Act requires owners to provide the NRC with early notification of planned decommissioning activities and allows no major decommissioning activities to be undertaken until after certain information has been provided to the NRC and the public.

When a power company decides to permanently close a nuclear power plant, the facility must be safely decommissioned by removing it from service, reducing residual radioactivity to a level that permits release of the property and terminating its operating license. There are three decommissioning strategies, Decontamination (DECON) where the facility is immediately dismantled; Safe Storage (SAFSTOR) where the facility is monitored in a condition that allows for radioactive decay prior to dismantling; and entombing the entire site in concrete (ENTOMB) where the radioactive contaminants decay over time in concrete until the property is safe. These strategies can be standalone and/or combined. To date, no NRC-licensed facility has requested the ENTOMB strategy.

Successful decommissioning of nuclear power plant facilities requires early communication and documentation with the NRC and the public. There are five documentation steps to the decommissioning process, including (1) certification to the NRC of permanent cessation of operations and removal of fuel; (2) submittal and implementation of the post-shutdown decommissioning activities report (PSDAR); (3) submittal of the license termination plan (LTP); (4) implementation of the LTP; and (5) submittal of the final status survey report (FSSR) for the facility.

After an LTP is approved, the NRC staff will periodically inspect the decommissioning operations at the site to ensure compliance. These inspections will normally include in-process and confirmatory radiological surveys, all within 60 years of permanent cessation of operations, unless otherwise approved by the NRC. At the conclusion of decommissioning activities, the licensee will submit an FSSR, which documents the final radiological conditions of the site, and requests that the NRC either: (a) terminate the 10 CFR Part 50 license; or (b) if the licensee has an independent spent fuel storage installation (ISFSI), reduce the 10 CFR Part 50 license boundary to the footprint of the ISFSI.

2.3.4 Hydroelectric

There are several factors that may lead to the decommissioning of hydroelectric projects. These include:

- High cost of operation relative to alternatives, with significant costs to relicense and implement new license conditions.
- Significant investment needed to address aging assets/equipment failure.
- Disproportionate infrastructure costs—maintenance/repair of conveyance systems, roads, bridges, etc.
- Costlier environmental mitigation requirements.

Maryland currently has six operating hydroelectric projects and one licensed but not yet constructed project at an existing non-power dam. Of these, all but one are licensed by the Federal Energy Regulatory Commission (FERC), which has jurisdiction if the license were to be surrendered and the project decommissioned. To surrender a license, the licensee must prepare an application in accordance with FERC regulations. Each application for license surrender must include the reason for surrendering the license, a copy of the license and all amendments associated with the project. All licensees filing a surrender application with FERC must address issues such as dam and public safety and environmental resources.

Surrender applications for existing projects also need to include a plan for decommissioning the project. Decommissioning can include leaving project features in place for other uses, or removal of project features and site restoration. The plan should address any dam safety or environmental concerns that could remain after the license is surrendered.

The only currently operating hydroelectric facility in the state without a FERC license is Deep Creek Hydroelectric Project, which was released from FERC jurisdiction in the early 1990s, and since that time has been operating under a Water Appropriations Permit from the Maryland Department of the Environment. As recently as 2008, four additional facilities were included in the list of state hydroelectric projects. These projects were all very small and have been abandoned for some time; the dams have remained in place without decommissioning plans. Only one of the four was licensed by FERC (Gilpin Falls in Cecil County). FERC requested a license surrender in 2010 and terminated the license in 2011. No decommissioning plan was developed or implemented.

2.4 Transforming Maryland's Electric Grid

In December 2016, the Maryland PSC initiated Public Conference 44 (PC44) with the intent of ensuring that Maryland's electric grid is customer-centered, affordable, reliable and environmentally sustainable. To achieve this goal, the PSC reviewed Maryland's electricity distribution system to explore areas to maximize benefits and choice to Maryland electric customers, and, in particular, assess how the evolving electric grid impacts low- and moderate-income ratepayers. In January 2017, after reviewing public comment on its initial scoping, the PSC settled on six specific issues, for which it set up individual workgroups:

- Rate Design
- Electric Vehicles
- Competitive Markets and Customer Choice
- Interconnection Process
- Energy Storage
- Distribution System Planning[4]

2.4.1 Rate Design

The Rate Design Workgroup is responsible for developing two time-of-use (TOU) pilot programs, one for customers that receive electric supply from standard offer service (SOS) and another for customers that receive electric supply service from a retail supplier. In August 2017, the Workgroup provided the PSC its first Workgroup report, which proposed two opt-in TOU pilot programs. The PSC found the proposals to be lacking specific details and provided guidance to the Workgroup to further develop the pilots. In February 2018, the Workgroup filed a second report requesting a PSC decision on six points regarding the pilots.

Ultimately, the PSC approved a voluntary, opt-in residential time-varying rate pilot program for BGE, Potomac Electric Power Company (Pepco) and Delmarva Power and Light Company (DPL or Delmarva).[5] The pilot will run through the end of 2021, with new time-varying rates effective as of April 1, 2019. Table 2-2 compares the PSC-approved TOU rates ("Peak" and "Off-Peak") with the current SOS rate ("Default") for each approved utility pilot. The peak-hour rates are significantly higher than off-peak rates.

[4] The PSC lists Distribution System Planning as a sixth issue, but exploration of this issue is dependent upon available funding. To date, the PSC has not undertaken this issue.

[5] Maryland Public Service Commission, Mail Log No. 220322.

Table 2-2 TOU Pilot Residential Pricing

	Summer (Jun 2019 - Sept 2019, Jun 2020 - Sept 2020)				Winter (Oct 2019 - May 2020, Oct 2020 - May 2021)			
	Peak	Off-Peak	Peak to Off-Peak Ratio	Default "R" Rate	Peak	Off-Peak	Peak to Off-Peak Ratio	Default "R" Rate
BGE	$0.347	$0.075	4.65	$0.110	$0.362	$0.076	4.76	$0.113
Pepco	$0.399	$0.091	4.38	$0.158	$0.419	$0.099	4.22	$0.132
DPL	$0.507	$0.087	5.82	$0.142	$0.514	$0.089	5.77	$0.142

Notes: Rates for each period are simple averages of all variable components of rates in each month, as provided by the JUs. Variable rates include all applicable volumetric charges for transmission, distribution, generation, administrative credits, receipt taxes, stabilization adjustments, procurement adjustments, and county surcharges. The default "R" rate column refers to the flat volumetric rate tariff that applies to the majority of residential customers who have not opted to purchase energy from a third-party supplier.

Source: PC44 Time of Use Pilots: End-of-Pilot Evaluation, October 4, 2021 (Attachment 1. Brattle Group Analysis) brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf.

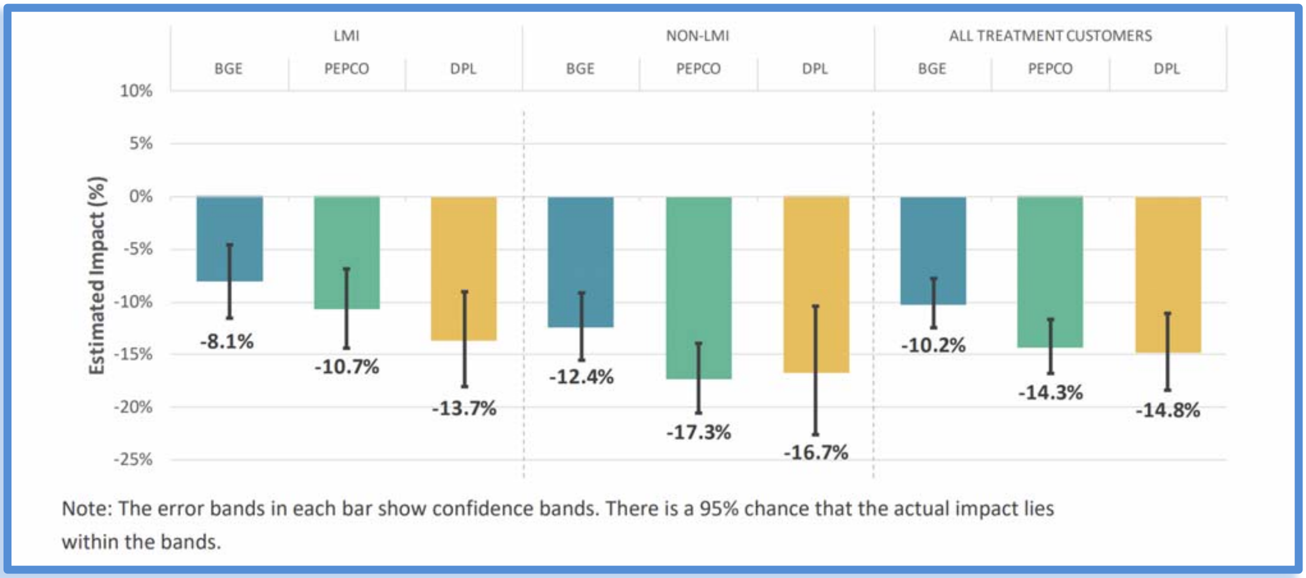
In May 2018, the PSC directed BGE, Delmarva and Pepco to issue requests for proposals (RFPs) related to the retail supplier TOU pilot. The RFPs were designed to solicit two proposals, one for a retail supplier TOU with a 3-5 hour summer on-peak period and optional peak during winter, and one for innovative retail supplier TOU rates. Upon reviewing the bids received through the RFPs, the PSC ordered the utilities to reject all of the bids received, noting that they were not compliant with the requirements of the RFPs. After receiving the results of the second solicitation, the PSC directed Pepco and BGE to partner with the selected suppliers.[6] Pepco partnered with Inspire Energy Holdings LLC for their Innovative Load Shaping Proposal and BGE partnered with Constellation NewEnergy Inc.

Preliminary results for the first year of the pilots indicate statistically valid findings for the majority of the pilot metrics and the pilot rates remain in effect. The TOU pilots had an enrollment rate ranging from 0.5 percent to 1.9 percent with approximately two-thirds of customers who participated experiencing a decrease in electric bills without changing their load behavior. While one would expect usage to shift to off-peak hours as a result of the TOU pricing, the pilots found that this did not occur. There were also savings experienced during the non-summer months (October through May); however, that reduction was not as significant as summer months (June through September), 3-5 percent compared to 8-16 percent, respectively. Overall, pilot participants experienced a 5-10 percent reduction in their bills. Figure 2-5 shows the decrease in usage during peak summer weekdays by utility for the first year of the pilot.[7]

[6] Maryland Public Service Commission, 2020 Annual Report. RM62. psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

[7] PC44 Time of Use Pilots: Year One Evaluation.

Figure 2-5 Pilot Year One – Summer Peak Weekday Usage



Source: PC44 Time of Use Pilots: Year One Evaluation.

In addition to the TOU, the PSC directed Pepco and BGE to engage with the shortlisted suppliers to develop two innovative rate options aimed to shift and shape residential customer load. Due to the COVID-19 pandemic, the supplier pilots were postponed until door-to-door sales could restart and the pilot could take place during a time when retail conditions were more likely to recur in the future.[8]

2.4.2 Electric Vehicles

The Maryland PSC, recognizing the importance of electrification of the transportation industry, charged the Electric Vehicles (EV) Workgroup with the following goals:

- Making currently available EV tariffs apply in other utility territories…;
- Allowing retail choice for EV tariffs in all utility territories;
- Considering additional rate structures for customers with EVs, including EV-only time-varying rates;
- Planning a limited utility infrastructure investment in electric vehicle supply equipment (EVSE), working with private industry and identifying locations at which it is difficult to attract private capital for EVSE investment;
- Developing a strategy in partnership with other state agencies and in consultation with our [PSC] utilities to address grid-related costs associated with vehicle fleet electrification;
- Considering unique tariffs for corporate fleets and workplace & commercial EVSE; and

[8] Maryland Public Service Commission, 2020 Annual Report, psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

- Partnering with Maryland Department of Transportation and the auto industry to promote the cost savings and other benefits of EV rate structures.[9]

The EV Workgroup submitted its non-consensus EV recommendations for the PSC's consideration in January 2018. In January 2019, following a hearing on the recommendations, the PSC concluded that the implementation of a coordinated and well-planned charging infrastructure will support the growth in EVs in Maryland. The PSC issued an order approving a five-year EV charging infrastructure pilot program, which is intended to test a limited EV charging deployment, and thus to limit exposure to Maryland ratepayers.[10] The PSC also required utilities to submit a benefit-cost analysis in support of applications for cost recovery associated with utility EV programs. The PSC expects these pilots to provide the needed insight into Maryland's trajectory toward achieving its goal of 300,000 Zero Emission Vehicles by 2025 and assist in determining the appropriate next steps for implementing an efficient and reliable charging network in Maryland. The PSC approved the following pilot programs:

- Residential
    - Rebates for a limited number of smart chargers
    - Lower off-peak rates for charging electric vehicles
    - Whole-house TOU rates for those who own electric vehicles
- Nonresidential
    - Rebates for smart chargers in multi-unit and multi-tenant buildings
    - Demand charge credits for commercial customers who install chargers
- Utilities to own and operate a limited number of public charging stations
- BGE's managed charging pilot study which could provide a potential mechanism for smoothing out electric vehicle TOU charging demand throughout the off-peak period.

The utilities will report to the PSC biannually, with a final report due in March 2024.

In 2017, BGE reported the results of its charging pilot study to smooth charging demand throughout the off-peak period. The study determined pilot participants used more energy than the overall EV user population, which also exceeds the average BGE customer. However, through the pilot, participants shifted their charging behavior to off-peak periods and 25 of the 30 participants experienced a savings on their bill compared to standard rates. Additionally, there was a strong correlation between the pilot participants and their participation in other BGE programs designed to control or shift energy usage. Overall, 91 percent of the participants were satisfied with the EV rate provided in the pilot.

On July 31, 2019, the PSC approved a modified version of Southern Maryland Electric Cooperative's (SMECO's) May 14, 2019 request to install 60 utility-owned and -operated public chargers in a program comparable to the four investor-owned utilities (IOUs), raising the total number of approved public-

[9] Maryland Public Service Commission, Mail Log No. 212176, pp. 8-9.

[10] Maryland Public Service Commission, Order No. 88997, psc.state.md.us/wp-content/uploads/Order-No.-88997-Case-No.-9478-EV-Portfolio-Order.pdf.

facing chargers to 5,106. BGE and Pepco Holdings, Inc. (PHI) officially launched their programs in July 2019. Potomac Edison Company (PE) and SMECO started their programs in 2020.

On May 15, 2020, BGE, as part of its application for a multiyear rate plan, requested cost recovery for its EV pilot program and included a benefit-cost analysis. On December 16, 2020, the PSC directed the EV Workgroup to develop a consensus benefit-cost analysis framework, using the National Standard Practice Manual and the EmPOWER Maryland Evaluation, Verification and Measurement as examples. On December 1, 2021, the EV Workgroup filed its recommended framework for benefit-cost analysis.

On January 11, 2022, the PSC made several changes to utility EV programs. Among other things, the PSC denied additional residential rebates for BGE and limited income rebates for BGE and PHI, approved the addition of multifamily chargers for BGE and PE, and denied budget requests for education and outreach. The PSC directed the EV Workgroup to explore make-ready incentives and programs; provide additional information on car share programs; develop consensus EV charger reliability standards before August 1, 2022; explore cost sharing for fleet electrification assessment; consider the incorporation of other technologies, like storage, into EV charging; and address educational efforts for off-peak charging.[11]

As of February 1, 2021, 892 residential EV chargers were rebated, 83 multifamily EV charging ports were installed, and 122 utility-owned public chargers were installed and operational across the state.

2.4.3 Competitive Markets and Customer Choice

The Competitive Markets and Customer Choice (CMCC) Workgroup is charged with considering revisions to Maryland’s retail choice electric and natural gas markets to promote competition. Additionally, the CMCC Workgroup is tasked with developing “a statewide standard data sharing format for implementation by utilities that have deployed Advanced Metering Infrastructure (AMI).”[12] In January 2018, the CMCC Workgroup requested the PSC initiate a rulemaking to consider draft regulations and the PSC established Rulemaking 62, “Revisions to COMAR 20.32, 20.50, 20.53, 20.55, and 20.59 – Competitive Markets and Retail Gas and Electric Customer Choice.” Below are the Workgroup’s proposed revisions:

- Implement instant connects for electric customers, i.e., customers can take service on the day they sign up with an electric supplier instead of requesting enrollment; and
- Implement seamless moves for electric and gas customers, i.e., customers can retain their chosen electric supplier when relocating.

Neither of these proposed revisions was adopted by the PSC. However, the PSC did approve some additional protection for residential and nonresidential customers that elect to receive service from a retail supplier, including the following regulations:

[11] Maryland Public Service Commission. Order Approving, In Part, Modifications to the Statewide Electric Vehicle Charging Pilot Program, Order No. 90036, January 11, 2022.

[12] Maryland Public Service Commission, Mail Log No. 212176, p. 10.

- Regulations regarding criminal background checks for electric supplier employees who market door to door; and
- Regulations that provide more transparency in regard to billing options with a supplier, i.e., budget billing.

2.4.4 Interconnection Process

The PSC tasked the Interconnection Workgroup with "implementing rules and policies to promote competitive, efficient and predictable distributed energy resources (DER) markets that maximize customers' choices."[13] In November 2017, after several meetings, the Workgroup requested the PSC to initiate a rulemaking proceeding to review draft regulations proposed by the group, including some nonconsensus regulations. In total, the Workgroup identified 45 items for potential revisions to COMAR 20.50.09. Subsequently, the PSC opened Rulemaking 61, "Revisions to COMAR 20.50.02 and 20.50.09 – Small Generator Facility Interconnection Standards." During the Rulemaking, the PSC did not accept the initial proposed COMAR revisions but provided the Workgroup with guidance on the pertinent issues. In March 2018, the Interconnection Workgroup submitted a modified COMAR revision proposal for PSC consideration. In September 2018, the PSC adopted several, but not all, of the proposed revised regulations, including:

- Broadening the definition of "small generator facility" to include: (i) energy storage devices; and (ii) facilities larger than 10 MW;
- Allowing a single interconnection point for a facility's multiple generating or storage devices; and
- Streamlining the interconnection application process.

Two additional phases were added to address interconnection issues that arose during Phase I. Some of the issues addressed in Phase II included: FERC versus Maryland interconnection jurisdiction, establishing fees for interconnection requests, assessing interconnection facility cost responsibility and developing Smart Inverter requirements.

The following PC44 Interconnection Workgroup Phase II revisions to COMAR went into effect on April 20, 2019:

- <u>Interconnection Jurisdiction</u> – The Workgroup further clarified the applicability of FERC interconnection jurisdiction requirements versus Maryland jurisdiction requirements for small generator facility interconnection requests in Maryland regulations.
- <u>Utility Fees</u> – The Workgroup recommended regulation modifications to allow utilities to establish fees for interconnection requests greater than 20 kilowatts (kW) in their tariffs.
- <u>Flexible Interconnection Options for Energy Storage</u> – The Workgroup added provisions in Maryland regulations to improve the efficient utilization of energy storage devices on the electric distribution grid.

[13] Maryland Public Service Commission, Mail Log No. 199669, p. 3.

- Hosting Capacity – The Workgroup proposed regulations to codify the concepts of reserve hosting capacity, closed circuits and restricted circuits, and established that utilities are required to annually report on their plans for providing hosting capacity information and maps.
- Smart Inverters – A new generation of smart inverters compliant with Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 will be available before 2022.
- Utility Monitoring and Control Plan – The Workgroup clarified the definition of utility monitoring and control plans in the aggregate versus site-specific utility monitoring and control plans.
- Miscellaneous Regulation Modifications – The Workgroup codified the ability for utilities to be able to customize several interconnection documents to meet evolving interconnection needs as long as these interconnection documents are consistent with COMAR regulations.
- Interconnection Process Reporting – The Workgroup codified additional annual reporting regulations for utilities that will provide more transparency to the Commission and other stakeholders on various aspects of the Maryland interconnection process.

Meanwhile, the Commission has requested that the Workgroup address four issues in Phase III:

- Interconnection Facility Costs – Recommend an alternative to the "causer pays" principle for interconnection upgrade costs.
- Smart Inverters – Track the progress for setting statewide smart inverter settings.
- Utility Monitoring and Control Plans – Consider alternatives per stakeholder comments made in Phase II.
- Hosting Capacity – Consider additional hosting capacity topics per stakeholder comments made in Phase II.[14]

On May 14, 2021, Staff Counsel of the Commission filed the Small Generator Facility Interconnection Phase III Report of the PC44 Interconnection Workgroup with the following proposed regulations to be added for small generator facilities seeking to interconnect under Maryland jurisdiction:

- A small generator facility will only be able to sell wholesale electric energy through PJM by joining a distributed energy resource aggregate at an electric distribution interconnection facility.
- The small generator facility will be interconnected to an electric distribution circuit and its energy will not be transmitted across state lines for a wholesale customer other than the electric distribution owner.[15]
- Utilities are required to post default inverter settings profiles, either from the state or from the specific utility. A list of unacceptable inverters is also to be posted on utility websites.

[14] PC44 Interconnection Workgroup, Phase III Kick-off Presentation, October 22, 2019.

[15] PC44 Interconnection Workgroup, Phase III Final Report, May 14, 2021, p. 6.

- Utilities are also required to have procedures for calculating hosting capacity, and to do so at least annually, or more frequently in areas experiencing significant growth or distributed energy resource penetration.

On September 9, 2021, the Commission approved a Workgroup request to indefinitely delay the requirement that smart inverters be implemented in Maryland by January 1, 2022, because of industry-wide problems in developing a smart inverter testing standard. The Commission requested that the Workgroup address the following issues in Phase IV:

- Consider reforming the current "causer pays" for the costs associated with system upgrades necessary to interconnect a small generator facility; and
- Consider requiring utilities to publish utility-specific system profiles for various smart inverter capabilities such as voltage control in their tariffs.

2.4.5 Energy Storage

The Energy Storage Workgroup was tasked with (1) facilitating increased understanding of energy storage; (2) exploring how energy storage may be used by individual customers and as a distribution grid asset; and (3) evaluating the criteria to be used when determining whether a utility should utilize energy storage as a distribution asset, and if so, how the utility should be compensated for the investment. In January 2019, the Workgroup presented the PSC with a proposal, the short-term Proof of Regulatory Concept Program, designed to evaluate various energy storage business and regulatory models focused on reducing ratepayer costs and providing benefits to competitive storage providers, the electric grid, ratepayers and utilities. Under the program, the utilities would solicit projects under the following four models to pilot over a three-year period:

- <u>Utility Only Model</u> – A utility would own and operate the energy storage system, as a rate-based asset, in an effort to defer distribution system upgrades. The energy storage asset could be offered as a resource into PJM in times when it is not being used for grid reliability to generate additional revenue to offset the cost to ratepayers. An example is Southern California Edison's 8 MW / 32 MWh Tehachapi Wind Energy Storage Project.

- <u>Utility and Third-Party Model</u> – A utility would own the energy storage system but would contract with a third party that would bid the asset into the PJM market when it is not in use for grid reliability. The revenues recognized from the PJM market would be used to offset the cost of the asset. This proposal would evaluate coordination with a third party and the PJM markets. An example is the 100 MW / 129 MWh government-owned energy storage project at Neoen's Hornsdale Wind Farm in South Australia. The South Australian government uses 70 percent of the capacity of the battery system to balance the grid, allowing Neoen, the third party, to use the asset's capacity in the wholesale market.

- <u>Third-Party Ownership Model</u> – A third party would contract with a utility to provide grid reliability services through an energy storage system and the utility would recover the costs of the contract through an alternative mechanism. There is potential for this service to be less expensive than a utility investment. An example is the Lockheed Martin 500 kW / 3 MWh storage project in Boothbay, Maine built to defer a transmission line upgrade in an area with increased load. The project is fully dispatchable by the utility. It is estimated the transmission line upgrade would have cost twice as much as the energy storage project.

- Virtual Power Plant Model – A utility contracts with a third-party developer which owns, operates and synchronizes a portfolio of behind-the-meter storage, residential or commercial. The portfolio is used to meet distribution grid reliability needs as a flexible resource or a peaking resource to meet wholesale needs, thus, increasing system reliability through lower-cost, behind-the-metered resources. An example is California's Demand Response Auction Mechanism (DRAM) where developers can bid their aggregated assets in the IOUs' resource adequacy requirements and the California Independent System Operator's (CAISO's) real-time and day-ahead markets.

The PSC had yet to provide a decision on this proposal when Senate Bill (SB) 573 was passed during the 2019 legislative session. The bill requires the PSC to establish an energy storage pilot program with pilot projects ranging between 5 and 10 MW. Additionally, SB 573 requires each IOU to solicit offers for each of the ownership models: utility only, utility and third-party, and third-party ownership. SB 573 requires the energy storage pilot projects to come online by February 28, 2022, but gives the PSC authority to grant extensions based on good cause. As a result of the bill, the PSC ordered the Energy Storage Workgroup to develop and propose metrics on the environment and clean energy objectives, as well as impacts on the retail energy market, for use in evaluating project proposals by December 31, 2019.[16]

During fall 2019, the Workgroup, with assistance from the Regulatory Assistance Project, developed methodologies to quantify different value streams that may be associated with the energy storage projects that will be proposed under the PC44 Energy Storage proceeding. The values for which benefits are to be calculated include:

- Environmental and public health benefits associated with shifting load from high emissions periods to lower emissions periods;
- Avoidance or deferral of distribution system upgrades;
- Optionality benefits (i.e., additional flexibility in capital planning);
- Peak demand reduction, including reduced zonal capacity obligations;
- PJM market service revenue; and
- Distribution system improvements (e.g., increased reliability).[17]

On July 13, 2020, the PSC held a legislative-style hearing to consider the applications for six pilot programs filed by BGE, Pepco, Delmarva and PE and hear stakeholder comments. The PSC approved (subject to some modifications) the projects proposed by BGE, Pepco and Delmarva, but rejected PE's Little Orleans project and deferred consideration of its Town Hill proposal. The PSC conditioned that

[16] Maryland Public Service Commission, Mail Log No. 226537, Case No. 9619, August 23, 2019.

[17] Submission PC44 Energy Storage Working Group, Case No. 9619, December 31, 2019.

each approved project must participate in available PJM revenue markets, and by February 1, 2021, each project shall file the following:

- A narrative description, an estimate of costs, and identify the source of funding;
- Certification that a project has met all technical specifications and performance standards for participation in PJM markets;
- Plans to prevent and address fires and explosions and for safe removal of damaged batteries; and
- Plans for decommissioning and disposal of batteries.

Additionally, Delmarva was directed to address in its report any safety concerns associated with installing storage resources in customer homes, and its plans for informing potential participants of those risks. The PSC directed the Workgroup to reconvene to develop an updated recommendation on data collection, metrics, and related pilot parameters for each project approved in Order No. 89664.

Distribution System Planning

This Workgroup discusses the components of distribution planning, what areas the PSC should focus on and whether it should authorize a study on key topics. The Workgroup was formed in response to a Task Force on Comprehensive Electricity Planning (Task Force) formed by the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO). On February 11, 2021, the Task Force released its final report, titled the "Blueprint for State Action." The goal of the Task Force was to bring together state regulatory and energy policy agencies to develop ways for states to both increase involvement in distribution system planning and to further align planning processes with state goals and the proliferation of distributed energy resources. Maryland representatives on the Task Force recommended that the PSC consider the findings of the Task Force report in relation to the objectives of PC44 and convene the previously contemplated Distribution System Planning (DSP) Workgroup after the conclusion of the technical conference. On March 25, 2021, the PSC held a legislative-style hearing to discuss the application of the recommendations contained in the final report of the Task Force. Having considered the final report and the recommendations of stakeholders, the PSC established a DSP Workgroup in Case No. 9665, which will be led by an external Commission-selected facilitator. The PSC directed the DSP Workgroup to engage in an iterative process with frequent opportunities for feedback from the Commission. Currently, the DSP Workgroup's first task is to review the Jade Process Map,[18] and consider its relevance and application to Maryland's electric distribution utilities. The DSP Workgroup is further directed to develop and propose any changes or modifications to the Jade Process Map to best align with Maryland's public policy goals and existing processes, including interactions with existing dockets concerning electric reliability, EmPOWER Maryland and other PC44 activities. The DSP Workgroup is further directed to consider possible processes whereby stakeholders can participate in discussions with utilities regarding Performance Incentive Mechanisms (PIMs) that may be proposed by utilities.[19]

[18] The Jade Process Map describes an idealized electricity distribution planning process for the hypothetical state of Jade, a deregulated state located within a federally regulated market.

[19] Maryland Public Service Commission, Order Initiating Distribution System Planning Work Group. Order No. 89865, Case No. 9665 and PC44 (ML 235860).

Chapter 3 – Power Generation, Transmission and Use in Maryland

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 are not price-regulated in Maryland; prices are established by the competitive wholesale and retail electricity markets. 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 Maryland Public Service Commission (PSC) website.

Maryland's Electricity Market

Generation companies produce power to be sold in the wholesale marketplace. Generation of electricity is a competitive industry in Maryland (i.e., It is not subject to price regulation). Retail power supply to end–use customers is also competitive, allowing consumers to choose their own supplier.

Transmission is the high–voltage, long–distance movement of power, while **distribution** is the low–voltage, local delivery of power.

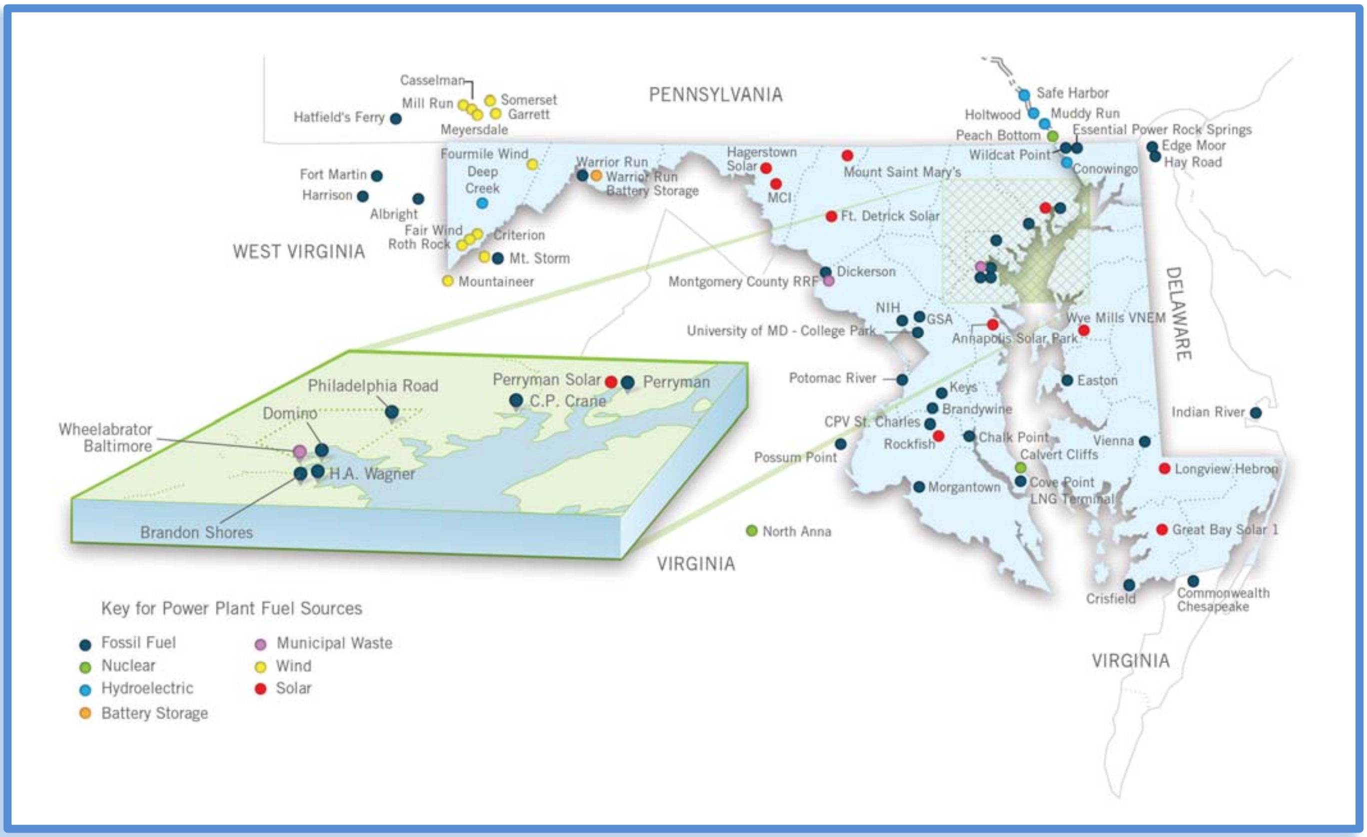
Transmission and **distribution** of electricity continue to be provided by local utilities within their various franchised service territories.

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 4.4.1). It is therefore subject to price and quality-of-service regulation by the PSC.

3.1 Electricity Generation in Maryland

Currently in Maryland, 41 power plants with generation capacities greater than 10 megawatts (MW) are interconnected to the regional transmission grid. Table 3-1 lists the individual power plant sites. Figure 3-1 shows the plant locations. In aggregate, these 41 Maryland power plants represent nearly 15,000 MW of operational capacity. The largest portion of Maryland's generating capacity comes from fossil fuels (see Figure 3-2), with the remainder attributed to nuclear and renewables. With the addition of 3,464 MW of natural gas capacity in 2017 and 2018, and the retirement of coal plants throughout the decade, there has been a significant shift between coal and natural gas generation within the state, as noted in Figure 3-2. Since 2016, natural gas capacity increased approximately 58 percent and natural gas generation increased 160 percent, while the capacity of coal has decreased almost 23 percent and generation has declined by 76 percent.

Figure 3-1 Power Plants in Maryland



Note: The coal-fired C.P. Crane facility in Baltimore County ceased operation in May 2018; the owner has received a CPCN to construct and operate a new 160 MW natural gas-fired facility at the existing site. Coal-fired units Dickerson and Chalk Point were decommissioned in August 2020 and June 2021, respectively.

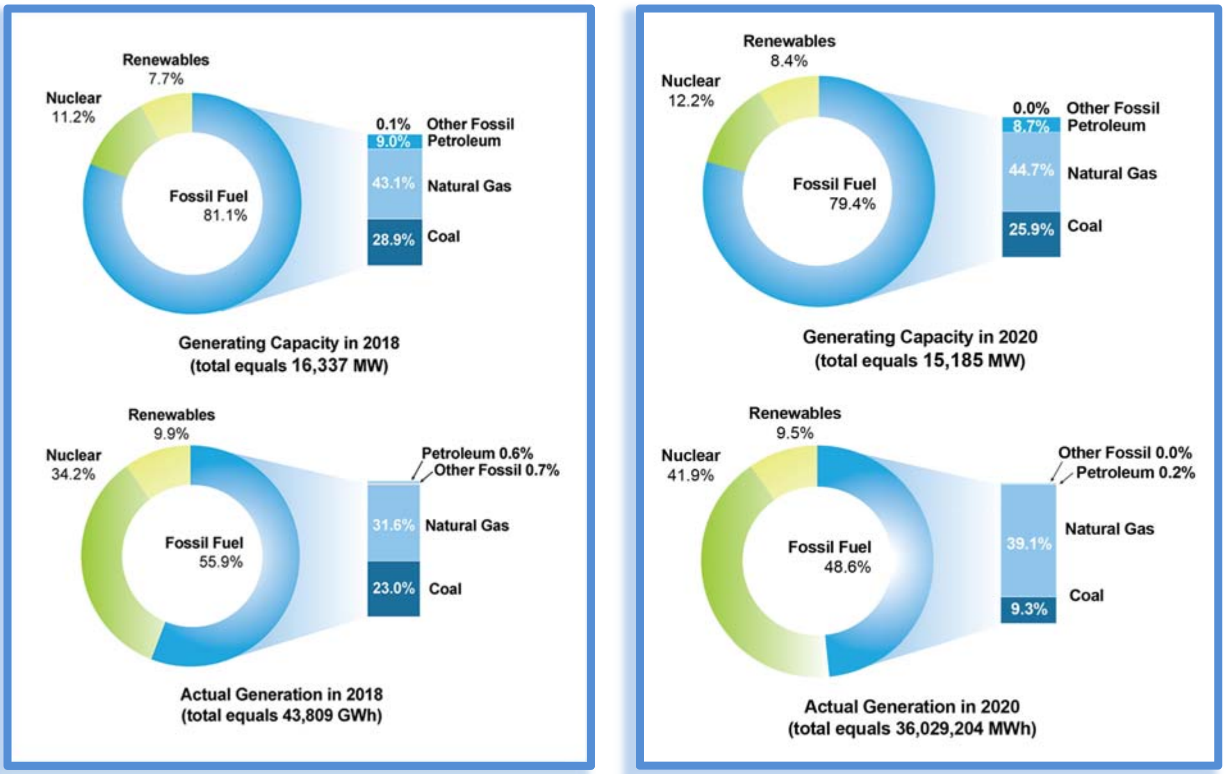
Table 3-1 Operational Generating Capacity in Maryland, December 2020 (10 MW or greater)

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
INDEPENDENT POWER PRODUCERS			
AES Enterprise	Warrior Run	Coal	229
AES Tait LLC	AES Warrior Run Energy Storage Project	Batteries	11
Annapolis Solar Park, LLC	Annapolis Solar Park LLC	Solar	12
Berkshire Hathaway's Dominion Cove Point LNG, LP	Cove Point LNG Terminal	Natural Gas/Oil/other	229
BP Piney & Deep Creek, LLC	Deep Creek	Hydroelectric	20
Brandon Shores LLC	Brandon Shores	Coal	1,370
Calpine Corporation	Crisfield	Oil	12
CD Arevon USA, Inc.	Maryland Solar - Located at Maryland Correctional Institute (MCI)	Solar	27
Constellation Energy Corporation*	Calvert Cliffs Nuclear Power Plant	Nuclear	1,850
	Conowingo	Hydroelectric	531
	Criterion Wind Park	Wind	70
	Fair Wind Power Partners	Wind	30
	Fourmile Ridge	Wind	40
	Mount Saint Mary's	Solar	14
	Perryman	Oil/Natural Gas	492
	Perryman Solar	Solar	17
	Philadelphia Road	Oil	83
Covanta	Montgomery County Resource Recovery Facility (RRF)	Waste	68
CPV Maryland LLC	CPV St. Charles Energy Center	Natural Gas	775
Essential Power Rock Springs LLC (Carlyle Group LP)	Essential Power Rock Springs LLC	Natural Gas	773
GenOn Chalk Point, LLC	Chalk Point LLC	Coal/Oil/Natural Gas	2,647
GenOn Mid-Atlantic LLC	Dickerson**	Oil/Natural Gas	345
	Morgantown Generating Plant	Coal/Oil	1,548
Gestamp Wind	Roth Rock Wind Facility	Wind	50
Great Bay Solar 1 LLC	Great Bay Solar 1	Solar	75
H.A. Wagner LLC	Herbert A Wagner	Coal/Oil/Natural Gas	923

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
KMC Thermo LLC	Brandywine	Natural Gas	289
LaFarge Holcim	Hagerstown Solar	Solar	10
Marina Energy LLC	Longview Solar – Hebron	Solar	14
Maryland Economic Development Corporation	University of Maryland – College Park	Natural Gas	27
Montevue Lane Solar, LLC	Fort Detrick Solar PV	Solar	16
NRG Energy	Vienna	Oil	181
Pepco Energy Services	National Institutes of Health (NIH)	Natural Gas	28
PSEG Keys Energy Center, LLC	Keys Energy Center	Natural Gas	831
Rockfish Solar LLC	Rockfish Solar LLC	Solar	10
Tesla, Inc.	Wye Mills VNEM	Solar	10
Wheelabrator Technologies	Wheelabrator Incinerator	Waste	65
PUBLICLY OWNED ELECTRIC COMPANIES			
Easton Utilities	Easton	Oil/Biodiesel	72
Old Dominion Electric Cooperative and Essential Power	Wildcat Point Generation Facility	Natural Gas	1,114
SELF-GENERATORS			
American Sugar Refining Co.	Domino Sugar	Natural Gas	10
GSA Metropolitan Service Center	Central Utility Plant	Oil/Natural Gas	54
Total:			**14,980**

* Capacity figures for Exelon-owned facilities were provided by Exelon Generation. Note that Exelon Corporation separated into two publicly traded companies in early 2022, with the power plant business (including nuclear) operating under the name Constellation Energy Corporation.
** Dickerson decommissioned its coal units in August 2020.
Source: U.S. Energy Information Administration, Form EIA-860, 2020 Final Release.

Figure 3-2 Power Plant Capacity and Generation in Maryland by Fuel Category, 2018 compared to 2020



Source: 2020 data "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)," U.S. Energy Information Administration, 2020 Final Release; "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)," U.S. Energy Information Administration, 2020 Final Release.

2018 data "2018 Form EIA-860 Data – Schedule 3 'Generator Data' (Operable Units Only)," 2018 Final Release; "EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2018 Final Revision, Sources: EIA-923 and EIA-860 Reports," 2018 Final Release.

Note: EIA data for generation contain the fossil fuel category, "Other," which is not included in EIA data for capacity.

3.1.1 Fossil Fuels

In Maryland, coal, natural gas and petroleum are the fossil fuels utilized to produce electricity. Because of steep price declines in recent years, the primary fuel used for electricity in Maryland is natural gas.

Coal

In 2020, Maryland consumed 1.3 million tons of coal for electricity generation, which was a decrease of 71 percent compared to 2018. Most Maryland power plants cannot efficiently burn coal mined in the state because they were designed for coal with higher volatility characteristics, which allows for it to ignite more easily. Based on 2020 data, 100 percent of the coal received by Maryland plants was mined in the Appalachia region of the U.S. Table 3-2 lists the amount of coal received at each power plant in 2020. According to the U.S. Energy Information Administration (EIA), U.S. bituminous coals sold for an average of $50.05/short ton in 2020 compared to $14.43/short ton for subbituminous coals.

Table 3-2 Tons of Coal Purchased at Maryland Power Plants in 2020

Origin of Coal	Brandon Shores	Chalk Point	Morgantown	Warrior Run	Total by Source
Appalachia	252,241	136,452	448,930	503,606	1,341,229
% of Total	19%	10%	33%	38%	100%

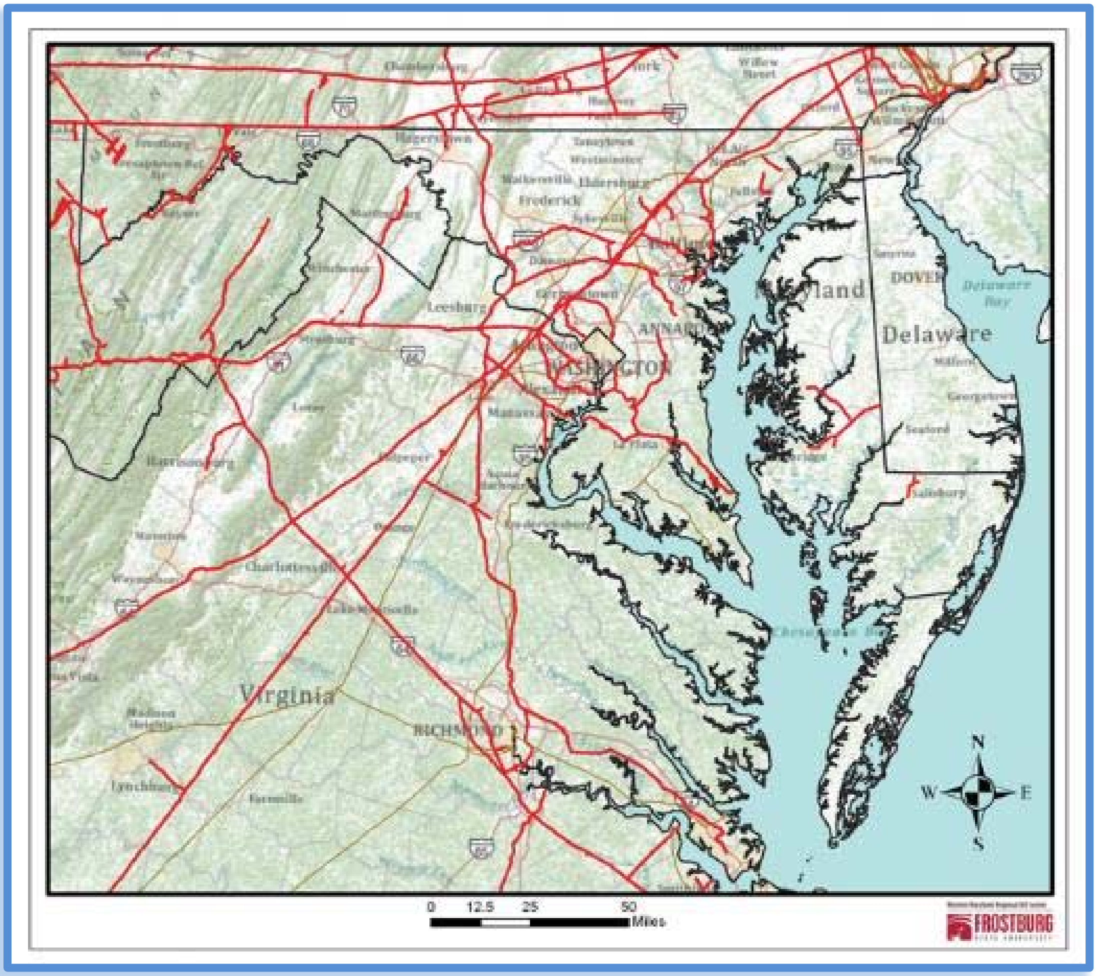
Source: U.S. Energy Information Administration, EIA-923 Schedule 5 Fuel Receipts and Cost Time Series File, 2020 Final Release.

Natural Gas

In 2020, approximately 94.7 billion cubic feet of natural gas was used for electricity generation in Maryland, representing 33 percent of the total statewide consumption of natural gas for all uses.[20] While more natural gas was used for electricity generation in 2018 (97.7 billion cubic feet) as compared to 2020, 2020 saw a 1 percent increase in its share of the total statewide consumption of natural gas over 2018 levels. Currently, Maryland receives natural gas from several interstate pipelines that traverse the state (see Figure 3-3). 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.

[20] U.S. Energy Information Administration, "Natural Gas Consumption by End Use" for Maryland, eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMD_A.htm, last accessed December 31, 2020.

Figure 3-3 Interstate Natural Gas Pipelines in Maryland



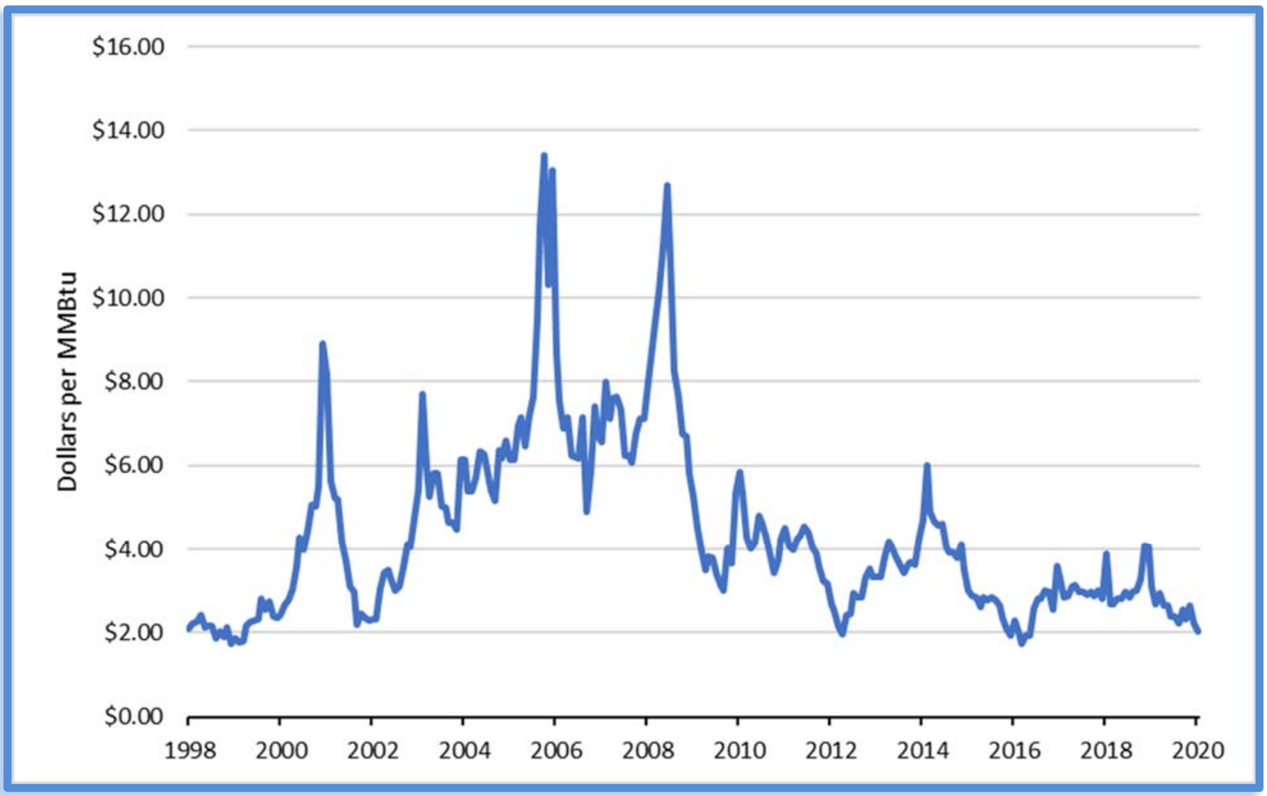
There has been a significant increase in natural gas production in the U.S. resulting from the use of new drilling techniques. Shale gas trapped in deep, fine-grained rock formations in the southwest and northeast regions of the U.S. was not economical to recover until the development of horizontal drilling and hydraulic fracturing techniques in the 1990s. Between 2009 and 2020, as natural gas producers continued utilizing these techniques, U.S. natural gas production increased 62 percent. Domestic natural gas consumption over the same period increased only 33 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,[21] 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, averaging between \$2 and \$4/MMBtu since 2015, primarily attributable to increased shale gas production (see Figure 3-4). In 2018, the average natural gas price was

[21] Wholesale natural gas futures contracts priced on the New York Mercantile Exchange 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.

$3.15/MMBtu but decreased to an average of $2.04/MMBtu in 2020 primarily due to impacts from the COVID-19 pandemic.

Figure 3-4 U.S. Natural Gas Henry Hub Spot Prices, 1998-2020



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 decreased from $0.83 per million cubic feet (MMcf) in 2009 to $0.56/MMcf in 2020.[22] Import volumes at the Cove Point LNG facility in Lusby, Maryland increased 41 percent between 2015 and 2020.[23] Cove Point, which is owned by Dominion Cove Point LNG, LP, an affiliate of Dominion Resources, Inc., is one of 12 LNG import facilities and seven existing LNG export facilities operating in the U.S., with five more LNG export facilities under development.[24] 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 Cove Point LNG, LP 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

[22] U.S. Energy Information Administration, "Price of Liquefied U.S. Natural Gas Exports," monthly release, last accessed September 30, 2021.

[23] U.S. Energy Information Administration, "U.S. Natural Gas Imports by Point of Entry," release date September 30, 2021, eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm.

[24] Federal Energy Regulatory Commission, "North American LNG Import Terminals: Existing," September 17, 2020.

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, FERC issued an order authorizing Dominion Cove Point LNG, LP to export LNG.[25] During the next month, construction began and the Cove Point LNG export facility was operational by April 2018. In 2020, Cove Point exported 230,937 MMcf of LNG.[26]

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 EIA, fuel oil consumption for electric power in Maryland totaled 7.4 million gallons in 2020, which is significantly lower than the 75.2 million gallons used for electric power consumption in 2007. 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, a major petroleum products pipeline that traverses the state on its way to New York.

3.1.2 Nuclear

Maryland is home to one nuclear power facility, Constellation Energy Corporation'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 1,850 MW facility represents 12 percent of the state's total electricity generation capacity and accounted for 30 percent of the state's total generation in 2020. More information on Calvert Cliffs is included in Section 5.5.2.

3.1.3 Distributed Generation

Distributed generation (DG) refers to those generating resources located close to, or on the same site as, the facility using power. DG is typically installed on the customer side of the meter and used to serve onsite 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

[25] Federal Energy Regulatory Commission, "Order Granting Section 3 and Section 7 Authorizations," September 29, 2014, elibrary.ferc.gov/eLibrary/filelist?accession_number=20140929-3053&optimized=false.

[26] U.S. Energy Information Administration, "U.S. Natural Gas Exports and Re-Exports by Point of Exit," release date September 30, 2021, eia.gov/dnav/ng/NG_MOVE_POE2_DCU_YCPT-Z00_M.htm.

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 Energy Portfolio Standard (RPS) and a federal tax credit. The tax credit for business and residential taxpayers is set at 26% through 2022, then declines to 22% through 2025 and falls to 10% for businesses and expires altogether for residential taxpayers.

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.

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 3.5.1 for discussion on RECs).

Onsite 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 waiver:

- 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 3.1.5).

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

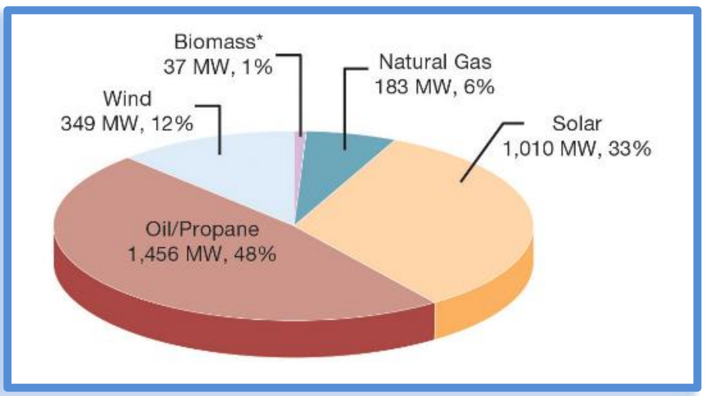
- Type I – a generator that is not synchronized with the local electric company's transmission and distribution system, and will not export electricity to the grid;
- Type II – a generator that is synchronized with the electric system, but will not export electricity to the grid;
- Type III – a generator 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.

From 2001 through October 2021, 2,149 MW of generation capacity had been granted CPCN exemptions in Maryland, including 183 MW of natural gas-fired capacity, 124 MW of solar capacity, and 349 MW of land-based wind power. According to the 2021 PSC report on net metering, an additional 886 MW of solar DG and 1.1 MW of small wind facilities were installed in Maryland by June 30, 2021 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 3-5) are mostly fossil-fueled, consistent with their use for backup power. A large share of DG capacity is solar, which is predominantly grid-tied for purposes of net metering and generating solar RECs (SRECs) for sale or trade. Between 2020 and 2021, for example, statewide net metered solar system capacity increased 7 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 3-5 Distributed Generation by Fuel Type, as of 2021



Source: PSC CPCN Database and Maryland Public Service Commission, "Report on the Status of Net Energy Metering in the State of Maryland," October 2021, psc.state.md.us/wp-content/uploads/2021-Net-Metering-Report-FINAL.pdf..

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

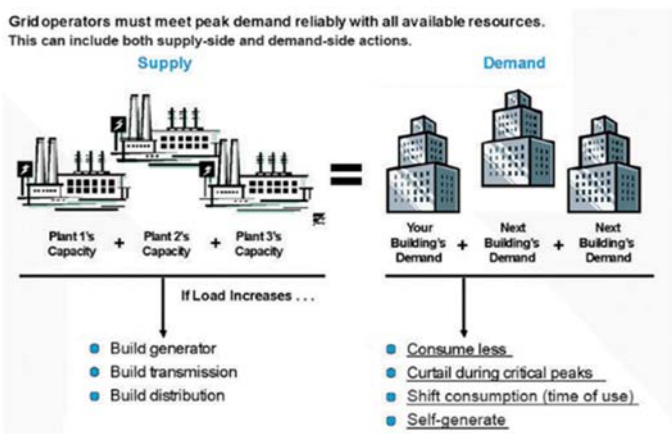
*Biomass includes digester and landfill gas units.

3.1.4 Demand Response

Demand response (DR) serves as a tool for bolstering energy efficiency and conservation efforts in Maryland. 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. Through these voluntary, opt-in programs, utilities can cycle residential consumers' 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).

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.

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 10 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. However, DR resources can only provide two of the three services and are limited to 33 percent for each category. DR resources can also provide nonsynchronized (nonspinning) and supplemental reserves in PJM.

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. For example, an auction held in 2018 would be for the 2021/2022 delivery year.

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 10 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 10 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,[27] PJM revised and restructured its capacity market. Approved by 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 overperforming, as well as to increase penalties for nonperformers. The revised capacity market went into effect with the 2018/2019 RPM BRA. In the most recent auction, the 2020/2021 RPM BRA, 9,847 MW were offered, of which 7,820 MW cleared the auction, which is 2,528 MW lower than the prior auction.[28] While a decline in prices was expected, the magnitude of the price decline was far beyond expectations. According to the 2022/2023 BRA post-auction analysis, regional transmission organization (RTO) prices cleared at $50/MW-day, reaching the lowest levels seen since the 2013/2014 delivery year (DY). Several Locational Deliverability Areas (LDAs) separated in price from the RTO, but also saw substantial price declines. Overall, the weighted-average clearing price declined from $155.71/MW-day to $74.27/MW-day.[29] The potential factors resulting in this price drop could have been the relatively prompt timing of the auction and associated resource planning constraints. Another factor could have been the long delay between auctions and the large number of market design changes that occurred for this auction which may have resulted in more cautious bidding.[30]

In March 2011, 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 (IOUs) and competitive CSPs. In spring 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 U.S. Supreme Court 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

[27] The Polar Vortex was a period of intense cold weather across the PJM region in January 2014, resulting in record-setting winter peak demand and significant electricity price spikes.

[28] PJM moved the 2019/2020 BRA for Delivery Year (DY) 2022/2023 to August 2019; however, PJM suspended all auction activities and deadlines related to DY 2022/2023 and DY 2023/2024 auctions until FERC issues an order regarding PJM's requested changes to its capacity market. Note: The DY 2022/2023 auction took place in May 2021. Auction results report: pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx.

[29] icf.com/insights/energy/pjm-2022-2023-bra-auction-analysis#.

[30] Ibid.

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 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 3.5.5 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. In 2018, Baltimore Gas and Electric Company (BGE) offered its demand response as a PRD resource.

In February 2019, PJM proposed to align the PRD program with its Capacity Performance Resources general rules, with the main change being that the nominal PRD value would be the lesser of summer and winter load reductions. However, the Independent Market Monitor (IMM) stated that the proposal does not calculate the nominal PRD value (compensation) based on how PJM customers pay for capacity, i.e., the customer's load during PJM system peak. In June 2019, FERC agreed with the IMM and rejected PJM's proposal and stated that the PRD should be more consistent with the annual peak-based billing framework for load-serving entities (LSEs). See Section 3.5.5 for more information on smart grid technologies.

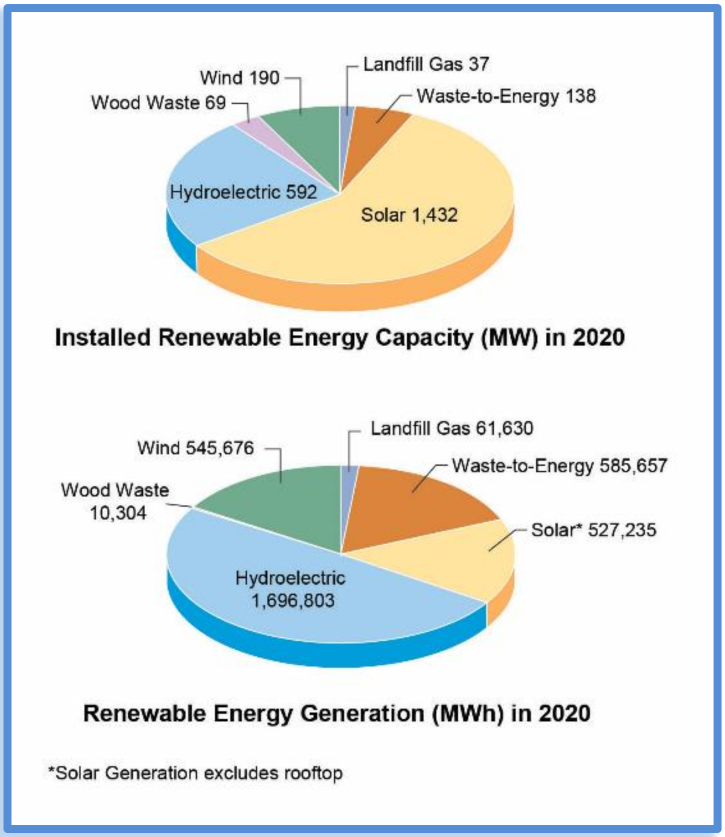
In October 2019, PJM re-submitted its suggested PRD program modifications. While PRD resources can offset the amount of required capacity resources on a one-to-one basis, PJM emphasized in its filing that the existing PRD regulations do not impose the same requirements as the rules for capacity resources. As a result, PJM proposed specific improvements to the PRD program to better align it with the regulations and standards that apply to capacity resources. PJM suggested, among other things, that PRD providers be eligible for bonus payments for load reductions that exceed the MW value pledged to be reduced during system emergencies. PJM also addressed FERC's concerns about PRD pricing in the June 2019 order by preserving the current pricing structure, which is based on an LSE's capacity obligation determined from its annual coincident peak demand. FERC approved PJM's proposals in January 2020, but in response to a protest filed by PJM's IMM, the commission ordered PJM to revise its tariffs to specify that an LSE is not eligible for bonus payments for load reductions during system emergencies if the prevailing locational marginal price (LMP) has not reached the applicable trigger price.[31]

[31] troutmanenergyreport.com/2020/01/ferc-accepts-revisions-to-pjms-price-responsive-demand-program/.

3.1.5 Renewable Resources

Presently, there are four main types of renewable energy resources in use in Maryland: wind, biomass (including wood waste, landfill gas and municipal waste-to-energy), solar and hydropower. Approximately 2,459 MW of generation capacity in Maryland comes from these resources (see Figure 3-6).

Figure 3-6 Renewable Energy in Maryland, as of 2020



Source: PJM Generation Attribute Tracking System (GATS) for capacity, and EIA-923 for generation. Solar capacity includes both utility-scale and rooftop solar. Solar generation excludes rooftop solar. Hydroelectric capacity includes 572 MW installed capacity for Conowingo Dam, which differs from the capacity listed in PJM GATS.

Wind

The conversion of wind power to electricity is typically accomplished by constructing an array of wind turbines in a suitable location. Wind turbines range in size from 20-watt microturbines (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.

At the conclusion of 2020, there were 122 gigawatts (GW) of land-based wind in operation throughout the United States, making the country the second-leading installer of wind capacity in the world after

China.[32] Texas is the leading state in land-based wind, with 33.1 GW of capacity.[33] In addition to land-based wind, the United States has two operating offshore wind energy projects, a 30-MW project at Block Island, Rhode Island, and a 12-MW project off Virginia Beach, Virginia. As of 2020, there were over 35 GW of offshore wind capacity under various stages of development (see Figure 3-7). States have announced goals or mandates to acquire nearly 40 GW of offshore wind capacity, while the Biden Administration set a nationwide goal of 30 GW of offshore wind by 2030.[34]

Figure 3-7 U.S. Offshore Wind Pipeline – Project Locations

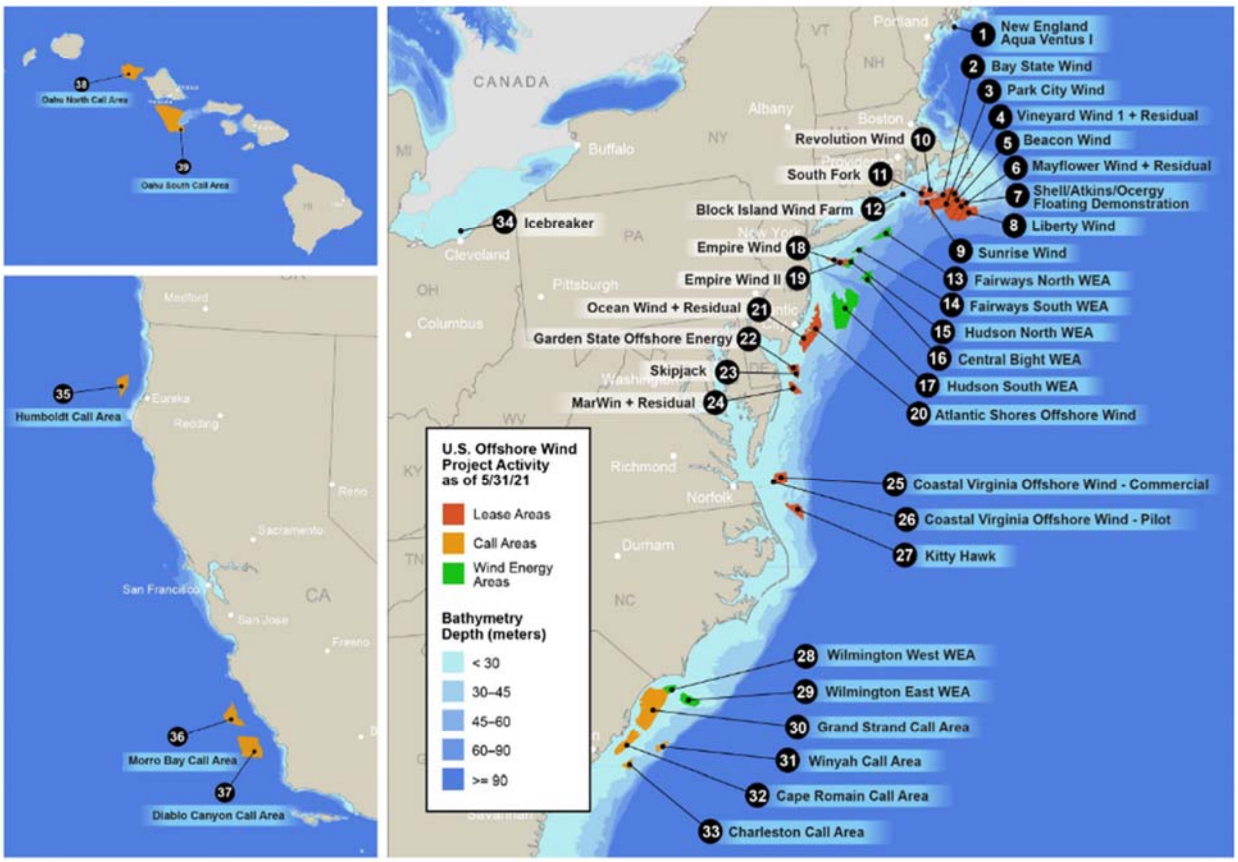


Figure ES-1. Locations of U.S. offshore wind pipeline activity and Call Areas as of May 31, 2021. ***Map created by NREL***

Source: U.S. Department of Energy, Offshore Wind Market Report: 2021 Edition energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf.

[32] World Wind Energy Association, wwindea.org/worldwide-wind-capacity-reaches-744-gigawatts/.

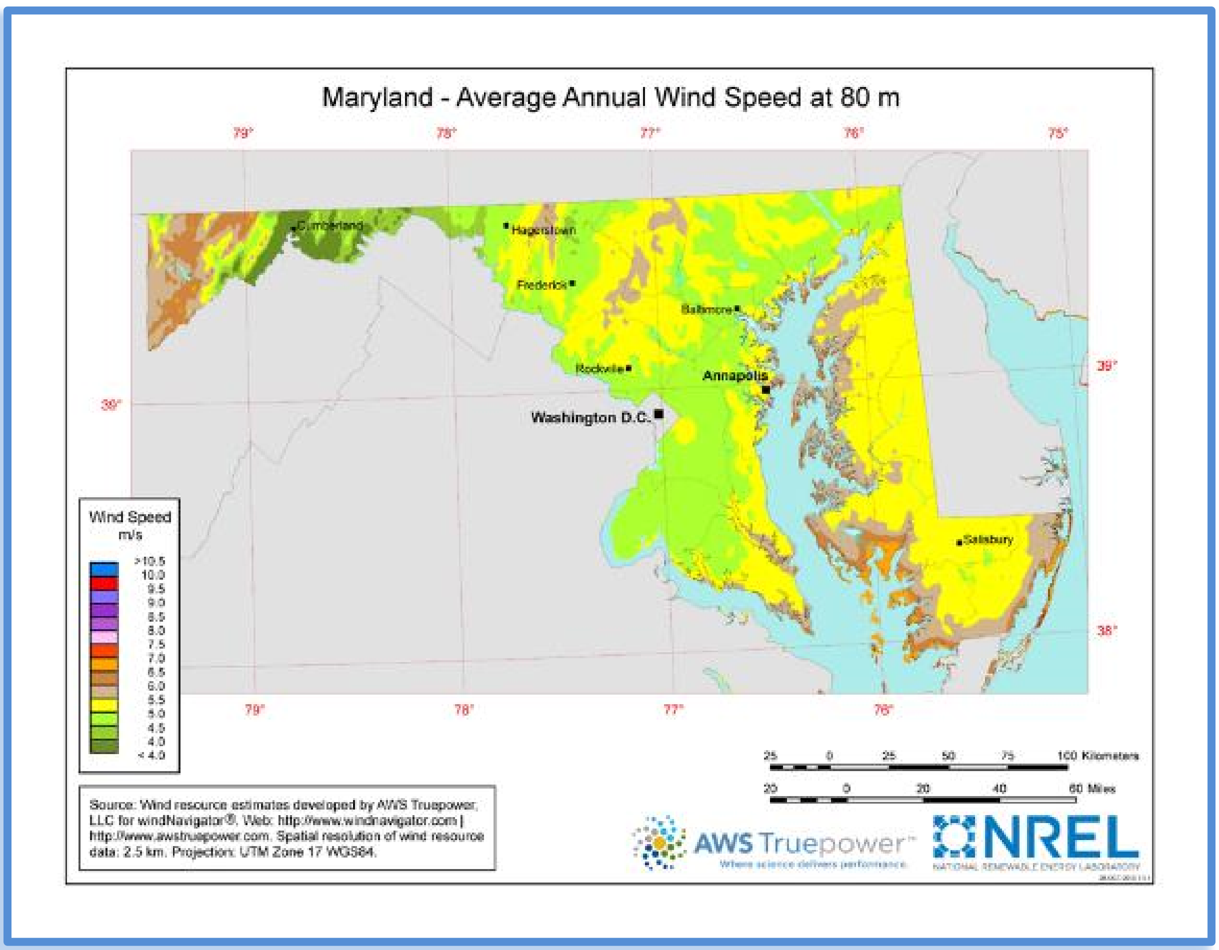
[33] windexchange.energy.gov/maps-data/321.

[34] U.S. Department of Energy, Offshore Wind Market Report: 2021 Edition, energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf.

Whether these projects will ever come online will depend on the ability of developers to secure financing and power purchase agreements (PPAs), as well as navigating federal and state permitting requirements. In 2020, the U.S. Congress enacted a 30 percent investment tax credit (ITC) for offshore wind projects that begin construction by 2025. Existing law and Internal Revenue Service (IRS) "safe harbor" regulations allow the ITC to be used up to 10 years after construction begins, meaning an offshore wind project could go into service as late as 2035 and still take advantage of the ITC.

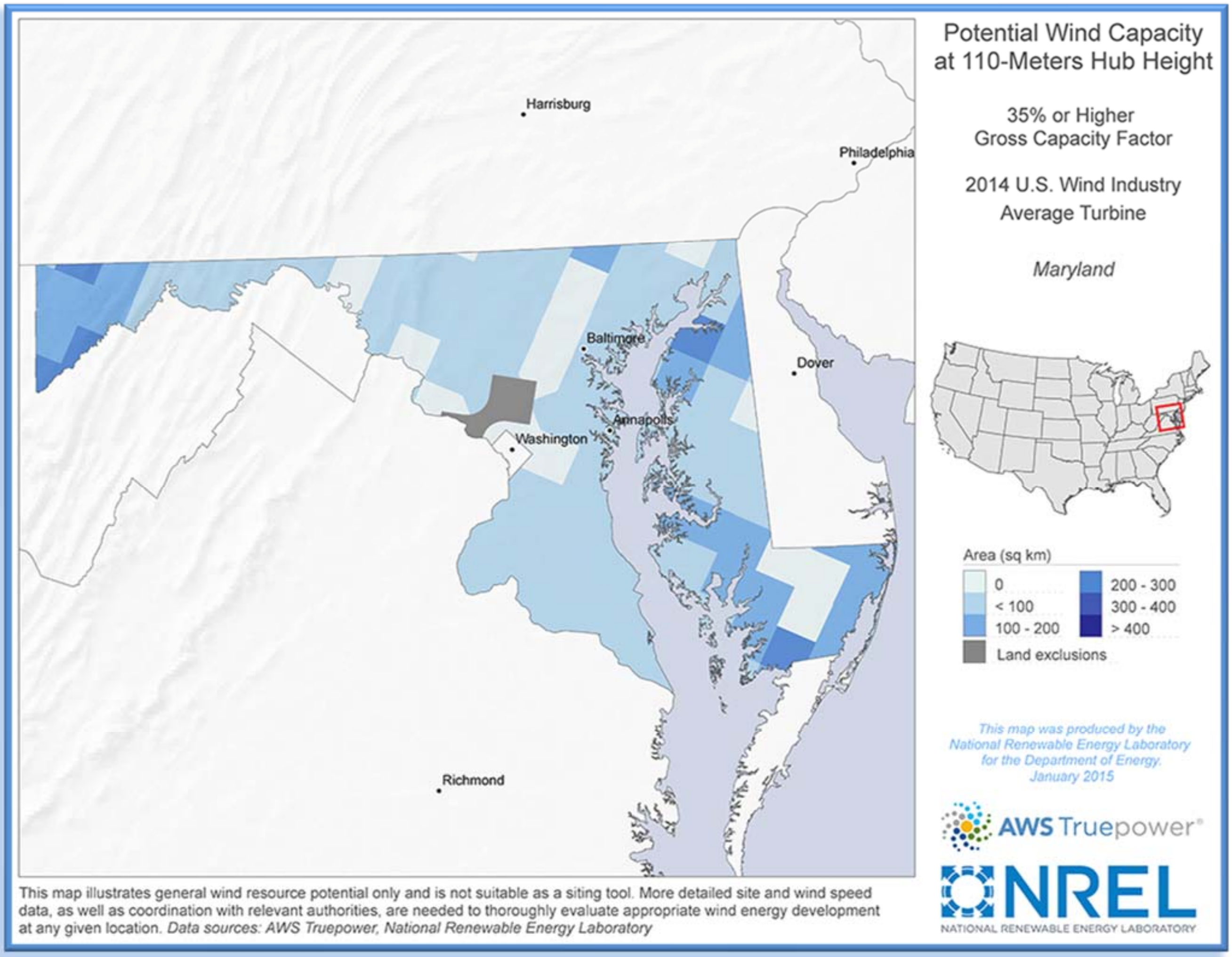
In Maryland, the greatest wind resources are located in the westernmost counties and off of the Atlantic coast on the Outer Continental Shelf. The DOE's National Renewable Energy Laboratory (NREL) estimates that the United States may have a potential land-based wind resource capacity in excess of 10,000 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: 10.3 GW at 110 meters and 18 GW at 140 meters. The four NREL graphics included in Figure 3-8 illustrate the prospective land-based wind resource areas in Maryland.

Figure 3-8 Maryland Potential Wind Resources



Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Maryland 80- Meter Wind Resource Map," NREL WindExchange, windexchange.energy.gov/maps-data/54.

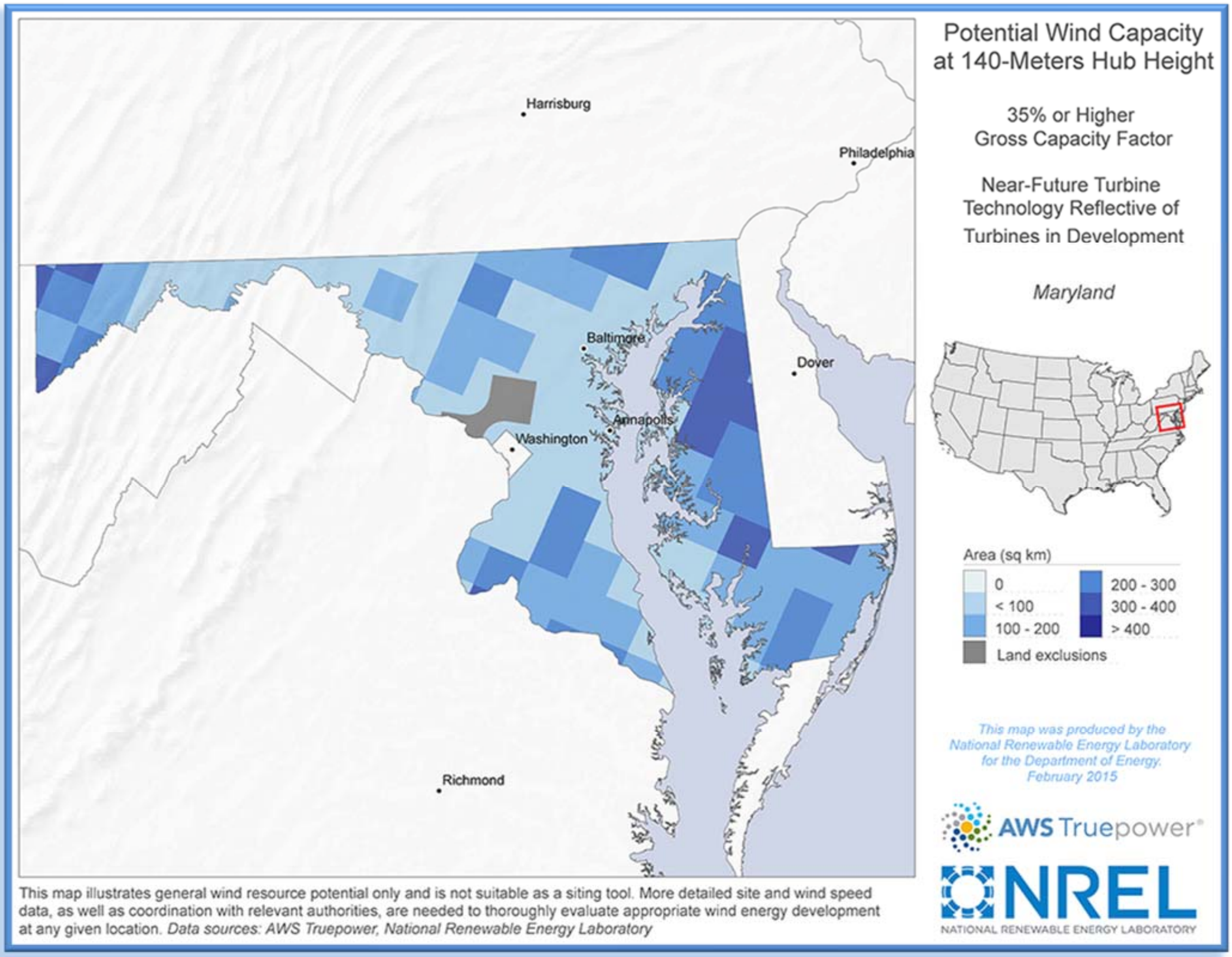
Figure 3-8 Maryland Potential Wind Resources (continued)



Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Wind Energy in Maryland," NREL WindExchange, windexchange.energy.gov/states/md.

Note: The map shading indicates the amount of land area with a gross capacity factor of 35 percent or higher. The darker the shading, the larger the amount of developable area.

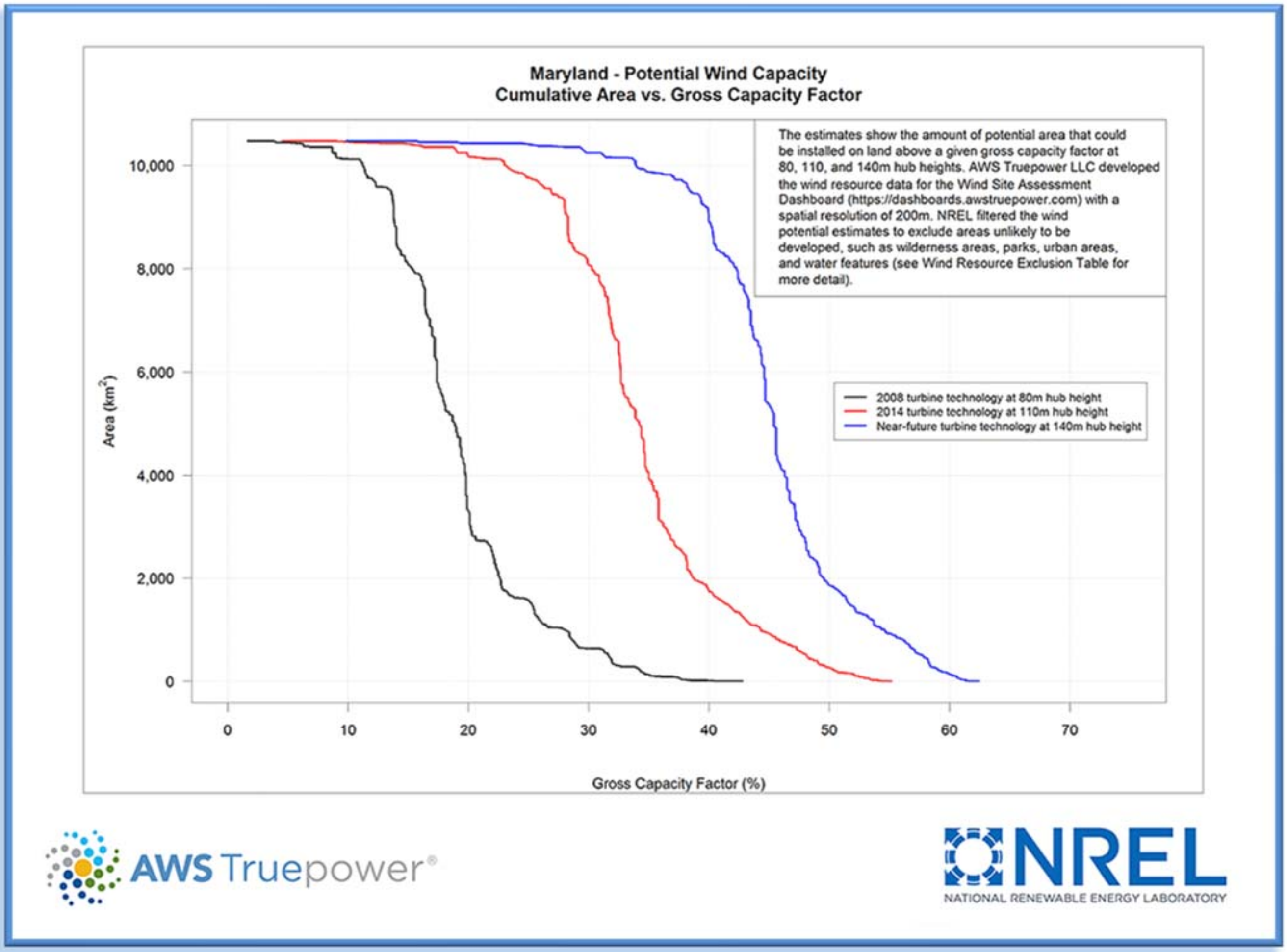
Figure 3-8 Maryland Potential Wind Resources (continued)



Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Wind Energy in Maryland," NREL WindExchange, windexchange.energy.gov/states/md.

Note: The map shading indicates the amount of land area with a gross capacity factor of 35 percent or higher. The darker the shading, the larger the amount of developable area.

Figure 3-8 Maryland Potential Wind Resources (continued)



Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, "Wind Energy in Maryland," NREL WindExchange, windexchange.energy.gov/states/md.

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, operations 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 site-specific issues such as 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 maintain a given distance from the Patuxent River Naval Air Station. The radius of this exclusion zone may not exceed 46 miles and would be determined in a PSC proceeding.

The majority of counties in Maryland have adopted some form of zoning ordinance for wind turbine development (see sidebar). Garrett County did not have any zoning regulations regarding the development of commercial-scale wind turbines until 2013, when 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.

Counties in Maryland with Wind Energy Ordinances

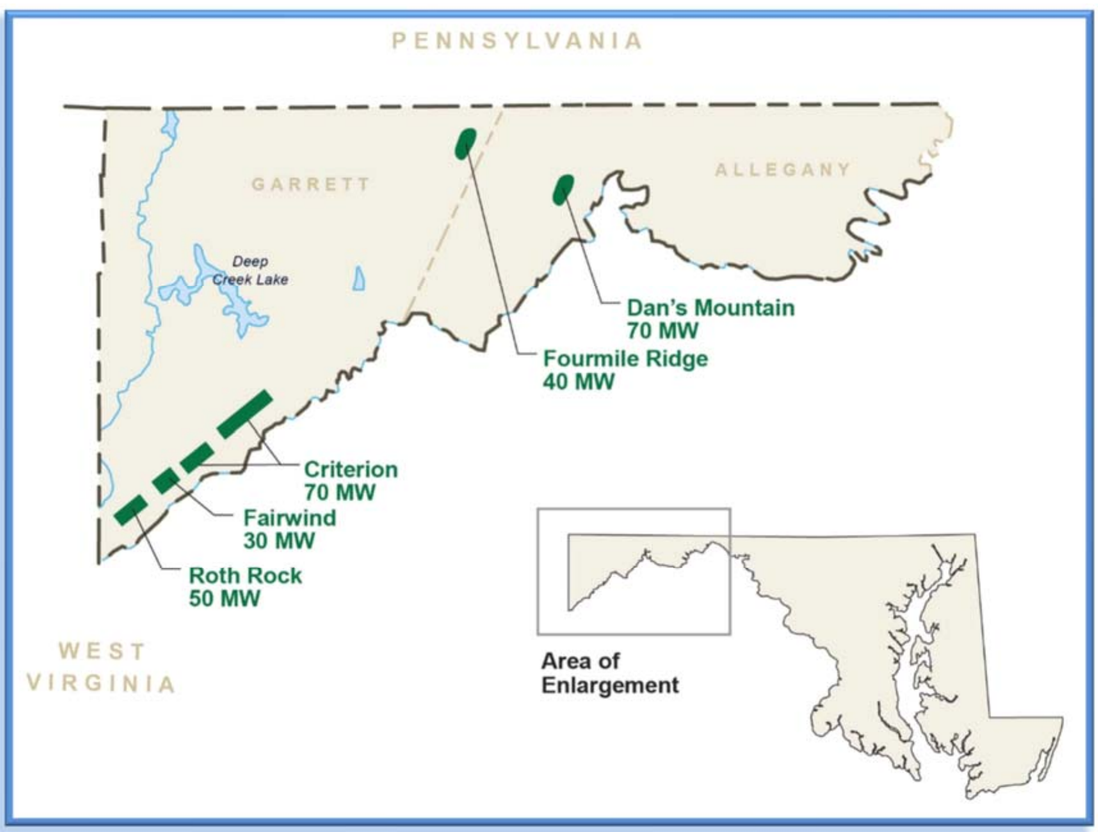
Land-Based Wind Projects in Maryland

Table 3-3 and Figure 3-9 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. One other project, representing about 70 MW, is currently in the planning and development stage.

Table 3-3 Status of Land-Based Wind Projects in Maryland

Project – Developer/Owner	Size (MW)	Location	Nearest Town	Status
Criterion – Constellation Energy Corporation	70	Backbone Mountain, Garrett County	Oakland	Operational
Roth Rock – Gestamp Wind	50	Backbone Mountain, Garrett County	Oakland	Operational
Fourmile Ridge – Constellation Energy Corporation	40	Fourmile Ridge, Garrett County	Frostburg	Operational
Dan's Mountain – Laurel Renewable Partners	70	Dan's Mountain, Allegany County	LaVale	CPCN Denied, County Approved, Appealed to Maryland Special Court of Appeals
Fairwind – Constellation Energy Corporation	30	Backbone Mountain, Garrett County	Oakland	Operational

Figure 3-9 Approximate Locations of Wind Energy Projects in Maryland



Originally developed by Clipper Windpower, the 70 MW Criterion Wind Project was acquired by Constellation Energy Corporation (Constellation) in April 2010. In 2012, the Criterion Wind Project was acquired by Exelon through Exelon's merger with Constellation. In early 2022, Exelon spun off its generating assets, including the Criterion Wind project, to Constellation Energy Corporation. 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 Old Dominion Electric Cooperative (ODEC) for both the energy and the RECs produced by the wind facility. The Criterion Wind Project generated about 190,000 MWh in 2020.

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 Delmarva Power and Light Company (DPL or Delmarva) for both the energy and the RECs produced at the facility. The Roth Rock Wind Facility generated about 130,000 MWh in 2020.

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 and generated about 126,000 MWh in 2020. As with the Criterion Wind project, Exelon transferred the Fourmile Wind Energy plant to Constellation Energy Corporation.

Clipper Windpower proposed the 30 MW Fairwind Project, 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 and generated about 90,000 MWh in 2020. As with the Criterion Wind and Fourmile Wind Energy projects, Exelon transferred the Fairwind Project to Constellation Energy Corporation.

Maryland has one other wind project under development. Dan's 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 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 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. 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 CPCN was denied, based on the county's opposition and the potential visual, noise and shadow flicker impacts on nearby residents. Dan's Mountain appealed, and the Commission upheld its decision in June 2017. Dan's Mountain sought judicial review of the Commission's decision and in 2018, the Maryland Court of Special Appeals voted to send it back to the Allegany County zoning board for another review. In October 2019, the Allegany County Board of Zoning Appeals voted 2-1 to permit the construction of 17 wind turbines. Opponents have appealed to the Maryland Court of Special Appeals.

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 instead; however, the PSC denied this CPCN request in February 2017. 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 prevented 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 subsequently converted the project to solar and received approval by the PSC for the 150 MW Great Bay solar project in 2015. Phase I, the first 75 MW, was operational in early 2018, and the U.S. General Services Administration (GSA) committed to purchase the output of this first project phase. Phase II added another 43 MW and came online in August 2020.

Offshore Wind

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 130 GW, with a potential generation of 603 TWh. Using existing offshore wind turbine technology and limiting development to shallow waters reduces the offshore wind potential to 23.8 GW and 80 TWh, respectively.[35] Still, if fully developed, offshore wind would far exceed the state's electric demand.

Permitting Issues

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.
- An Outer Continental Shelf (OCS) air permit, required to ensure that sources within 25 nautical miles of a state seaward boundary comply with air quality requirements of the nearest onshore area. Typically, the U.S. Environmental Protection Agency (EPA) issues this permit; however, the Maryland Department of the Environment (MDE) requested delegation from the EPA for the implementation, administration and enforcement of Title 40 of the Code of Federal Regulations, Part 55 (OCS Regulations) and was granted approval in 2015.

[35] Walt Musial, Donna Heimiller, Philipp Beiter, George Scott and Caroline Draxl, 2016 Offshore Wind Energy Resource Assessment for the United States, National Renewable Energy Laboratory, September 2016, nrel.gov/docs/fy16osti/66599.pdf.

- A 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.
- A 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 FAA of any construction exceeding 200 feet in height.
- U.S. Coast Guard permission to establish aids to maritime navigation.
- Bureau of Ocean Energy Management (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.[36]

Offshore Wind Turbines Research and Development

Over 60 percent of potential offshore wind locations in the U.S. are in deep waters,[37] i.e., the water is so deep that the usual techniques of affixing large steel piles or lattice structures to the ocean floor are not possible. Utilizing floating foundations for offshore wind turbines could allow access to these offshore wind resource areas, and could 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.

Currently, there are 11 floating offshore wind projects worldwide, representing 79 MW. Another 15 projects and about 300 MW of capacity are either under construction or have received financing. Another 90 projects totaling over 26 GW are at an early stage of development. The floating offshore wind energy market has transitioned from small-scale, single-wind-turbine prototypes (2009-2015) to

Block Island Offshore Wind

In December 2016, 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.

[36] U.S. Department of the Interior, Office of Renewable Energy Programs, Bureau if Ocean Energy Management, Information Guidelines for a Renewable Energy Construction and Operations Plan (COP), Version 4.0, May 27, 2020, boem.gov/sites/default/files/documents/about-boem/COP%20Guidelines.pdf.

[37] U.S. Department of Energy, "Offshore Wind Research and Development," energy.gov/eere/wind/offshore-wind-research-and-development.

multi-turbine demonstration projects (2016-2022). Commercial-sized floating offshore wind projects may be installed as soon as 2022.[38]

Environmental and Socioeconomic Risks

Wind turbines can provide environmental benefits through the reduction of greenhouse gas (GHG) emissions and the 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:

- <u>Marine species populations</u>**:** 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. Submerged foundations for these offshore wind turbines can also act as artificial reefs, resulting in an increase in shellfish and the fish and marine animals that consume them.

- <u>Avian and bat populations</u>**:** 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.

- <u>Visual effects/property values</u>**:** 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. U.S. 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.

- <u>Tourism</u>**:** Coastal communities that are dependent on beach vacationers and the resulting local revenues and tax base have expressed concerns about the presence of offshore wind turbines; however, the evidence is ambiguous. Denmark currently attracts tourists with “Energytours” of offshore wind facilities.

- <u>Marine safety</u>**:** 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,

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[38] U.S. Department of Energy, Offshore Wind Market Report: 2021 Edition, energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf.

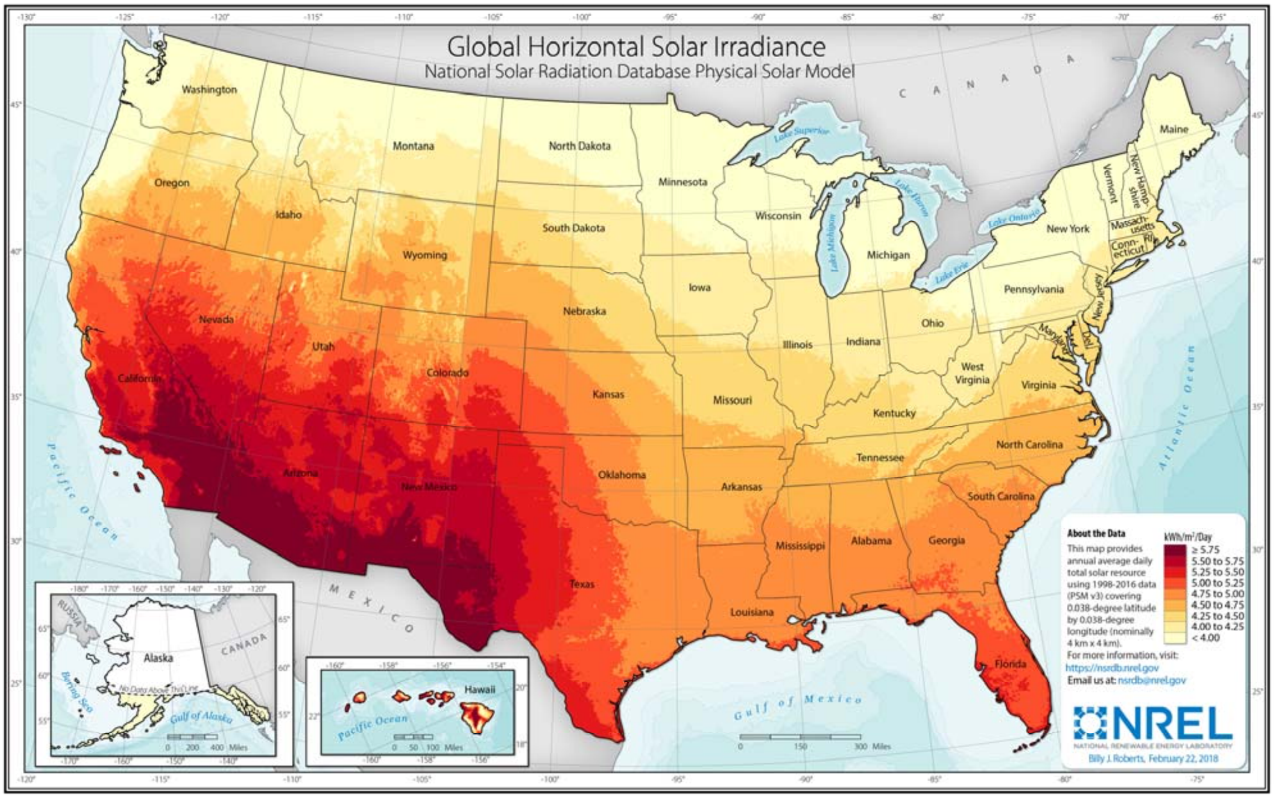
etc.). The U.S. Coast Guard created the Atlantic Coast Port Access Route Study (ACPARS) to assess the impact of alternative energy facilities, including offshore wind, on shipping lanes and vessel traffic. The ACPARS issued an interim report in 2012 which stated that offshore projects would disrupt vessel 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; and (3) recommendations to modify designated wind energy development areas to increase boating safety. In response to the final report, BOEM expressed concerns that the final report is a one-size-fits-all approach that eliminates designated wind areas, and BOEM believes that site-specific development for distance setbacks would be a more appropriate method. Additionally, the report was criticized for ignoring European risk assessments, such as one conducted for the Horns Rev II wind facility located off the coast of Denmark, which concluded that the likelihood of a ship-to-ship collision is "significantly higher" than the probability of a vessel colliding with a wind turbine. Despite several concerns filed against the report, the Coast Guard filed the final report with the Federal Register in 2017 without any modifications.

- 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 operational 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.

Solar

By virtue of its location, Maryland has only an average solar resource with moderate solar energy intensities, as illustrated in Figure 3-10. 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 50 percent renewable energy by 2030, with 14.5 percent coming from solar energy. Solar systems must be connected with the distribution grid in Maryland to be eligible. LSEs can self-generate solar power, purchase 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 3-10 Quality of Photovoltaic (PV) Resource



Source: nrel.gov/gis/assets/images/solar-annual-ghi-2018-usa-scale-01.jpg.

At the end of 2020, there were 74,529 solar facilities in Maryland representing 1,425 MW of generating capacity, 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), 164 systems larger than 1 MW have come online representing 600 MW of solar generating capacity. Table 3-4 lists the GATS-registered solar facilities by system size. In 2020, Great Bay Solar Phase I in Somerset County became the largest operational solar facility in Maryland. From 2016 to September 2021, the PSC issued CPCNs to 32 solar facilities with a combined capacity of 941 MW, and there are six cases pending before the Commission with a combined capacity of 296 MW. The largest CPCN approved to date is for Cherrywood Solar, a 202 MW solar facility located in Caroline County.

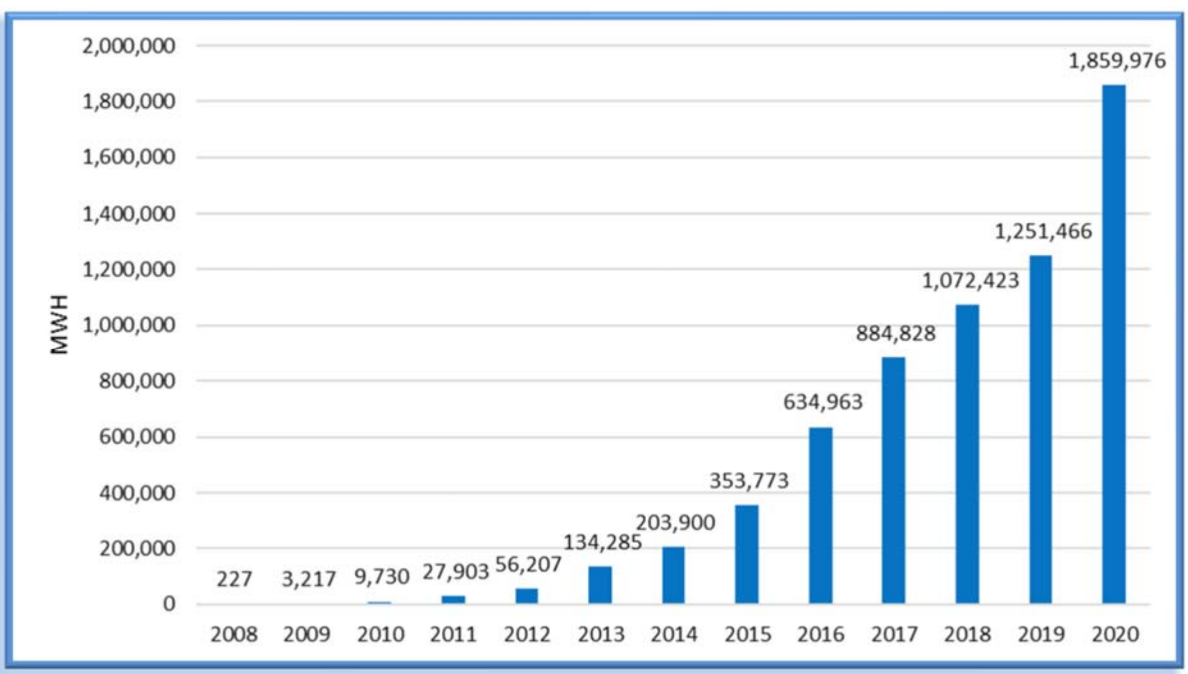
Table 3-4 Maryland's Solar Facilities Listed in PJM GATS, 2020

System Size (kW)	Number of Projects	Total Capacity (MW)
0 to ≤ 3	2,513	6
> 3 to 6	17,611	83
> 6 to 10	27,609	220
> 10 to 50	26,059	370
> 50 to 100	203	15
> 100	534	731
Total	74,529	1,425

Source: PJM Generation Attribute Tracking System.

Solar energy generation capacity in Maryland went from 0.1 MW in 2007 to 1,425 MW in 2020 due in large part to Maryland's implementation of a solar carve-out under the Maryland RPS. The General Assembly passed a bill in 2019 that further increased the percentage of the solar carve-out in the Maryland RPS from 2.5 percent by 2020 to 14.5 percent by 2030. Prior to that, in 2017, the solar carve-out had increased from 2 to 2.5 percent. Overall, solar generation in Maryland increased 1,285 percent, or approximately 1,725,691 MWh, between 2013 and 2020 (see Figure 3-11). For more information on the Maryland RPS solar carve-out, see Section 3.5.1.

Figure 3-11 Solar Generation in Maryland, 2008-2020



Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report, Various Years. Appendix A in this publication lists aggregate SRECs retired in Maryland. 2020 data sourced from PJM GATS.

Similar to Maryland, New Jersey also provides strong policy support for solar technologies. As of December 2020, New Jersey had about 3.5 GW of installed solar capacity.[39] In July 2021, New Jersey established the Successor Solar Incentive (SuSI) Program, which replaces the SREC Registration Program (SRP) that was closed to new registration in April 2020, and the Transition Incentive (TI) Program that provided a bridge between the Legacy SRP and the SuSI Program.[40]

The SuSI Program is made up of two sub-programs.[41] The Administratively Determined Incentive (ADI) Program provides incentives for 150 MW of net metered residential projects, 150 MW of net metered nonresidential projects of 5 MW or less, and 150 MW of community solar projects (low- and moderate-income [LMI] and non-LMI).[42] There is a $20 adder for a public entity (i.e., state entity, school district, county, municipality and New Jersey public university).

The ADI Program also provides incentives for an interim period for projects previously eligible to seek conditional certification (up to 75 MW) and is available for solar facilities certified as being located on brownfield, historic fill or properly closed landfills (see Figure 3-12).

Figure 3-12 ADI Incentives (NJ-SREC-IIs) Per Market Segment

Market Segments	System Size MW (dc)	Incentive Values ($/SREC-II)	*Public Entities (($20 Adder)
Net-Metered Residential	All Sizes	$90	N/A
Small Net-Metered Non-Residential located on Rooftop, Carport, Canopy and Floating Solar	Projects smaller than 1 MW (dc)	$100	$120
Small Net Metered Non-Residential Ground Mount	Projects smaller than 1 MW (dc)	$85	$105
Large Net Metered Non- Residential located on Rooftop, Carport, Canopy and Floating Solar	Projects 1 MW to 5 MW (dc)	$90	$110
Large Net Metered Non-Residential Ground Mount	Projects 1 MW to 5 MW (dc)	$80	$100
Community Solar LMI	Up to 5 MW (dc)	$90	N/A
Community Solar Non-LMI	Up to 5 MW (dc)	$70	N/A
**Interim Subsection (t) Grid	All Sizes	$100	N/A

Source: njcleanenergy.com/renewable-energy/programs/susi-program/adi-program. Last accessed on October 27, 2021.

[39] New Jersey's Clean Energy Program, "Installation and Project Status Reports," December 2020, njcleanenergy.com/renewable-energy/project-activity-reports/solar-activity-report-archive.

[40] programs.dsireusa.org/system/program/detail/22418/successor-solar-incentive-susi-program (updated October 1 and viewed October 27, 2021).

[41] New Jersey's Clean Energy Program, "Successor Solar Incentive (SuSI) Program," njcleanenergy.com/renewable-energy/programs/susi-program.

[42] New Jersey's Clean Energy Program, "Administratively Determined Incentive (ADI) Program," njcleanenergy.com/renewable-energy/programs/susi-program/adi-program.

*"Public Entity" is defined as a customer that is a State entity, school district, county, county agency, county authority, municipality, municipal agency, municipal authority, New Jersey public college, or New Jersey public university.

**Subsection (t) Grid solar facilities are defined as solar facilities certified as being located on brownfield, historic fill, or properly closed landfills.

The other subprogram is the Competitive Solar Incentive (CSI) Program that provides competitively set incentives for grid supply projects and net metered nonresidential projects greater than 5 MW. New Jersey is currently working with stakeholders to develop the design of the CSI Program with the goal of holding the first solicitation by early to mid-2022.

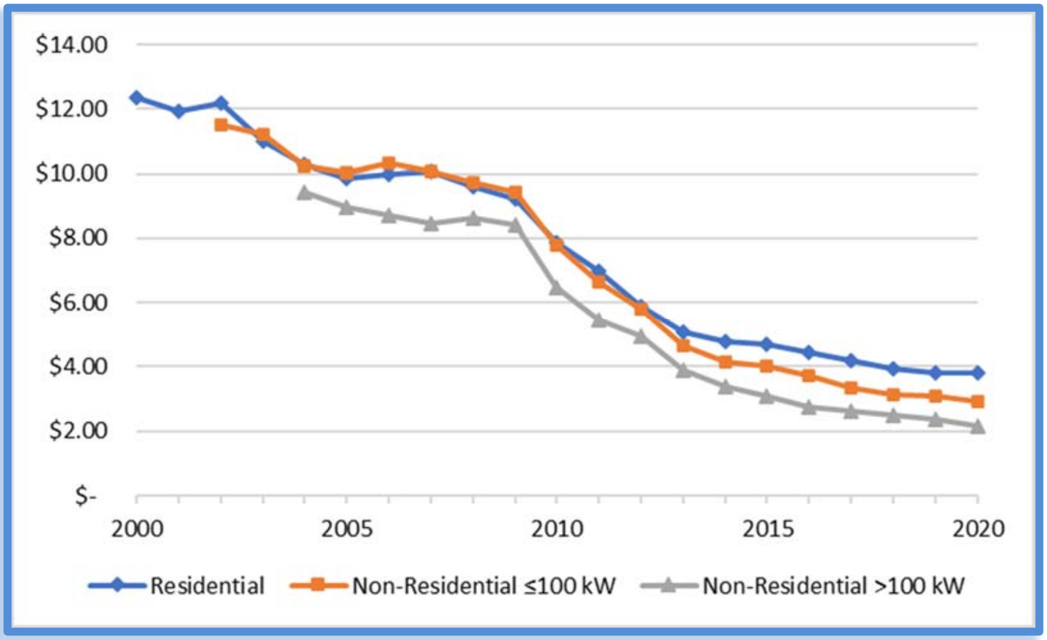
Nationally, installed solar costs for systems up to 5 MW have declined, on average, by 6 to 9 percent per year since 1998, depending on customer class (residential or nonresidential). Cost declines, however, have not occurred at a steady pace. In fact, installed costs have declined markedly since 2009. National median costs of solar systems dropped by 59 percent for residential systems, 69 percent for nonresidential systems below 100 kW and 74 percent for nonresidential systems over 100 kW (see Figure 3-13) in 2020, as compared to 2009.[43] Costs for utility-scale solar systems (5 MW and above) have also dropped sharply, from over $5/watt$_{AC}$ to $1.1/watt$_{AC}$ in 2020.[44]

Certain incentive policies, like the Maryland and New Jersey RPS policies, have assumptions of declining photovoltaic (PV) installation costs built into the enforcement mechanisms. In the case of state RPS policies, the alternative compliance payment (ACP) effectively places a ceiling on SREC costs and generally moves lower year to year. If the solar industry cannot match these downward cost profiles, utilities may opt to pay the ACP in lieu of installing solar facilities.

[43] Barbose, Galen, Naim Darghouth, Eric O'Shaughnessy and Sydney Forrester, Tracking the Sun 2021 Edition: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, Lawrence Berkeley National Laboratory, September 2021, emp.lbl.gov/sites/default/files/2_tracking_the_sun_2021_report.pdf.

[44] Mark Bolinger, Joachim Seel, Cody Warner and Dana Robson, Utility-Scale Solar, 2021 Edition, Lawrence Berkeley National Laboratory, October 2021, emp.lbl.gov/sites/default/files/utility_scale_solar_2021_edition_slides.pdf.

Figure 3-13 Cost of Solar PV in the United States ($/watt), 1998-2020



Source: Barbose, Galen Naim R. Darghouth, Eric O'Shaughnessy, and Sydney Forrester, Tracking the Sun 2021 Edition: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, Lawrence Berkeley National Laboratory, September 2021. emp.lbl.gov/sites/default/files/2_tracking_the_sun_2021_report.pdf.

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.

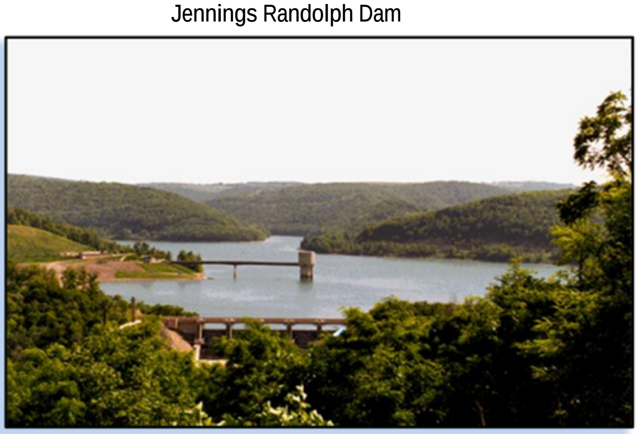
In 2013, President Obama signed two bills aimed at boosting development of the nation's hydropower resources. House Resolution (H.R.) 267, the Hydropower Regulatory Efficiency Act, promotes the development of small hydropower and conduit projects and aims to shorten regulatory time frames of certain other low-impact hydropower projects, such as adding power generation to the nation's existing non-powered dams and closed-loop pumped storage. Since 2013, FERC reported it has extended 16 exemption permits for small conduit hydropower projects.

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.

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 was delayed as the project waited for approval by the Corps. In June 2021, FERC granted a delay to begin construction by April 30, 2023 and to commence operations by April 30, 2026.

Jennings Randolph Dam



In 2018, Congress enacted the America's Water Infrastructure Act. The law required FERC to (1) create a two-year decision timetable for qualifying facilities at existing non-powered dams; (2) establish a list of non-powered federal dams with the greatest potential for hydropower development; (3) develop a two-year process for licensing of closed-loop pump storage projects; and (4) increase the duration of the preliminary permit from three years to four. The law allows FERC to (5) approve extensions for preliminary permits from two years to four; (6) consider development opportunities for closed-loop pump storage projects at abandoned mine sites; and (7) extend the deadline for starting construction from two years after FERC grants a hydro license to eight.[45] FERC issued implementation rules in April 2019.[46]

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 generates approximately 240 MWh annually. The construction of the plant was completed in 2012 and the plant 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 four additional small-scale facilities that are currently in operation. Maryland's hydroelectric plants are listed in Table 3-5 with locations shown in Figure 3-14. Conowingo Dam is the state's largest hydro facility. In October 2019, Exelon, the then owner and operator of Conowingo Dam, proposed a settlement with MDE to FERC, where Exelon will spend over $200 million over 50 years on several protection, mitigation and enhancement measures, including fish passage attraction flows, eel passage, invasive species management, a revised downstream operating flow regime, trash and debris removal, dissolved oxygen monitoring, shoreline management, turtle management, a waterfowl nest plan, sturgeon

[45] America's Water Infrastructure Act of 2018, Pub. L. No. 115-270 (2018), govtrack.us/congress/bills/115/s3021/text. See also Anne E. Sibree, "Hydro Review: The Revitalization of Hydropower," Hydro Review, October 16, 2019, hydroreview.com/2019/10/16/hydro-review-the-revitalization-of-hydropower/, and Rocío Uría-Martínez, Megan M. Johnson, and Rui Shan, U.S. Hydropower Market Report, U.S. Department of Energy/Oak Ridge National Laboratory, January 2021, energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf.

[46] Federal Energy Regulatory Commission Final Rule 18 CFR Pt. 7, Hydroelectric Licensing Regulations Under the America's Water Infrastructure Act of 2018, Order No. 858, 167 FERC ¶ 61,050 (2018), p. 4. ferc.gov/sites/default/files/2020-04/H-1_1.pdf. See also Anne E. Sibree, "Hydro Review: The Revitalization of Hydropower," Hydro Review, October 16, 2019, hydroreview.com/2019/10/16/hydro-review-the-revitalization-of-hydropower/.

monitoring, mussel restoration, water quality project funding and other measures.[47] In March 2021, FERC approved relicensing, granting Exelon a new 50-year license to operate the dam.[48] Exelon transferred the Conowingo project to Constellation Energy Corporation in early 2022. Section 5.2.2 includes further discussion about hydroelectricity and its potential impacts.

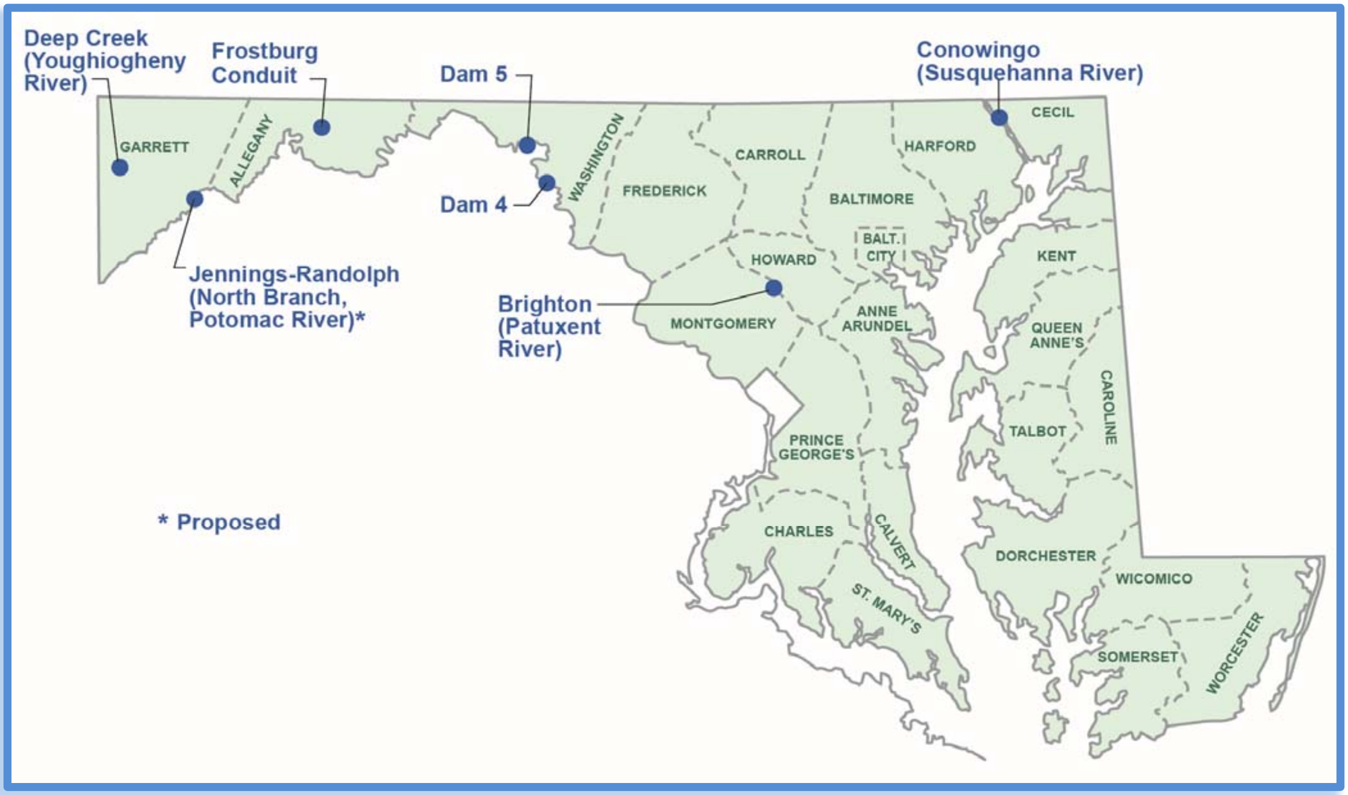
Table 3-5 Hydroelectric Projects in Maryland

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	Constellation Energy Corporation	Major License	2021	2071	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	FERC construction permit extended through 2021
SMALL-SCALE PROJECTS								
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
Dam 4	1.9 MW	Potomac River	2516	Cube Hydro	Minor License	2004	2034	1909
Dam 5	1.21 MW	Potomac River	2517	Cube Hydro	Minor License	2004	2034	1919

[47] Exelon Corporation, "Exelon Generation and State of Maryland Reach Agreement to Restore and Sustain Chesapeake Bay," October 29, 2019, exeloncorp.com/newsroom/conowingo-announcement.

[48] ferc.gov/news-events/news/ferc-relicenses-conowingo-hydroelectric-project.

Figure 3-14 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 waste 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.

WTE was classified as a Tier 2 resource under the Maryland RPS until 2011, 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 3.5.1 for information on the Maryland RPS Tier 1 and Tier 2 requirements.

As of 2020, there are 83 WTE facilities currently operating nationwide according to the U.S. Energy Information Administration, including two facilities in Maryland that are certified under Maryland's RPS. WTE facilities are heavily regulated due to various environmental impacts. As displayed in Table 3-6, one plant was shut down in 2016 and another had its permit revoked. 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.

Baltimore City Clean Air Act

In early 2019, the Baltimore City Council adopted the Baltimore City Clean Air Act which establishes strict pollution limits on commercial solid waste incinerator facilities, such as the Wheelabrator waste-to-energy plant located in South Baltimore, which receives proceeds through its production of RECs under the Maryland RPS. Beginning in 2022, the ordinance would require all facilities to have real-time monitoring and disclosure of pollutants on a website, and limits to emissions such as mercury, sulfur dioxide and nitrogen oxides. In order to be in compliance, the Wheelabrator facility, which combusts 1.2 million tons of garbage annually, would require significant investment. Wheelabrator sued the City of Baltimore, and a judge ruled against the City in March 2020, stating the Baltimore City Clean Air Act is inconsistent with state and federal regulatory authority. In November 2020, the City of Baltimore and Wheelabrator settled the case, with the City extending its contract with Wheelabrator through the end of 2031, and Wheelabrator agreeing to invest $39.9 million in air emission control upgrades.

Source: wastedive.com/news/baltimore-wheelabrator-lives-on-controversy-zero-waste/588279/.

Table 3-6 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)	Shutdown in 2016	1.2	Energy Recovery Operations
Fairfield Renewable Energy Power Plant (Baltimore, Maryland)	Permit Revoked	140	Energy Answers International

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 CO_2, 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 CO_2. Both CO_2 and methane are GHGs; however, methane has 25 times the global warming potential of CO_2, thus converting methane to CO_2 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 3-7 lists the LFG-to-energy projects that are currently operating in Maryland. The 3.2 MW Millersville LFG project collects LFG and sells it directly to the Army's Fort Meade installation to fuel operations at the installation.

Table 3-7 Landfill Gas Projects in Maryland

Name (Location)	Estimated Total Waste in Place (Tons)	Project Status	Project Start Date	Project Type	Capacity (MW)	Project Developer
Brown Station Road (Prince George's County)	36,602,454	Shut down Operational	1987 2003	Reciprocating Engine Reciprocating Engine	2.6 3.5	PG County
Eastern/White Marsh (Baltimore County)	21,088,122	Shut down Shut down Operational	2006 2017 2020	Reciprocating Engine Reciprocating Engine Reciprocating Engine	1.68 0.84 1.68	Pepco Energy Services Pepco Energy Services Energy Power Plants
Newland Park (Wicomico County)	3,736,006	Operational	2007	Reciprocating Engine	1.32	INGENCO
Central Landfill (Worcester County)	1,244,656	Shut down	2008	Reciprocating Engine	2.0	Curtis Engine
Gude (Montgomery County)	4,800,000	Shut down Operational	1985 2009	Reciprocating Engine Reciprocating Engine	2.0 0.8	Covanta SCS Engineers
The Oaks (Montgomery County)	6,874,060	Retired	2009	Reciprocating Engine	2.4	SCS Engineers
Quarantine Road (Baltimore County)	10,632,202	Retired	2009	Cogeneration	1.5	Ameresco Federal Solutions
Reichs Ford Landfill (Frederick County)	3,940,387	Retired	2010	Reciprocating Engine	2.1	Energenic-US
Sandy Hill (Prince George's County)	16,403,208	Shut down Operational	2003 2011	Boiler Boiler	Steam Steam	Toro Energy
Millersville (Anne Arundel County)	8,454,059	Operational	2012	Reciprocating Engine	3.2	Northeast Maryland Waste Disposal Authority
Alpha Ridge (Howard County)	3,039,793	Operational	2012	Reciprocating Engine	0.58	Pepco Energy Services, Inc.

Notes: The Brown Station Road, 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.

3.1.6 Energy Storage

Overview

Energy storage allows for energy produced at one point in time to be used at a later time. Storage systems are unique in that they can be in various forms and satisfy multiple functions, such as being able to serve as a generator, transmission asset and/or distribution asset. Examples of energy storage technologies include pumped hydroelectric, compressed air energy storage (CAES), flywheels, and various types of batteries, e.g., lead-acid batteries, lithium-ion batteries and zinc-bromide batteries. Each of the various technologies has different benefits, economics and operational characteristics. Hence, the various technologies can be used to serve multiple end-uses. The principal end-uses of energy storage include:

- <u>On-peak power supply</u> – Provides 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.

- <u>Electric grid support</u> – Supports 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 infrequently.

- <u>End-user cost management</u> – Stores electric power during periods when market prices are low and draws on that power when market prices are higher.

- <u>End-user reliability enhancement</u> – Provides power supply during times when the electric grid is not available.

- <u>Variable renewable energy generation</u> – Reduces the variability of certain renewable electric generation technologies, such as wind and solar. For example, storage could be used to reduce the output fluctuations from a PV array due to passing clouds. Furthermore, storage can enhance the value of variable 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.

Historically, only pumped hydroelectric and CAES have been used nationwide 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. Recent declines in the costs of battery storage have led to a number of hybrid projects co-located with another generation technology.[49] As of the end of 2020, there were 226 such hybrid projects, each 1 MW or above, totaling over 30 GW of capacity. Of these, solar+storage was the most common (73 projects with 992 MW of PV and 250 MW of storage), followed by several different fossil hybrid combinations (fossil+PV, fossil+hydro and

[49] Most, but not all, of these hybrid projects paired a generation technology with energy storage.

fossil+storage). Of the planned solar projects, 159 GW of the more than 460 GW of solar PV in interconnection queues across the country are hybrid projects, mostly paired with storage.[50] The duration of battery storage ranges from two to five hours and applications include shifting solar energy to late afternoon/early evening hours, or minimizing/alleviating curtailment of solar generation. In the Mid-Atlantic region, battery systems and flywheels are 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.

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 (EVs), have been significant in recent years and prices are generally expected to continue to decline over time. Based on the potential uses of storage, energy 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.

At the conclusion of 2020, there were 24 GW of total energy storage installed in the United States. In 2020, 571 MWh of new energy storage was added to the U.S. electric grid, which is 70 percent higher than the 336 MWh interconnected in 2016. Residential markets continue to experience the highest levels of growth, likely due to policies and mandates in California, Hawaii and Vermont. The overall growth in energy storage will likely continue due to the establishment of energy storage targets in states such as California, Massachusetts, New Jersey, Connecticut, New York, Oregon, Nevada and Virginia, coupled with the decrease in the cost of energy storage, which fell by 72 percent from 2015 to 2019. In fact, EIA predicts that based on current large-scale battery storage trends, large-scale battery additions are set to install around 10 GW of capacity between 2021-2023.[51]

In spring 2017, the Maryland General Assembly enacted legislation that required the Power Plant Research Program (PPRP) to study regulatory reforms and market incentives that may be needed or may benefit energy storage in Maryland. The final report, released January 22, 2019, provides a review of the energy storage technologies, their applications, efforts by other states to promote storage, the current state of storage in Maryland, and the barriers that discourage widespread implementation.[52]

Following the release of the report, the Maryland Senate introduced Senate Bill (SB) 573 which requires the Maryland PSC to establish an energy storage pilot program with pilot projects ranging between 5-10 MW. The pilot is designed to evaluate energy storage ownership models and answer whether a utility can own storage in a deregulated electricity market. Under SB 573, which passed in April 2019, the state's four investor-owned utilities (IOUs) were required to solicit two energy storage projects for the PSC's approval by April 15, 2020 and September 15, 2020, respectively, with project operational dates by February 28, 2022. The projects must solicit offers that fall under two of the following four utility ownership models: utility-only, utility and third party, third-party ownership, and a virtual power plant.

[50] Mark Bolinger, Will Gorman, Joseph Rand, Ryan H Wiser, Seongeun Jeong, Joachim Seel, Cody Warner and Bentham Paulos, Hybrid Power Plants: Status of Installed and Proposed Projects, Lawrence Berkley National Laboratory, August 2021. escholarship.org/content/qt9979w72n/qt9979w72n.pdf

[51] eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

[52] dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

Under the last ownership model, the utility would utilize services provided by energy storage devices owned by customers or a third-party aggregator.[53]

BGE, Potomac Electric Power Company (Pepco) and Delmarva each filed two pilot applications on April 15, 2020, as described further below:

- BGE proposed a 2.5 MW / 7.1 MWh, utility-owned and -operated lithium-ion battery storage unit at BGE's Fairhaven substation in Anne Arundel County. BGE stated the Fairhaven project will improve distribution system reliability and help address any contingency overloads as a result of winter peak demand. The project's capacity is projected to degrade to 4 MWh over time.

- BGE's second project is a 2 MWh lithium-ion battery storage unit owned and operated by a third party, Ameresco, at one of four potential distribution sites. This Chesapeake project will serve the purposes of improving reliability during peak winter demand, participating in PJM's frequency markets and providing energy arbitrage.

- Pepco proposed a utility-owned but third-party-operated lithium-ion facility at National Harbor. The project is rated at 1.05 MW / 4.25 MWh but is expected to degrade to 1 MW / 3 MWh over time. Pepco says the project will defer a new substation, provide peak shaving and grid reliability benefits, and participate in PJM markets.

- Pepco's second project is a lithium-ion energy storage system at a bus depot in Silver Spring. Pepco, by contract, can utilize 3 MWh over a 3-hour period for up to 10 days per year, over 10 years. The contract can be extended to 15 years. Pepco estimates the project will defer, and perhaps avoid, a $3.6 million feeder upgrade to serve the bus depot and will also provide peak shaving and backup power during emergency grid conditions.

- Delmarva proposed a virtual power plant at Elk Neck State Park in Cecil County, consisting of behind-the-meter energy storage systems at 110 homes in Elk Neck. The systems will be networked together, capable of providing 0.5 MW / 1.5 MWh, and will provide peak shaving and backup power during emergency events. Participating homeowners will own the equipment after 10 years.

- Delmarva's second project is a utility-owned and -operated lithium-ion system in Ocean City, totaling 1.0 MW / 3.6 MWh. The system will provide peak shaving, frequency regulation to PJM, emergency backup and overall improved reliability.

The PSC conditionally approved the proposals from BGE, Pepco and Delmarva in November 2020 but required that all of the projects participate in PJM markets, and that utilities file an emissions management plan and provide notice if they anticipate spending more than half of the contingency funding allocated for each project.[54]

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[53] mgaleg.maryland.gov/2019RS/bills/sb/sb0573T.pdf.

[54] Maryland Public Service Commission, Order on Energy Storage Pilot Proposals, Order No. 89664, November 6, 2020.

In October 2021, BGE, Delmarva and Pepco jointly submitted to the PSC a report indicating that four of the six approved pilot projects are expected to require more than 50 percent of the contingency funding approved per project. However, the utilities added that three of these four projects are still projected to be cost-effective. Reasons cited for the higher costs include additional safety requirements, increasing system vendor costs, unexpectedly high IT and communications costs, additional engineering costs due to modifications and upgrades, retaining a PJM scheduler, site location change, more specific interconnection costs, retaining third-party engineering support and additional material needs. The utilities also indicated that five of the six projects are likely to have operational dates after the deadline required by SB 573 of February 28, 2022. The utilities cited delays related to complex design challenges, permitting processes, supply chain disruptions and protracted vendor negotiations, among others. They requested deadline extensions for "good cause," which the PSC granted in December 2021.[55]

Potomac Edison Company (PE) also filed two energy storage proposals. The first is a third-party-owned and -operated project in Little Orleans that is rated at 1.75 MW / 8.4 MWh. Known as the Town Hill project for the name of the circuit on which it will be located, the project will allow PE to island the circuit in the case of a reliability event and still provide power to customers, and will serve as an alternative for building a connection to another circuit. PE can reserve the Town Hill project for up to 20 days annually.

PE's second energy storage pilot project is a utility-owned and -operated 500 kW project that will serve an EV direct current (DC) fast-charging station in Urbana. In addition to providing EV charging, the Urbana pilot project will also provide demand management, frequency regulation and energy arbitrage via the PJM energy market.

The PSC approved both projects in April 2021, subject to the same conditions in the PSC's November 2020 order.[56]

[55] Maryland Public Service Commission, Letter Order, December 15, 2021.

[56] Maryland Public Service Commission, Order on Energy Storage Pilot Proposals of Potomac Edison, Order No. 89805, April 21, 2021.

Maryland Energy Storage Pilot Program

In May 2019, Governor Hogan signed into law SB 573 (Energy Storage Pilot Project Act), requiring the state's four investor-owned utilities (Baltimore Gas and Electric Company, Delmarva Power and Light Company, Potomac Electric Power Company and Potomac Edison Company) to propose two energy storage pilot projects per utility. Collectively, the projects were to total 5-10 MW of storage capacity. The intent of the pilot program is to test different ownership models and multi-use operating modes for energy storage, as well as to gain experience with performance metrics, contracting, accounting and billing. By April 2021, the Maryland PSC had approved eight energy storage pilot projects, as shown in the table below.

Selected Characteristics of Proposed Energy Storage Projects

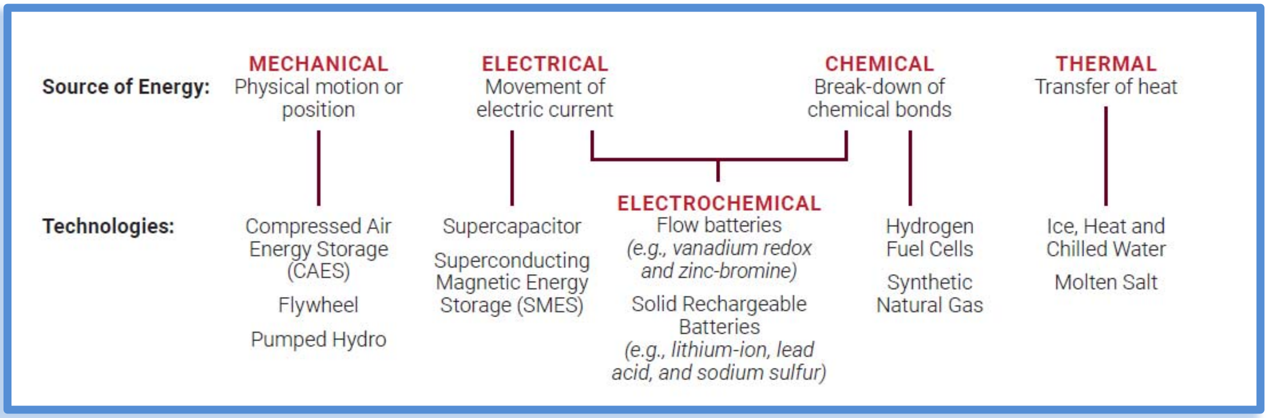
	JOINT EXELON UTILITIES						POTOMAC EDISON	
	BGE		Delmarva		Pepco			
	Fair-haven	Chesapeake	Elk Neck	Ocean City	National Harbor	Bus Depot	Town Hill	Urbana
Ownership Model								
Utility owned/operated	X			X				X
Utility owned/3rd party operated					X			
3rd party owned/operated		X				X	X	
Virtual power plant			X					
Operating Modes[1]								
Peak shaving	1	1		1	1	1		1
Grid reliability / backup power			1	1		2	1	
PJM Markets	2	2	3	2	2		2	2
DER Integration (on site) / Demand mgmt.			2			3		
Resiliency				3				

[1] These assignations reflect PPRP's effort to standardize operating mode descriptions, which vary somewhat by project.

Energy Storage Technologies

Energy for storage systems can come from four sources: mechanical, electrical, chemical and thermal. As noted in Figure 3-15, there is a wide variety of electricity storage devices currently in use, including pumped hydroelectric power, chilled water, batteries and flywheels.

Figure 3-15 Energy Storage Sources of Energy and Common Technologies



Source: Maryland Department of Natural Resources Power Plant Research Program, "Energy Storage in Maryland," dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf, pp. 1-2.

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 22 GW of energy storage in the United States. Water is pumped into an upper reservoir when electricity prices are low, generally during nighttime, off-peak periods, and 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. Some energy companies are also testing the use of batteries for grid management and energy storage. The largest facility in the United States is the Florida Power and Light Manatee Energy Storage Center that came online in December 2021 with a capacity of 409 MW / 900 MWh. This facility will replace two aging gas plants in the area.

Warrior Run Battery Facility

Maryland's largest grid-scale battery is the 10 MW Warrior Run Battery Facility. The facility is co-located with the 205-MW, coal-fired Warrior Run Plant in Cumberland, Maryland. The lithium-ion battery facility, owned by AES Corporation, became operational in November 2015. The project is interconnected at the transmission level and provides frequency regulation services to PJM. The modular design is considered to be unique as it can be separated into various configurations. The facility is considered to be a 20 MW flexible resource since the batteries can absorb a total of 10 MW of excess power from the grid or supply up to 10 MW to the grid. Depending upon the configuration, the facility can provide output ranging from 15 minutes to four hours.

Source: AES FERC Registered Entities aesusgeneration.com/

Flow batteries use 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. VRB® Energy is the process of installing the largest vanadium redox flow battery project in the world as part of the Hubei Zaoyang Storage Integration Demonstration project. The project, which is planned to reach 10 MW / 40 MWh, successfully commissioned the first 250 kW / 1 MWh vanadium redox flow battery module in late 2018 and a 3 MW / 12 MWh vanadium redox flow battery in January 2019, thus completing Phase I of the project.

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 25 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.

Other Emerging Battery Storage Technologies

Rail cars are also becoming a potential 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. In 2016, Constellation Energy (a subsidiary of Exelon at the time) partnered with Viridian Energy to expand this pilot program to a 10 MW battery storage network at seven SEPTA stations. 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 began construction on a 50 MW commercial-scale rail car storage system in Nevada in October 2020. The facility can provide up to 15 minutes of regulation at full capacity.[57]

Thermal storage reserves energy that is produced in the form of heat or cold to be used at a later time. An example would be to create ice for an ice chiller during off-peak hours and utilize the chiller during peak hours to assist with cooling.

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.

Energy Storage Tax Credit

In May 2017, Maryland introduced a state income tax credit for the installation of energy storage systems, making it the first and only state to offer a tax credit for this type of technology. For systems installed between January 1, 2018 and December 31, 2022, MEA will award tax credits for up to 30 percent of the total installed costs of the energy storage system for qualified systems installed on residential or commercial properties. The systems that qualify for the tax credit include chemical (batteries), thermal (ice/chilled water), and electrical energy and mechanical (flywheels, compressed air). As of September 20, 2021, MEA had awarded $339,000 in tax credits out of the $750,000 allocated for the 2021 tax year.[58]

[57] ARES, "Pahrump Valley Times: Energy Storage Project Breaks Ground in Pahrump," October 16, 2020, aresnorthamerica.com/pahrump-valley-times/.

[58] energy.maryland.gov/business/Pages/EnergyStorage.aspx.

3.2 New and Proposed Power Plant Construction

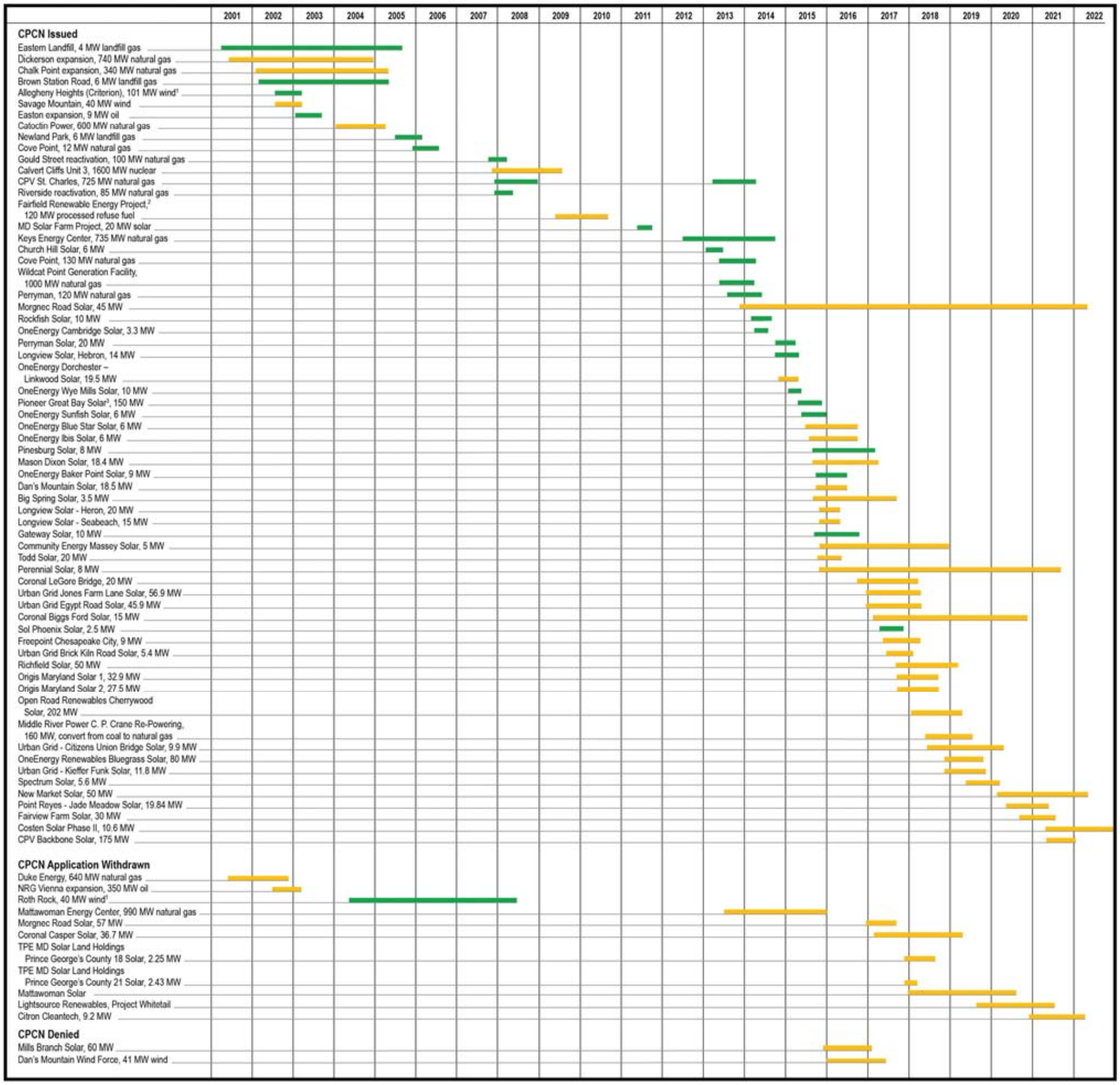
Since early 2015, the PSC has received 47 CPCN applications for proposed new generating facilities—an unprecedented level of licensing activity. Over the past 20 years, the PSC has received 74 CPCN applications for new generation, representing several thousand megawatts of potential generating capacity at existing facilities and at greenfield sites, with numerous application reviews ongoing (see Figure 3-16). While the majority of these proposed plants obtained a CPCN, only 24 are now in operation. The remainder are under construction or have been delayed or abandoned for various financial or commercial reasons.

Maryland has seen a sharp increase in utility-scale solar projects in recent years. Developers are proposing these solar projects to capitalize on federal tax incentives and support the Maryland RPS (see solar discussion in Section 3.1.5).

In terms of capacity, the 2010s were dominated by new natural gas-fired facilities in Maryland. Spurred by the abundance of natural gas (especially in the nearby Marcellus Shale basin) and low fuel prices, developers proposed and constructed several new gas-fired plants. However, with the movement to zero-carbon emissions, there have not been any new gas-fired power generation facilities proposed or permitted since 2019. In fact, one developer, Mattawoman Energy, LLC, withdrew its CPCN in 2021 due to economic reasons. Mattawoman Energy, a subsidiary of Panda Power Funds, LLC, had received CPCN approval in October 2015 for the proposed 990 MW facility in Brandywine, Maryland. One remaining project, Middle River Power, obtained a CPCN in June 2019 to build a 160 MW gas-fired facility at the site of the existing CP Crane coal-fired plant. The coal-fired units at Crane ceased operation in May 2018. Middle River Power requested an extension of construction deadlines in early 2021; if approved, construction is planned to begin July 24, 2022.

Most recently, from the renewable energy project perspective, CPV Backbone Solar, LLC has proposed to construct a large, utility-scale, 175 MW alternating current (AC) generating capacity solar PV facility in Garrett County, Maryland. If permitted, this will be the first utility solar facility to be constructed to effectively reuse reclaimed underground coal mine property with minimal impacts to neighboring properties. One other smaller solar PV facility to be constructed on reclaimed surface coal mine property was recently granted a CPCN in May 2021. Several other utility-scale solar projects are currently under review.

Figure 3-16 CPCN Requests, 2001 through April 2022



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:

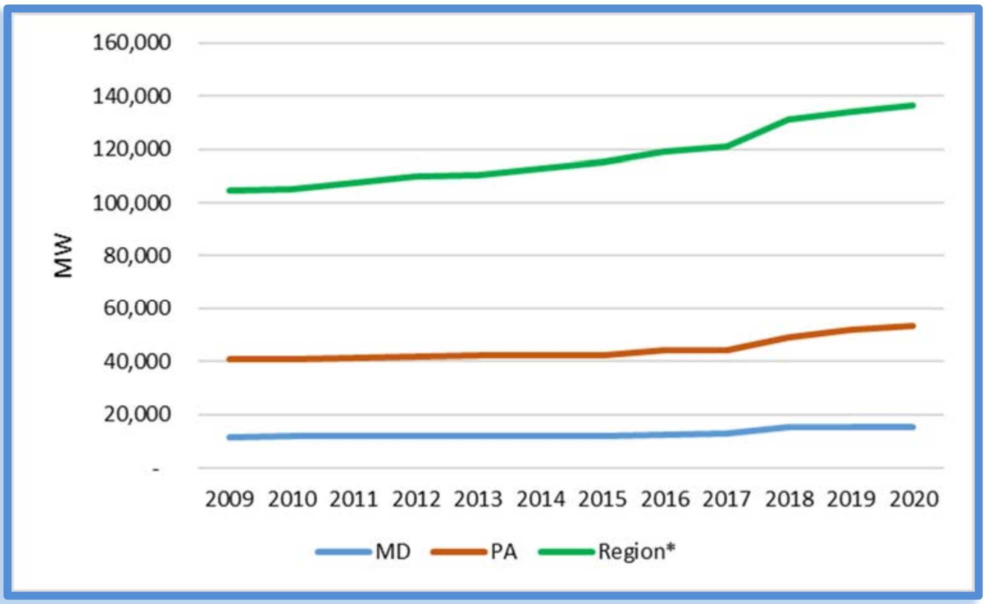
= Project is operational = Project is not operational

[1] Project was subsequently reconfigured, granted a CPCN exemption, and is now operational.
[2] Air permit denied.
[3] The CPCN is for 150 MW solar array; only 75 MW of the project are in operation as of October 2019.

Chart does not reflect the following CPCN cases ongoing as of April 2022: Waypost Solar.

As a market-based state, Maryland's electric 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 3-16 demonstrates the recent increase in the number of CPCN requests in Maryland after a multiyear period with relatively few open applications but much larger individual projects. Figure 3-17 shows the amount of capacity online for Maryland, Pennsylvania and the region.

Figure 3-17 Maryland and Regional Capacity



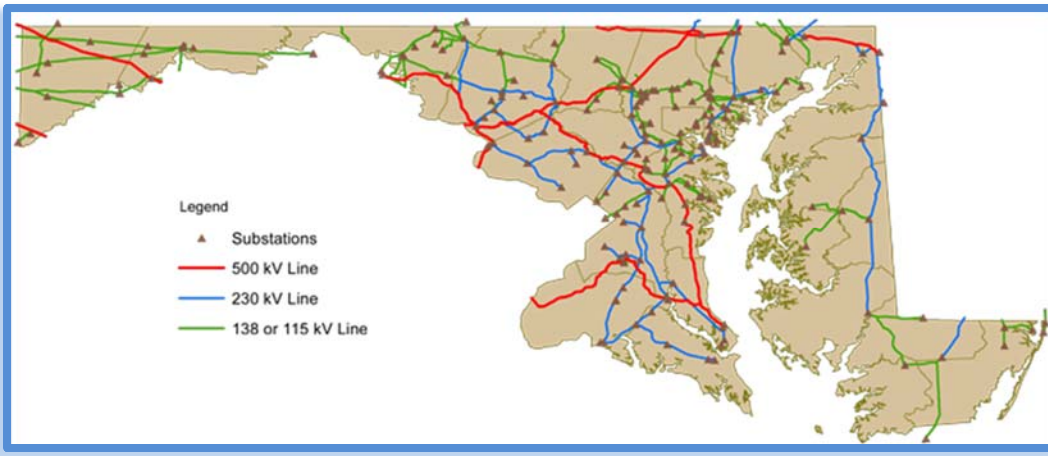
*Region includes Delaware, Maryland, New Jersey, Pennsylvania, Virginia, the District of Columbia, and West Virginia.
Source: U.S. Energy Information Administration, EIA-860, 2020 Final Release.

Over the last decade, capacity growth has been stagnant in Maryland but has grown slightly in Pennsylvania, and more in the PJM region as a whole. The increase in capacity is due almost entirely to natural gas plants, with renewable energy resources contributing a small portion of the total capacity growth. The growth in capacity has more than offset the retirements of coal plants that have occurred in PJM. Growth in capacity overall has been suppressed by a number of factors, including energy efficiency and demand response efforts, transmission upgrades, capacity in excess of reliability requirements and low load growth.

3.3 Electric Transmission

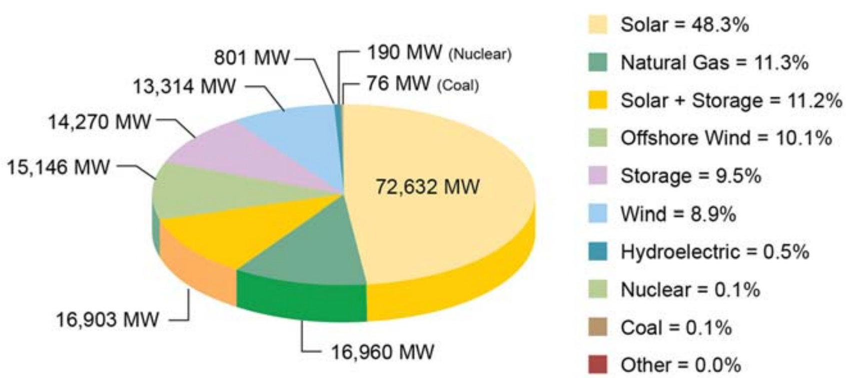
The network of high-voltage lines, transformers and other equipment that connects power-generating facilities to distribution systems is part of an expansive electric transmission system. In Maryland, there are more than 2,000 miles of transmission lines operating at voltages between 115-500 kV. Figure 3-18 shows a map of this high-voltage transmission grid in Maryland.

Figure 3-18 Transmission Lines in Maryland (> 115 kV)



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 December 2020, the PJM interconnection queue consisted of projects totaling nearly 150 GW of capacity (stated as winter net capacity). Solar is the dominant resource, followed by natural gas. The breakdown by fuel type is shown in the pie chart below. Renewable energy projects accounted for around 89 percent of the total capacity in the PJM interconnection queue. Although most 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.



While the economic and environmental effects of generation can be 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, often with significant environmental impacts and ratepayer costs. Upgrading existing heavily used facilities must be done quickly, often within 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.

PJM and New Jersey's transmission solicitation for Offshore Wind

In 2020, the New Jersey Board of Public Utilities (NJBPU) requested that PJM integrate the state's offshore wind policy goal (7,500 MW by 2035) into the grid operator's transmission planning process through the State Agreement approach established by FERC Order No. 1000. The action authorized PJM to solicit potential offshore wind transmission solutions from qualified developers on behalf of NJBPU. Through this process, New Jersey, the first state to engage in a competitive solicitation process managed by PJM, will be able to see how a coordinated strategy could lead to more cost-effective, efficient transmission options.

On April 15, 2021, PJM opened the 120-day solicitation window on behalf of NJBPU for qualified developers to submit potential transmission solutions that would help deliver offshore wind energy to the existing power grid. The PJM-managed solicitation process will allow NJBPU Staff to analyze a wide range of ready-to-build transmission solutions that would otherwise be unavailable at this point of offshore wind development. NJBPU and PJM will analyze all applications once the solicitation window closes on August 13, 2021 to determine which, if any, combination of project proposals can achieve the state's offshore wind policy goals. The competitive solicitation process contains extensive consumer protections such as the ability to phase-in transmission upgrades to control cost, and provides NJBPU the right to terminate the process at any time without making a selection.

Sources: pjm.com/-/media/about-pjm/newsroom/2020-releases/20201118-pjm-new-jersey-collaborate-to-advance-states-offshore-wind-goals-through-regional-planning-process.ashx.

nj.gov/bpu/newsroom/2021/approved/20210415.html.

bpu.state.nj.us/bpu/newsroom/2020/approved/20201118a.html.

PJM has operational control over and planning responsibility for 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, usually in the form of market efficiency projects that may relieve congestion and provide the lowest electric costs for consumers in the region, 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. More details on the RTEP process are discussed in Section 4.3.3.

3.3.1 New and Proposed Transmission Projects

On June 30, 2020, the PSC granted a CPCN to Transource Energy, LLC (Transource) to build two new 230 kV overhead transmission lines, one in Frederick County, Maryland (IEC West) and the reconfigured IEC East portion in Harford County, Maryland. The reconfigured IEC East portion, to be constructed, owned and maintained by BGE, consisted of a 230 kV circuit on the existing Otter Creek – Conastone 230 kV line, and another 230 kV circuit on the Manor – Graceton 230 kV line. This project was selected by PJM in 2016 as a solution to address transmission congestion on the AP-South Reactive Interface. However, on May 24, 2021, the Pennsylvania Public Utility Commission (PA PUC) denied the siting applications of the IEC East project in York County, Pennsylvania and the IEC West project in Franklin County, Pennsylvania because Transource failed to establish the need for the proposed transmission lines.[59] On June 15, 2021, Transource Maryland LLC requested that the Maryland PSC extend the construction deadline defined in the CPCN. The PSC granted an extension to construct on June 22, 2021.

Two ongoing transmission projects include:

- BGE's Five Forks to Windy Edge Reliability Project overhead transmission line rebuild will replace the existing double-circuit 115 kV line and its associated lattice structures with new weathering steel monopole towers. The approximately 20-mile line is located from the Five Forks substation in northern Harford County to the Windy Edge substation located in northern Baltimore County and was placed into service approximately 100 years ago. The new transmission line will replace more than 400 existing lattice structures with 219 new monopole structures. The project will address aging infrastructure and avian interactions, and will reduce tower strike risk by reducing structure foundation size. BGE filed its application for the project on January 15, 2021.

- PE's Doubs to Goose Creek overhead transmission line rebuild will replace the existing 500 kV line located in Frederick and Montgomery counties, Maryland. The approximately 18-mile extra-high-voltage line will connect with an extra-high-voltage line that continues into Virginia. The new line will replace facilities that have been in service for 40 years and are reaching the anticipated end of life. The maximum operating capacity will increase from 2,442 MVA to 4,330 MVA. PE filed its application for the project on August 3, 2021.

Transmission planning and regulatory drivers, as well as oversight, are described in Section 4.3.

[59] Pennsylvania Public Utility Commission, Docket Nos. A-2017-2640195 and A-2017-2640200.

3.3.2 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, proximity to existing infrastructure, sensitive resources and urban areas. While traditional overhead AC transmission lines are the most common, alternative transmission line types, such as underground, submarine and DC, are becoming more prevalent. These types of technologies are discussed in the following sections.

Underground Transmission Cables

Underground transmission lines are typically installed 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 three to five feet below the ground surface in conduits or reinforced duct banks or are directly buried in specially prepared soil, as shown in Figure 3-19. 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. Frequently, the individual cables required to make up a circuit are placed in polyethylene, PVC or fiberglass conduits and installed as a group.

Figure 3-19 Direct-Burial Underground Transmission Line Installation

Source: ABB, 2008.

Modern underground cables, such as those composed of cross-linked polyethylene (XLPE), do not require pressurized liquid or gas insulating and cooling systems that were predominant in earlier cable types, and therefore, do not pose the environmental contamination risk associated with coolant releases. Such cables may be installed in concrete-encased duct banks where generated heat is dissipated through the earth to the surface. The cables can be designed for AC or DC systems and are manufactured in finite lengths that need to be spliced together, typically 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, accessing and reinstalling the cables. Despite the longer repair times, underground cables generally have a longer useful life, are not damaged as often and can be more secure.

The last transmission project to include an underground construction component was a new 230 kV transmission line from Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary's County. The PSC granted a CPCN in 2009 to Southern Maryland Electric Cooperative (SMECO) for the construction of this project that included a short segment of the project under the Naval Recreation Facility (see below for submarine construction component of this project). More recently, several solar facility projects in Maryland have incorporated underground transmission cables for interconnection to the electrical system.

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 the river bottom or seabed. These cables have not been used often 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, 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 six to 15 feet, depending on specific site conditions.

The benefits of implementing a submarine system are a limited disruption to navigation and minimized visual impacts once the cables are installed as 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.

Direct Current Transmission Lines

According to the DOE, several thousand miles of high-voltage DC (HVDC) transmission lines are presently installed in the U.S., which is only a fraction of the more than 200,000 miles of total installed high voltage transmission lines (including hybrid AC and DC) in the U.S. However, the implementation of DC technology into project design is becoming increasingly 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, 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. This technology is becoming more widely used across the industry; however, there are no projects within Maryland proposing the use of high-voltage DC transmission. This technology could be used to support future offshore wind projects to meet the recent increases in the amended Maryland RPS (see Section 3.5.1).

3.3.3 Electricity Distribution

There are 13 utilities distributing electricity to customers in Maryland (see Table 3-8). Four of these are large, investor-owned electric companies organized as for-profit, tax-paying businesses: Potomac Edison (formerly Allegheny Power), BGE, DPL and Pepco. They are owned by two holding companies—FirstEnergy (which owns Potomac Edison) and Exelon (which owns BGE, DPL and Pepco). Maryland's investor-owned utilities serve approximately 90 percent of the customers in the state.

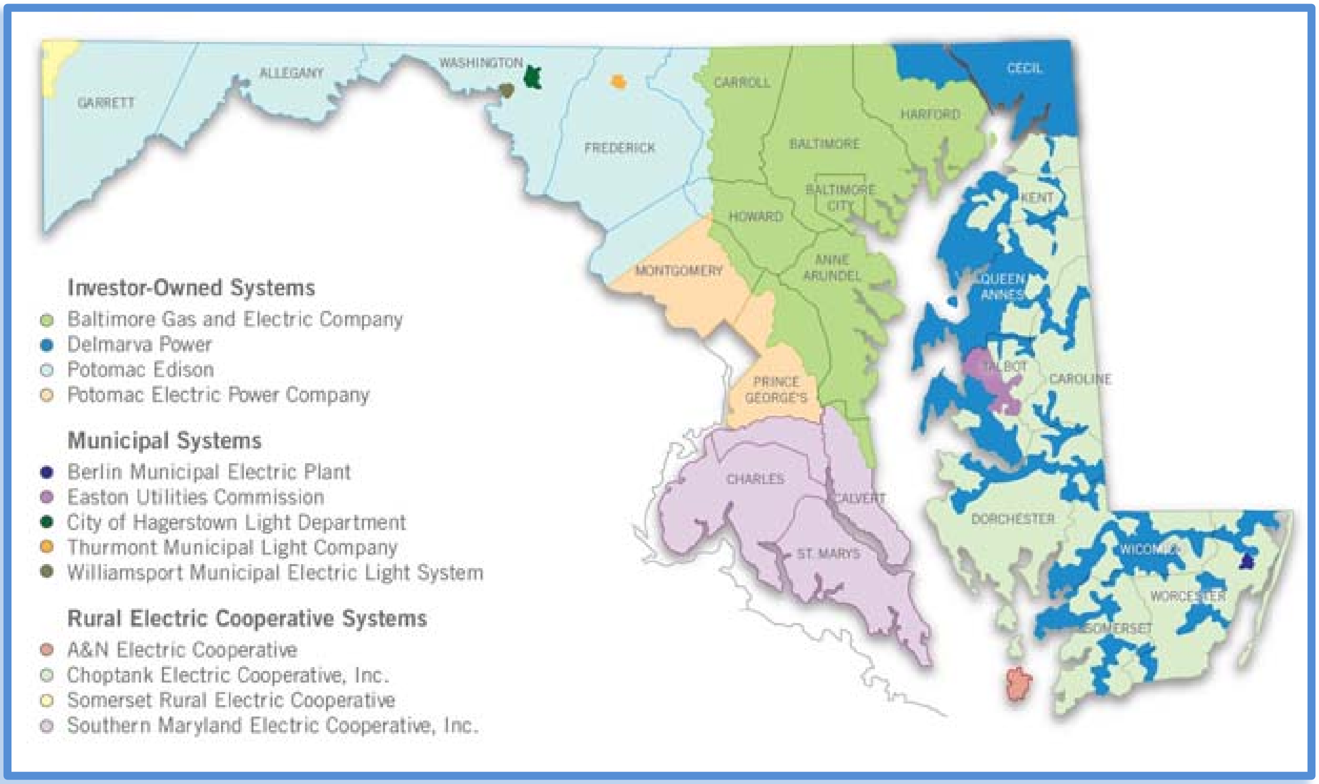
Five utilities are owned and operated by municipalities providing local electric distribution to a specific area. Four utilities are electric cooperatives, serving generally less populated rural areas. The service territories for the state's distribution companies are illustrated in Figure 3-20.

Table 3-8 Maryland Electric Distribution Companies, 2020

Company	Approximate Number of Maryland Consumers
INVESTOR-OWNED*	
Potomac Edison Company (owned by FirstEnergy)	281,401
Baltimore Gas & Electric Company (owned by Exelon)	1,322,286
Delmarva Power & Light Company (owned by Exelon)	214,520
Potomac Electric Power Company (owned by Exelon)	589,134
Subtotal	2,407,341
MUNICIPAL SYSTEMS**	
Berlin Municipal Electric Plant	2,595
Easton Utilities Commission	10,823
City of Hagerstown, Light Department	17,517
Thurmont Municipal Light Company	2,875
Williamsport Municipal Electric Light System	1,011
Subtotal	34,821
COOPERATIVE SYSTEMS**	
A&N Electric Cooperative***	313
Choptank Electric Cooperative, Inc.**	54,675
Somerset Rural Electric Cooperative, Inc.****	762
Southern Maryland Electric Cooperative, Inc.*	168,898
Subtotal	224,651
Total Customers	2,666,051

* Source: Maryland Public Service Commission, Electric Choice Enrollment Report December 2020.
** Source: Maryland Public Service Commission, Ten-Year Plan for 2020-2029. Forecast number of customers. Actual 2020 data were not available for these utilities.
*** Source: U.S. Energy Information Administration, EIA-861 2020.
**** Source: Somerset Rural Electric Cooperative, Utility Annual Report for 2020. webapp.psc.state.md.us/newIntranet/Maillog/submit_new.cfm?MaillogPath=234066&DirPath=//Coldfusion/Admin%20Filings/200000-249999/234066&maillognum=234066.

Figure 3-20 Electricity Distribution Service Areas



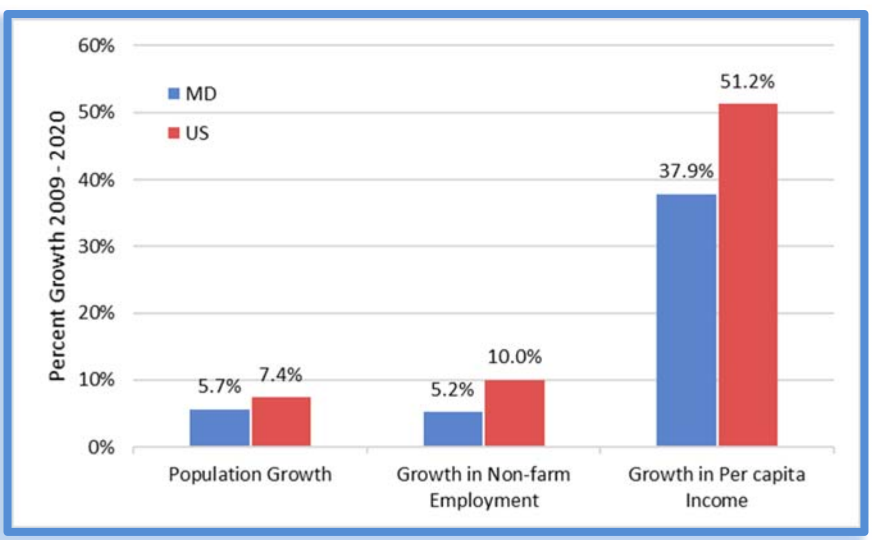
3.4 Maryland Electricity Consumption

Maryland end-use customers consumed about 57.5 thousand GWh of electricity during 2020.[60] Between 2009 and 2018, the annual average growth rate in electricity consumption in Maryland was lower than in the U.S. as a whole (negative 0.76 percent in Maryland versus a positive 0.17 percent in the U.S.). Figure 3-21 compares some of the key factors contributing to growth in electricity demand in Maryland and the U.S. from 2009 through 2020.

Maryland's population growth accelerated between 2007 and 2010, slowed significantly between 2010 and 2016, and then increased between 2016 and 2017 before slowing to a halt in 2020, as depicted in Figure 3-22. Despite overall growth in population and per capita income, electricity consumption has continued to decline. In general, slower population and per capita income growth will negatively affect electricity use, other factors held constant; however, the recent decline in electricity consumption can be attributed to businesses and households investing in more efficient energy technology, effectively reducing their energy usage.

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 3-23). Conversely, the industrial sector's electricity use in Maryland is significantly lower than the rest of the country (25 percent for the nation as a whole [919.5 thousand GWh]). In 2009, the industrial sector accounted for 8 percent, or 5.3 thousand GWh, of Maryland's energy consumption; comparatively, in 2020, the industrial sector consumed approximately 3.3 thousand GWh, or 37 percent less electricity than in 2009.

Figure 3-21 Comparison of U.S. and Maryland Growth Factors Affecting Electricity Consumption (2009-2020)



Source: Bureau of Economic Analysis Regional Data, Bureau of Labor Statistics. apps.bea.gov/iTable/iTable.cfm?reqid=70&step=1&acrdn=2.

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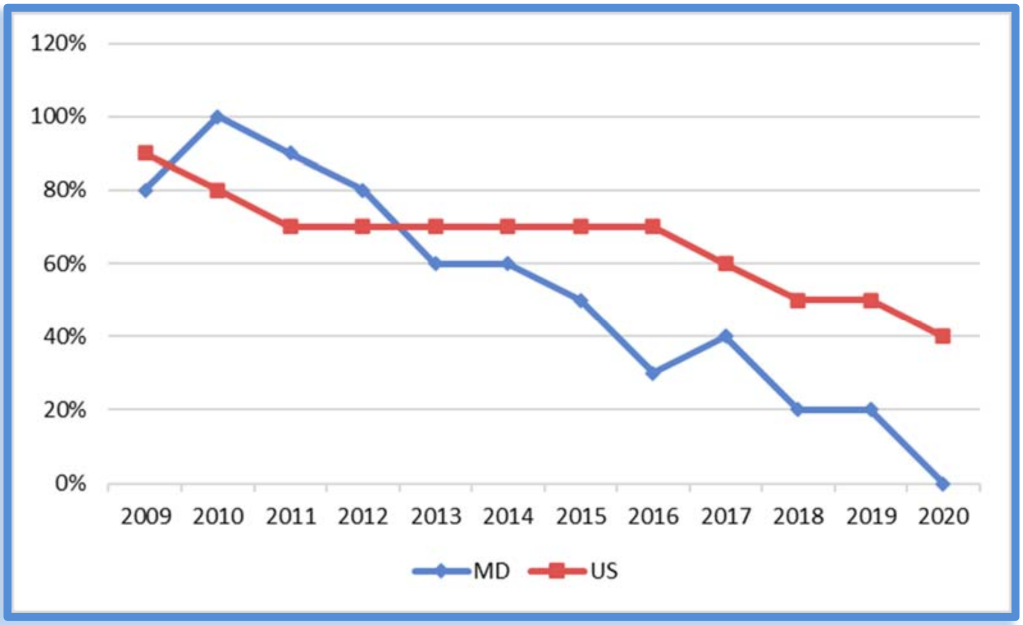
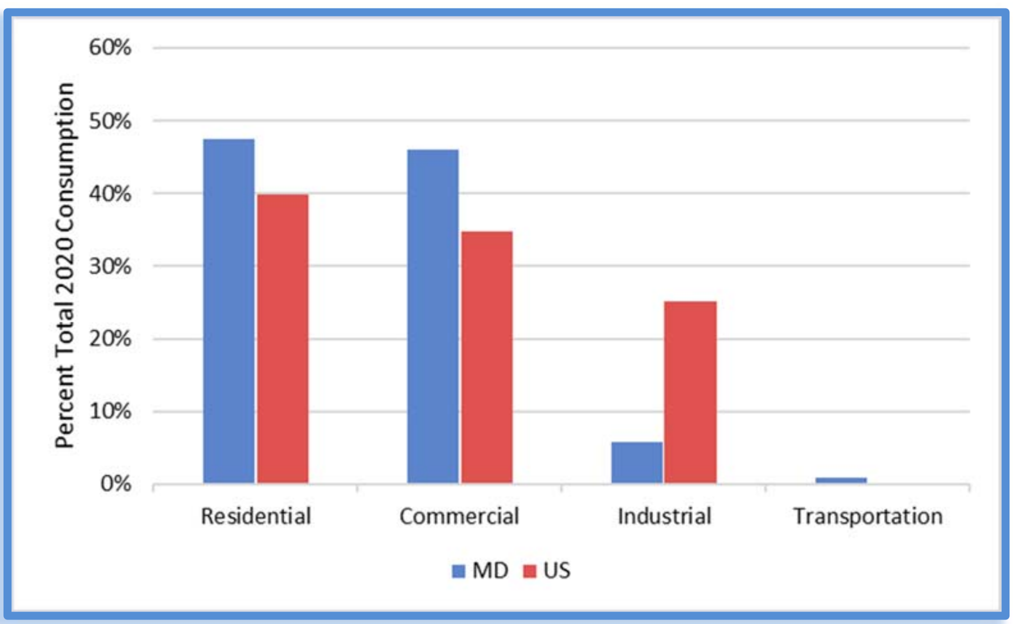
[60] U.S. Energy Information Administration, "Retail Sales of Electricity," Maryland, Electricity Data Browser, eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=g0000008&endsec=vg&linechart=ELEC.SALES.US-ALL.A&columnchart=ELEC.SALES.US-ALL.A&map=ELEC.SALES.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

Figure 3-22 Population Growth Trends in Maryland and the U.S. (2009-2020)



Source: Bureau of Economic Analysis Regional Data, SAINC1.

Figure 3-23 Electricity Consumption by Customer Class for 2020



Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annual." eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=g0000008&endsec=vg&linechart=ELEC.SALES.US-ALL.A&columnchart=ELEC.SALES.US-ALL.A&map=ELEC.SALES.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

3.4.1 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 more 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, electricity consumption fell nearly every year in 2011-2017, and increased in 2018, though the 2018 value (62.0 thousand GWh) is still below the 2009 value (62.6 thousand GWh). This decline is largely due to the impact of the EmPOWER Maryland legislation.

EmPOWER Maryland targeted a 15 percent reduction in per capita electricity consumption by 2015 from 2007 levels. For more information about EmPOWER Maryland, refer to Section 3.5.4. Since 2018, electricity consumption in Maryland has continued its downward trend, decreasing annually by an average of 3.7 percent.[61] Table 3-9 compares the average change in electricity consumption by sector for both the United States and Maryland from 2016 through 2020. Residential sector electricity consumption in Maryland has been relatively flat compared to the increase in the United States. In the commercial and industrial sectors, electricity consumption has fallen at a faster rate in Maryland compared to the U.S. In Maryland, the industrial and transportation sectors make minimal contributions to overall electricity consumption.

Table 3-9 Average Annual Change in Retail Sales of Electricity by Sector, 2016-2020

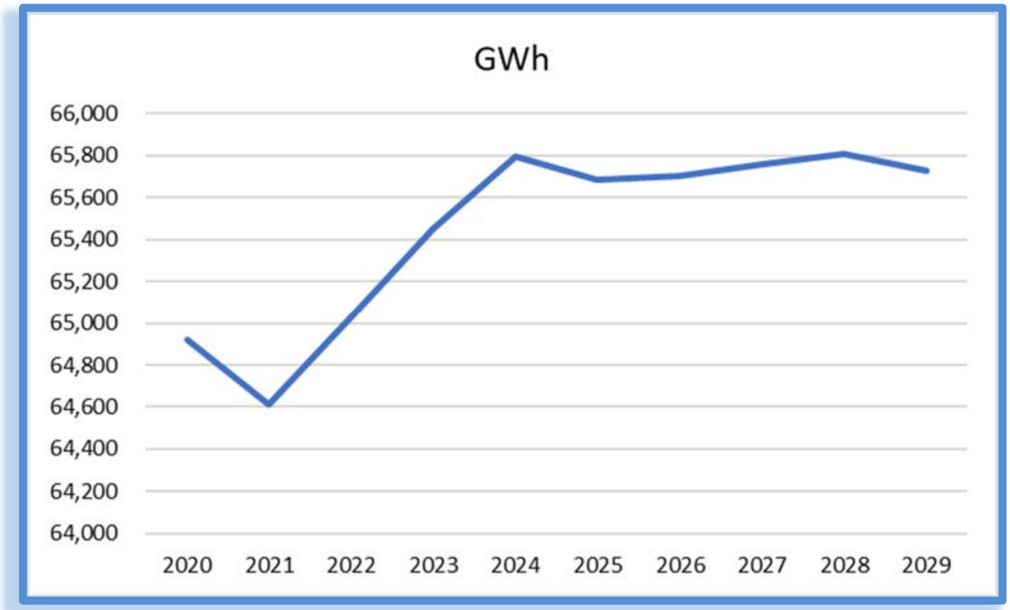
	All Sectors	Residential	Commercial	Industrial	Transportation
Maryland	-1.59%	-0.02%	-2.83%	-3.57%	-2.90%
United States	-0.66%	0.89%	-1.72%	-1.50%	-3.39%

Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annual." eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=g0000008&endsec=vg&linechart=ELEC.SALES.US-ALL.A&columnchart=ELEC.SALES.US-ALL.A&map=ELEC.SALES.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

Figure 3-24 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 an increase of 0.14 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 and 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, consumers more commonly replace their stock of electricity-consuming equipment and appliances with more energy-efficient appliances to reduce energy costs.

[61] Note that the COVID-19 pandemic depressed energy consumption across the U.S., making 2020 an outlier in terms of the level of annual electricity consumption.

Figure 3-24 Maryland Forecasted Consumption, 2020-2029



Source: Maryland Public Service Commission 2020 Ten-Year Plan, psc.state.md.us/wp-content/uploads/2020-2029-Ten-Year-Plan-Final-1.pdf.

PJM produces an independent forecast of electric energy consumption, and PJM's most recent forecast covers the 15-year forecast period of 2020 through 2035. 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 in PJM's Mid-Atlantic region is expected to grow at an average annual rate of approximately 0.6 percent, whereas Maryland's forecast calls for a more modest increase in consumption over the 10-year period ending in 2029, as forecasted by the Maryland utilities.[62]

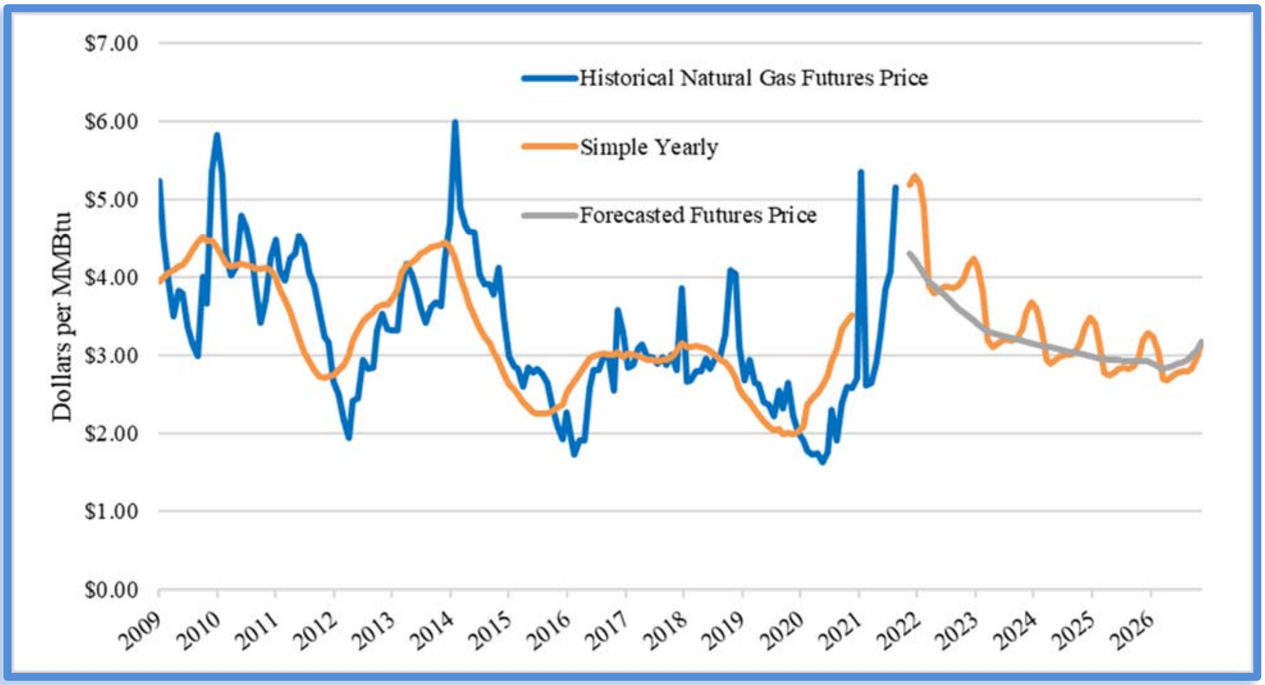
Future electricity prices (and hence consumption of electricity) are affected by wholesale natural gas prices, in addition to a range of other factors. Wholesale natural gas futures contracts priced on the New York Mercantile Exchange (NYMEX) are based on the delivery price at the Henry Hub in Erath, 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 3-25, natural gas prices peaked at around $6 per MMBtu in 2014 during the Polar Vortex, but declined shortly after, hovering between $3 and $4 per MMBtu or below. Natural gas prices increased sharply in summer 2021 to between $5 and $6 per million BTU due to sharply increasing demand for natural gas for electricity generation and liquefied natural gas (LNG) for gas-importing nations, lower amounts of natural gas put in storage and supply disruptions from Hurricane Ida. EIA

[62] pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en.

projects that prices will stay at this level for the remainder of 2021 and slowly decline to $3.98 per MMBtu by the end of 2022.[63]

Figure 3-25 Historical and Future NYMEX Henry Hub Natural Gas Prompt Month Futures Prices, 2009-2026



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

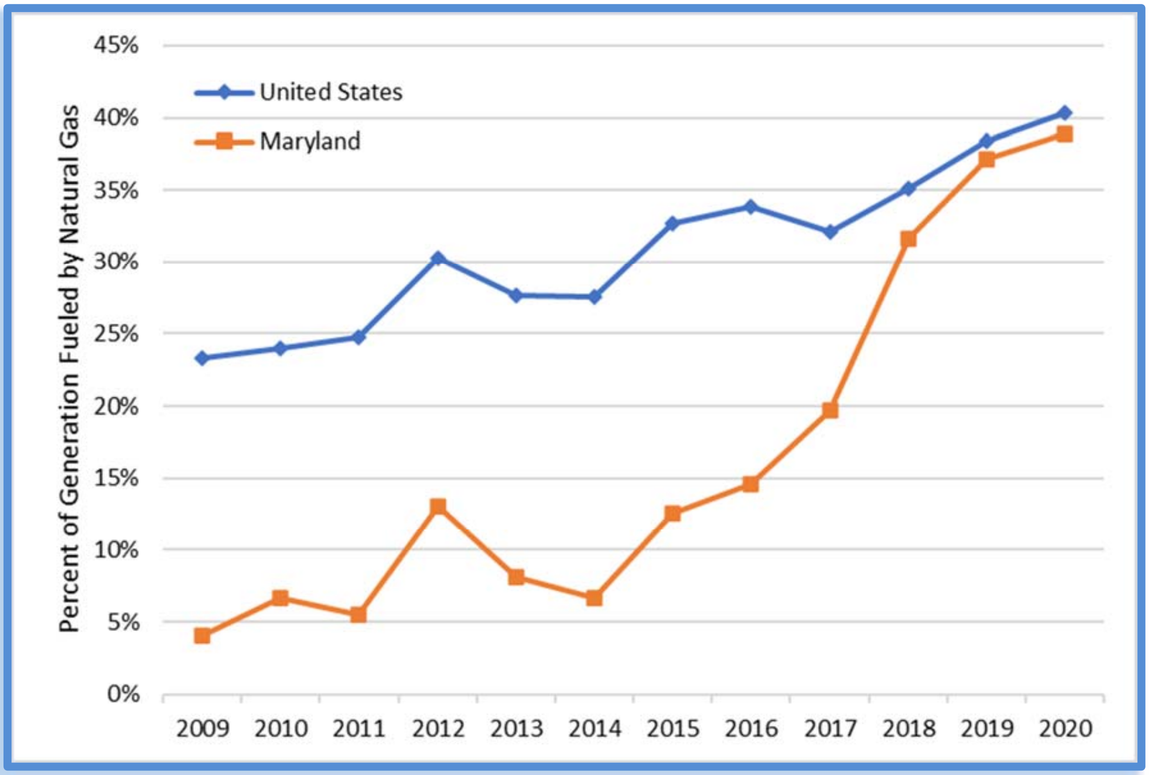
Until they began increasing in 2021, consistently low natural gas prices led to low wholesale power prices and an increase in natural gas generating capacity in Maryland and in PJM. The load-weighted, real-time LMPs in PJM were the lowest in 2020 since PJM became an RTO in 1999, at $21.77/MWh.[64] This continued a trend that began several years ago. As shown in Figure 3-26, 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, the retirement of coal plants, and natural gas generating facilities operating for more hours of the year. In Maryland, there has been a significant increase due to the addition of 2,880 MW of natural gas capacity since 2017. The increase in natural gas prices led to a higher load-weighted, real-time LMP in PJM during the first nine months of 2021, at $35.68/MWh.[65] Refer to Chapter 4 for more information on natural gas and electricity markets.

[63] U.S. Energy Information Administration, Short-Term Energy Outlook, October 2021, eia.gov/outlooks/steo/report/index.php.

[64] Monitoring Analytics LLC, 2020 State of the Market Report for PJM, March 2021, monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf.

[65] Monitoring Analytics LLC, Quarterly State of the Market Report for PJM, January through September 2021, November 2021, monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021q3-som-pjm.pdf.

Figure 3-26 Natural Gas Share of Fuel for Electricity Generation in the U.S. and Maryland, 2009-2020



Source: U.S. Energy Information Administration, "U.S. and Maryland Natural Gas Generation Data." eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvvvu&geo=g0000008&sec=g&freq=A&start=2001&end=2020&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

In addition to economic factors and EmPOWER Maryland 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.

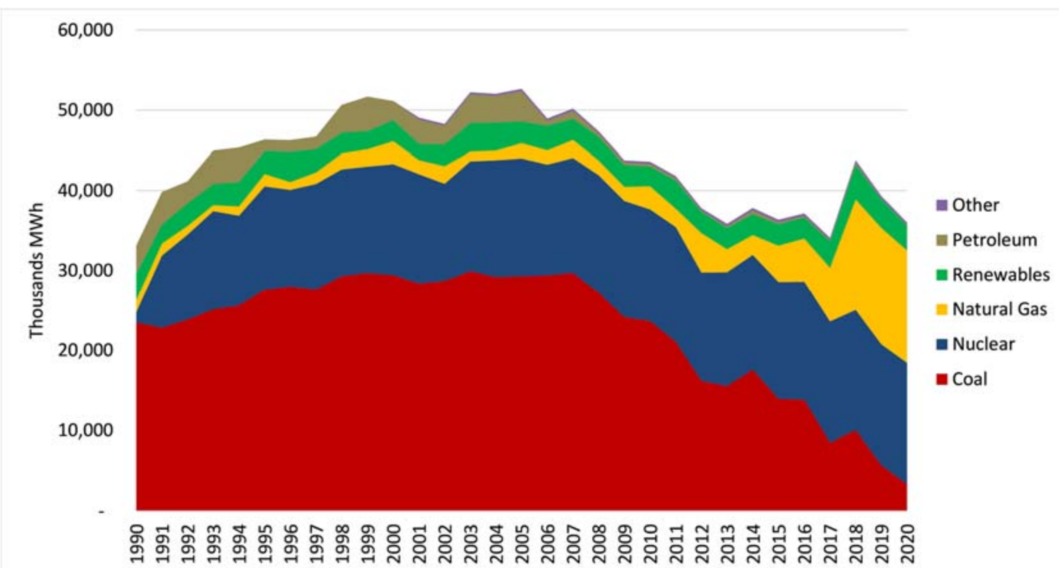
3.4.2 Generation: Comparison with Consumption

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.

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 was the predominant generating fuel in Maryland; however, its share of total generation has declined since 2007 and is now below nuclear generation. In 2018, natural gas surpassed coal to become the second-highest generating fuel and has maintained this status through 2020. In addition, the amount of electricity generated in Maryland has significantly declined since it peaked in 2005 with 52.6 million MWh, as Maryland generated 36.0 million MWh in 2020. Although this is 32 percent below 2005 generation, it is only 5 percent lower than the average generation for 2014 -2019.

Maryland Generation Fuel Mix



Source: U.S. Energy Information Administration Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).

Because of high import requirements, interregional transmission plays a much more critical role in sustaining reliable service. In addition, Maryland's high electric demand relative to instate 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.

Electricity consumption in Maryland during 2020 exceeded electricity generation in the state by approximately 40 percent.[66] Table 3-10 compares electricity consumption and generation in Maryland over the past 11 years. The significant decrease in net imports in 2018 coincides with three gas-fired power plants that came online in Maryland that year, which resulted in natural gas-fired generation surpassing coal-fired power plants. In 2018, coal-fired power plants generated 10,067 GWh as compared to 23,668 GWh in 2010.[67] Comparatively, natural gas power plants generated 2,897 GWh in 2010 compared to 13,850 GWh in 2018.[68] Net imports increased in 2019 and remained relatively constant in 2020.

Table 3-10 Total Maryland Electric Energy Consumption and Generation (GWh), 2009-2020

	Retail Sales (Consumption)	Sales + T&D Losses*	Generation	Net Imports	Percentage of Sales Imported
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	61,872	64,966	36,390	29,099	44%
2016	61,354	64,422	37,167	27,255	42%
2017	59,304	62,269	34,104	28,165	45%
2018	62,086	65,190	43,810	21,380	33%
2019	60,721	63,757	39,326	24,431	38%
2020	57,533	60,410	36,029	24,380	40%

*Assumes Transmission and Distribution (T&D) losses of 6 percent through 2013 and then 5 percent for 2014 through 2018.
Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annual" and EIA-923 Net Generation.

PJM's 2020 "Regional Transmission Expansion Plan" (RTEP) report notes that power plant deactivation notifications decreased in 2020 compared to 2018, with retirements expected between 2020 and 2023.[69]

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[66] U.S. Energy Information Administration, "Retail Sales of Electricity, Annual."

[67] U.S. Energy Information Administration, "Net Generation by State by Type of Producer by Energy Source, EIA-906, EIA-920, and EIA-923."

[68] Ibid.

[69] pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.

In 2020, PJM received deactivation requests totaling 4,428 MW, compared to the deactivation requests between 2004 and 2011 which collectively equaled 11,000 MW. Of the 22 notifications received in 2020, two were from plants in Maryland totaling 1,213 MW of capacity, both located within the Pepco zone. Both plants have since retired.[70]

In prior RTEPs, PJM noted that if all deactivation plans are carried out, more than 27,000 MW of coal-fired plants will retire between 2011 and 2020. PJM noted that over the last decade, deactivation requests are primarily the result of the economic impact of environmental regulations and age, as many of the plant deactivations are for plants more than 40 years old. Also, in prior RTEPs, PJM noted that competition from new generating plants fueled by Marcellus Shale natural gas, new renewable energy plants, and market impacts from demand response and energy efficiency programs, have impacted the decision by owners to retire plants.

[70] Chalk Point Units 1 and 2 retired in June 2021 and Dickerson Station Units 1 – 3 retired in August 2020.

3.5 Policy Initiatives and Energy Programs

By law, Maryland encourages the development and use of clean energy technologies such as solar, wind, energy storage and electric vehicle charging stations. In addition, the state continues to evaluate and implement policies that encourage a customer-centered distribution grid that is affordable, reliable and environmentally sustainable.

3.5.1 Maryland Renewable Energy Portfolio Standard

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 sales from Maryland-certified Tier 1 and Tier 2 renewable resources. Currently, the Maryland RPS requires 52.5 percent of electricity sales to come from Tier 1 and Tier 2 resources by 2030. Every MWh generated by qualified renewable energy resources is eligible to be registered as one Maryland-certified Renewable Energy Credit (REC). Eligible RECs may come from a PSC-certified renewable energy facility that is either located within PJM or for the electricity the facility delivers into PJM from an adjacent control area outside of PJM. The 2004 RPS law has been modified by legislation 12 times from 2007 through 2021, mainly to increase the requirement and to change the eligibility of renewable energy resources. Figure 3-27 illustrates the RPS requirements over time.

The current version of the Maryland RPS 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, refuse-derived fuel and offshore wind. Black liquor was removed as an eligible technology in 2021. The Tier 1 requirement began at 1 percent and increases annually; in 2020 it was 28 percent and will reach its 50 percent maximum in 2030.

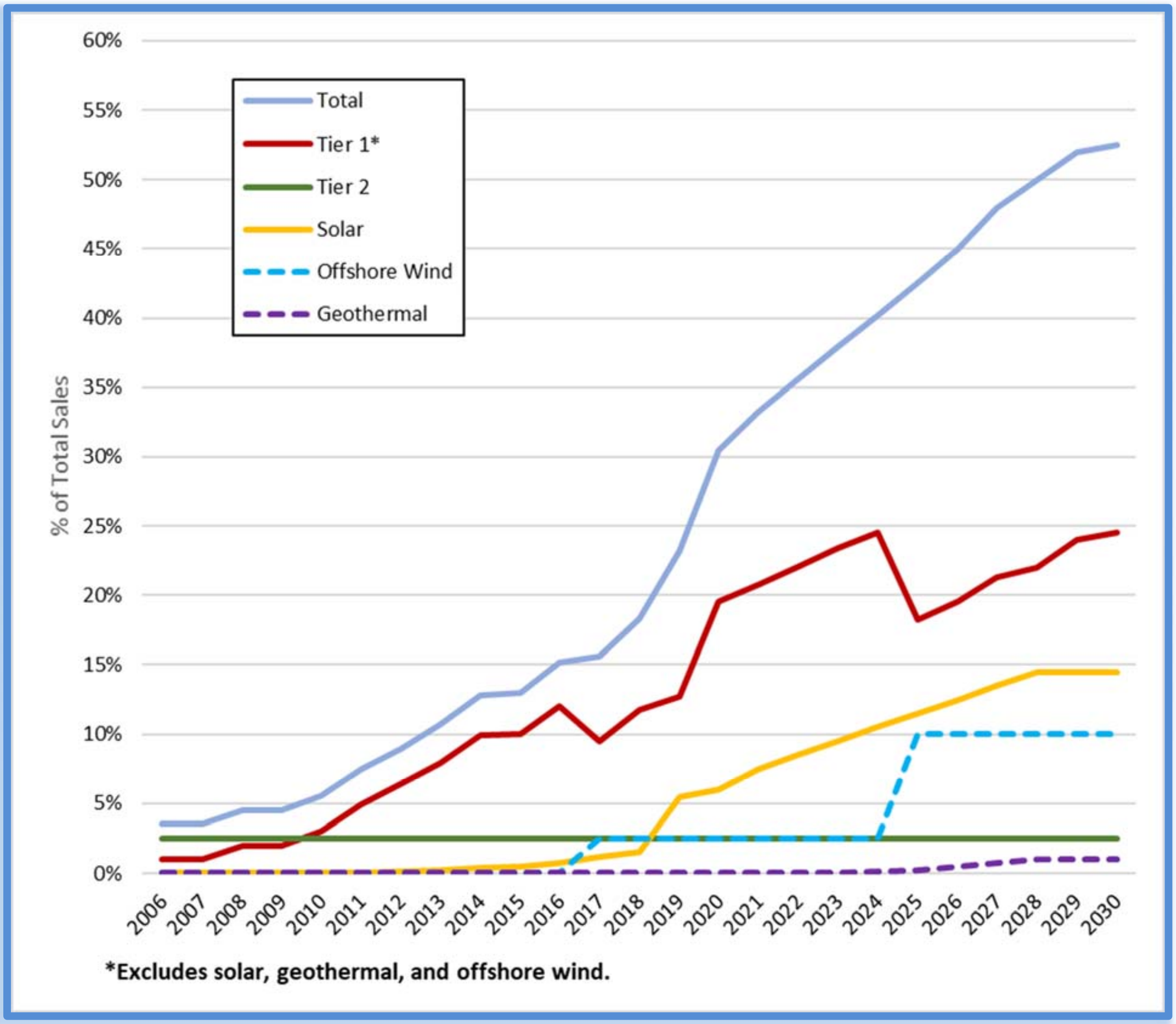
- The solar energy carve-out requires that a specified percentage of energy supply must come from instate solar facilities. The solar carve-out began in 2008 at 0.005 percent and will reach its maximum of 14.5 percent in 2030. The 14.5 percent solar requirement is part of the Tier 1 overall 50 percent requirement.

- The Maryland Offshore Wind Energy Act, which was passed in 2013, created a separate carve-out for offshore wind facilities. The offshore wind energy carve-out requires that a specified percentage of energy in the state must come from offshore wind facilities located between 10 and 80 miles off the coast of Maryland. Each year, the PSC will set the percentage of required offshore energy, to be no less than 400 MW of offshore wind by 2026, 800 MW by 2028, and 1,200 MW by 2030. This is in addition to the 368 MW of offshore wind approved by the PSC to receive Offshore Renewable Energy Credits (ORECs) in 2017.[71]

[71] Maryland General Assembly, Maryland Public Utilities Articles § 7-701 - § 7-713.

- A new carve-out of Tier 1 for geothermal will begin in 2023, starting at 0.05 percent and increasing to 1 percent by 2028.
- Existing hydroelectric facilities that are not pump-storage and are over 30 MW qualify to meet the Tier 2 standard as long as the facilities were operational as of January 1, 2004. Tier 1 resources may also be used to meet the 2.5 percent Tier 2 standard.

Figure 3-27 Maryland RPS Requirements Summary, 2006-2030



Source: Maryland Senate Bill 516; 2019 and the Annotated Code of Maryland, PUA §7-703.

Electricity suppliers have the option to make an Alternative Compliance Payment (ACP) in place of RECs. As summarized below, the ACP varies based upon tier and carve-out.

- Tier 1 ACP – $0.0375 for each kilowatt-hour (kWh) (i.e., $37.50/MWh) in 2017 and 2018. Decreases to $0.03/kWh ($30/MWh) from 2019 to 2023, then gradually decreases each year until 2030 when it is set at $0.02235/kWh ($22.35/MWh) and remains constant thereafter.

- Tier 1 Solar Carve-Out ACP – Began at $0.45/kWh ($450/MWh) in 2006 but has since decreased to $0.1/kWh in 2020. The ACP will continue to decrease, reaching $0.055/kWh by 2025, and finally reaching a maximum of $0.0225/kWh ($22.5/MWh) in 2030.

- Tier 1 Geothermal Carve-Out ACP – Begins at $0.1/kWh ($10/MWh) from 2023 through 2025, decreases to $0.09/kWh ($9/MWh) in 2026 and $0.08/kWh ($8/MWh) in 2027, and reaches a fixed $0.065/kWh ($6.50/MWh) in 2028.

- Tier 2 ACP – $0.015/kWh ($15/MWh).[72]

At the conclusion of 2020, there were 75,661 renewable energy facilities certified by the Maryland PSC, providing approximately 16,045 MW of renewable energy capacity in PJM (see Table 3-11).

[72] ACPs are different for industrial process load customers. For Tier 1, the ACP is 0.2 cents/kWh ($2/MWh). There is no ACP for Tier 2 resources. The ACP drops further to 0.1 cents/kWh ($1/MWh) in years where suppliers are required to buy ORECs, and nothing at all if the net rate impact of OREC purchases exceeds $1.65/MWh, in 2012$.

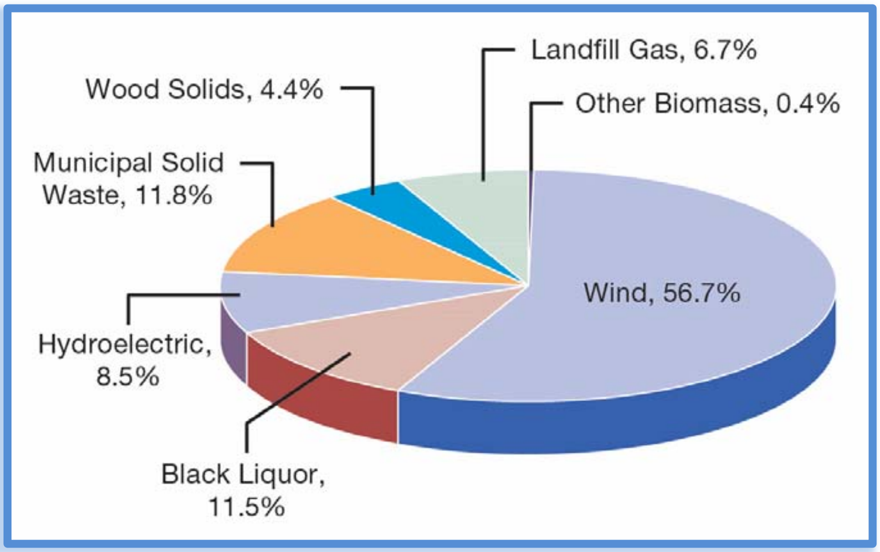
Table 3-11 Maryland RPS Certified Capacity as of December 2020 (MW)

	Tier 1										Tier 2	
State	Solar	Solar Thermal	Wind	Hydro	Landfill Gas	Other Biomass Gas	Black Liquor	Municipal Solid Waste	Wood Waste	Geothermal	Hydro	Total
Maryland	1,417	7	190	20	32	-	65	138	4	2	474	2,349
Delaware	-	-	-	-	9	-	-	-	-	-	-	9
Illinois	-	-	4,399	20	88	-	-	-	-	-	-	4,507
Indiana	-	-	2,202	8	8	-	-	-	-	-	-	2,218
Kentucky	-	-	-	2	18	-	-	-	5	-	-	25
Michigan	-	-	-	15	4	-	-	-	-	-	-	19
Missouri	-	-	146	-	-	-	-	-	-	-	-	146
New Jersey	-	-	8	11	70	-	-	-	-	-	-	89
North Carolina	-	-	208	-	-	-	152	-	-	-	725	1,085
North Dakota	-	-	180	-	-	-	-	-	-	-	-	180
Ohio	-	-	990	-	64	4	93	-	-	-	47	1,198
Pennsylvania	-	-	1,337	95	96	1	164	-	-	-	501	2,194
Tennessee	-	-	-	-	-	-	50	-	-	-	206	256
Virginia	-	-	-	69	127	3	288	63	50	-	266	866
West Virginia	-	-	677	54	-	-	-	-	-	-	159	890
Washington, D.C.	-	-	-	-	-	14	-	-	-	-	-	14
TOTAL	**1,417**	**7**	**10,337**	**294**	**516**	**22**	**812**	**201**	**59**	**2**	**2,378**	**16,045**

Source: PJM Generation Attribute Tracking System (GATS), as of December 31, 2020.
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 3-28, wind power is the leading fuel source for compliance with the Tier 1 Maryland RPS, followed by municipal solid waste, black liquor, small-scale hydro, landfill gas and wood waste.

Figure 3-28 Tier 1 Nonsolar Retired RECs by Fuel Source, 2020



Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2020, November 2021, psc.state.md.us/wp-content/uploads/CY20-RPS-Annual-Report_Final.pdf

The PSC is charged with ensuring compliance with the RPS and certifying eligible facilities. Retail electricity suppliers are required to submit annual compliance reports by April of the following year. Table 3-12 shows the aggregate supplier obligation, the RECs retired and the ACPs submitted from 2006-2020.[73] Each retired REC represents one MWh of renewable energy generated from a Tier 1 or Tier 2 facility.

In 2020, Maryland generated about 2.6 million MWh of renewable electricity from instate Tier 1 resources and about 1.7 million MWh of renewable electricity from instate Tier 2 resources, with a total of 4.3 million RECs produced. Of the total Maryland-generated RECs retired for compliance purposes in 2020, about 96 percent were retired in Maryland. Overall, the cost of compliance with the 2020 RPS requirement was about $223 million.

Table 3-12 Maryland RPS Compliance, 2006-2020

RPS Compliance Year		Tier 1 Solar	Tier 1 (Nonsolar)	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

[73] Retirement of a REC means that it has been used by the owner; it can no longer be sold.

RPS Compliance Year		Tier 1 Solar	Tier 1 (Nonsolar)	Tier 2	Total
	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)	15,451,000	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
2015	RPS Obligation (MWh)	299,456	6,131,624	1,531,193	7,962,273
	Retired RECs (MWh)	299,525	6,134,653	1,531,279	7,965,457
	ACP Required	$7,000	$16,000	$1,515	$24,515
2016	RPS Obligation (MWh)	411,466	7,210,870	1,500,440	9,136,129
	Retired RECs (MWh)	411,787	7,216,439	1,501,587	9,129,813
	ACP Required	$0	$520	$30	$33,933
2017	RPS Obligation (MWh)	556,929	7,004,181	1,442,923	9,029,149
	Retired RECs (MWh)	557,224	7,006,113	1,448,567	9,011,904

RPS Compliance Year		Tier 1 Solar	Tier 1 (Nonsolar)	Tier 2	Total
	ACP Required	$1,170	$3,375	$255	$55,032
2018	RPS Obligation (MWh)	857,023	8,627,719	1,500,715	11,017,750
	Retired RECs (MWh)	857,232	8,627,737	1,599,819	11,084,788
	ACP Required	$795	$2,280	$135	$67,796
2019	RPS Obligation (MWh)	1,141,734	10,076,186	205,611	11,439,238
	Retired RECs (MWh)	1,167,329	10,210,275	55,879	11,433,483
	ACP Required	$2,658,500	$4,981,178	$59,132	$7,730,223
2020	RPS Obligation (MWh)	1,854,176	12,007,171	367,082	14,228,429
	Retired RECs (MWh)	1,859,976	12,117,585	366,260	14,343,821
	ACP Required	$29,800	$270	$22,170	$52,240

Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2020, November 2021, psc.state.md.us/wp-content/uploads/CY20-RPS-Annual-Report_Final.pdf .

Federal Investment Tax Credit and Production Tax Credit

Business Energy Investment Tax Credit

The federal Investment Tax Credit (ITC) provides a federal tax credit for investments in solar electric, solar heating and lighting technologies, fuel cells, waste energy recovery and small wind plants. There is also a 10% federal tax credit available for investments in geothermal heat pumps and electric systems, microturbines, and combined heat and power systems that expires at the end of 2023. The ITC has been amended several times, with the most recent amendment occurring in December 2020. Electric and nonelectric solar systems were eligible for the full 30% tax credit until the end of 2019. After that, the tax credit dropped to 26% through 2022 and drops further to 22% until the end of 2025. At that point, the credit expires altogether for residential customers but remains at 10% for nonresidential customers. The latest update to the ITC in 2020 expanded the credit to include waste-to-energy recovery property and offshore wind systems. The ITC for offshore wind systems is set at 30% through 2025. Projects that begin construction or incur 5% or more of the total cost of the facility in the year that construction begins are still eligible as long as the facility is placed into service within 10 years after construction has begun.

The Renewable Electricity Production Tax Credit

The federal Renewable Electricity Production Tax Credit (PTC) is a per-kWh tax credit for electricity generated by qualified energy resources (wind, geothermal, closed-looped biomass and solar systems not claiming the ITC) 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. For nonwind resources, the credit expired at the end of 2017. The full credit of 2.37¢/kWh remains available for wind projects that commence construction before December 31, 2019; however, the credit is phased down each year between 2017-2019. If under construction by the PTC deadline, projects will be eligible to receive the PTC for a total of 10 years. The PTC was reduced by 20% per year to 80% in 2017, 60% in 2018 and 40% in 2019. In December 2019, the U.S. Congress extended the PTC to the end of 2020 and somewhat reversed the phase-out by going back to allowing 60% of the value of the PTC for wind projects that begin construction in 2020. The bill also retroactively extends the full PTC through 2020 for closed and open loop biomass, geothermal, municipal solid waste, marine, and hydrokinetic and qualified hydropower facilities. In December 2020, Congress extended the 60% PTC through December 31, 2021. Between 2016 and 2019, projects that begin construction, or incur 5% or more of the total cost of the facility in the year that construction begins, can receive a four-year extension, and a five-year extension for projects that began construction in 2020.

Sources:
crsreports.congress.gov/product/pdf/IF/IF10479#:~:text=For%20offshore%20wind%2C%20the%20credit,and%20does%20not%20phase%20out;
U.S. Congress, Bipartisan Budget Act of 2018, February 9, 2018, congress.gov/bill/115th-congress/house-bill/1892/text/eas2?q=%7B%22search%22%3A%5B%22bipartisan+budget+act+of+2018%22%5D%7D&r=1#toc-H2CA0A15EDA714CD3B7964CDED8037202;
energy.gov/savings/renewable-electricity-production-tax-credit-ptc
eia.gov/todayinenergy/detail.php?id=46576

In 2017, the General Assembly enacted legislation requiring PPRP to conduct a comprehensive review of the costs and benefits of the state's RPS and the likely impacts of increasing the RPS in the future. The legislation directed PPRP to consider a wide range of topics including the standard's effectiveness in reducing the carbon content of imported electricity; the impact of long-term clean energy contracts; whether RPS benefits are equitably distributed among communities; whether adequate supply exists to meet a more ambitious RPS; specific opportunities for job creation; the types of system flexibility needed to meet future goals; how best to address flexible resources such as advanced energy storage systems; and the role of instate clean energy in reaching GHG reduction goals and promoting economic development. The final report was submitted to the General Assembly in December 2019 and is available on PPRP's website.[74] The Maryland Clean Energy Jobs Act of 2019 requires PPRP to conduct a supplemental study on the cost and benefits of increasing the RPS to 100 percent by 2040 and to study nuclear energy's role as a renewable or clean energy resource for addressing climate change in the state. The final report on Maryland nuclear energy was submitted to the General Assembly in January 2020 and is available on PPRP's website.[75] The supplemental RPS study is due to the General Assembly by January 2024 and has been expanded to include clean energy sources such as nuclear energy and combined heat and power.

3.5.2 Net Metering in Maryland

Ratepayers with distributed generation, e.g., rooftop solar, may receive compensation for generation beyond their consumption through a billing mechanism known as net metering. Net metering is the method of compensating consumers with distributed generation capacity in periods when a customer produces more energy than they consume. Essentially, when a consumer is producing more electricity than they are consuming, the meter "runs backwards" in order to track the net amount of energy the customer consumes in a billing period. Net metering allows the consumer to sell electricity back to the utility in the form of a per-kWh credit and the excess energy is exported to the distribution grid for the utility to sell to other customers. Net metering is like a ratepayer utilizing the local electric grid as battery storage.

Maryland's net metering regulations, originally enacted in 1997, have been amended multiple times. The current law, set forth in Public Utilities Article (PUA) §7-306 and Code of Maryland Regulations (COMAR) 20.50.10, as amended in 2021 by House Bill (HB) 569, sets a statewide aggregate cap of 3,000 MW for net metered systems. All investor-owned utilities (IOUs), cooperatives and municipal utilities comply with the regulations by installing a meter capable of accurately measuring the bi-directional flow of electricity. Additionally, each electric provider in the state must offer a tariff rate or contract rate at nondiscriminatory prices to customers with qualified onsite generation who wish to receive net metered service.

Net metering is commonly associated with solar photovoltaic (PV) panels, but can also be used for numerous other onsite distributed generators like small-scale wind, biomass and fuel cells. Specifically, the State of Maryland designates solar, wind, biomass, fuel cell, closed-conduit hydroelectric and micro-combined heat and power (CHP) as resources eligible for net metering. Ownership of the net metered system can be direct or through a third-party contract such as through a lease or power purchase agreement (PPA). The maximum capacity for individual net metered systems is limited to 200 percent of the customer's total annual baseline energy consumption, capped at 2 MW. All types of facilities (e.g., homes, schools, businesses and government properties) may participate in net metering as long as the net metered system is installed with the principal intention of offsetting the customer's onsite energy

[74] Maryland Department of Natural Resources, Power Plant Research Program, Final Report Concerning the Maryland Renewable Portfolio Standard as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017, December 2019, dnr.maryland.gov/pprp/Documents/FinalRPSReportDecember2019.pdf.

[75] Maryland Department of Natural Resources, Power Plant Research Program, Nuclear Power in Maryland: Status and Prospects, January 2020, dnr.maryland.gov/pprp/Documents/NuclearPowerinMaryland_Status-and-Prospects.pdf.

consumption (e.g., a rooftop solar array on a residential building used to deliver a portion of the resident's electricity). The net metered system must be interconnected with the local utility's transmission and distribution facilities. Furthermore, agricultural, municipal and county governments, and nonprofit organizations can combine meter readings from more than one utility service point, referred to as aggregate net metering. Utilities provide this service by using physical interconnection of service points or by summing the total usage from two or more meters (virtual aggregation). Aggregating multiple individual loads allows customers to take advantage of economies of scale and build a large system.

The PSC must submit an annual report on the status of the net metering program to the General Assembly by September 1 each year. A summary of the net metering capacity through June 30, 2021 is provided in Table 3-13. As of June 30, 2021, there was a total of 888 MW of net metering capacity, or 30 percent of the new capacity limit set by the PSC (59 percent of the original cap); solar PV represents 886 MW of this capacity. At current growth rates, the PSC projected in 2020 that the net metering cap would be reached in 2024 or 2025. While installed net metering capacity has grown every year, the annual growth rate has slowed from a peak of 93 percent year over year in 2016 to 8 percent in 2021. Despite the decrease in growth, in that same period installed capacity has more than doubled from 387 MW in 2016 to 888 MW in 2021.

Table 3-13 Net Metering Capacity as of June 30, 2021 (kW)

Utility	Solar	Wind	Biomass	Total	Year Over Year Percent Change
Baltimore Gas and Electric Company	337,168	84	-	337,252	9%
Choptank Electric Cooperative	27,990	15	30	28,035	6
Delmarva Power and Light Company	103,322	889	240	104,451	5
Easton Utilities Commission	2,698	-	-	2,698	2
Hagerstown Utilities Commission	199	-	-	199	3
Thurmont Municipal Light Company	199	-	-	199	29
Mayor and Council of Berlin	482	-	-	482	22
Potomac Electric Power Company	254,306	78	0	254,384	6
Potomac Edison Company	94,374	7	256	94,997	14
Williamsport Municipal Light Plant	28	-	-	28	0
Southern Maryland Electric Cooperative	64,712	36	320	65,068	7
Maryland Total	**885,838**	**1,109**	**846**	**887,793**	**9%**

Source: Maryland Public Service Commission, Report on the Status of Net Energy Metering in the State of Maryland, October 2021, psc.state.md.us/wp-content/uploads/2021-Net-Metering-Report-FINAL.pdf.
*Table excludes community solar resources.

In Maryland, if a customer's generation is greater than its demand (a concept known as net excess generation), then the billed kWh credit is carried over to the next month. Once per year (ending in April of each year), if the customer still has net excess generation remaining, the utility compensates the customer for the net excess generation balance at the prevailing electricity commodity rate. Customers have the added benefit of owning all RECs accumulated by their net metered system, allowing the customer to sell its credits in the REC market. Table 3-14 shows the net excess generation credits paid to customers over the 12-month period ending April 30, 2021. In total, Maryland utilities paid $4,057,323, with Pepco and BGE paying 18 percent and 51 percent, respectively, of the total net excess generation.

Table 3-14 Net Excess Generation Credit Payouts for Period Ending April 30, 2021

Utility	Residential Excess Generation Credits Paid	Commercial Excess Generation Credits Paid	Total Excess Generation Credits Paid	Percentage of Total Net Excess Generation Credits Paid
Baltimore Gas and Electric Company	$881,155	$1,184,309	$2,065,464	51%
Choptank Electric Cooperative	83,412	80,779	164,191	4%
Delmarva Power and Light Company	159,555	487,681	647,236	16%
Easton Utilities Commission	614	7,791	8,405	0%
Hagerstown Utilities Commission	139	-	139	0%
Thurmont Municipal Light Company	-	-	-	0%
Mayor and Council of Berlin	1,322	625	1,947	0%
Potomac Electric Power Company	649,803	99,580	749,383	18%
Potomac Edison Company	129,481	194,932	324,413	8%
Williamsport Municipal Light Plant	-	-	-	0%
Southern Maryland Electric Cooperative	85,574	10,572	96,146	2%
Total	**$1,991,055**	**$2,066,269**	**$4,057,324**	100%

Source: Maryland Public Service Commission, Report on the Status of Net Energy Metering in the State of Maryland, October 2021, psc.state.md.us/wp-content/uploads/2021-Net-Metering-Report-FINAL.pdf.

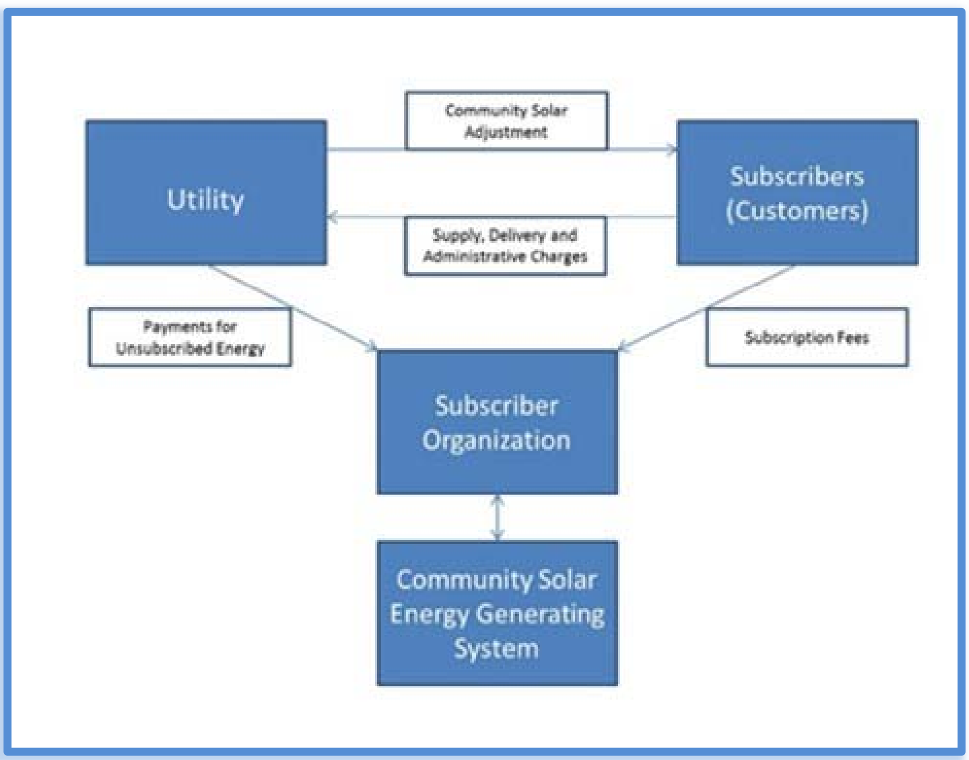
3.5.3 Community Solar in Maryland

Customers who may not have the means to own or install their own solar energy system may buy or "subscribe" to blocks of capacity from a nearby solar facility through community solar. A community solar facility is often located offsite; however, some facilities are referred to as "shared" and are located on the rooftop of an apartment complex or split among rooftops of a community, allowing that community to purchase the solar energy as a group. Community solar provides a credit to each subscriber of a community solar system based upon the amount of energy to which the customer has subscribed.

Community solar was implemented on a project-by-project basis in Maryland until the establishment of a Community Solar Pilot Program in July 2015. The pilot program commenced in April 2017, and is intended to attract new investment in solar systems and to provide a small carve-out in the total capacity for solar systems built on parking lots, industrial areas or brownfields. Maryland has a statewide limit for community solar of 416.9 MW, with a carve-out of 125 MW for projects focused on low- and moderate-income (LMI) customers. The Community Solar Pilot Program contributes to and is included as part of the total state net metering limit of 3,000 MW.

Figure 3-29 provides a simple overview of how community solar projects work in Maryland. Community solar projects are built and operated by PSC-approved subscriber organizations, such as utilities, electricity suppliers and solar developers. A subscriber must submit an interconnection application to the appropriate IOU based upon the service territory in which the project is located. Upon receiving conditional interconnection approval from the IOU, a subscriber organization must apply to the Community Solar Energy Generating System (CSEGS) Pilot program administered by the PSC. Once approved, the subscriber organization may sell community solar subscriptions to customers and the project is constructed once enough subscribers have enrolled. The subscriber organization will receive payment from the IOU for any generation produced by the CSEGS above what has been subscribed.

Figure 3-29 Basics of Maryland Community Solar Projects



Source: Adapted from bge.com/SmartEnergy/MyGreenPowerConnection/Pages/HomeBusiness/CommunitySolarSubscriberOrg.aspx.

Subscribers can purchase a share of the CSEGS, up to 200 percent of the subscriber's historical annual energy consumption. A subscriber pays either an upfront fee or a fixed monthly payment to the subscriber organization for the portion of power procured, and in return, the subscriber will receive a community solar adjustment credit on their electric bill from their IOU. A subscriber still receives its services from the IOU, including supply and delivery, and the credit offsets those charges. In this way, community solar is virtually net metered.

As of October 2021, 243.8 MW of community solar projects across the state have been proposed. The IOUs have to approve the CSEGS before the capacity can be accepted as part of the Community Solar Pilot Program, and of that 243.8 MW, 177.23 MW have been accepted. About 44.45 MW of community solar is in operation. Table 3-15 shows the Community Solar Pilot Program's reserved capacity (most of the offered capacity) and the amount accepted by IOUs compared to the amount of total capacity available over four years.

Table 3-15 Maryland Community Solar Pilot Program Capacity over Four Years

Utility	Offered Capacity (MW)	Accepted Capacity (MW)	Operating Capacity (MW)
Baltimore Gas and Electric Company	127.5	101.97	19.77
Delmarva Power and Light Company	20.87	17.66	4.98
Potomac Electric Power Company	63.23	30.52	11.63
Potomac Edison Company	32.23	27.08	8.08
State Total	**243.83**	**177.23**	**44.45**

Accepted capacity source: Maryland Public Service Commission, Report on the Status of Net Energy Metering in the State of Maryland, October 2021, psc.state.md.us/wp-content/uploads/2021-Net-Metering-Report-FINAL.pdf.

The Maryland General Assembly revised the Community Solar Pilot Program to extend the termination date of the pilot program from July 2020 to no sooner than December 31, 2024. Additionally, it removed the limit on the maximum number of subscribers to a community solar system to allow for any number of subscribers to participate in a project and raised the maximum capacity for an individual community solar project to 2 MW. The PSC is required to submit a report to the General Assembly by July 1, 2022 regarding the PSC's findings and recommendations concerning community solar.

3.5.4 EmPOWER Maryland

The EmPOWER Maryland energy initiative was announced in July 2007, 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 sought to achieve electric consumption and peak demand reductions as follows:[76]

[76] Maryland Public Utilities Article § 7-211.

- 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 included 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.[77] On December 23, 2014, the PSC approved WGL's residential and demand response programs,[78] which are designed to reduce gas consumption for heating and water heating in existing and new construction. In 2016, the PSC began considering the development of natural gas efficiency goals,[79] but as of 2021, no natural gas goals have been established.

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 was implemented for the 2018-2020 program cycle. The 2016 weather-normalized gross retail sales served 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. In spring 2017, the General Assembly enacted legislation to codify the 2 percent goal, thus continuing the EmPOWER Maryland efforts for the 2018-2020 and 2021-2023 program cycles. By July 1, 2022, the Commission must submit recommendations to the General Assembly on savings goals and cost-effectiveness approaches for the EmPOWER Maryland 2024-2026 program cycle.[80]

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, CHP 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. The Maryland Department of Housing

[77] Maryland Public Service Commission, Docket No. 9362, Mail Log No. 158098.

[78] Maryland Public Service Commission, Order No. 86785.

[79] Maryland Public Service Commission, Order No. 87082.

[80] psc.state.md.us/electricity/wp-content/uploads/sites/2/EmPOWER_2020-Data-1.pdf.

and Community Development (DHCD) conducts the Limited Income Energy Efficiency Program (LIEEP) for low-income customers of BGE, Pepco, Delmarva, Potomac Edison, SMECO and WGL. This program aids low-income households with the installation of energy-saving measures in their houses with no out-of-pocket costs.[81] To date, over 43,242 low-income customers have participated in EmPOWER Maryland through LIEEP.[82]

EmPOWER Maryland Peak Demand Reduction Programs

While energy efficiency programs can result in demand reduction, the majority of demand reduction comes from demand response and dynamic pricing programs (see Section 3.1.4 for more information on demand response). The EmPOWER Maryland utilities, with the exception of PE, have implemented these types of programs to meet these goals. PE cites a lack of any cost-effective mechanism to meaningfully reduce peak demand.

Concerning demand response programs, BGE 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. 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 have plateaued. At the end of 2019, the four demand response programs were capable of providing a demand reduction of 603 MW.[83]

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 3.5.5 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 their 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. In past years, BGE customers that participated in an event received, on average, a bill credit of $5 to $8 per event.[84] On average, BGE, DPL and Pepco customers have collectively reduced their loads by 226 MW annually in 2018, 2019 and 2020.[85] The annual dynamic pricing demand reductions, which fluctuate annually based upon customer engagement, are summarized in Table 3-16.

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81 psc.state.md.us/electricity/empower-maryland/.

82 Maryland Public Service Commission, 2020 Annual Report, psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

83 Maryland Public Service Commission, Docket No. 9494, Individual utility EmPOWER Maryland semiannual reports filed February 15, 2019.

84 BGE Smart Energy Rewards, Baltimore Gas and Electric, bge.com/smartenergy/smart-energy-rewards/Pages/default.aspx.

85 Maryland Public Service Commission, The EmPOWER Maryland Energy Efficiency Act Standard Report of 2021 With Data for Compliance Year 2020. psc.state.md.us/wp-content/uploads/2021-EmPOWER-Maryland-Energy-Efficiency-Act-Standard-Report.pdf

Table 3-16 Utility Dynamic Pricing Demand Reduction (MW)

	2013	2014	2015	2016	2017	2018	2019	2020
BGE	0	209	309	336	330	140	111	110
DPL	0	0	143	39	31	47	0	0
Pepco	309	125	47	126	135	124	91	55
Total	**309**	**334**	**499**	**501**	**496**	**311**	**202**	**165**

Source: Maryland Public Service Commission, The EmPOWER Maryland Energy Efficiency Act Standard Report of 2021 with Data for Compliance Year 2020.

EmPOWER Maryland Reductions

At the conclusion of 2015, the utilities achieved 99 percent of their energy reduction goal, reducing energy usage by 5,394,256 MWh, and 100 percent of the demand reduction goal by lowering electric demand by 2,117 MW. As the EmPOWER Maryland programs continue, the energy reduction savings have almost doubled, with the EmPOWER Maryland utilities recognizing over 11.9 million MWh of energy savings from 2009 through 2020. Additionally, the utilities have offset 2,363 MW in demand and from the purchase or installation of 128.3 million energy-efficient measures.[86] Energy and demand reductions of the electric EmPOWER Maryland utilities to date are summarized in Table 3-17, and the natural gas reductions from WGL's efficiency program to date are summarized in Table 3-18.

[86] Maryland Public Service Commission, 2020 Annual Report, psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

Table 3-17 EmPOWER Maryland Electric Program Results to Date

		Energy Reduction (MWh)			Demand Reduction (MW)		
		Goal/Forecast	Gross Reductions	Variance	Goal/Forecast	Gross Reductions	Variance
BGE	2009 - 2015	3,593,750	2,638,975	73%	1,267	1,156	91%
	2016 - 2017	1,149,791	1,335,350	116%	541	559	103%
	2018 - 2020*	1,430,944	2,448,950	171%	996	708	71%
	Total**	6,174,485	6,423,275	104%			
DPL	2009 - 2015	143,453	382,605	267%	18	147	815%
	2016 - 2017	213,471	202,421	95%	42	144	346%
	2018 - 2020*	289,222	309,014	107%	159	86	54%
	Total**	6646,146	1,540,186	283%			
PE	2009 - 2015	415,228	529,519	128%	21	82	392%
	2016 - 2017	162,274	174,922	108%	24	35	147%
	2018 - 2020*	356,168	386,804	109%	48	55	115%
	Total**	933,670	1,091,245	117%			
Pepco	2009 - 2015	1,239,108	1,600,813	129%	672	640	95%
	2016 - 2017	686,546	786,428	115%	580	638	110%
	2018 - 2020*	1,168,129	1,296,587	111%	558	447	80%
	Total**	3,093,783	3,683,828	119%			
SMECO	2009 - 2015	83,870	242,347	289%	139	92	67%
	2016 - 2017	116,181	102,736	88%	28	17	62%
	2018 - 2020*	161,201	167,155	104%	87	73	84%
	Total**	361,252	512,238	142%			
Total	**2009 - 2015**	**5,475,409**	**5,394,259**	**99%**	**2,117**	**2,117**	**100%**
	2016 - 2017	**2,328,263**	**2,601,857**	**112%**	**1,215**	**1,394**	**115%**
	2018 - 2020*	**3,037,609**	**1,436,783**	**47%**	**1,658**	**1,230**	**74%**
	Total**	**10,841,281**	**9,432,899**	**87%**			

* Excludes savings from MD Department of Housing and Community Development Limited Income Programs.
** Demand response savings is not additive.

Table 3-18 WGL Natural Gas Program Results to Date

	Reduction in Therms		
	Goal/Forecast	Gross Reductions	Variance
2015 - 2017*	2,224,955	1,698,312	76%
2018 - 2020	5,265,406	2,556,498	7%
Total	**5,877,669**	**1,947,284**	**33%**

* For the 2015-2017 program cycle, WGL only reported net reductions, not gross.

The EmPOWER Maryland utilities have collectively spent over $3.2 billion, including $2.1 billion on energy efficiency and conservation (EE&C) and $883 million on demand response programs. Projected savings from EmPOWER Maryland is $11.8 billion over the life of the installed measures for the EE&C programs. The average monthly residential bill impact for 2020, by utility, is provided in Table 3-19.

Table 3-19 Average Monthly Residential Bill Impact by Utility, 2020

	EE&C	Demand Response	Dynamic Pricing	Total
BGE	$4.66	$3.45	($0.19)	**$8.30**
DPL	$4.84	$1.08	($0.09)	**$5.83**
PE	$5.63	N/A	N/A	**$5.63**
Pepco	$4.37	$2.47	($0.09)	**$6.92**
SMECO	$5.77	$2.47	N/A	**$8.24**

Notes: Bill impact assumes the average monthly usage of 1,000 kWh.
"N/A" indicates that the utility does not offer that program.
Source: Maryland Public Service Commission 2021 Annual Report for the Calendar Year Ending December 31, 2020.

3.5.5 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 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 (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.

Each utility must defer incremental costs related to AMI in a regulatory asset until the AMI project is proven cost-effective. BGE, DPL, Pepco and SMECO have completed the installation of AMI meters in their respective service territories, and each has received PSC approval to recover AMI-related costs through base rates for each utility with the exception of SMECO. In February 2017, the PSC denied SMECO's request to recover AMI costs, stating that SMECO can seek recovery once it has delivered a cost-effective AMI system. At this time, PE has not filed plans to install AMI meters. For customers who wish to opt out of receiving the AMI meter, the PSC has established opt-out fees that vary by service territory. Refer to Table 3-20 for the number of meters installed and opt-out percentage data.[87]

Table 3-20 Number of Meters Installed and Opt-out Percentage

Company	Number of Meters (electric and gas) Installed	Opt-Out Percentage
BGE	2.1 million	2.7%
Pepco	560,851	0.25%
DPL	211,115	0.5%
SMECO	165,178*	0.22%

Source: SMECO Annual Report 2018: smeco.coop/~/media/pdf/About/2018-Annual-Report.pdf?la=en

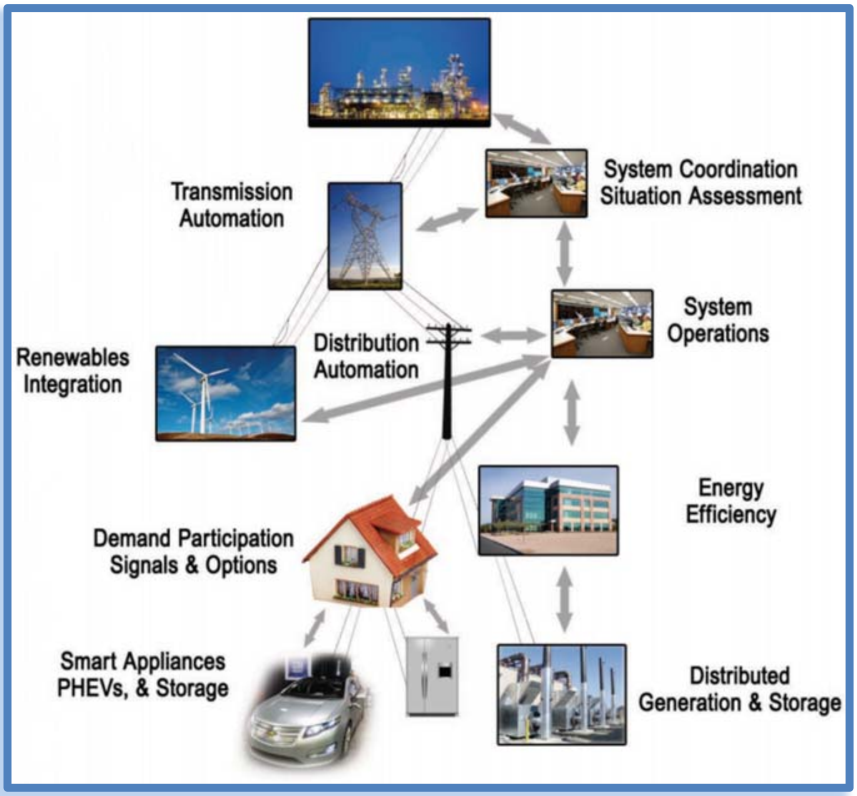
Smart Grid Integration

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 a 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 3-30). 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.

[87] Maryland Public Service Commission, 2020 Annual Report, psc.state.md.us/wp-content/uploads/2020-MD-PSC-Annual-Report.pdf.

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 3-30 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 threats from cyberattacks. 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 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. In 2015, 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. In 2016, further strengthening those two efforts, President Obama 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. In November 2018, President Trump signed the Cybersecurity and Infrastructure Security Agency Act, which established the Cybersecurity and Infrastructure Security Agency (CISA). The agency, under the U.S. Department of Homeland Security, utilizes resources in the public and private sectors to assist in defending against cyberattacks and to provide the federal government with the tools necessary to ensure "secure and resilient infrastructure for the American people."[88] CISA includes the National Cybersecurity and Communications Integration Center (NCCIC), which shares cyber and communications information with the cybersecurity community to assist in building awareness and understanding on how to mitigate cyber threats and vulnerabilities.

Over the last several years, FERC has adopted cybersecurity standards under the Critical Infrastructure Protection (CIP) standards. In early 2016, FERC Order No. 822 revised seven of the North American Electric Reliability Corporation's (NERC's) CIP standards. In addition, the Order requires NERC to develop modifications to (1) protect transient electronic devices used at low-impact Bulk Electric System (BES) cyber systems; (2) protect communication network components between control centers; and (3) refine the definition for low-impact external routable connectivity. In July 2016, FERC issued Order No. 829, which directed NERC to develop a new or modified reliability standard that addressed supply chain risk management for BES operations. FERC Order No. 843, released in April 2018, adopted NERC's proposed reliability standard related to these matters, with one exception—a directive regarding controls for low impact BES cyber systems. In its denial of this directive, FERC directed NERC to complete a study within 18 months to assess whether the proposed directive provides adequate security.

On July 21, 2016, FERC issued a Notice of Inquiry (Notice) to address potential modifications to the CIP reliability standards as a result of lessons learned from the 2015 cyberattack on an electric grid in Ukraine. The Notice: (1) sought comments on whether there should be a separation between the internet and the BES control systems in control centers that perform transmission operator functions; and (2) required computer administration practices that prevent unauthorized programs from running. In response to its Notice, FERC received 18 comments opposing modifications to CIP reliability standards. As a result, FERC terminated the proceeding, citing that the CIP reliability standards allow flexibility with implementing security controls.

[88] dhs.gov/cisa/about-cisa.

In June 2019, FERC expanded the reporting requirements for cybersecurity incidents under the CIP reliability standards. Under the adopted standard, cybersecurity incidents and attempts to disrupt or the disruption of BES cyber systems require initiation of a response plan and a subsequent report on the incident. Incident reports will be sent to the NCCIC and the Electricity Information Sharing and Analysis Center at NERC.

In 2020, FERC approved changes to three CIP NERC reliability standards in order to broaden the scope of assets subject to supply chain cybersecurity requirements and obligations. These changes included electronic access control and monitoring systems that are connected with, and provide access to, bulk power system assets. The revisions affect CIP-013-2, Cyber Security – Supply Chain Risk Management; CIP-005-7, Cyber Security – Electronic Security Perimeter(s); and CIP-010-4, Cyber Security – Configuration Change Management and Vulnerability. Entities registered with NERC and subject to the reliability standards will need to change their planning procedures to comply with the updated reliability standards, notably in regard to engineering design and procurement of BES Cyber Systems, Electronic Access Control or Monitoring Systems (EACMS), Physical Access Control Systems (PACS) and Protected Cyber Assets (PCA). It is expected that, since vendors and suppliers of these devices are not focused on the energy industry, this will be the first time they address NERC standards, and as result the new requirements may pose a significant challenge.

In December 2020, FERC issued a draft notice of a proposed rulemaking that would allow utilities to request incentive rates for cybersecurity investments that exceed those required under the CIP reliability standards. Two different approaches are under consideration:

- The NERC CIP Incentives Approach would allow a 200-basis points adder to a utility's return on equity for eligible cybersecurity capital investments if a utility voluntarily applies higher-level CIP requirements than required for their BES size (i.e., a medium- or high-impact BES cyber system to a low-impact BES).

- Utilities could request deferred cost recovery for incurred costs to implement security controls in the National Institute of Technology's Cybersecurity Framework.

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."[89] The PSC approved BGE's, DPL's and Pepco's respective Cybersecurity Plans filed in October 2012. SMECO filed a proposed Smart Grid Cyber Security Plan on January 23, 2017.[90] In addition, the PSC

[89] Maryland Public Service Commission, Order No. 89015.

[90] Maryland Public Service Commission, Order No. 88827, psc.state.md.us/wp-content/uploads/Order-No.-88827-Case-No.-9492-Cybersecurity-Reporting.pdf.

approved a Cybersecurity Reporting Plan,[91] 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 Maryland Energy Administration (MEA). Additionally, the three utilities fund the PSC's access to a cybersecurity consulting firm which serves at the discretion of the PSC. The firm provides independent advice to the PSC regarding the process and sufficiency of AMI-related cybersecurity.

In 2018, the PSC issued a Notice of Initiating a Proceeding and Request for Comments on the Final Report of the Cyber-Security Reporting Workgroup, a document that provided recommendations regarding "(i) cyber-security definitions, (ii) Maryland utilities periodic cyber-security reporting applicability, (iii) cyber-security reporting agenda, (iv) cyber-security reporting certification, (v) cyber-security briefing parties, (vi), cyber-security report briefing frequency, (vii) cyber-security breach reporting, and (viii) cyber-security briefing information handling protocols."[92] In Order No. 89015 issued in February 2019, the PSC adopted the final report's recommendations, including:

- Expanding the definition of information technology systems to include "hardware and software related to electronic processing, and storage, retrieval, transmission; and manipulation of data"
- Establishing triennial reporting requirements beginning in 2019 for utilities with more than 300,000 customers; and
- All utilities must report cybersecurity breaches.

[91] Maryland Public Service Commission, Order No. 85680.

[92] Maryland Public Service Commission, Order No. 89015, https://www.psc.state.md.us/wp-content/uploads/Order-No.-89015-Case-No.-9492-Cyber-Security-Reporting-of-Maryland-Utilities.pdf

Chapter 4 – 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, 13 other states, typically states characterized by high electricity prices, and the District of Columbia 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.

4.1 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 (RTO), PJM Interconnection LLC (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 (over 2 MW) and high-voltage transmission development (over 69,000 volts) through the Certificate of Public Convenience and Necessity (CPCN) process (see Chapter 1).

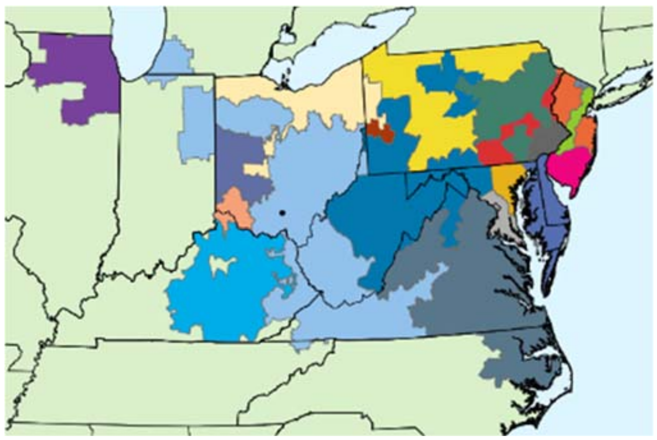
In states with restructured markets such as Maryland, electricity is generated by a power company that is separate from the entity responsible for transporting and delivering power to end-use customers. Entities selling energy on the wholesale market include competitive suppliers and power marketers 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 resold several times before finally being consumed. These sales and resale 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 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 65 million people. PJM also operates a wholesale competitive power market that annually exceeds $33 billion in volume. PJM is the oldest, continuously operating power pool in the world.

PJM's Service Area



Source: PJM

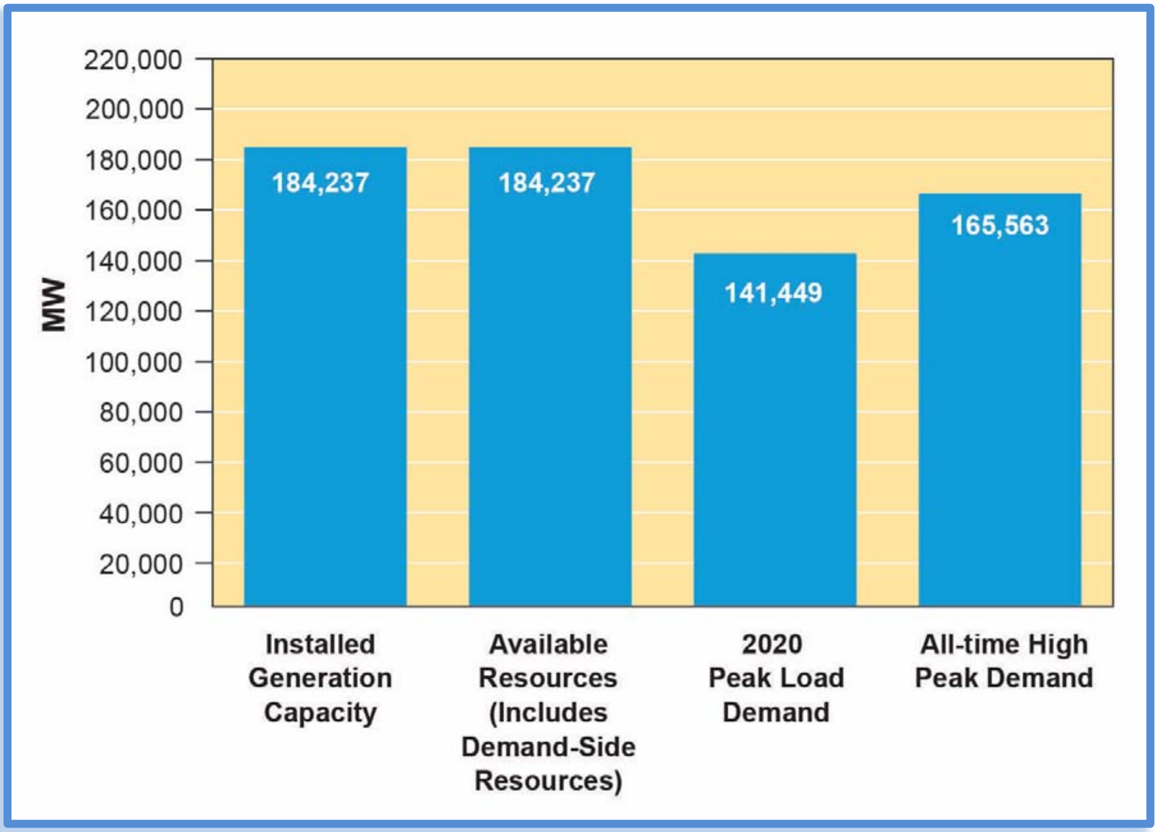
PJM began in 1927 when the Public Service Electric and Gas Company, Philadelphia Electric Company (now a subsidiary of the Exelon Corporation) and Pennsylvania Power & Light Company formed the P.A. - N.J. Interconnection power pool. The intent of the power pool was to centrally dispatch electric generating 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, they would meet PJM reliability targets. The name was changed to the Pennsylvania-New Jersey-Maryland Interconnection, or PJM, in 1956 when Baltimore Gas & Electric Company (now a subsidiary of Exelon Corporation) and General Public Utilities (now a part of FirstEnergy) joined.

In 1997, the Federal Energy Regulatory Commission (FERC) approved PJM as the first fully functioning independent system operator (ISO). ISOs 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 an RTO. PJM became the first fully functioning RTO in 2001 and integrated a number of utilities into its system between 2002 and 2013, including Rockland Electric (2002), Allegheny Power (2002), Commonwealth Edison (2004), American Electric Power (2004), Dayton Power and Light (2004), Duquesne Light (2005), Dominion (2005), ATSI (2011), Cleveland Public Power (2011), Duke Energy Ohio and Duke Energy Kentucky (2012), and East Kentucky Power Cooperative (2013). In addition, Ohio Valley Electric Corporation (OVEC) integrated in PJM in 2018. These additions allow for the diversification of electricity resources available within PJM's wholesale electricity market.

Source: PJM, PJM Annual Report for 2020, services.pjm.com/annualreport2020/ "PJM History," PJM Interconnection, pjm.com/about-pjm/who-we-are/pjm-history.aspx.

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 the development of new generation capacity necessary to meet electricity demand. Figure 4-1 shows supply and demand in PJM in 2020.

Figure 4-1 PJM Supply and Demand for 2020



Source: Installed Generating Capacity and 2018 Peak Demand: Monitoring Analytics, 2020 State of the Market Report for PJM.

4.1.1 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 offer 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 their names, 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 this 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 can extend several years into the future.

For energy products on the day-ahead market, the PJM operator determines the sub-hourly dispatch of plants based on price bids submitted by suppliers. Energy prices in PJM are based upon the offers that designate a price and quantity at which a generator is willing to sell electricity. PJM stacks these offers from lowest price to highest price until it can 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. The average PJM region day-ahead and real-time LMPs for 2020 are shown in Table 4-1.

Table 4-1 PJM Off-Peak and On-Peak Hourly Locational Marginal Prices for 2020 ($/MWh)

	Day-Ahead		Real-Time	
	Off-Peak	On-Peak	Off-Peak	On-Peak
Average	17.39	23.67	17.64	24.09
Median	16.54	21.64	16.29	20.52

Source: Monitoring Analytics, 2020 State of the Market Report for PJM.

Since energy prices may vary considerably by location due primarily to transmission congestion, 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 4-2) 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. Based on real-time market outcomes, PJM estimates that in 2020, congestion added approximately $3.30/MWh to the average LMPs in the Baltimore Gas and Electric Company (BGE) zone, $1.47/MWh in the Potomac Electric Power Company (Pepco) zone, and $0.65/MWh in the Delmarva Power & Light Company (DPL or Delmarva) zone. Congestion accounted for 9 percent, 7 percent and 7 percent of load-weighted average, real-time LMPs in the BGE, Pepco and DPL zones, respectively. BGE, with a real-time congestion component of $3.30/MWh, had the highest real-time congestion component of all PJM control zones in 2020. Between 2019 and 2020, total congestion costs decreased from $583.3 million to $528.6 million, representing a 9.4 percent decline. There was a more significant decrease in day-ahead congestion costs than real-time congestion costs between 2019 and 2020. For comparison, the day-ahead congestion costs decreased from $714.0 million to $662.5 million, while the real-time congestion costs decreased from $752.3 million to $749.3 million between 2019 and 2020. This was the combined result of mild weather conditions and demand reductions due to COVID-19.

Table 4-2 Real-Time Average Annual Load-Weighted Locational Marginal Prices ($/MWh)

PJM Zone	2019	2020	Variance
Baltimore Gas and Electric Company (BGE)	$30.82	$25.78	$5.04
Potomac Electric Power Company (Pepco)	$29.68	$23.59	$6.09
Delmarva Power & Light Company (DPL)	$27.71	$22.90	$4.81
Allegheny Power Systems (APS)	$27.83	$22.40	$5.43

Source: Monitoring Analytics, 2020 State of the Market Report for PJM.

Compared to prior years, the congestion costs and LMPs have dropped, and the differences in LMPs between the eastern and western zones of PJM have declined. Total congestion in 2020 was lower than congestion in any year since 2008. The energy prices in 2020 were recognized as the lowest since 1999 when the PJM markets were established. The load-weighted average real-time LMP was $21.77/MWh in 2020 compared to $27.32/MWh in 2019, with half of the difference occurring due to lower fuel costs. COVID-19 and mild winter weather assisted with the decrease in LMP. The capacity factor of coal plants declined from 30.1 percent in 2019 to 25.6 percent in 2020, while coal's proportion of total PJM energy generation fell from 23.8 percent to 19.3 percent and natural gas's share climbed from 36.4 percent to 39.8 percent. 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 prices 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 natural gas. PJM's Market Monitor reports that it anticipates 44,684 MW of generation to retire between 2011 and 2022, approximately 70 percent of which is from coal-fired steam units. In 2020, 3,255 MW of generation resources and 457 MW of pseudo-tied resources were retired,[93] and 2,557 MW of new generation resources were added. PJM does not expect these retirements to result in degraded reliability since as of December 31, 2020, there were 173,581 MW of capacity in the generation queue, indicating that there is still sufficient capacity in the queue to compensate for retirement of generation units. In addition, PJM

[93] PJM defines a pseudo-tied resource as a time-varying energy transfer that is updated in real-time and included in the net interchange (i.e., exchange of power between balancing areas) in the same manner as a transmission line connecting two or more balancing areas.

has a reserve margin of over 23.9 percent, or about 39,500 MW for the 2020/2021 delivery year.[94] PJM's required reserve margin is 24.2 percent of expected demand, when accounting for fixed resource requirement.

4.1.2 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 Maryland Public Service Commission (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 3.1.4 and Appendix B for more information on the RPM.

From the late 1990s through the 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 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 became 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."[95] 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 (IOUs) to issue Requests 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.

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

[94] pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.

[95] Maryland Public Service Commission, Order No. 82936, Case No. 9214, September 29, 2009.

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 offer 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 ineligible to be counted toward resource adequacy requirements for Maryland utilities.

As a result of the conflicting approaches taken by Maryland and New Jersey to actively promote increased generation instate, 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; the project came online in February 2017.

On April 19, 2016, the Supreme Court upheld the lower court's decision, stating in its opinion that the PSC's ruling overstepped FERC's authority as granted by the Federal Power Act. In its opinion, the Supreme Court noted that in deregulated markets,[96] power must be procured one of two ways: (1) through bilateral contracts where LSEs agree to purchase power through a power purchase agreement (PPA); 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 LSEs and guaranteed the plant a contract price rather than the auction clearing price;[97] 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 CPV plant clearing the capacity market.

[96] Hughes v. Talen Energy, 578 U.S. 14614, 2016, supremecourt.gov/opinions/15pdf/14-614_k5fm.pdf.

[97] Under a contract for differences, a power generator would either be paid or would pay a power buyer the differences between a pre-determined contract price and the wholesale electricity market price.

Separately, Old Dominion Electric Cooperative (ODEC) proposed to build a 1,000 MW natural gas power plant in Cecil County (see Section 5.2.1). In April 2013, ODEC asked the PSC for expedited approval of a CPCN for the project in order for it to bid into PJM's May 2014 capacity auction. ODEC expected 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 was completed and commenced operations in May 2018.

4.2 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.

4.2.1 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, 10 years after the Act's enactment, only 2.8 percent of residential customers were being served by competitive suppliers. By December 2020, 20 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 4-3). At the end of 2020, competitive electric suppliers in the state served 515,691 commercial, industrial and residential customers. This number represents a 2.5 percent decrease from 2019 when suppliers served 529,329 customers.

Table 4-3 Percentage of Customers Served by Competitive Suppliers

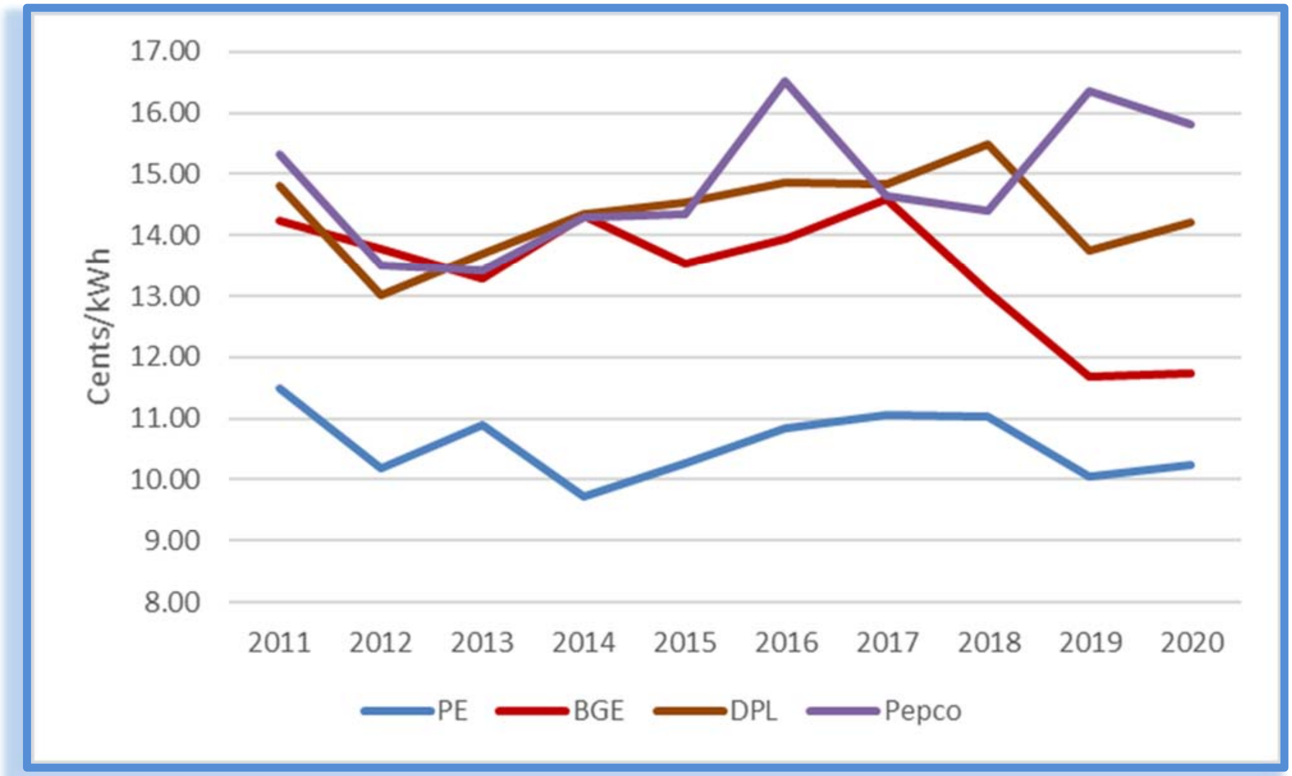
Residential	Small Commercial & Industrial	Mid-size Commercial & Industrial	Large Commercial & Industrial
16.9%	29.9%	48.2%	80.5%

Source: Maryland Public Service Commission, Electric Choice Enrollment Monthly Report, December 2020.

Residential and small commercial customers that cannot or do not choose to transact with a competitive supplier are provided 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 IOUs procure 25 percent of the total residential SOS load every six months under two-year, fixed-price contracts with competitive wholesale suppliers. SOS rates declined for Pepco residential customers and increased for BGE, Delmarva and Potomac Edison (PE) residential customers for the 12 months beginning June 2020, compared to the prior year. In comparison to the previous year, SOS rates declined for Pepco's small commercial customers and climbed for Delmarva, BGE and Potomac Edison's small commercial customers. Maryland's number of licensed electric suppliers increased by 3 percent from 400 in 2019 to 412 by the end of 2020.

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. Market prices remained relatively stable from 2012 through 2018, but have experienced some volatility in recent years, depending upon the utility. Figure 4-2 shows the average annual IOU residential rates in effect in summer 2011 and for each subsequent summer.

Figure 4-2 Average Annual Retail Electricity Rates for Maryland Residential Customers, 2011-2020



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, Potomac Edison's 2013 and 2015 rates, and DPL's 2020 rate, which were unavailable. EEI's summer editions take the average of the rates from the 12 months ended June 30 of the edition year.

4.2.2 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 customer's contracted rate with a competitive supplier. Transmission rates are set by 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 and 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 (usually quarterly, semiannually or annually) through proceedings that are less intensive than a full rate case. Figure 4-3 shows a sample residential BGE bill with some details on billing components.

Figure 4-3 BGE Bill Detail Example

Residential - Schedule R
Billing Period: Apr 23, 2021 - May 24, 2021 Days Billed: 31
Next Scheduled Reading: June 22, 2021

Read on May 24

Current Reading		Previous Reading		
40643	-	40347	=	296 kWh used

ELECTRIC SUPPLY				**$20.88**
BGE	296 kWh	x	.07053	20.88
BGE ELECTRIC DELIVERY				**$21.40**
Customer Charge				8.00
EmPower MD Chg	296 kWh	x	.00594	1.76
Distribution Chg	296 kWh	x	.03934	11.64
TAXES & FEES				**$0.54**
MD Universal Svc Prog				0.32
Envir Srchg	296 kWh	x	.000129	0.04
Franchise Tax	296 kWh	x	.00062	0.18
TOTAL				**$42.82**

The BGE customer profiled in Figure 4-3 is on Rate Schedule R, the standard residential service schedule. In this particular month, the customer used 296 kWh of energy and was charged a total of $42.82. The BGE electric supply rate during this billing period was an average of $0.07053/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 $11.64 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. Other elements in the bill include a universal surcharge, as well as the environmental surcharge. Both of these surcharges are designed to support certain state programs, such as the Power Plant Research Program (PPRP).

The electric generation component makes up about $20.88 of this customer's entire bill, or 49 percent. Distribution charges comprise about 27 percent, while transmission charges only amount to about 1 percent of the total charges. The rest of the charges consist of the customer charge, riders, surcharges and taxes (about 24 percent). As noted earlier, the utilities contract for energy supply in the wholesale market and, therefore, the electric generation price of $0.07053/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 4-4 profiles a residential Pepco customer with a slightly higher consumption than that of the aforementioned BGE customer. Pepco's bill is structured differently than BGE's. Note that the Pepco bill example shows how PJM transmission charges and taxes are rolled into the total electricity supply charge.

Figure 4-4 Pepco Bill Detail Example

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)	Oct 19	Sep 21	29	932
		Reading	**Reading**	**Multiplier**	
		111567	110635	1	

Delivery Charges: These charges reflect the cost of bringing electricity to you.
Current charges for 29 days, **summer rates in effect.**

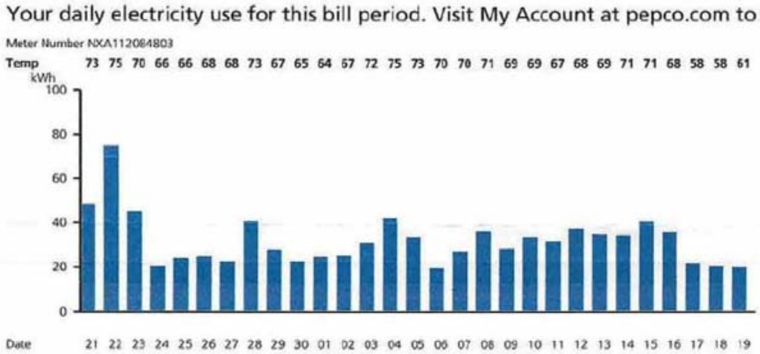
Type of charge	How we calculate this charge	Amount($)
Distribution Services:		
Customer Charge		8.01
Energy Charge	932 kWh X $0.0699520 per kWh	65.19
Pepco MRP Rate Offset		3.33–
Franchise Tax (Delivery)	932 kWh X $0.0006200 per kWh	0.58
Universal Service Charge		0.32
Energy Wise Rewards Monthly Credit		8.00–
MD Environmental Surcharge	932 kWh X $0.0001470 per kWh	0.14
Empower MD Chg	932 kWh X $0.0063180 per kWh	5.89
Gross Receipts Tax	at 2.0408%	1.56
Montgomery County Energy Tax	932 kWh X $0.0113114 per kWh	10.54
Administrative Credit	932 kWh X $0.0002912- per kWh	0.27–
Total Electric Delivery Charges		**80.63**

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. Your Price to Compare is 7.72 cents ($0.0772) per kWh. When shopping for electric suppliers, compare this price to those proposed by other suppliers. This price reflects the average annual amount a customer on this rate pays per kilowatt-hour for Electric Supply. For information on electric energy suppliers please visit mdelectricchoice.com.

Billing Period: Sep 21, 2021 to Oct 19, 2021 (29 days)

Type of charge	How we calculate this charge	Amount($)
Transmission Services:		
Energy Charge	932 kWh X $0.0114500 per kWh	10.67
Gross Receipts Tax	at 2.0408%	0.22
Generation Services:		
Energy Charge	932 kWh X $0.0660944 per kWh	61.60
Procurement Cost Adjustment	932 kWh X $0.0034852- per kWh	3.25–
Total Electric Supply Charges		**69.24**
Total Electric Charges - Residential Service		**149.87**

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



Paying for Power During Storm Outages – Bill Stabilization Adjustment

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 Maryland 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.

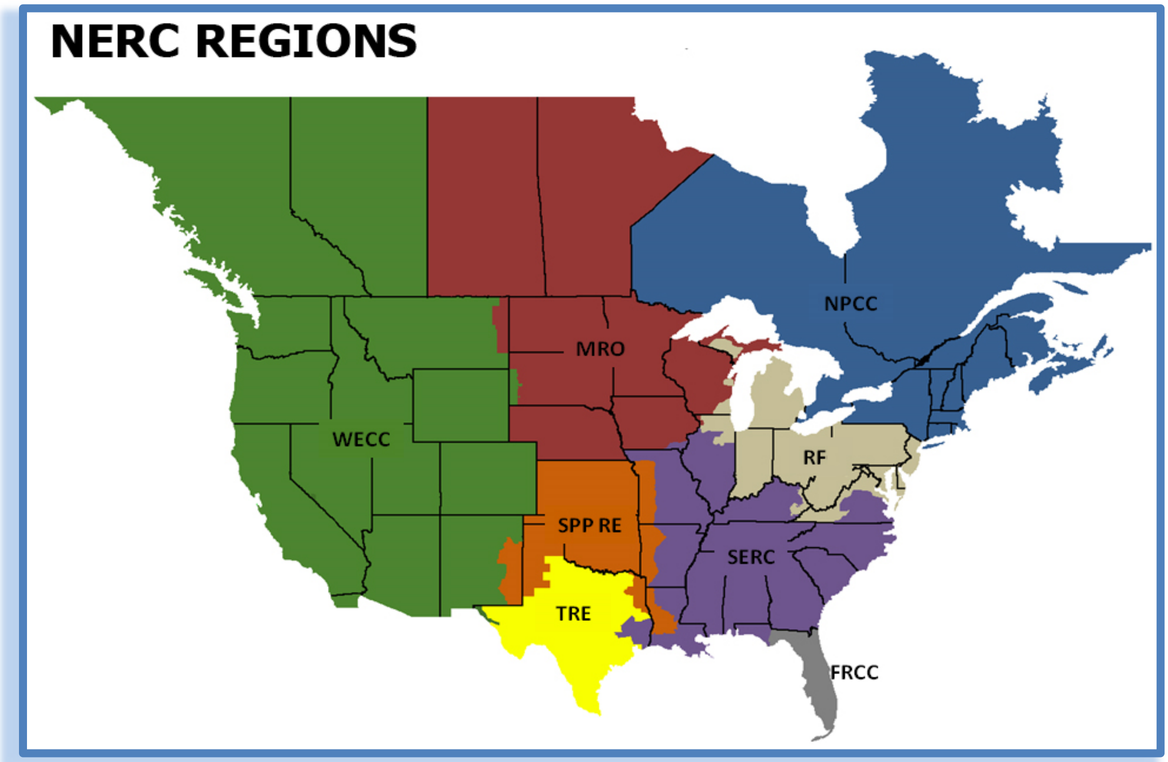
4.3 Transmission and Distribution System Planning and Reliability

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 No. 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 of their distribution systems.

4.3.1 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 FERC. The Energy Policy Act of 2005 requires electricity market participants to comply with NERC reliability standards. If participants are found in violation of the Energy Policy Act, participants are 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) which serves the PJM RTO (see Figure 4-5).

Figure 4-5 NERC Reliability Councils



Source: North American Electric 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 has sufficient resources such that there is no loss of load more than one day in 10 years. 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.

4.3.2 Transmission Congestion

The economic impacts of transmission congestion are described in Section 4.1.1; 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.

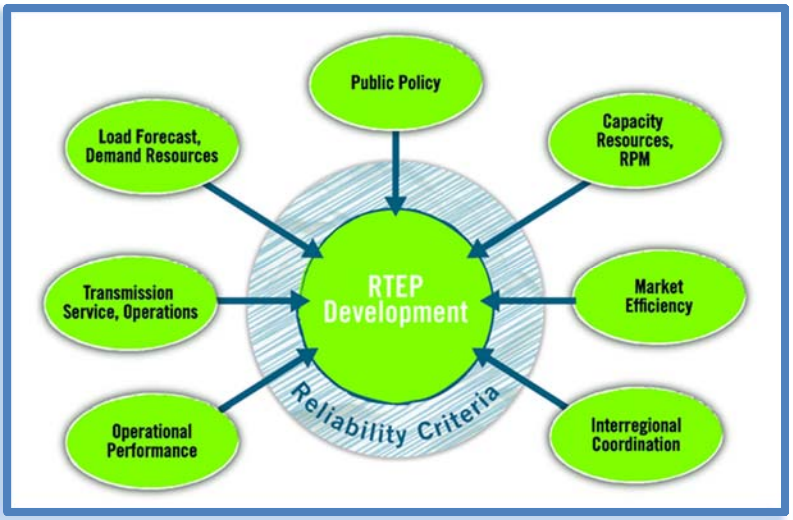
Eliminating or reducing key constraints can alleviate congestion. This may be achieved through the construction of new transmission lines, building new generation within a load pocket, upgrades to existing facilities or demand side management. PJM routinely conducts transmission planning to ensure reliability is maintained. In that regard, congestion that threatens reliability will be addressed in PJM's transmission planning process. Economic congestion, as described in Section 4.1.1, 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 competitive planning process to improve market efficiency.

4.3.3 PJM Transmission Planning

PJM conducts annual transmission planning to forecast and address potential reliability issues. PJM's Regional Transmission Expansion Plan (RTEP) planning 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 developed the 15-year 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 portfolio standard policies) when considering transmission upgrades. (See Figure 4-6 for the RTEP planning criteria.)

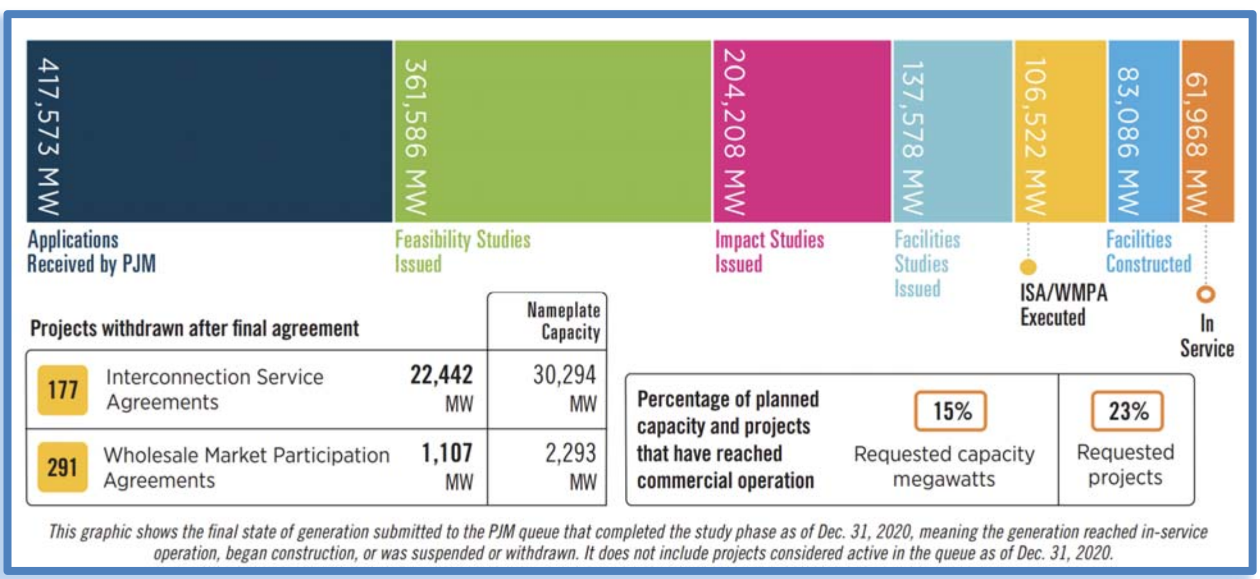
Figure 4-6 PJM RTEP Transmission Planning Criteria



Source: PJM 2015 Regional Transmission Expansion Plan.

In February 2021, PJM released the 2020 RTEP report, which outlines planned system upgrades approved by the PJM Board through December 31, 2020. In 2020, the PJM Board received an unprecedented 1,208 new service requests equaling 70,375 MW of generation and 44,179 MW of Capacity Interconnection Rights (CIRs). Most notably, as of December 31, 2020, 88 percent of the capacity in PJM's generation queue was from renewable energy technologies. The vast majority of projects in the queue will not come online—only 15 percent of capacity in the queue has reached commercial operation as of December 31, 2020. As shown in Figure 4-7, as generation requests move through the queue, the amount of generation decreases through each step of the process.

Figure 4-7 PJM Generation Queue



Source: PJM 2020 Regional Transmission Expansion Plan.

In April 2021, PJM started its new Interconnection Process Reform Task Force, which will focus both on PJM Interconnection-specific issues and the federal interconnection process. The Task Force will review interconnection studies, cost concerns including project costs and cost-sharing responsibility, interim operations and agreements, requirements for new service requests and the interconnection process, as well as opportunities to reduce the current and future interconnection backlog. In January 2022, PJM indicated it will propose to FERC several reforms to its interconnection process such as prioritizing generating projects that are ready to be studied rather than first in, first out. PJM also plans to propose a moratorium on new generation interconnection requests between fall 2022 and fall 2024 to allow PJM to catch up on its backlog of queue applications.[98]

PJM Market Efficiency

As part of PJM's Regional Transmission Expansion Plan (RTEP) planning process, transmission projects submitted during the RTEP Process Window to resolve reliability criteria violations undergo a market efficiency analysis to determine whether the project can provide economic benefits by relieving congestion. The purpose of the market analysis is to (1) ascertain whether economic benefits are realized if the project is accelerated; (2) determine whether additional enhancements may result in economic benefits; and (3) identify economic benefits that may result from modifying a transmission project to relieve one or more economic constraints. Market efficiency enhancements are reviewed during a 12- or 24-month process before they are presented to the PJM Board of Managers for approval. The 12-month process is designed to review all approved RTEP projects, while the 24-month process reviews economic transmission projects proposed to be implemented during years five through 15 of the 15-year RTEP study period. During both review processes, PJM develops assumptions such as fuel prices, emissions prices, annual PJM load forecast, quantity of demand and generation modeled, and generation additions and retirements. PJM then performs its market efficiency analysis to determine whether the projected economic benefits will exceed PJM's required minimum benefit/cost ratio of 1.25. PJM performs its benefit/cost calculations by comparing the present value of the total energy and capacity benefits for 15 years compared to the total annual cost over the first 15 years of the life of the enhancement. Once PJM has identified potential solutions, it solicits comments and recommendations from its Transmission Expansion Advisory Committee (TEAC), which is responsible for reviewing PJM's assumptions and analysis. After incorporating comments and recommendations, PJM presents its final RTEP market efficiency plan to the PJM Board of Managers for approval.

Maryland RTEP Upgrades

For Maryland, the 2020 PJM RTEP lists one baseline upgrade (equal to or greater than $10 million) (shown in Table 4-4), and six supplemental upgrades (equal to or greater than $10 million) (shown in Table 4-5). Baseline projects ensure compliance with NERC, regional and local transmission owner planning criteria and address market efficiency and congestion relief. Supplemental projects, known at one time as Transmission Owner initiated projects, are not required for compliance with system reliability but could address equipment material condition performance and risk, operational flexibility and efficiency, infrastructure resilience and customer service. The cost of these baseline transmission

[98] PJM, "Interconnection Process Reform Task Force Update," January 24, 2022, pjm.com/-/media/committees-groups/committees/mc/2022/20220124/20220124-item-08b-iprtf-report.ashx.

upgrades is expected to total $15 million. The 2020 PJM RTEP only lists transmission upgrades with cost estimates greater than $10 million that were approved by the PJM Board in 2020.

Table 4-4 Baseline Projects in Maryland (Greater than $10M) Included in 2020 PJM RTEP

Baseline Projects	Date	Cost ($M)	Zone
Rebuild 12 miles of Wye Mills-Stevensville line to achieve needed ampacity.	12/1/2023	15	DPL

Source: PJM 2020 Regional Transmission Expansion Plan.

Table 4-5 Supplemental Projects in Maryland (Greater than $10M) Included in 2020 PJM RTEP)

<table>
<tr><th>Supplemental Projects</th><th>Date</th><th>Cost ($M)</th><th>Zone</th></tr>
<tr><td>Rebuild two single-circuit 115 kV wood H-frame circuits as one double-circuit steel pole line</td><td>12/31/2021</td><td>21.4</td><td>BGE</td></tr>
<tr><td>Rebuild 10 miles of existing Talbert-Oak Grove 230 kV double-circuit lattice tower transmission lines with new steel monopole structures along existing route.</td><td>12/1/2024</td><td>38.0</td><td>Pepco</td></tr>
<tr><td>Rebuild and reconductor the First Energy (FE) portion of the Doubs-Goose Creek 500 kV line utilizing existing right-of-way. Replace breaker disconnect switches, line metering and relaying, substation conductor and breakers at Doubs 500 kV station.</td><td>6/1/2025</td><td>60.0</td><td>PE</td></tr>
<tr><td>Construct two 69 kV substations along the existing Wye Mills to Stevensville circuit and retire existing Grasonville substation.</td><td rowspan="3">6/1/2023</td><td rowspan="3">18.5</td><td rowspan="3">DPL</td></tr>
<tr><td>Construct new five-breaker ring bus substation west of existing Grasonville substation.</td></tr>
<tr><td>Construct new five-breaker ring bus substation west of existing Wye Mills Substation</td></tr>
</table>

Source: PJM 2020 Regional Transmission Expansion Plan.

4.3.4 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 distribution 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."[99] On April 17, 2012, new regulations were adopted, including the following:

[99] Maryland Public Service Commission, Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011. psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/RuleMaking/RM43//001.pdf

- 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.
- 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 the 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 3.5.5.)

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 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 were amortized over a five-year period that began in December 2010.

On December 2, 2015, the PSC adopted proposed regulations regarding reliability and service quality standards.[100] The proposed regulations established numerical reliability standards in terms of an allowable number of outage minutes for calendar years 2016 through 2019. The PSC has since updated the allowable number of outage minutes by utility through 2023.

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[100] Maryland Public Service Commission, Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011. psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/RuleMaking/RM43//001.pdf

4.4 The Role of Federal Entities

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

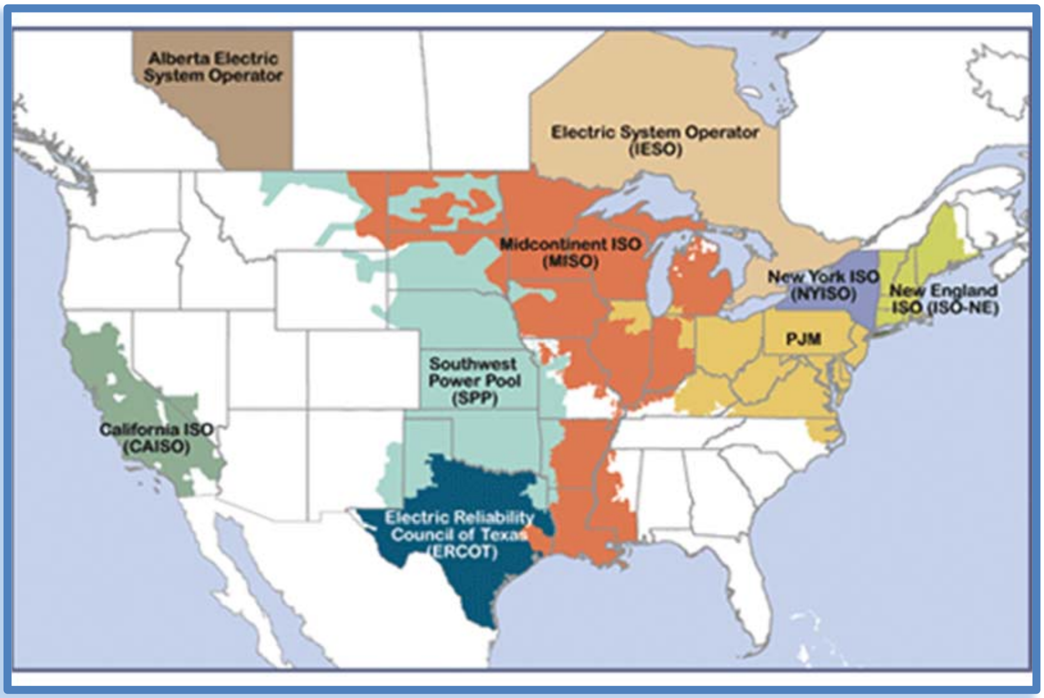
4.4.1 Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) is an independent regulatory arm of the U.S. Department of Energy (DOE). FERC authority derives from the 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 (1) hydroelectric projects on interstate waterways (those not otherwise regulated by other federal entities such as the U.S. Army Corps of Engineers); (2) interstate natural gas pipelines and certain types of gas storage, transmission and wholesale sales of electricity in interstate commerce; and (3) 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 the Tennessee Valley Authority).

Electricity Transmission

FERC jurisdiction over wholesale transmission applies to entities that own, control or operate interstate transmission facilities, primarily IOUs, 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 region of Texas within the Electric Reliability Council of Texas (ERCOT) 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 ERCOT). The North American ISOs and RTOs are shown in Figure 4-8. Regulation of transmission owners outside of an ISO/RTO varies on a case-by-case basis.

Figure 4-8 North American RTOs and ISOs



Source: Federal Energy Regulatory Commission.

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 nondiscriminatory 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 that 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 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 agree 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 (NYISO) is also provided for through a JOA. While PJM and NYISO modified the JOA, PJM believes the enhancements only partially comply with Order 1000. Finally, PJM and the Southeast Regional Transmission Planning (SERTP) entities filed an agreement on planning and cost allocation to meet the Order 1000 provisions. Compliance points were developed by PJM and SERTP stakeholders, and tariff language (rather than a JOA) was filed with FERC.

Various utilities and the National Association of Regulatory Utility Commissioners (NARUC) have sued FERC, arguing that some of the provisions in Order 1000 are beyond FERC's authority. In September 2013, FERC argued before the U.S. Court of Appeals, District of Columbia Circuit that it does 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 NARUC 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.

Although Order 1000 was viewed as a landmark order, it has not produced the expected results. Order 1000 was intended to expand transmission to meet the increase in renewable generation, and while new transmission has come online since the order went into effect, 70 percent of the system is 25 years or older. Therefore, in July 2021, FERC unanimously voted for an advanced notice of a proposed rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection." The proposed rulemaking will explore how long-term regional planning can be improved and how costs associated with network upgrades are allocated.

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 60 hertz (Hz). The other major interconnection is the Western Interconnection. The three minor interconnections are the Québec Interconnection, Alaska Interconnection and Texas Interconnection.

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

ERCOT, Winter Storm Uri and PJM

What Happened?

Winter Storm Uri swept across the U.S. from February 13-17, 2021, bringing severe winter conditions to South-Central states largely unaccustomed to winter weather. Most notably, the Electric Reliability Council of Texas (ERCOT) experienced a record-high peak demand spike of 69.2 GW on February 14, but was left with only 42 GW as the storm caused outages of more than 26 GW of thermal generation (i.e., natural gas, coal and nuclear) due to freezing equipment and fuel, and 17 GW of wind and solar generation due to excessive cloud and snow coverage and a lack of necessary de-icing technologies, respectively. ERCOT was forced to order transmission operators to reduce demand by 16.5 GW, but many distribution utilities could not implement the rotating outages quickly enough and were forced instead to implement widespread blackouts. To make matters worse, the loss of generation meant that there was insufficient "black start" generation to bring some areas back online. As of February 16, approximately 4.9 million Texas customers were without access to power with outages persisting for many customers through February 27. At least 210 people were killed either directly or indirectly from the storm. The deterioration of ERCOT's power supply and demand, as well as natural gas production freeze-offs and increased gas heating demand, had a profound effect on the wholesale power and natural gas prices in the region. Real-time prices in the ERCOT market spiked to a systemwide cap of $9,000/MWh and remained there for many hours during the storm, with prices staying above $2,000/MWh for several days. Typical wholesale power prices generally fall between $20 to $50/MWh during the winter months. On February 17, the index spot price at two natural gas hubs located within the ERCOT footprint, the Katy Hub and the Waha Hub, peaked at over $338 per million British thermal units (MMBtu) and $209/MMBtu, respectively. In comparison, on the same day in 2020, the index spot price peaked at $1.82/MMBtu at the Katy Hub and $0.55/MMBtu at the Waha Hub.

Why Was ERCOT So Badly Impacted?

The neighboring RTOs/ISOs with portions of their grids located in the South-Central states, i.e., the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO), faced similar market conditions but were better able to cope with the extreme operational conditions primarily due to two features of ERCOT's power market. First, ERCOT's transmission grid is located solely within the State of Texas and is not synchronously interconnected to the Western and Eastern Interconnections. Therefore, ERCOT could not bring in enough power to help counteract the loss of generation. Policymakers in Texas have historically limited these ties with the rest of the U.S. in order to avoid federal electric power regulations. Second, ERCOT operates an energy-only, real-time, and day-ahead market construct, meaning that ERCOT relies only on scarcity pricing to provide resource adequacy (i.e., higher energy prices during periods when energy reserves are scarce are what creates an incentive to build generation). Unlike other RTOs/ISOs, ERCOT does not have a forward capacity market to compensate generators that commit to providing available capacity in the future. As such, generators within ERCOT do not have the same incentives to build new plants or guarantee that their facilities will be capable of generating power when they are most needed.

Could a Similar Event Happen In PJM?

For the same reasons that the states in MISO and SPP fared better than Texas during Winter Storm Uri (see above), Maryland, as part of PJM, is better protected against a severe winter weather event than Texas. PJM's capacity market structure rewards generators for being ready to produce at short notice, and generators are both incentivized and required to winterize their plants. Additionally, if power plants in Maryland were to fail, power could be drawn from more than 1,200 facilities across the rest of PJM or elsewhere in the Eastern Interconnection. That said, extreme weather events can happen anywhere, and PJM's power grid is not without its own vulnerabilities. PJM relies on natural gas-fired generation and is therefore at risk for disruptions in the natural gas market. In the "2021 Quarterly State of the Market Report for PJM: January through June," PJM's Market Monitor highlighted a number of issues related to the misalignment of the natural gas and electric markets in PJM that cause concern for fuel security during critical events, including gas pipeline restrictions and limits on gas pipeline flexibility; a lack of a gas RTO/ISO to help ensure reliability; the need for rules in PJM requiring capacity resources to have firm fuel supplies; and the need for current, detailed and complete information on the gas supply arrangements of all generators.

Source: monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021q2-som-pjm.pdf

Hydroelectric and Liquefied Natural Gas

Unless a project has a valid pre-1920 federal permit, nonfederal 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 a U.S. 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 LNG, 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.

4.4.2 The Role of the NRC

Under federal law, the U.S. 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 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' operation, 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 Installation (ISFSI) at the site. These licenses have finite periods, with the Calvert Cliffs facility receiving a license extension to 2034 for Unit 1 and 2036 for Unit 2, and through November 2052 for the ISFSI. 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.

4.4.3 The Role of the Environmental Protection Agency

Regarding generation, the U.S. Environmental Protection Agency (EPA) issues laws and regulations affecting air, waste and water, as well as ensures compliance with standards such as those regulating the disposal of coal combustion residuals (coal ash). Laws and regulations enforced by the EPA include the Clean Power Plan (see Section 5.1.5), Cross-State Air Pollution Rule (CSAPR), National Emission Standards for Hazardous Air Pollutants (NESHAP), 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 Clean Air Act (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 (NAAQS) 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 (see Chapter 1). The CPCN serves as the air quality permit to construct the proposed project, including PSD and NA-NSR permits. PPRP conducts a comprehensive review in coordination with the Maryland Department of the Environment (MDE) to provide consolidated recommendations and CPCN licensing conditions to the PSC. 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 CAA 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 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 EPA Region III.

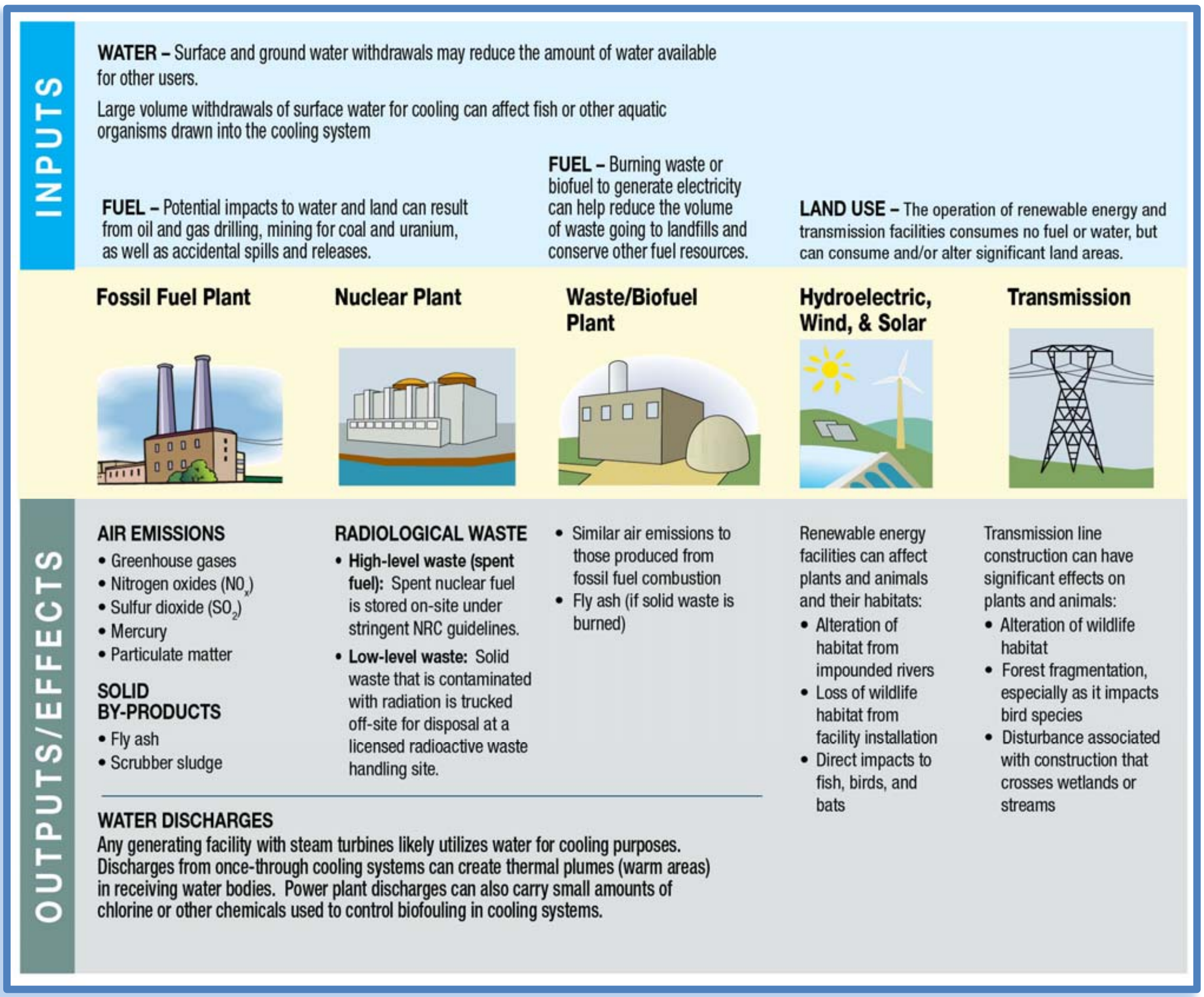
The CWA, enacted in 1948, regulates the discharge of pollutants in water throughout the United States and established standards for water quality. Under the CWA, the EPA has enacted pollution control programs and standards for the electric generation industry. For example, Section 316(b) of the CWA required the EPA to issue regulations regarding the design and operation of cooling water intake structures (see Section 5.2.2). 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 groundwater, blowing of containments in the air and reporting requirements. The rule also supports responsible recycling of CCR.

Chapter 5 – 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 socioeconomic impacts associated with the construction, operation and maintenance of these facilities.

This chapter describes each of these impact areas in some detail and discusses the Power Plant Research Program's (PPRP's) efforts to better understand the magnitude of these impacts in Maryland and how they can be mitigated, minimized and managed. Controlling the amount of electrical energy Marylanders use, and the amount of fuel consumed to generate that electricity, is also critical to reducing adverse environmental impacts. Other chapters of this report provide more information on how Maryland is promoting energy efficiency and the development of more sustainable energy sources. The figure below illustrates some of the primary environmental impacts associated with electricity generation and transmission in Maryland



5.1 Impacts on Air Quality

5.1.1 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 was passed in 1963, but Congress first approached air pollution issues in the mid-1950s with the passage of the Air Pollution Control Act of 1955. In the Clean Air Act Amendments of 1965, Congress divided regulation of air pollution into two titles, one to address pollution prevention in general, and one to address mobile sources. The first law to resemble air quality rules as we know them today was the Clean Air Act Amendments of 1970. These Amendments provided the framework for air quality regulation in the United States that remains in effect today. Importantly, these Amendments differentiated areas of the country with relatively good air quality (those meeting established ambient standards, known as "attainment" areas) from those with relatively poor air quality (known as "nonattainment" areas) and created different rules to regulate air pollution in these different areas. Congress again passed significant amendments to the CAA in 1977, which established increasingly stringent requirements on new and existing sources. Even with the more stringent requirements included in the 1977 Amendments, many areas of the country continued to have trouble meeting the National Ambient Air Quality Standards (NAAQS). Despite this fact, Congress stalled the development of new air quality legislation at the federal level for many years, until it passed the Clean Air Act Amendments of 1990.

Among other issues, the Amendments of 1990 addressed what Congress saw as four significant threats to the health and welfare of Americans, all of which have affected power plants and other sources of air pollution:

- Acid rain and regional haze (Title IV of the CAA) – For the first time, required cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions from fossil fuel-fired power plants to prevent acidic deposition and improve visibility. Title IV of the 1990 CAA Amendments established the first "cap and trade" program for SO_2 emissions designed to use market forces and pollutant trading to drive pollution control.

- Toxic or hazardous air pollution (Title III of the CAA) – Identified 189 Hazardous Air Pollutants (HAPs) and, for the first time, established control technology-based standards for various types of sources, most requiring at least 95 percent reduction in HAP emissions.

- Urban air pollution (Title I of the CAA) – In addition to the new toxics provisions, greatly expanded the number and types of pollutants and sources subject to regulation to address persistent "ozone smog" pollution in most metropolitan areas.

- Stratospheric ozone depletion (Title VI of the CAA) – Identified and regulated, for the first time, ozone-depleting substances (ODS) and provided a framework for U.S. participation in the "*1987* Montreal Protocol on Substances that Deplete the Ozone Layer."

The Six Criteria Pollutants

Fossil fuel-fired power plants emit most of the six criteria pollutants for which the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS). The criteria pollutants 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 "NOx" and is primarily composed of nitric oxide (NO) and NO_2. NOx 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 NOx and VOCs react in the presence of sunlight and elevated temperatures.

Since the early days of air quality management in the U.S., regulators have based many air quality rules and regulations on the NAAQS that the CAA authorized the U.S. Environmental Protection Agency (EPA) to develop. EPA established NAAQS, which represent the maximum pollutant concentrations that are allowable in ambient air for six common air pollutants (referred to as the "criteria" pollutants). "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 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 5-1 lists the current NAAQS.

Table 5-1 National Ambient Air Quality Standards as of August 2021

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 hour	35 ppm	
Lead (Pb)	Primary and Secondary	Rolling 3-month average	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)	Annual mean.
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, averaged over 3 years.
	Secondary	1 year	15.0 µg/m^3	Annual mean, averaged over 3 years.
	Primary and Secondary	24 hours	35 µg/m^3	98th percentile, averaged 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.

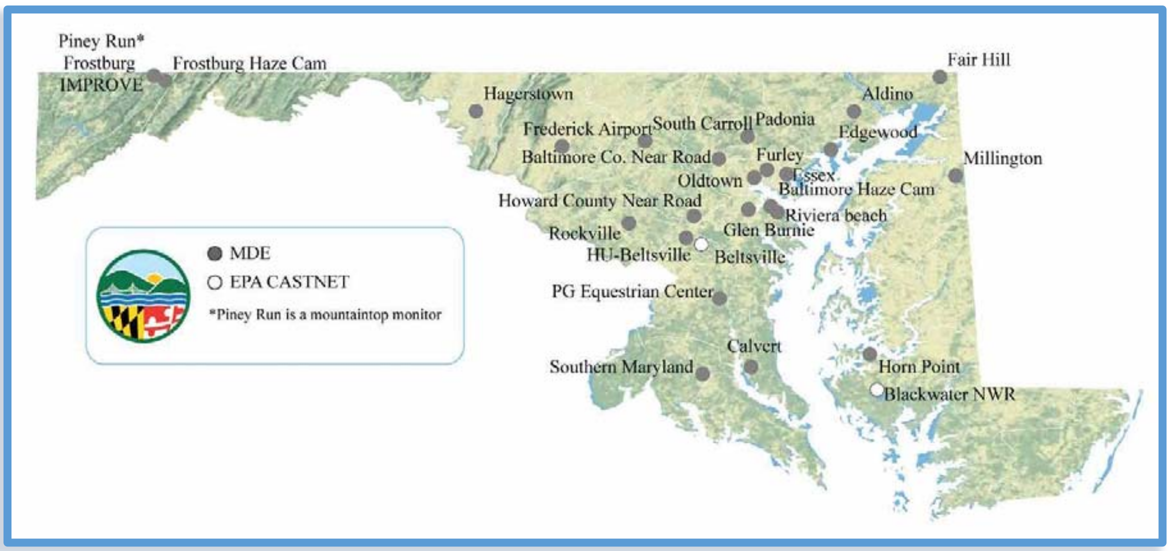
Source: United States Environmental Protection Agency, "National Ambient Air Quality Standards." Reviewing National Ambient Air Quality Standards – Scientific and Technical Information. epa.gov/criteria-air-pollutants/naaqs-table, last accessed August 20, 2021.

ppm - parts per million
ppb – parts per billion
mg/m^3 - milligram per cubic meter
µg/m^3 - 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/m^3 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. Additionally, some areas may have certain continuing implementation obligations under the prior revoked 1-hour (1979) and 8-hour (1997) O_3 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 one 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 SIP to demonstrate attainment of the required NAAQS.

Across the country, EPA, state and local regulatory agencies monitor concentrations of the criteria pollutants near ground level. The Maryland Department of the Environment's (MDE's) Ambient Air Monitoring Program handles ambient monitoring in Maryland. Figure 5-1 presents the locations of ambient air monitoring stations in Maryland. In addition to the ambient air monitoring stations operated by MDE, two Clean Air Status and Trends Network (CASTNET) sites are located in Maryland: Blackwater National Wildlife Refuge and Beltsville. CASTNET is a long-term environmental monitoring network with 90 sites located throughout the U.S. and Canada. CASTNET was established under the 1990 CAA Amendments to assess trends in acidic deposition due to emission reduction programs such as the EPA's Acid Rain Program.

Figure 5-1 Ambient Pollutant Monitoring Stations in Maryland



Source: Maryland Department of the Environment, Ambient Air Monitoring Network Plan for Calendar Year 2022, May 11, 2021, mde.maryland.gov/programs/Air/AirQualityMonitoring/Documents/MDNetworkPlanCY2022.pdf. Last accessed January 24, 2022.

EPA makes attainment/nonattainment designations for any area of the country 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 regulators base many air regulatory requirements in part on whether a source is located in an attainment area, where emissions must be limited to ensure the air quality remains 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.

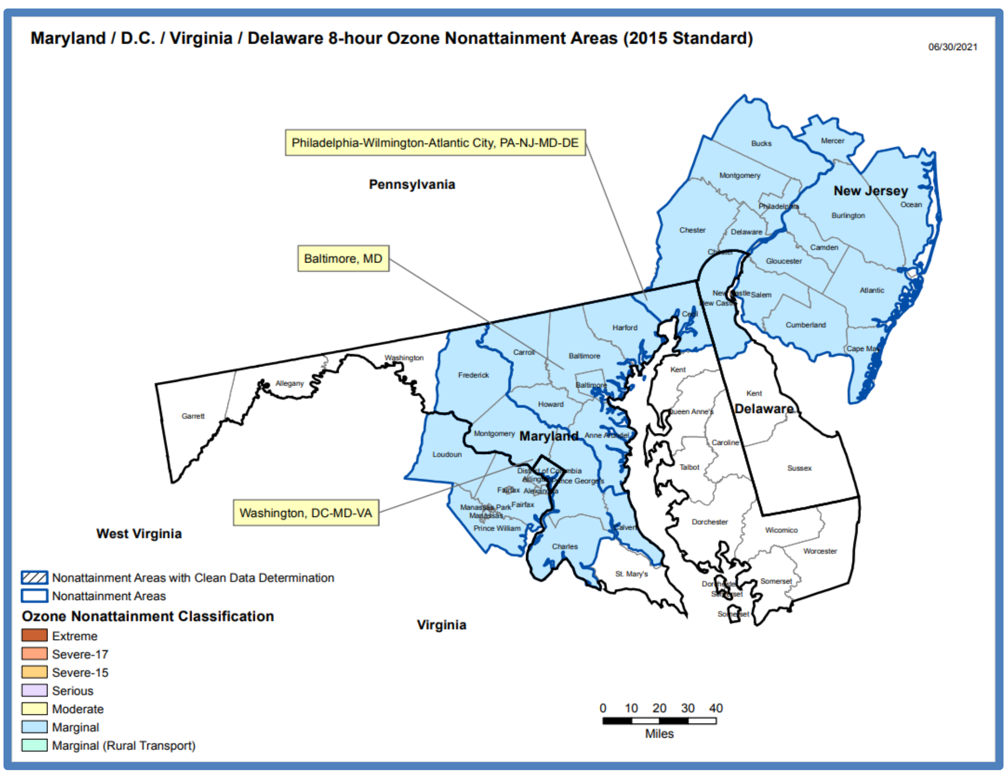
Currently, all of Maryland is in attainment with the NAAQS for most of the criteria pollutants (NO_2, $PM_{2.5}$, PM_{10}, CO, and lead). On December 14, 2012, EPA lowered the fine particulate matter NAAQS by revising the primary annual $PM_{2.5}$ standard to 12 micrograms per cubic meter ($\mu g/m^3$) from 15 $\mu g/m^3$ and retaining the 24-hour fine particle standard of 35 $\mu g/m^3$. All of Maryland is currently in attainment with the 2012 standard.

In June 2016, EPA designated areas in Anne Arundel and Baltimore counties as nonattainment for the 2010 1-hour SO_2 NAAQS. This nonattainment designation was based in part on air quality modeling of SO_2 emissions from the Wagner and Brandon Shores power plants, which are located south of Baltimore in Anne Arundel County. Under the June 2016 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. On October 1, 2015, a new 8-hour ozone NAAQS of 0.070 parts per million (ppm) went into effect. Effective August 3, 2018, EPA designated three areas as "marginal" nonattainment with respect to the 2015 ozone NAAQS: the Baltimore, Philadelphia and Washington, D.C. regions. As a result, these three areas must reach attainment status within three years of their designation or voluntarily reclassify to a higher nonattainment category. The latter approach would lead to a required attainment plan from the State of Maryland to the EPA outlining how attainment will be achieved.

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 1990 CAA Amendments created the Northeast Ozone Transport Region (OTR), comprised of 12 states (including Maryland) and the District of Columbia to address the regional nature of ozone pollution. 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 only the central portion of the state is in nonattainment. Figure 5-2 depicts current 8-hour ozone nonattainment area designations in Maryland.

Figure 5-2 Ozone Nonattainment Areas in Maryland (2015 Standard)



Source: U.S. Environmental Protection Agency, "Maryland/ D.C./Virginia/Delaware 8-hour Ozone Nonattainment Areas (2015 Standard)," epa.gov/airquality/greenbook/mddcvade8_2015.html. Last accessed August 20, 2021.

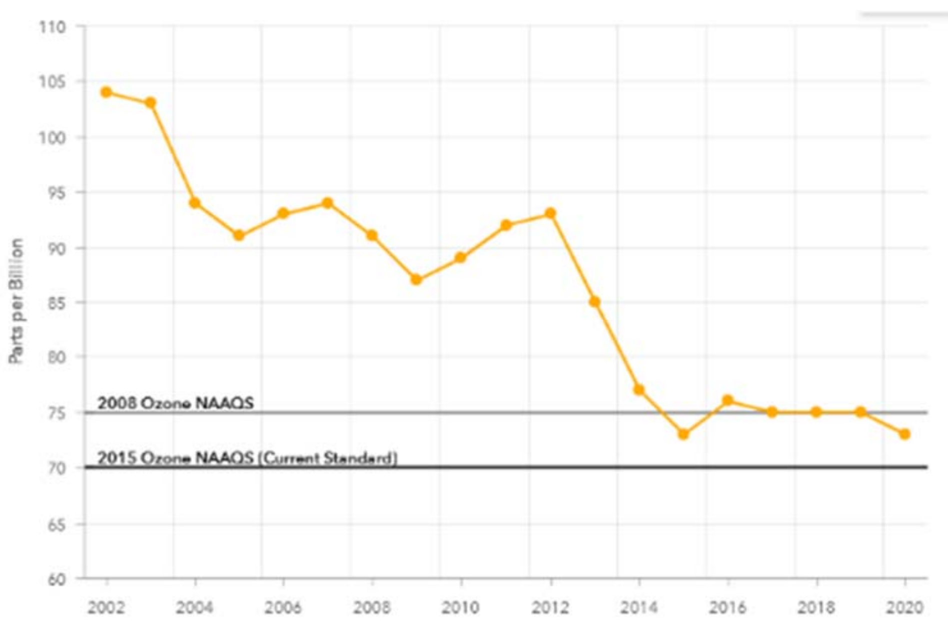
EPA routinely evaluates the NAAQS to determine whether more stringent or different standards are warranted. The most recent update to the NAAQS was the 8-hour ozone standard in October 2015.

While the NAAQS themselves do not directly affect stationary sources, lowering the ambient air 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 statewide. This, in turn, likely means additional regulation at the state level of air emission sources in Maryland and throughout the United States.

Maryland Clean Air Progress

According to the MDE 2021 *Maryland Clean Air Progress Report*, Maryland is in compliance with five out of six criteria pollutant standards. Particle levels in the state have continued to trend down each year since 2010 and are well below the annual and daily standards. Additionally, although Maryland has one area designated as nonattainment for SO_2, current measurements are showing concentrations well below the standard. Ground-level ozone has been Maryland's most challenging air pollution problem for the past 30 years; however, there has been progress. Maryland has recently met the 2008 ozone standard, but has not yet been able to comply with the more stringent 2015 ozone standard. Maryland continues to reduce NOx emissions from industry and mobile sources, but has been unable to achieve the 2015 ozone standard due to NOx emissions and transported air pollution from other states. The figure below illustrates Maryland's progress in reducing ozone concentrations over the last 19 years. In 2020, Maryland recorded the fewest number of "bad" ozone days ever recorded.

Maryland Ozone Design Values



Source: Maryland Clean Air Progress Report 2021, storymaps.arcgis.com/stories/728245a96a1e4fce827cedc38a8a9b42.

5.1.2 Emissions from Power Plants

Power plants in the U.S. are a major source of air emissions. However, according to the report "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" (based on the July 2021 update),[101] emissions of SO_2, NOx, carbon dioxide (CO_2) and mercury have all decreased significantly in recent years. Power plant emissions of SO_2 and NOx were 95 percent and 88 percent lower, respectively, than in 1990 when the Clean Air Act amendments were passed, mercury emissions were 92 percent lower than they were in 2000, and CO_2 emissions decreased by 40 percent from their peak in 2007. Overall trends in electric generation show a displacement of coal by natural gas and renewable energy sources, influencing the observed decrease in emissions over time.

Air emissions are often discussed in terms of three classes of pollutants: criteria pollutants, hazardous air pollutants (HAPs) and greenhouse gases (GHGs). The following 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, NOx and PM Emissions

Of the criteria pollutants, SO_2 and NOx emissions from power plants 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. Particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) are also pollutants of concern as EPA has recognized that airborne particulate matter is associated with adverse health effects, including premature mortality, cardiovascular illness and respiratory illness. EPA continually attempts to understand better 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 $PM_{2.5}$.

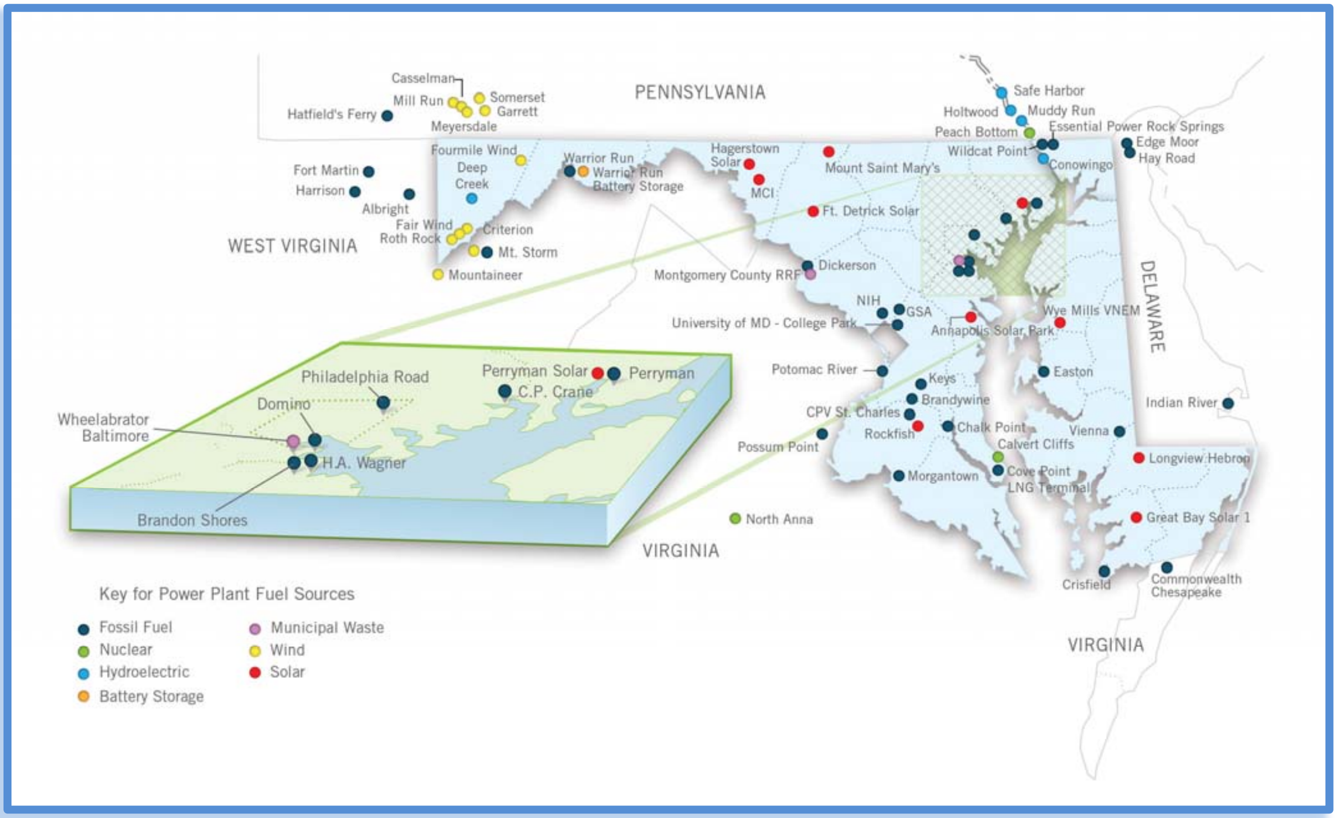
Emissions of SO_2, PM_{10} and $PM_{2.5}$ are dependent on the types and amounts of fuel combusted at each generating unit; the type, age and configuration of the generating units; and the type, age and efficiency of their associated air pollution control equipment. Most coal-fired power plants in Maryland have installed state-of-the-art pollution control systems to meet requirements of the 2007 Maryland Healthy Air Act (HAA), which were required by a federal deadline of 2010. MDE has regulated NOx emissions more stringently and for a longer period than SO_2 and particulates, so there was a less remarkable decrease in NOx with the implementation of the HAA beginning in 2009 and 2010. NOx emissions from power plants have declined in recent years due to the installation of control equipment including selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) and due to process changes. MDE's "emergency NOx" regulation approved May 1, 2015 reduced ozone season NOx emissions in 2015. The final version of the regulation that was promulgated in December 2015 established additional requirements to further reduce summertime ozone formation by establishing more stringent NOx emission requirements. This regulation may be contributing to some of the trends in NOx

[101] "M.J. Bradley & Associates. Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States 2021. ceres.org/resources/reports/benchmarking-air-emissions-100-largest-electric-power-producers-united-states-2021, last accessed August 20, 2021.

reductions that were seen in Maryland through 2017 for coal-fired power plants. Section 5.1.4 describes in detail the implications for regulations with respect to Maryland's coal-fired power plants.

Figure 5-3 shows the type and location of the 42 electric generating facilities operating in Maryland as of May 2021. Power plant emissions in Maryland mostly come from natural gas, petroleum, biomass and coal-fired plants. With the slated retirement of the Morgantown coal-powered plant by June 2022, Maryland will be left with three coal-fired power plants in operation. Two of those three are scheduled to retire in October 2025.

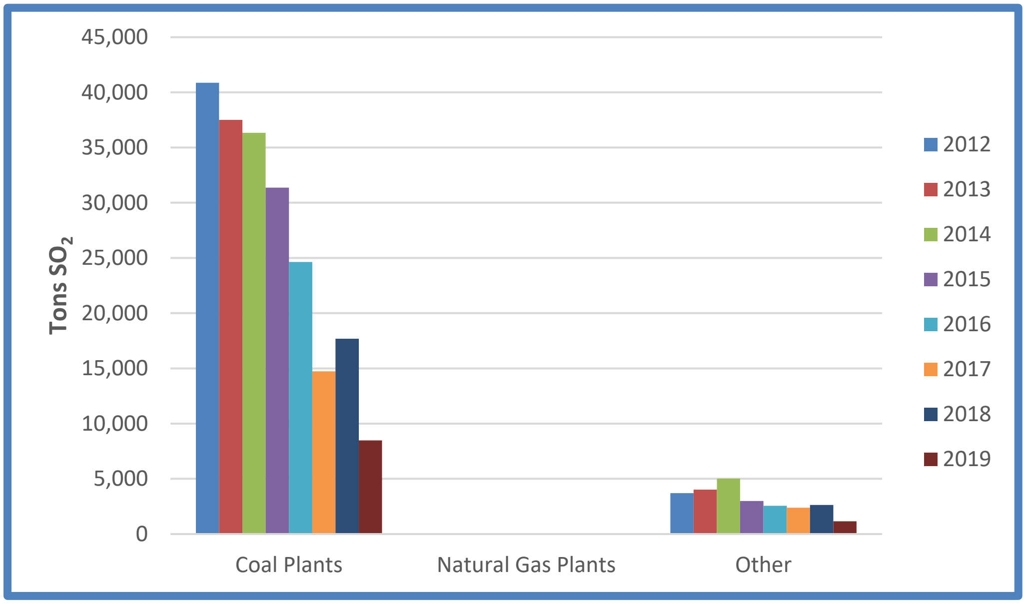
Figure 5-3 Maryland Power Plants by Generation Type



Note: The coal-fired C.P. Crane facility in Baltimore County ceased operation in May 2018; the owner has received a Certificate of Public Convenience and Necessity (CPCN) to construct and operate a new 160 MW natural gas-fired facility at the existing site. Coal-fired units Dickerson and Chalk Point were decommissioned in August 2020 and June 2021, respectively.

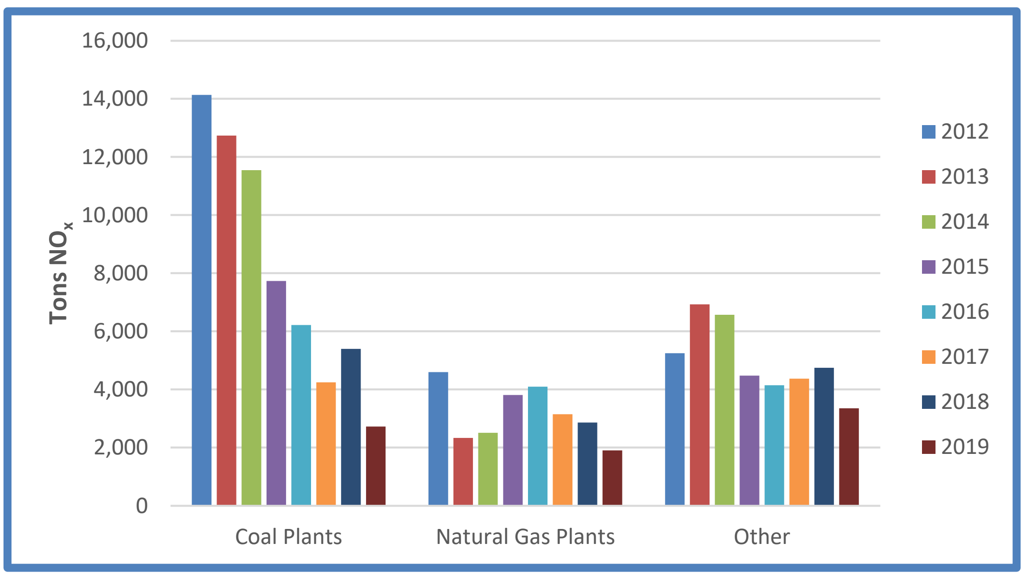
Trends in SO_2 and NOx emissions from generating units in Maryland of different fuel types are shown in Figure 5-4 and Figure 5-5, respectively. Coal-fired power plants in Maryland dominate the annual SO_2 emissions, as typical coal being used in Maryland contains about 2 percent sulfur by weight. SO_2 emissions in Maryland have decreased over time as generators took steps to comply with Maryland's HAA and with the addition of flue-gas desulfurization (FGD) technology installed at Maryland's coal-fired power plants. SO_2 and NOx emissions from coal-fired power plants have also decreased as the power sector continues to move away from coal and towards natural gas and renewable energy sources.

Figure 5-4 Annual SO_2 Emissions by Power Plant Type in Maryland



Source: Emissions reported in Maryland Electricity Profile 2019, md.xls, eia.gov/electricity/state/maryland/index.php, last accessed August 20, 2021.

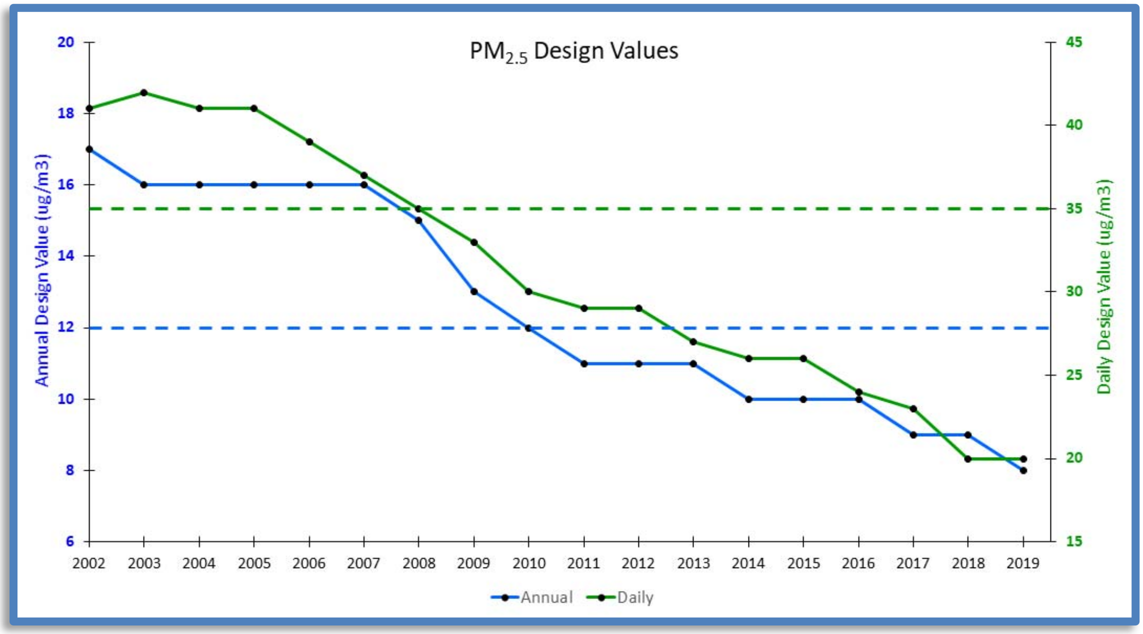
Figure 5-5 Annual NOx Emissions by Power Plant Type in Maryland



Source: Emissions reported in Maryland Electricity Profile 2019, md.xls, eia.gov/electricity/state/maryland/index.php, last accessed August 20, 2021.

Power plants are required by federal and state regulations to monitor NOx and SO_2 emissions continuously and report those emissions publicly. Most plants are not required to monitor and report $PM_{2.5}$ emissions in the same manner, so $PM_{2.5}$ emissions data from power plants are not readily available. Figure 5-6 shows annual ambient $PM_{2.5}$ concentrations (rather than emissions) across Maryland over the last 18 years as reported in the "Maryland Clean Air 2019 Progress Report." $PM_{2.5}$ concentrations in Maryland have decreased steadily in recent years because recent regulations have required significant reductions in $PM_{2.5}$ precursor emissions (SO_2 and NOx), particularly from coal-fired power plants.

Figure 5-6 Annual and Daily Ambient $PM_{2.5}$ Design Values in Maryland



Source: Maryland Clean Air Progress Report 2021, storymaps.arcgis.com/stories/728245a96a1e4fce827cedc38a8a9b42.

Hazardous Air Pollutant Emissions

In 1990, the U.S. 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.[102] 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.

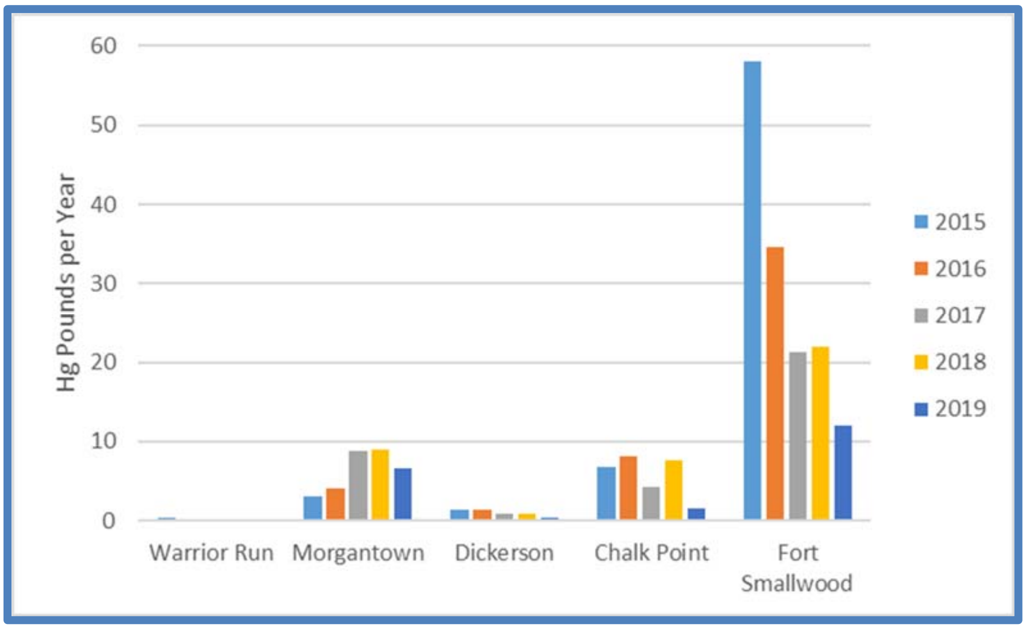
Although fossil fuel-fired power plants emit HAPs, chemical plants and petroleum refineries that use and emit highly toxic compounds have historically been considered more significant sources of air toxics than power plants. Before the CAA Amendments of 1990, EPA regulations did not apply to HAP emissions from power plants, and even with the 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. EPA's Mercury and Air Toxics Standards (MATS), promulgated in 2011, regulate HAP emissions from power plants. Section 5.1.4 further discusses recent MATS developments.

[102] On June 11, 2021, EPA issued an Advanced Notice of Proposed Rulemaking (86 FR 31225) in order to add 1-bromopropane (1-BP) to the Clean Air Act's list of hazardous air pollutants by the end of 2021.

Among the HAPs emitted by power plants, mercury is a pollutant of particular concern because of its significant adverse health effects.[103] Figure 5-7 presents annual emissions of mercury from Maryland's coal-fired power plants from 2015 through 2019 as reported in EPA's Toxics Release Inventory (TRI) for each facility. As illustrated in Figure 5-7, mercury emissions from Maryland's power plants show reductions in the most recent two years available, especially for Chalk Point and Fort Smallwood.

Hydrochloric acid (HCl) is a HAP emitted in large quantities from coal- and oil-fired power plants. HCl is an "acid gas" like SO_2, so the pollution controls for SO_2 installed at coal plants in response to the Maryland HAA also reduced HCl emissions. Also, coal units at both the H.A. Wagner (which is included in "Fort Smallwood" in Figure 5-7) and C.P. Crane facilities installed dry sorbent injection (DSI) in 2015 in response to the MATS to control HCl. C.P. Crane's coal units ceased operation in May 2018.

Figure 5-7 Annual Mercury Emissions from Coal-Fired Power Plants in Maryland



Notes: Emissions reported in EPA's Toxics Release Inventory. As of August 20, 2021, the mercury emissions data are only available through 2019. Fort Smallwood consists of the combined Brandon Shores and H.A. Wagner generating stations.

Maryland is also home to two waste-to-energy incinerators. While these incinerators are considered renewable energy plants in Maryland's Renewable Energy Portfolio Standard (RPS), they produce significantly more criteria pollutant and HAP emissions than the other types of renewable power sources.

[103] Environmental Health & Engineering, "Emissions of Hazardous Air Pollutants from Coal-fired Power Plants, csu.edu/cerc/researchreports/documents/EmissionsOfHazardousAirPollutantsFromCoal-FiredPowerPlants2011.pdf, last accessed August 20, 2021.

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). Section 5.1.5 describes the status of recent federal GHG regulations. The principal GHGs that enter the atmosphere due to human activities are described below.

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 the 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.

Figure 5-8 presents CO_2 emissions from fossil-fuel fired power plants in Maryland for 2012-2019. Power plants do not have add-on CO_2 pollution control systems, so GHG emissions are generally a direct result of the amount of fuel burned, thus fluctuations in annual GHG emissions are largely a result of changes in fuel consumption caused by power demand. These annual GHG emissions data show a decrease in coal and an increase in natural gas generation over time.

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). GWP 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, they absorb much more energy than CO_2. The GWP reflects both the net effect of the shorter lifetime and higher energy absorption. 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. EPA's "Major Long-Lived Greenhouse Gases and Their Characteristics" table below shows the GHG average lifetime and the 100-year GWP of individual compounds.

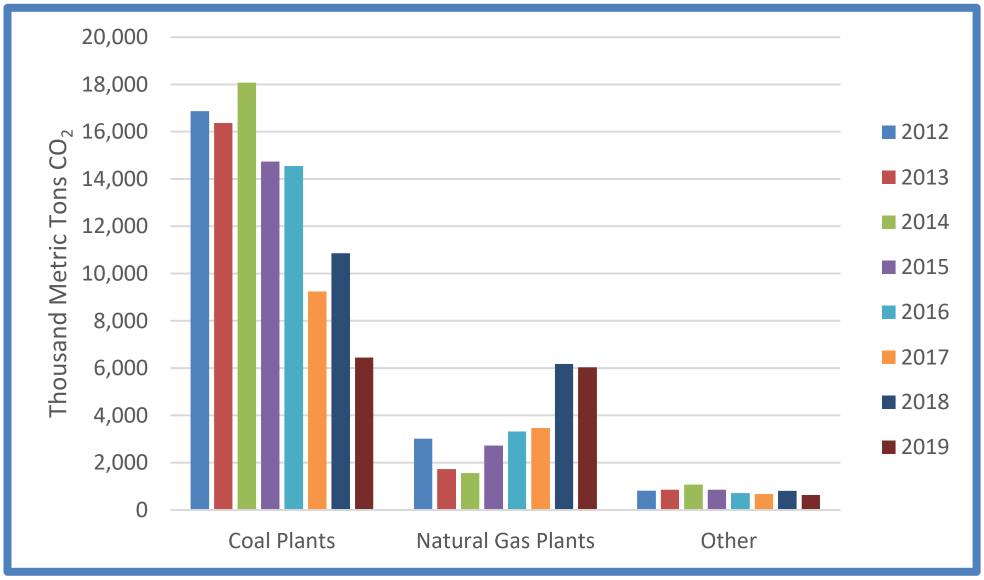
Greenhouse gas	How it's produced	Average lifetime in the atmosphere	100-year global warming potential
Carbon dioxide	Emitted primarily through the burning of fossil fuels (oil, natural gas and coal), solid waste, and trees and wood products. Changes in land use also play a role. Deforestation and soil degradation add carbon dioxide to the atmosphere, while forest regrowth takes it out of the atmosphere.	see below[1]	1
Methane	Emitted during the production and transport of oil and natural gas as well as coal. Methane emissions also result from livestock and agricultural practices and from the anaerobic decay of organic waste in municipal solid waste landfills.	12.4 years[2]	28–36
Nitrous oxide	Emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste.	121 years[2]	265–298
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)

[1] Carbon dioxide's lifetime cannot be represented with a single value 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 is 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.

[2] The lifetimes shown for methane and nitrous oxide are perturbation lifetimes, which have been used to calculate the global warming potentials shown here.

Source: epa.gov/climatechange/science/indicators/ghg/ Climate Change Indicators: Greenhouse Gases. EPA Climate Change, last accessed August 20, 2021.

Figure 5-8 Annual CO_2 Emissions by Power Plant Type in Maryland



Notes: Emissions reported in Maryland Electricity Profile 2019, md.xls, eia.gov/electricity/state/maryland/index.php, last accessed August 20, 2021.

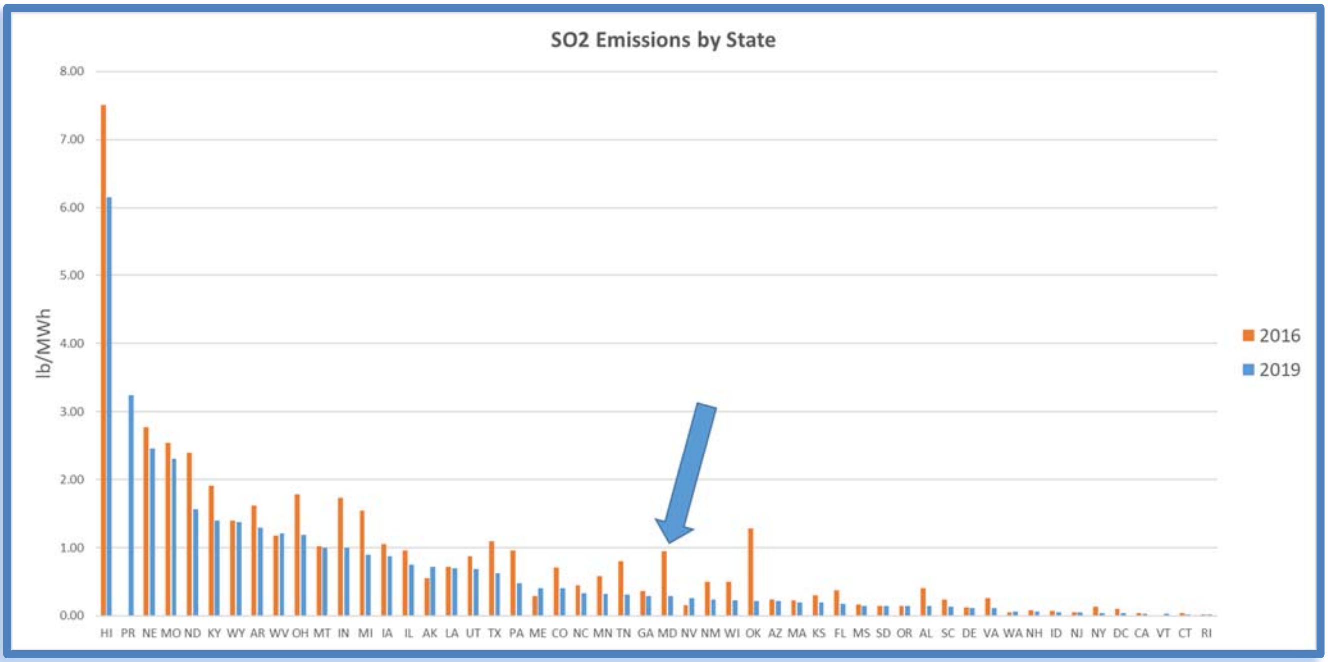
Maryland Power Plant Emission Rates Relative to Other States

To put Maryland's power plant emissions in perspective, Figure 5-9 and Figure 5-10 present a comparison of SO_2 and NOx emission rates from all power plants in Maryland with emission rates from power plants in other states for the years 2016 and 2019. These figures represent the emission rates (in pounds per megawatt-hour of electricity generated) from the lower 48 states as reported in EPA's Air Markets Program Data (AMPD).

As seen in Figure 5-9, SO_2 emission rates from Maryland's power plants are comparable to the nationwide median. Although SO_2 emission rates declined from 2016 to 2019, the rate at which they declined was faster in comparison to the decline of SO_2 emission rates in most other states.

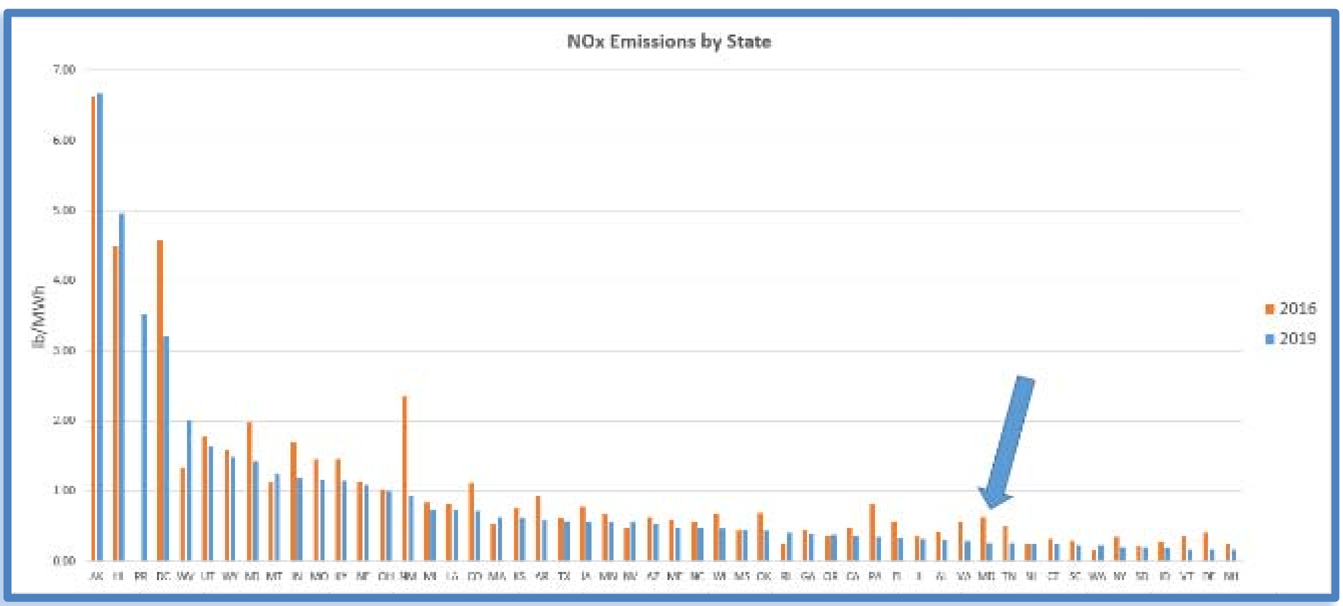
NOx emission rates from Maryland power plants were around the nationwide median in 2016 and declined in 2019 to a lower emission rate than most other states (see Figure 5-10). This decrease in NOx emissions is likely due to the move away from coal-fired power plants and toward the lower NOx-emitting natural gas-fired plants, as well as the installation of control equipment such as SCR and SNCR.

Figure 5-9 SO_2 Emission Rates from Maryland Power Plants Compared to SO_2 Emissions from Plants in Other States



Note: Emissions reported at epa.gov/egrid/data-explorer, last accessed August 20, 2021.

Figure 5-10 NOx Emission Rates from Maryland Power Plants Compared to NOx Emissions from Plants in Other States



Note: Emissions reported at epa.gov/egrid/data-explorer, last accessed August 20, 2021.

5.1.3 Impacts from Power Plant Air Emissions

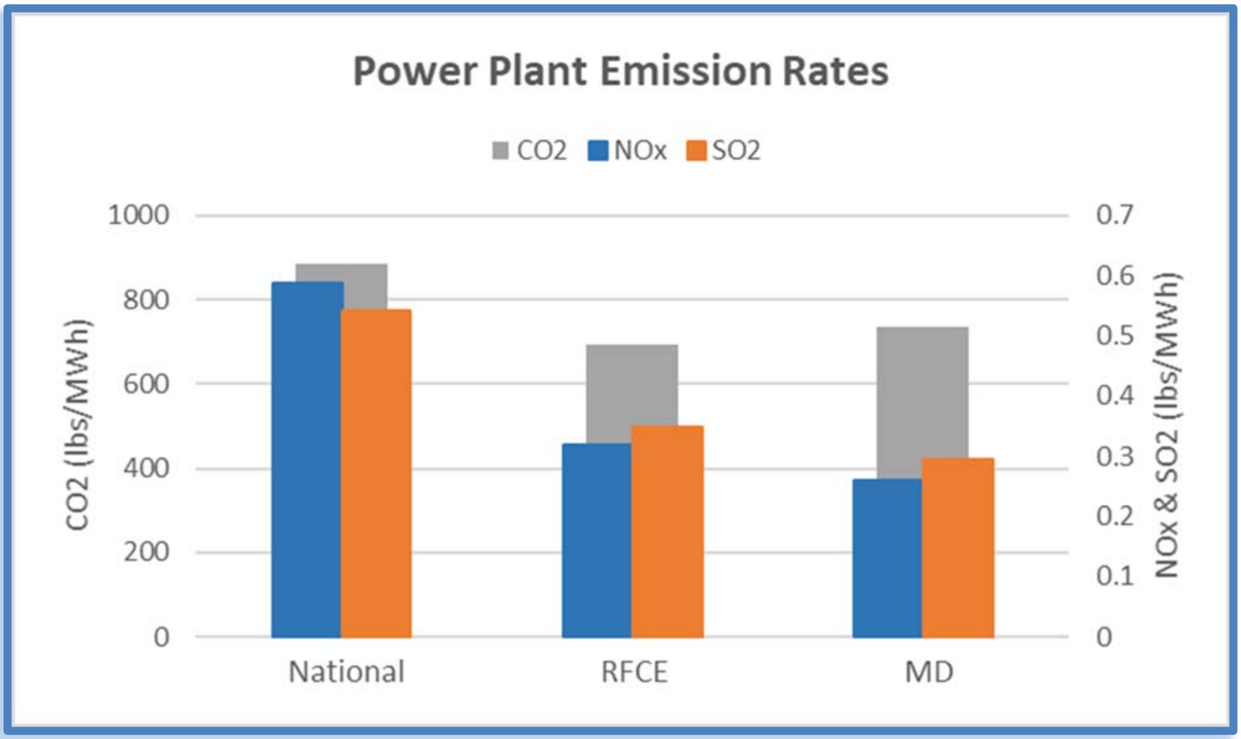
Impacts from Out-of-State Emissions

While this report has thus far analyzed emissions from power plants located in the State of Maryland, emissions may also be transported from sources located outside of the state. MDE estimates that up to 70 percent of ozone and fine particle air pollution in Maryland originates in upwind states.[104] EPA's "good neighbor" provision, Section 126 of the Clean Air Act, addresses the issue of interstate pollution transport by requiring each state to manage emissions that may significantly contribute to NAAQS violations in a downwind state in its State Implementation Plan (SIP). If the state does not resolve the issue, then the EPA may step in on its own or at the state's request. On November 16, 2016, the State of Maryland submitted a petition to the EPA over ozone nonattainment concerns due to NOx contributions from out-of-state sources. More specifically, the petition cites 36 power plants in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia as significant contributors of upwind NOx emissions. The EPA denied Maryland's petition in a decision that was published in the Federal Register on October 5, 2018. The State of Maryland submitted a petition for judicial review to the U.S. Court of Appeals on October 12, 2018. In a ruling dated May 19, 2020, the Court required EPA to reconsider its denial of part of Maryland's petition that requests further reductions from coal-fired power plants equipped with selective non-catalytic reduction controls.[4]

Maryland may also be connected to out-of-state emissions because of its import of electricity from the PJM Interconnection LLC (PJM) grid. As mentioned in Section 3.4, Maryland's consumption of electricity has historically exceeded the amount of energy generated within the state. Out-of-state resources through PJM help to provide a lower-cost resource to meet electricity consumption needs. Maryland's reliance on out-of-state power plants raises interest in the emissions from these facilities. An online EPA tool provides a comparison of average emission rates for the Reliability First Corporation East (RFCE) eGRID region, which covers most of the PJM domain, with the national average emission rates. These emission rates are compared with the average emission rates from power plants in Maryland in Figure 5-11. This figure helps to show that energy imported into Maryland is likely associated with relatively greater NOx and SO_2 emissions and lower CO_2 emissions.

[104] Maryland Department of the Environment, 2021 Clean Air Progress Report, mde.maryland.gov/programs/Air/Pages/AirQualityReports.aspx.

Figure 5-11 Average Power Plant Emission Rates

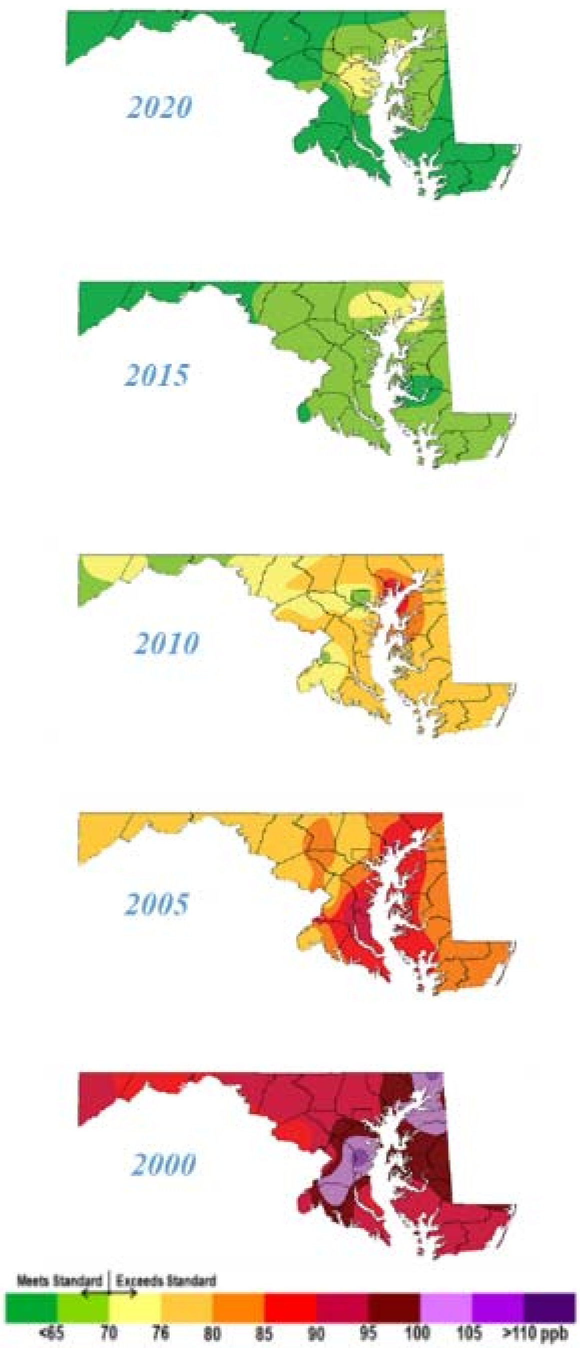


Source: epa.gov/egrid/data-explorer, last accessed August 20, 2021.

Ozone

The persistent ozone "smog" problem in many areas of the country has been one of the most important drivers for the regulation of power plant NOx emissions over the past two decades. Ozone exists naturally in the upper levels of the atmosphere (from six 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. Sources do not emit ozone directly into the atmosphere in significant amounts, but ozone instead forms through chemical reactions in the atmosphere. Ground-level ozone is formed when the precursor compounds—NOx from both mobile and stationary combustion sources (such as automobiles and power plants, respectively) and volatile organic compounds (VOCs) from industrial, chemical, and petroleum facilities and 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 longer and the sun's rays are more direct.

Figure 5-12 Maryland's Ozone Trend – 2000-2020



Source: MDE Report on the Environment, "Clean Air Progress Report 2019," mde.maryland.gov/programs/Air/Documents/GoodNewsReport/GoodNews2019.pdf.

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 NOx emissions during the summer months. Maryland's ozone season extends from April through October.

Ground-level ozone has the potential to cause adverse health effects on humans. Breathing air with high ozone concentrations can cause chest pain, throat irritation and congestion; it can also worsen preexisting conditions like emphysema, bronchitis and asthma. Children and the elderly are especially vulnerable to health problems caused by ground-level ozone. Action in 2015 by EPA reduced the level of ozone standard (8-hour) from 75 parts per billion (ppb) to 70 ppb, introducing additional challenges for states including Maryland to develop a plan to achieve the standard. Maryland is required to comply with this standard by August 3, 2021 (for areas designated marginal, three years after the effective date of the NAAQS designation). Currently, there are many areas of Maryland that are still designated as marginal nonattainment for 2015 ozone NAAQS (40 CFR §81.321). Figure 5-12 shows the positive trend in ozone concentrations in Maryland over the last 20 years.

Since the mid-1990s, there have been a series of federal NOx reduction regulations, implemented at the state level, that have resulted in significant reductions in summertime ("ozone season") emissions of NOx from power plants in Maryland and surrounding states. One of the most significant, referred to as the "NOx SIP Call" because it called for affected states to update their SIPs to address ozone issues, is based on a NOx cap-and-trade program that allows sources to acquire "allowances" to emit a certain quantity of pollutants. Sources can reduce emissions or purchase allowances from other plants that have reduced emissions below their caps. In some states, including Maryland, emissions exceeded statewide NOx allocations for many years in the first decade of the 2000s, meaning that some plants in these states were buying NOx allowances rather than reducing plant-level NOx 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. Maryland's Healthy Air Act led to the installation of controls for some of Maryland's largest power plants. NOx reductions were further aided by Maryland's 2015 NOx regulation for coal-fired power plants. Of the major coal-fired plants in Maryland, all have installed SCR, SNCR or Selective Auto Catalytic Reduction (SACR) technology.[105] The NOx SIP Call requirements were replaced by the Clean Air Interstate Rule in 2005. Maryland is currently subject to the Cross-State Air Pollution Rule that was promulgated in 2011 and recently revised in April 2021 (see discussion below).

CAMNET Visibility Haze Cams

Regional haze cameras (haze cams) have been set up as part of CAMNET, a project of the Northeast States for Coordinated Air Use Management (NESCAUM) to evaluate the effects of air pollution on visibility. Maryland has haze cams located in Baltimore and Frostburg. The Baltimore haze cam provides an enhanced wide angle view of the Francis Scott Key Bridge and Baltimore City. The Frostburg haze cam is positioned on top of a mountain peak and provides a view towards the northeast across Maryland and into the Mt. Davis area of Pennsylvania. The CAMNET website, hazecam.net, provides real-time images every 15 minutes. The photo below is from the Baltimore haze cam.

Source: hazecam.net/. "Realtime Air Pollution & Visibility Monitoring."

Visibility and Regional Haze

Fine particulate matter, or $PM_{2.5}$, consists of particles 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 NOx emitted from fossil fuel combustion.

[105] Maryland Department of the Environment, Technical Support Document for COMAR 26.11.38 – Control of NOx Emissions from Coal-Fired Electric Generating Units, May 2015, mde.maryland.gov/programs/Regulations/air/Documents/TSD_Phase1_with_Appendix.pdf.

Aside from $PM_{2.5}$, or fine particulates, certain gases and larger particles can also interfere with visibility. 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. Figure 5-13 shows the location of Class I areas near Maryland. Since 1988, EPA and other agencies have been monitoring visibility in these areas.

Figure 5-13 Designated Prevention of Significant Deterioration (PSD) "Pristine" Areas near Maryland

Source: U.S. Environmental Protection Agency, "Mandatory Class I Areas," epa.gov/sites/production/files/2016-02/npsmap_basemap_classi_11x17.jpg, Last accessed August 20, 2021.

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 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 Chesapeake Bay have been the goal of the Chesapeake Bay Program since its inception in 1983. The program is a regional partnership that 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 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. The Chesapeake Bay partners again reaffirmed these goals in the 2010 Agreement but have acknowledged that they would not meet the goals. EPA has initiated a process of developing a total maximum daily load (TMDL) target for the Chesapeake Bay. The Chesapeake Bay TMDL is a federal "pollution diet" that sets limits on the amount of nutrients and sediment that can enter the Chesapeake Bay and its tidal rivers to meet water quality goals.

On June 16, 2014, representatives from each of the watershed's six states signed the Chesapeake Bay Watershed Agreement, committing to create a healthy Chesapeake Bay by accelerating restoration and aligning federal directives with state and local goals. This agreement contains 10 interrelated goals that work toward advancing the restoration and protection of the Chesapeake Bay, its tributaries and the land that surrounds them.

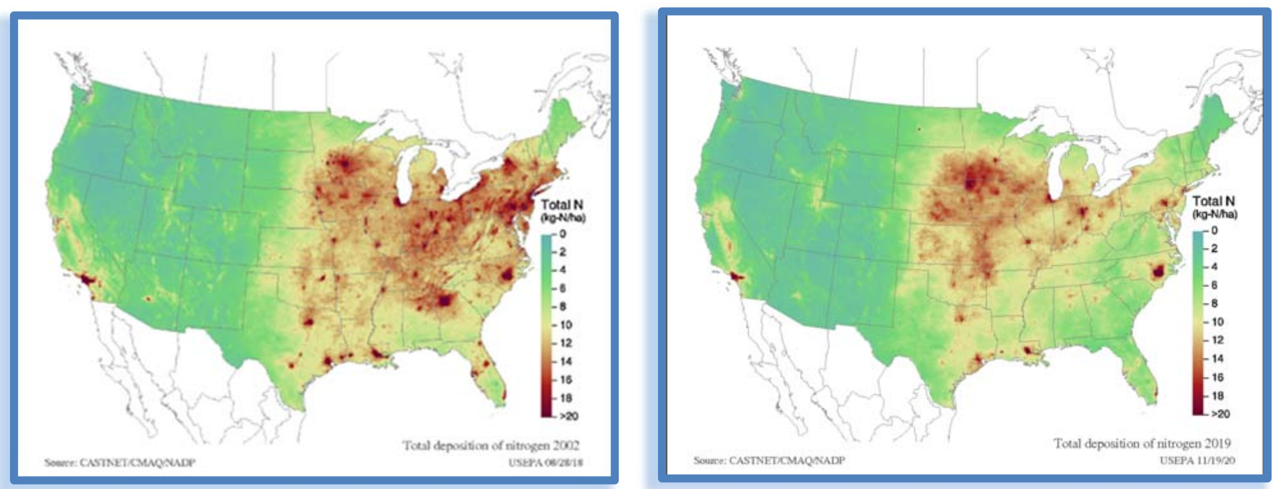
The Chesapeake Bay Program estimates that approximately 30 percent of the nitrogen load to the Chesapeake Bay comes from atmospheric deposition and subsequent transport of nitrogen through the watershed. Much of this loading comes from NOx emissions from power plants, industrial sources and mobile sources.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

PPRP has previously evaluated the regional sources of NOx emissions and their impacts on the Chesapeake Bay. As a part of this effort, scientists used advanced computer models to simulate the transport and subsequent deposition of emissions from these regional sources to the Chesapeake Bay. The actual loading to the Chesapeake Bay was calculated using a methodology similar to that used by the United States Geological Survey for its land-to-bay models. The model allowed PPRP to evaluate the relative contribution of Maryland sources and other regional sources to deposition totals. As a part of this study, PPRP developed a screening tool in 2010 to evaluate the potential reductions in nutrient loading to the Chesapeake Bay waters due to different emission control policies in different states. This tool is available to the public for free upon request to PPRP. By increasing access to this reliable data, 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 the combined NADP/National Trends Network (NADP/NTN) measured values or precipitation chemistry with precipitation estimates from the Parameter-elevation Regressions on Independent Slopes Model (PRISM). The PRISM model estimates precipitation across the U.S. based on elevation and slope. Dry deposition values are combined air concentration data with modeled deposition velocities. Figure 5-14 is a national map of total nitrogen deposition in 2002 and 2019. As shown in this figure, while total nitrogen deposition increased in some parts of the country, in the eastern U.S., levels decreased significantly from 2002 to 2019.

Figure 5-14 Total Nitrogen Deposition in 2002 and 2019



Source: National Atmospheric Deposition Program. "Total Deposition Maps." https://gaftp.epa.gov/castnet/tdep/2018_02_archive_images/n_tw/ Last accessed August 20, 2021.

Mercury Impacts

The primary stationary sources of mercury in the U.S., in order of decreasing emissions, are coal-fired power plants, industrial boilers, gold mining, hazardous waste incineration, chlor-alkali plants, municipal waste incinerators and medical waste incinerators.[106] Emissions from some source categories, notably medical waste incinerators, have decreased dramatically due to stringent EPA regulations. Additionally, as shown in Figure 5-7, mercury emissions from power plants in Maryland have decreased significantly since the implementation of the Maryland Healthy Air Act.

Due to the significance of power plant mercury emissions (including emissions from out-of-state sources), PPRP plays an important 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 using a continuous mercury monitoring instrument. This state-of-the-art monitoring effort provides valuable data to the mercury research community.

[106] EPA's Roadmap for Mercury, EPA-HQ-OPPT-2005-0013, July 2006, epa.gov/nscep.

PPRP is also involved with other projects related to the effects of mercury emissions. The first project involves working with the Smithsonian Environmental Research Center (SERC) and the University of Maryland Center for Environmental Science (UMCES) – 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 a cooperative project with MDE, researchers are monitoring mercury tissue burden in young fish, a long-term effort that will hopefully lead to a better understanding of trends in mercury tissue burden in response to federal and state regulations aimed at reducing mercury releases into the environment. The 2019 data report for this study concludes that while mercury loading and mercury deposition are slowly decreasing over time, it is not so easy to draw a conclusion about mercury loading in fish populations.[107] Mercury concentrations in rain are showing a significant downward trend, but a trend for loading, which also relies on precipitation data, is still uncertain. The average amount of mercury in fish has largely not changed at freshwater sites, and the overall reduction in mercury loading that one might have expected over the years has not yet materialized. This is likely due to the complexity of mercury loading in fish, which is a factor of fish age, precipitation amount, local and/or regional effects and selenium loading, to name a few.

Further research and monitoring are needed to investigate statistical relationships between mercury deposition and emissions and to track/develop trends. 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 Atmospheric Mercury Network (AMNet) that collects data consisting of speciated mercury concentrations and meteorological data. AMNet supplements the wet measurement network and improves understanding of total (wet plus dry) mercury deposition patterns.

In 2002, Maryland issued a statewide fish consumption advisory for lakes, reservoirs and other impoundments due to high mercury levels in fish and has since continued to update this advisory over the years.[108] 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. Figure 5-15 depicts 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.

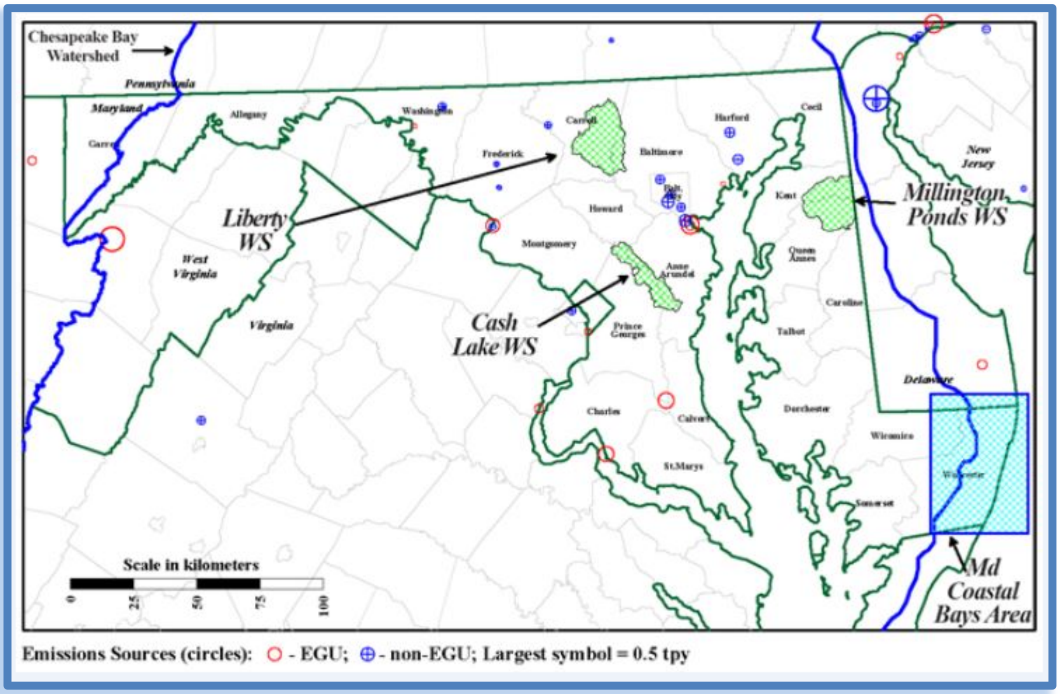
As part of the continuing effort to evaluate impacts of regional sources of mercury emissions on mercury loading to Maryland water bodies, PPRP conducted a study to determine the reduction in mercury loads to the state's water bodies due to implementation of Maryland HAA mercury controls. PPRP based this analysis 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

[107] Maryland Department of Natural Resources, "Young of the Year Fish Monitoring in Maryland Freshwaters and Estuaries: A Means of Observing Change in Hg Availability" Data Report: January 11, 2021. University of Maryland Center for Environmental Studies.

[108] Maryland Department of the Environment, "Statewide Fish Consumption Guidelines for All Ages," March 17, 2016, mde.maryland.gov/programs/Marylander/fishandshellfish/Documents/Fish%20Consumption%20Docs/Maryland_Fish_Advisories_2014_March17.pdf.

potentially reduce the mercury load to water bodies by 1 to 28 percent, the lower estimate being the Western Maryland water bodies, which are influenced predominantly 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 complete this analysis.

Figure 5-15 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.

5.1.4 Recent and Developing National and State Air Regulatory Drivers Affecting Power Plants

Developing Maryland SO_2 Regulations

MDE has been working on several new control initiatives to reduce SO_2 emissions within a small area in Anne Arundel and Baltimore counties identified by EPA as not meeting the 2010 SO_2 NAAQS. This designation was not based on monitoring data, which is typical for attainment designation, and MDE's analysis projected that SO_2 levels would be below the standard. The main sources of SO_2 in this area are the Brandon Shores and Herbert A. Wagner power plants. The two coal units at C.P. Crane had historically been large emitters of SO_2; however, the plant was shut down in June 2018. All units at both plants have installed controls for SO_2 at the coal-fired generating units. Both units at Brandon Shores have been operating with state-of-the-art FGD systems since 2010; coal units at Wagner began using lower-sulfur coal and operating dry sorbent injection pollution control systems in 2015 and 2016. In June 2017, a monitoring plan was submitted to the EPA that detailed the path that MDE planned to implement to attain compliance with the 1-hour SO_2 NAAQS. The plants subject to the plan were Brandon Shores, C.P. Crane (since decommissioned), Chalk Point, H.A. Wagner, Verso Luke Mill (shut down in 2019) and Morgantown. Upon further evaluation of the SO_2 modeling, MDE will develop regulations to bring the SO_2 nonattainment areas into attainment status. In January 2020, MDE submitted its 1-hour SO_2 SIP to EPA for approval.[109] Due to the shutdown of the Verso Luke Mill Plant and as recommended by MDE,[110] on August 13, 2020, EPA notified MDE of its intention to classify Allegany County as attainment/unclassifiable.[111]

Recent Maryland GHG Regulation

On May 12, 2015, the Maryland Climate Change Commission Act became law. The 2015 Act expanded the Maryland Commission on Climate Change (MCCC) originally created in 2007. MDE worked with MCCC on the 2015 Greenhouse Gas Emissions Reduction Act Plan Update. In 2016, the Greenhouse Gas Emissions Reduction Act Reauthorization was signed into law, and added a new benchmark requiring a 40 percent reduction in emissions from 2006 by 2030. In fall 2019, MDE released a comprehensive, economy-wide draft plan to dramatically reduce GHG emissions that contribute to climate change. The final plan, named the "2030 GGRA Plan," was published in 2021.[112] The 2030 GGRA calls for deep GHG reductions of nearly 50 percent by 2030, and net-zero, economy-wide GHG emissions by 2045. MDE will continue to work with MCCC to address climate change in Maryland and track the state's progress toward the goals of GHG reduction. The MCCC has various workgroups to address climate change issues, including Mitigation; Adaptation and Resiliency; Scientific and Technical; and Education, Communication, and Outreach.

The Maryland Legislature continues to work on additional GHG legislation. For example, in 2021, the Legislature was considering the Climate Solutions Now Act, which would require a greater reduction of GHG emissions than current law. It calls for a 60 percent decrease from 2006 levels, rather than the current requirement for a 40 percent reduction by 2030.

Maryland NOx Regulation

In April 2015, MDE petitioned the Administrative, Executive and Legislative Review (AELR) Joint Committee of the Maryland General Assembly requesting "emergency status" to reduce NOx emissions during the 2015 summertime ozone season. The AELR Committee approved this emergency action on May 1, 2015 and projected it would reduce NOx emission by 10 tons on the worst "ozone days" each summer. On December 10, 2015, a final version of the emergency action was promulgated as Code of

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[109] Maryland Department of the Environment, "State of Maryland 1-Hour Sulfur Dioxide (SO2) National Ambient Air Quality Standard (NAAQS) State Implementation Plan for the Anne Arundel County and Baltimore County, MD ("Wagner") Nonattainment Area," January 31, 2020, SIP # 20-01, mde.maryland.gov/programs/air/airqualityplanning/pages/index.aspx, last accessed August 20, 2021.

[110] Letter from Ben Gumbles (MDE) to Cosmo Servidio (EPA Region 3) dated May 29, 2020, epa.gov/sulfur-dioxide-designations/sulfur-dioxide-so2-designations-round-4-maryland-state-recommendation, last accessed August 20, 2021.

[111] Letter from Cosmo Servidio (EPA Region 3) to Governor Lawrence Hogan signed August 13, 2020, epa.gov/sulfur-dioxide-designations/sulfur-dioxide-so2-designations-round-4-maryland-state-recommendation, last accessed August 20, 2021.

[112] The Greenhouse Gas Emissions Reduction Act - 2030 GGRA Plan, February 19, 2021, mde.maryland.gov/programs/Air/ClimateChange/Pages/index.aspx, last accessed August 20, 2021.

Maryland Regulations (COMAR) 26.11.38, establishing new NOx emission requirements beyond 2015 designed to reduce ozone formation in the summer. The regulation requires that all coal-fired electric generating units must implement one of four options to reduce NOx emissions by June 1, 2020. The fourth option is only available for a "system" of sources, which currently includes the three coal-fired generating units: Chalk Point, Dickerson and Morgantown.

1. Install SCR to meet a NOx emission rate of 0.09 lbs per million British thermal units (MMBtu) during ozone season;
2. Permanently retire the unit;
3. Switch fuel permanently to natural gas; or
4. Meet a systemwide daily NOx cap of 21 tons per day during the ozone season, or 0.13 lbs/MMBtu as a 24-hour block average. This option required reductions in emission rates starting in 2016 and further reducing rates biannually until 2020.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

Under 40 CFR Part 63, EPA established the National Emission Standards for Hazardous Air Pollutants (NESHAP) pursuant to Section 112 of the Clean Air Act as amended November 15, 1990. These NESHAPs regulate specific stationary source categories that emit (or have the potential to emit) one or more HAPs listed in 40 CFR Part 63 pursuant to Section 112(b) of the Clean Air Act. The standards 40 CFR Part 63 are independent of NESHAP contained in 40 CFR Part 61.

The NESHAPs are based on maximum achievable control technology, or "MACT." The NESHAPs are sometimes referred to as "MACT standards" because the underlying control technology for the Part 63 NESHAPs is MACT. MACT is not just limited to technology, but can also include processes, methods, systems and techniques that are used by a facility to reduce its HAP emissions.

The NESHAPs typically apply to a "major source," which is defined as any stationary source (or group of stationary sources) that emits at least 10 tons of any single HAP or 25 tons of multiple HAPs annually. If a source is not major then it is considered an area source. Some Part 63 NESHAPs also apply to area sources.

The two 40 CFR Part 63 NESHAP source categories that are especially relevant to large Maryland power plants are as follows, and each is summarized below:

- Subpart UUUUU—NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units
- Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Utility Mercury and Air Toxics Standard (MATS) - Subpart UUUUU

On December 21, 2011, the EPA promulgated a MACT standard, referred to as the Mercury and Air Toxics Standard, or the "Utility MATS," that will 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.

After 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 creating the regulations; the Court did not take issue with the standard itself. The EPA's response was the 2016 Supplemental Finding, published in the Federal Register on April 25, 2016, 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. However, on December 27, 2018, the EPA proposed to revise the Supplemental Finding for the MATS rule, determining that it is *not* "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the CAA. In the May 22, 2020 Federal Register, EPA promulgated its finding that it is not ''appropriate and necessary'' to regulate HAP emissions from coal- and oil-fired electric generating units (EGUs), after mainly comparing the cost of compliance relative to the benefits of HAP emission reduction from regulation. In that same Federal Register notice, EPA also finalized the residual risk and technology review (RTR) conducted for the coal- and oil-fired EGU source category regulated MATS. Based on the results of the RTR analyses, EPA did not promulgate any revisions to the MATS rule. The MATS rule will remain in place since the EPA is not proposing to remove coal- and oil-fired power plants from the grouping of sources, which are regulated under Section 112 of the CAA.

As the MATS rule currently stands, 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 SO_2 (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; newly constructed sources are subject to the standards at start-up.

For affected power plant sources in Maryland, add-on pollution control systems, such as wet FGD systems installed for HAA compliance and powdered activated carbon (PAC) injection for mercury (Hg), may be sufficient for compliance with the Utility MATS mercury and organic and metal HAPs standards. H.A. Wagner installed dry sorbent injection (DSI) systems in 2015 to meet the HCl emission limit.

Stationary Combustion Turbine NESHAPs - Subpart YYYY

Subpart YYYY establishes national emission limitations and operating limitations for HAPs emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

Currently, in Subpart YYYY, stationary combustion turbines have been divided into eight subcategories. Most importantly, when Subpart YYYY was originally promulgated in 2004, EPA set a 91 parts per billion by volume (ppbvd) at 15 percent oxygen (O_2) formaldehyde limit for new and reconstructed lean premix and diffusion flame gas-fired turbines (those constructed or reconstructed after January 14, 2003). EPA later stayed the effectiveness of the emissions standard for lean premix and diffusion flame gas-fired turbines. A court ruled in 2007 that EPA has no authority to delist subcategories of sources (such as those subject to the stay). Consequently, a petition to delist the entire Stationary Combustion Turbines source category was filed in August 2019.

In the March 9, 2020 Federal Register, EPA published the Stationary Combustion Turbine residual RTR Final Rule. EPA did not finalize its proposed removal of the administrative stay for new lean premix and diffusion flame gas-fired turbines subcategories. EPA is still reviewing the comments on lifting the stay and will respond to those comments in a separate action. Those comments included the petition to delist the entire Stationary Combustion Turbines source category.

New Source Review

Maryland requires any new or modified air pollution source to obtain an air quality permit to construct unless specifically exempted by the relevant regulation. New major sources or modifications to existing major sources must comply with the applicable provisions of Nonattainment New Source Review (NA-NSR) and/or Prevention of Significant Deterioration (PSD), depending on the attainment status of the area where the source is located and the quantity and type of air pollutants emitted.

Maryland follows the federal PSD regulations found at 40 CFR 52.21, which are incorporated by reference at COMAR 26.11.06.14. The NA-NSR requirements are found at COMAR 26.11.17. If a power plant is subject to PSD and/or NA-NSR requirements, they are included in the facility's Certificate of Public Convenience and Necessity (CPCN). The requirements are enforced by MDE.

Both programs are complex and revisions to the underlying guidance, and sometimes the regulations themselves, can occur. For example, in 2019 and 2020, EPA proposed or finalized three rules and issued five guidance documents.

Cross-State Air Pollution Rule (CSAPR)

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address air pollution from upwind states that crosses state lines and affects air quality in downwind states. SO_2 and NOx react in the atmosphere and contribute to the formation of $PM_{2.5}$. NOx also contributes to the formation of ground-level ozone. These emissions and the $PM_{2.5}$ and ozone they form can affect air quality and public health locally, regionally and in states hundreds of miles downwind.

CSAPR requires certain states in the eastern half of the U.S., including Maryland, to improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and $PM_{2.5}$ levels in downwind states. These improvements help downwind areas attain and maintain the $PM_{2.5}$ and ozone NAAQS. CSAPR replaced EPA's 2005 Clean Air Interstate Rule (CAIR) due to a 2008 court decision that required EPA to issue a replacement regulation. Implementation of CSAPR began on January 1, 2015. On September 7, 2016, EPA revised the CSAPR ozone season NOx program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update. The CSAPR Update ozone season NOx program largely replaced the original CSAPR ozone season NOx program starting on May 1, 2017. In the April 30, 2021 Federal Register, EPA finalized a Revised Cross-State Air Pollution Rule Update for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the rule requires additional NOx emissions reductions from power plants in 12 states, including Maryland.

NAAQS Revisions

As mentioned above, the CAA requires the EPA to review the NAAQS every five years. If EPA makes a NAAQS more stringent, it could have a significant impact on power plants in Maryland because MDE may dictate additional controls in order for various portions of the state to attain the more stringent standard. After a NAAQS is revised, EPA must determine which areas meet the standard and it must also develop an implementation plan in order for the NAAQS to be attained and maintained.

The CAA establishes a framework for EPA to set NAAQS based on the "latest scientific knowledge" through a notice and comment rulemaking process. Reviewing the NAAQS is a lengthy process and includes the following major phases:[113]

- Planning
- Integrated Science Assessment
- Risk/Exposure Assessment
- Policy Assessment
- Rulemaking

EPA provides timelines for the review of each of the NAAQS.[114]

5.1.5 Greenhouse Gas Policies

Evidence of a rising average global temperature has driven global efforts to reduce human impact on the earth's climate. Human activities, such as fossil fuel combustion for electricity generation and transportation, industrial processes, and changes in land use, including deforestation, contribute significant amounts of CO_2 and other GHGs to the atmosphere. At the turn of the twenty-first century, record-high levels of atmospheric concentrations of GHGs sparked national debate about the responsibility to reduce human contribution to global climate change.

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 and wellness.

The electricity sector is particularly vulnerable to the effects of sea level rise and extreme weather events. If global temperatures continue to trend upward, sea levels will continue to rise and extreme weather events are likely to occur more frequently. Thermal generating units often require large quantities of cooling water, which has resulted in the siting of these facilities adjacent to large water bodies, often in tidal waters. Therefore, investments in renewable energy stations sited in areas not affected by sea level rise and investments that modernize our transmission grids are necessary to make our electric systems more resilient and reliable.

[113] epa.gov/criteria-air-pollutants/process-reviewing-national-ambient-air-quality-standards.

[114] epa.gov/naaqs/historical-information-naaqs-review-process.

As published in Chapter 1 of "A Sustainable Chesapeake,"[115] historical tide-gauge records indicate that Maryland's coastal waters have increased by one foot in the past 100 years and are projected to continue to rise by over one meter by 2100,[116] with a subsequent loss of approximately 580 acres of land per year along the Maryland coast. As sea levels continue to rise, coastal floods reach higher lands, threatening the reliability of power plants in the affected regions and increasing the number of electric facilities put at risk. "Maryland and the Surging Sea" reports that 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.[117] According to MDE, Maryland has 3,100 miles of shoreline, and is the fourth most vulnerable state to suffer the effects of sea-level rise associated with climate change.[118]

Another effect of climate change is more frequent heat waves. In Maryland, mean annual temperature increased from 1977 to 1999 by 2°F according to the "Comprehensive Assessment of Climate Change Impacts in Maryland."[119] The study also indicated that in the late 1990s, there was an average of 30 days per year with maximum daily temperatures greater than 90°F. The number of days with a 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, including the following as provided in the U.S. Climate Resilience Toolkit:[120]

- Diversify supply chains to address multiple types of disruptions.
- Strengthen and coordinate emergency response plans to minimize the magnitude and length of disruptions.
- Develop flood and stormwater management plans to address extreme weather events and sea level rise.
- Develop drought management plans to address the potential for decreased water supplies.

[115] The Conservation Fund, A Sustainable Chesapeake: Better Models for Conservation, conservationfund.org/our-work/cities-program/resources/a-sustainable-chesapeake.

[116] Bradley, R., Karmalkar, A., and Woods, K. "Climate Change State Profiles Maryland." Climate System Research Center, University of Massachusetts Amherst, geo.umass.edu/climate/stateClimateReports/MD_ClimateReport_CSRC.pdf.

[117] Strauss, B., C. Tebaldi, S. Kulp, S. Cutter, E. Emrich, D. Rizza and D. Yawitz (2014). Maryland and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report. sealevel.climatecentral.org/uploads/ssrf/MD-Report.pdf.

[118] Maryland Department of the Environment, Climate Change Program, mde.maryland.gov/programs/Air/ClimateChange/Pages/index.aspx, last accessed August 20, 2021.

[119] Scientific and Technical Working Group of the Maryland Commission on Climate Change, Comprehensive Assessment of Climate Change Impacts in Maryland, Chapter 2, mde.state.md.us/programs/Air/ClimateChange/Documents/FINAL-Chapt%202%20Impacts_web.pdf.

[120] U.S. Climate Resilience Toolkit, toolkit.climate.gov/topics/energy-supply-and-use/building-resilience-energy-supply-and-use, last accessed August 20, 2021.

- Develop hydropower management plans to address the potential for hydrologic extremes.
- Build redundancy into facilities to allow for continued operation during partial disruptions.
- Storm-harden energy infrastructure and/or elevate water-sensitive equipment to address high water levels.
- Build coastal barriers using green, grey, or hybrid infrastructure to address high water levels.
- Improve reliability of grid systems through back-up power supply, intelligent controls, smart grid, micro-grids, and distributed generation to better respond to disruptions.
- Implement air-cooled or low-water-use cooling systems for thermoelectric power plants to address drought and increased temperatures of water for cooling.
- Expand the use of non-water-intensive energy technologies (for example, wind or photovoltaic solar).
- Relocate vulnerable facilities out of locations that may be inundated.
- Relocate facilities to areas with more sustainable water supplies.
- Add peak generation and power storage capacity to minimize disruptions.
- Add back-up power supply for grid disruptions.
- Add regional fuel product reserves to address vulnerable fuel supply disruptions.
- Increase transmission capacity within and between regions to overcome localized disruptions.
- Improve demand-response capabilities of energy infrastructure (for example, a smart grid).
- Improve residential and building energy, cooling and manufacturing efficiencies.
- Allow flexible work schedules to transfer energy use to off-peak hours.

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.

Maryland has been working to reduce the state's impact on the climate. The Maryland Commission on Climate Change (MCCC) was formed in 2007 to develop a statewide Climate Action Plan, which was published in 2008. This plan contained 61 policy options, programs and measures to reduce GHG emissions in the state 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), which was reauthorized in April 2016 (GGRA of 2016). That legislation is described in more detail below along with key federal and international climate initiatives.

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. That program is described in detail below.

Regional Greenhouse Gas Initiative

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. Maryland, as required by the state's Healthy Air Act of 2006, joined RGGI in 2007, the same year as Massachusetts and Rhode Island. Currently, 11 states participate in RGGI: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (withdrew in 2012, rejoined in 2020), New York, Rhode Island, Vermont and Virginia (joined in 2021). In 2019, Pennsylvania Gov. Tom Wolf directed the state's Department of Environmental Protection to develop regulations for the state to join RGGI by 2022.

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. As of 2020, the adjusted cap was reduced to 74.4 million short tons, which included 18 million short tons for returning RGGI entrant New Jersey. Emission reductions of 2.5 percent per year are required 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 5-2 lists the annual CO_2 emission, by compliance period, for each RGGI member state. (Emissions from Virginia sources are reported beginning January 1, 2021.) There were 18 power plants in the 2018-2020 control period in Maryland that are covered by RGGI. Maryland's 2020 RGGI budget allowance was 12.5 million tons of CO_2 or 17 percent of the 2020 regional CO_2 budget of 74.4 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 third control period, the RGGI power sector recognized a 65 percent decline in emissions since 2005. Before the overall cap is reduced between 2020 and 2030, there will be a fifth control period from 2021 through 2023. For 2021, the RGGI adjusted cap is 100,677,454 tons of CO_2 allowances, with 14.1 million allocated for Maryland. The RGGI states issued the Third Adjustment for Banked Allowances on March 15, 2021, which accounts for banked CO_2 allowances accumulated during the fourth control period and is applied to the RGGI cap. As established in the 2017 Model Rule, the adjustment is done over five years (2021-2025). Since 2005, emissions from Maryland's power sector have declined 66 percent, or by 24.58 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 concluded in December 2017, resulting in the 2017 Model Rule. The most significant change under the 2017 Model Rule included a reduction in RGGI's carbon cap by 30 percent from 2020 to 2030, effectively eliminating 22,750,000 tons of CO_2 from 2021 through 2030. The cost containment reserve mechanism will continue to operate, albeit with higher trigger prices ($13 per ton in 2021, increasing 7 percent annually). Beginning in 2021, a new mechanism known as the emissions containment reserve (ECR) was established. States can withhold up to 10 percent of their annual budget under the ECR if prices fall below certain thresholds ($6 per ton in 2021, increasing 7 percent annually). States may then choose to impose further reductions if prices are lower than expected. The auction price floor in 2021 was $2.38 per short ton, increasing 2.5 percent each year.[121] The ECR is implemented in seven states: Connecticut, Delaware, Maryland, Massachusetts, New York, Rhode Island and Vermont.

It should be noted that of the 13 states (plus the District of Columbia) that are included in whole or in part in the PJM footprint, only Maryland, Delaware, New Jersey and Virginia are participants in RGGI, although as mentioned, Pennsylvania is expected to join in 2022. 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 plants in Delaware, Maryland, New Jersey and Virginia are subject to the RGGI emissions cap while generation in PJM states not participating in RGGI (e.g., West Virginia) 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 5-2 CO_2 Emissions by RGGI States

State	Annual Historical 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 2015-2017	Compliance Period 4 2018-2020
Maryland	32.38 – 37.26	25.57 – 27.96	18.68 – 20.90	12.68 – 18.33	0.01 – 9.56
Connecticut	8.99 – 11.32	7.15 – 8.53	7.12 – 7.46	6.83 – 8.15	0.01 – 6.91
Delaware	7.56 – 8.30	3.71 – 4.30	3.93 – 4.84	3.52 – 4.04	0.01 – 2.97
Massachusetts	21.44 – 26.64	15.63 – 19.80	11.79 – 13.68	10.89 – 12.04	0.01 – 4.86
Maine	3.37 – 4.59	3.34 – 3.94	2.25 – 2.94	1.07 – 1.78	0.01 – 1.42
New Hampshire	7.10 – 8.97	5.53 – 5.90	3.57 – 4.64	1.98 – 3.82	0.13 – 3.55
New Jersey	20.60 – 22.07	16.36 – 19.68	N/A (see note a)	N/A (see note a)	0.01 – 2.91 (see note a)
New York	48.35 – 62.72	37.15 – 42.11	33.48 – 35.64	24.58 – 32.55	0.01 – 7.97
Rhode Island	2.69 – 3.29	3.42 – 3.95	2.77 – 3.74	2.83 – 3.21	0.01 – 3.96
Vermont	0.0026 – 0.0078	0.0020 – 0.0065	0.0023 – 0.00276	0.0012 –.0043	0.00168 – 0.00202

[121] International Carbon Action Partnership (ICAP) - USA - Regional Greenhouse Gas Initiative (RGGI) icapcarbonaction.com/en/?option=com_etsmap&task=export&format=pdf&layout=list&systems%5B%5D=50#:~:text=To%20date%2C%20only%20one%20offset,year%20(to%20reflect%20inflation).

State	Annual Historical 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 2015-2017	Compliance Period 4 2018-2020
Original RGGI 10 State Total	153.5 – 184.6	118.56 – 135.74	N/A	N/A	0.003 – 79.09
Current RGGI 9 State Total	132.9 – 162.5	N/A	86.53 – 92.73	64.49 – 82.99	N/A

Source: rggi.org/.
Notes:
(a) New Jersey withdrew from the RGGI program at the end of 2011 and rejoined on January 1, 2020.
N/A – Complete emissions data are not available. Some facilities in Connecticut and Delaware are shown as having incomplete data in the RGGI emissions reporting database.

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 is to be used for consumer benefit or strategic energy purposes. As of the December 2020 auction, Maryland has raised $744.03 million in RGGI proceeds. This revenue is directed to the Maryland Strategic Energy Investment Fund (SEIF), which is administered by the Maryland Energy Administration (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 $5 million – administration of the Fund.

RGGI Allowance Auctions

Each RGGI member state has its own independent CO_2 budget trading program. States sell their CO_2 allowances in regional quarterly 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; therefore, 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) 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. During the third control period from 2015 to 2017, 161 of the 163 power plants subject to RGGI requirements met their compliance obligations. Through the fourth control period (2018-2020), 198 of the 203 power plants subject to RGGI requirements, or 97.5

percent, have met their compliance obligations. In terms of emissions, 99.1 percent of covered power sector emissions were complying.[122]

While any entity may apply to participate in the quarterly auctions, in the first 44 auctions, 74 percent of the allowances were purchased by electric generators or their affiliates. Initially, the reserve or minimum allowance price was set at $1.86 per ton for the September 2008 auction and increased by 2.5 percent per year. However, beginning with the March 2014 auction, the reserve price was adjusted to $2 per ton and increases by 1.025 percent each year. Allowance clearing prices have ranged from $1.86 per ton to $7.50 per ton, as shown in Figure 5-16.

Beginning in December 2015, the auction clearing price began to decline, falling from a high of $7.50 per ton to $2.53 per ton in June 2017, slightly above the reserve minimum. In September 2017, the price began to increase, and reached $5.62 per ton at the June 2019 auction. The average auction clearing price increased 18 percent from $5.43 per ton in 2019 to $7.41 per ton by the end of 2020. During the fourth control period (2018-2020), the average auction allowance price was $5.08 per ton. In total, RGGI has resulted in $3.8 billion in revenues to 10 of the 11 member states as of the December 2020 auction.[123] Maryland has raised $744 million (see Table 5-3), the majority of which has been used for low-income energy assistance.

Table 5-3 RGGI Allowance Auctions, 2008-2020

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	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

[122] RGGI, Inc. "RGGI States Release Fourth Control Period Compliance Report," April 2, 2021, rggi.org/sites/default/files/Uploads/Press-Releases/2021_04_02_FoCP_Compliance.pdf.

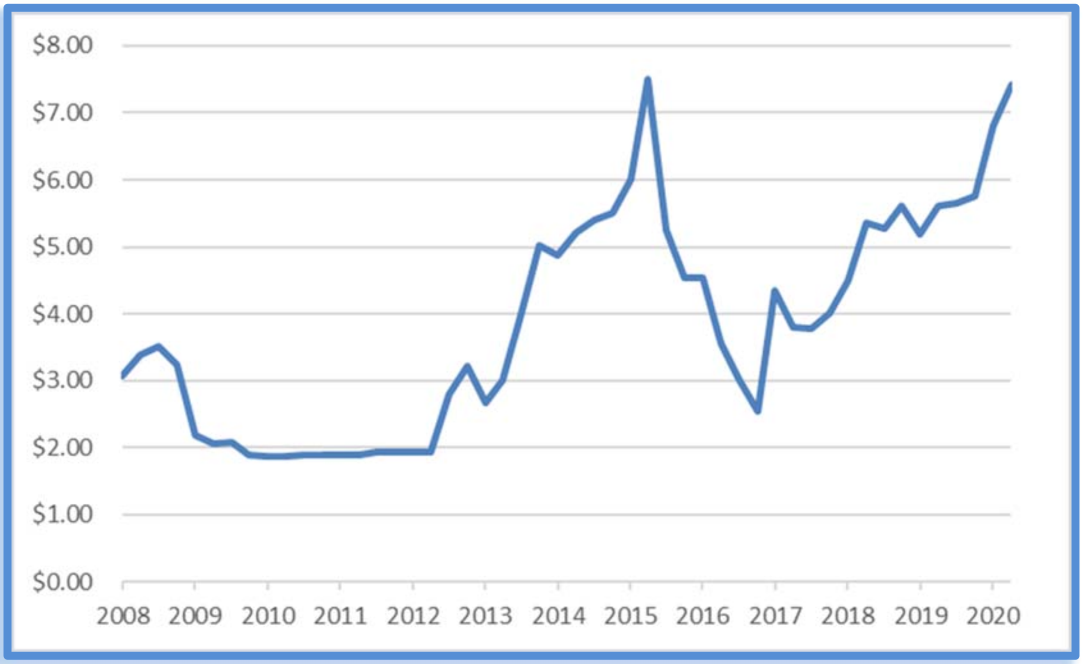
[123] RGGI revenues are not provided for Virginia.

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)
	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
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
Mar-16	Current	14,838,732	$5.25	2,994,243	$15.72
Jun-16	Current	15,089,652	$4.53	3,007,883	$13.6
Sep-16	Current	14,911,315	$4.54	3,066,826	$13.9

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)
Dec-16	Current	14,791,315	$3.55	2,946,826	$10.5
Mar-17	Current	14,371,300	$3.00	2,973,258	$8.9
Jun-17	Current	14,597,470	$2.53	2,973,542	$7.5
Sep-17	Current	14,371,585	$4.35	2,973,543	$12.93
Dec-17	Current	14,687,989	$3.80	2,973,543	$11.30
Mar-18	Current	13,553,767	$3.79	2,539,908	$9.63
Jun-18	Current	13,771,025	$4.02	2,576,249	$10.36
Sep-18	Current	13,590,107	$4.50	2,576,249	$11.59
Dec-18	Current	13,360,649	$5.35	2,576,249	$13.78
Mar-19	Current	12,883,436	$5.27	2,387,512	$12.58
Jun-19	Current	13,221,453	$5.62	2,389,718	$13.43
Sep-19	Current	13,116,447	5.20	2,620,524	$13.63
Dec-19	Current	13,116,444	5.61	2,620,525	$14.70
Mar-20	Current	16,208,347	5.65	2,330,353	$13.17
Jun-20	Current	16,336,298	5.75	2,314,790	$13.31
Sep-20	Current	16,192,785	6.82	2.314,790	$15.79
Dec-20	Current	16,237,495	7.41	2,359,501	$17.48
Total					$744.03

Source: rggi.org/market/co2_auctions/results.

Figure 5-16 RGGI Allowance Clearing Prices, 2008-2020 ($/ton of CO_2)



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 are awarded one CO_2 offset allowance for every ton of CO_2 reduced or sequestered. At this time, the RGGI states limit the award of offset allowances to five project categories, each of which is designed to reduce or sequester emissions of carbon dioxide or methane within the region. Although the CO_2 Budget Trading Programs in Massachusetts, New Hampshire, Rhode Island and Virginia do not grant CO_2 offset allowances, regulated power plants in those states may use CO_2 offset allowances awarded by another RGGI state. A source may cover up to 3.3 percent of its CO_2 emissions with offset project allowances. A total of 53,506 offsets were awarded to the one current offset project in Maryland, the New Beulah Landfill Gas Reconstruction Project.[124]

The five categories of offset projects that currently qualify under the RGGI program are:

1. Landfill Methane Capture and Destruction – applicable to municipal solid waste landfills that are not subject to New Source Performance Standards (NSPS).
2. Sulfur hexafluoride.
3. Sequestration of Carbon Due to Reforestation, improved forest management or avoided conversion – sequestering carbon through the conversion of land that has been in a non-forested state.

[124] RGGI CO_2 Allowance Tracking System, RGGI CO2 Budget Trading Programs, rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.project_offset&clearfuseattribs=true, last accessed July 15, 2021.

4. End-Use Energy Efficiency to reduce building sector CO_2 emissions by reducing onsite combustion of natural gas, oil or propane for end-use in existing or new commercial or residential buildings – applicable to projects that reduce CO_2 emissions through eligible energy conservation measures.
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 December 2017 did not include three categories that previously qualified for offsets: Afforestation, Sulfur Hexafluoride Reduction and End-Use Efficiency. As of 2020, Delaware, Maine, Maryland, New Jersey, New York and Vermont only allow the following two offsets: Landfill Methane Capture and Destruction and Avoided Methane Emissions from Agricultural Manure Management Operations.

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 by growing trees as their biomass increases. 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 by accreting carbon-containing sediments and organic matter. Marsh decline, however, is occurring throughout the region as sea level increases and land areas subside. Raising the elevation of the marsh beds by supplementing 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, PPRP has assisted with an effort by Restore America's Estuaries to develop a formal offset protocol for salt marsh systems (see sidebar).

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 Old Dominion Electric Cooperative (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.

Maryland has considerable 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 of 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 Affecting 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.

"Coastal Blue Carbon" Wetlands Restoration and Conservation Offsets

Research focusing on "Blue Carbon" in coastal wetland ecosystems suggests that some coastal wetlands can sequester carbon at rates three to five times greater than temperate forests, making them particularly valuable as carbon sinks that can offset carbon emissions by human activities. Unfortunately, current estimates indicate that 50 percent of U. S. coastal wetlands have been lost since the 1800s, and that coastal wetlands are being lost globally at a rate of 0.7 to 2 percent per year. Efforts to preserve and restore coastal wetlands can now be financed by payments for the additional carbon that the wetlands sequester.

Restore America's Estuaries, with support from PPRP, developed a GHG offset category for measuring and crediting climate benefits from a broad range of wetlands, including freshwater tidal coastal wetlands, salt marshes, seagrasses, floodplains, peatlands and other wetland types. The Wetlands Restoration and Conservation category, which received approval under the Verified Carbon Standard (VCS) in October 2012, allows increased private investment in wetland restoration and conservation projects through the issuance of internationally recognized carbon credits. VCS is the majority holder in the voluntary carbon market with a 58 percent global and U.S. share and is widely considered the leading certification available globally.

In late 2015, VCS approved the specific methodology for implementing tidal wetland and seagrass restoration projects in the Wetlands Restoration and Conservation offset category. The methodology, which is applicable throughout the world, details the procedures required to calculate, report and verify the GHG reductions from these projects and thereby obtain "carbon credits" that can be traded in the VCS or other carbon markets.

Maryland Climate Change Legislation

Over the last several years, Maryland has enacted legislation that will help the state, both directly and indirectly, meet its goals related to climate change. These bills target emissions from power plants and vehicles, spur the development of renewable energy and set energy efficiency and conservation goals.

During the 2009 session, the legislature passed the Greenhouse Gas Emissions Reduction Act (GGRA) via House Bill 315/Senate Bill 278. This law set a statewide GHG emissions reduction goal of 25 percent from a 2006 baseline by 2020. The GGRA also required 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 to assist in 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 provided 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 April 4, 2016, the GGRA of 2016 was signed into law by Governor Larry Hogan. It expanded the requirements of the 2009 GGRA by requiring a minimum of a 40 percent reduction in statewide GHG emissions from 2006 levels by 2030. To achieve this goal, the GGRA of 2016 required MDE to develop a statewide GHG reduction plan (2030 GGRA Plan).[125] MDE submitted the comprehensive plan to Governor Hogan and the State Legislature on February 19, 2021, to coincide with the return of the U.S. to the Paris Agreement.

MDE states in the 2030 GGRA Plan that Maryland's 2017 GHG emissions[126] indicate that activities in Maryland accounted for approximately 80.14 million metric tons of gross CO_2 equivalent emissions (MMtCO2e) in 2017, an amount equal to about a 25.8 percent reduction of the state's total gross GHG emissions in 2006 (108.06 MMtCO2e). In 2017, the 25.8 percent reduction in emissions was greater than Maryland's reduction goal for 2020 of 25 percent established by the GGRA. However, MDE cautions against concluding that the state met its 2020 goal. This is because emissions from electricity generation and residential and commercial buildings vary year to year with the weather. MDE also notes that Maryland had a mild winter and a relatively mild summer, leading to an especially steep drop in 2017 emissions. Electricity consumption accounted for 30 percent of Maryland's gross GHG emissions in 2017; transportation accounted for 40 percent; and buildings 18 percent.

The 2030 GGRA Plan is a comprehensive, multi-agency, multi-sector plan developed with assistance and input from numerous state agencies and nongovernmental organizations. MDE stated "… the programs outlined in the 2030 GGRA Plan provide a blueprint, which if fully implemented, will achieve reductions greater than the 40 percent GHG reduction required by the GGRA of 2016, with significant positive job growth and economic benefits." MDE estimates that the Plan puts Maryland on a track to achieve deep GHG reductions of nearly 50 percent by 2030 and calls for net-zero, economy-wide GHG emissions by 2045.

The 2030 GGRA Plan includes an electricity generation strategy designed to achieve 100 percent clean and renewable electricity by 2040 through the proposed Clean and Renewable Energy Standard (CARES) and the existing RPS and by capping and reducing emissions through RGGI.

In May 2015, the Maryland Climate Change Commission Act was signed into law to expand the MCCC originally created in 2007. MDE worked with the MCCC on the 2015 GGRA Plan Update and will

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[125] Maryland Department of the Environment, The 2030 Greenhouse Gas Emissions Reduction Act (GGRA) Plan, mde.maryland.gov/programs/Air/ClimateChange/Pages/Greenhouse-Gas-Emissions-Reduction-Act-(GGRA)-Plan.aspx, last accessed August 20, 2021.

[126] Maryland performs comprehensive greenhouse gas inventories on a 3-year cycle to coincide with the EPA's National Emissions Inventory. The most recent inventory year is 2017. MDE will complete the next inventory for 2020 in late 2021 once federal datasets on 2020 energy use are published.

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.

Clean Power Plan and the Affordable Clean Energy (ACE) Rule

The Clean Power Plan (CPP), finalized in 2015, was a comprehensive federal program mandating reductions in GHG emissions from large existing sources, including power plants, and potential new sources of GHGs. The CPP was rooted in Section 111 of the Clean Air Act, which laid out distinct regulatory approaches for new and existing sources of emissions. Section 111(b) covered federal programs to address new, modified and reconstructed sources by establishing emissions standards. Section 111(d) mandated a series of state-based programs covering existing sources; under Section 111(d), EPA established guidelines for states to design programs that fit within those guidelines to achieve target emissions reductions. In October 2017, EPA issued a notice proposing to repeal the CPP. While tied up in litigation, EPA proposed changes to the CPP, which would then become known as the Affordable Clean Energy (ACE) rule.

The ACE rule was proposed on August 21, 2018 as a replacement for the CPP. Centered on Section 111(d) of the Clean Air Act, which governs how an agency issues emission guidelines and plans, the ACE rule establishes new guidelines for state regulation of coal-fired power plant emissions, shifting the responsibility away from federal programs and agencies, and providing the states with added time and flexibility. The ACE rule defines the "best system of emission reduction" for GHG emissions from existing coal-fired power plants as onsite improvements to heat-rate efficiencies. The ACE rule additionally provides incentives for efficiency improvements at existing power plants and provides the states with a list of technologies to establish standards of performance for incorporation into their state plans. This rule has the potential to affect roughly 300 coal-fired power plants. The final ACE rule was published in the Federal Register on July 8, 2019, along with the final repeal of the CPP. This publication was quickly followed by a petition for review of the ACE rule by multiple parties.

On January 19, 2021, the United States Court of Appeals, District of Columbia Circuit vacated the ACE rule and remanded to the EPA for further proceedings consistent with its opinion. EPA issued a memorandum stating EPA's view that the court's opinion did not result in any obligation for states to submit Clean Air Act Section 111(d) state plans under the CPP,[127] nor do states have any obligations under the vacated ACE rule. EPA reasoned that because the court vacated ACE and did not expressly reinstate the CPP, the court's decision left neither of those rules in place with respect to GHG emissions from electric generating units (EGUs). The ruling was appealed to the U.S. Supreme Court, where it is now pending. It is unclear what options EPA will propose going forward for regulating GHGs from both new and existing power plants.

[127] Memorandum from Joseph Goffman, Acting Assistant Administrator, to EPA Regional Administrators, re: "Status of Affordable Clean Energy Rule and Clean Power Plan," February 12, 2021, epa.gov/stationary-sources-air-pollution/memorandum-status-affordable-clean-energy-rule-and-clean-power-plan, last accessed August 20, 2021.

International Climate Change Initiatives

There has been global activity to address climate change since the 1990s, and most recently the key initiative was the Paris Agreement.[128] On November 4, 2020, the Trump Administration formally withdrew the U.S. from the Agreement. President Biden announced on the first day of his presidency that the U.S. would rejoin the Paris Agreement, and the U.S. re-entered the Agreement in February 2021.

At the 21st Conference of the Parties (or "COP 21") to the United Nations Framework Convention on Climate Change (UNFCCC), on December 12, 2015, the Parties reached a landmark agreement to combat climate change and to accelerate and intensify the actions and investments needed for a sustainable low-carbon future. According to the UNFCCC:

> "…The Paris Agreement's central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. Additionally, the agreement aims to increase the ability of countries to deal with the impacts of climate change, and at making finance flows consistent with a low GHG emissions and climate-resilient pathway. To reach these ambitious goals, appropriate mobilization and provision of financial resources, a new technology framework and enhanced capacity-building is to be put in place, thus supporting action by developing countries and the most vulnerable countries, in line with their own national objectives. The Agreement also provides for an enhanced transparency framework for action and support."

The Agreement requires the Parties to put forward their best efforts to reduce emissions through "nationally determined contributions" (NDCs) and to strengthen these efforts in the years ahead. This includes requirements that all Parties report regularly on their emissions and their implementation efforts.

On April 22, 2021, during his Leaders Summit on Climate, President Biden committed the U.S. to cutting greenhouse gas emissions 50-52 percent below 2005 levels by 2030, reaching a 100 percent carbon pollution-free power sector by 2035, and achieving a net-zero economy by no later than 2050.[129]

On September 17, 2021, the United Nations published a synthesis of climate action plans as communicated in countries' NDCs. The NDC Synthesis Report indicated that the trend is that GHG emissions are being reduced over time; however, it also showed that "… nations must urgently redouble their climate efforts if they are to prevent global temperature increases beyond the Paris Agreement's

[128] cop23.unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement/key-aspects-of-the-paris-agreement, last accessed August 20, 2021.

[129] whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

goal of well below 2°C – ideally 1.5°C – by the end of the century."[130] This is because the available NDCs of all of the Agreement's Parties taken together showed an increase in global GHG emissions in 2030 compared to 2010, of about 16 percent. According to the latest findings from the Intergovernmental Panel on Climate Change (IPCC), unless actions are taken immediately, such an increase may lead to a temperature rise of about 2.7°F by the end of the century.

The NDC Synthesis Report was requested by Parties to assist them in assessing the progress of climate action ahead of the 26th Conference of the Parties (or "COP 26") that was held in Glasgow, Scotland from October 31 through November 13, 2021. Many observers found the culmination of the negotiations disappointing. However, all 197 countries agreed to the Glasgow Climate Pact. The Pact references "phasing down" unabated coal power and "phasing out" inefficient fossil fuel subsidies. The PACT also calls for parties that have not yet submitted new or updated NDCs to do so before the next COP, scheduled for November 2022. It also calls for developed countries to increase adaptation funding to developing nations.[131]

5.1.6 Fossil Fuel-Fired Generation and CO_2

Background and Definition

Coal-fired power plants historically have supplied over half of Maryland's net electricity generation and have been effective in meeting baseload, intermediate load and peak demands given their high reliability. However, the availability of vast reserves of economically viable, domestic unconventional gas has changed the face of the electric generation fuel mix in the United States and in Maryland. Since 2012, the sources of Maryland's net electricity generation have changed substantially, with coal falling to only 9 percent of the total in 2020, while natural gas-fired generation has increased to 39 percent. The increased gas supply incentivizes 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 experienced a shift as natural gas resources displace coal resources throughout the PJM region. The U.S. Energy Information Administration (EIA) predicts that total domestic production of natural gas will continue to grow through 2050, and natural gas-fired electric generation is expected to grow steadily but be outstripped by renewables growth that is projected to surpass natural gas generation and become the dominant electricity fuel source for the U.S. by 2050.

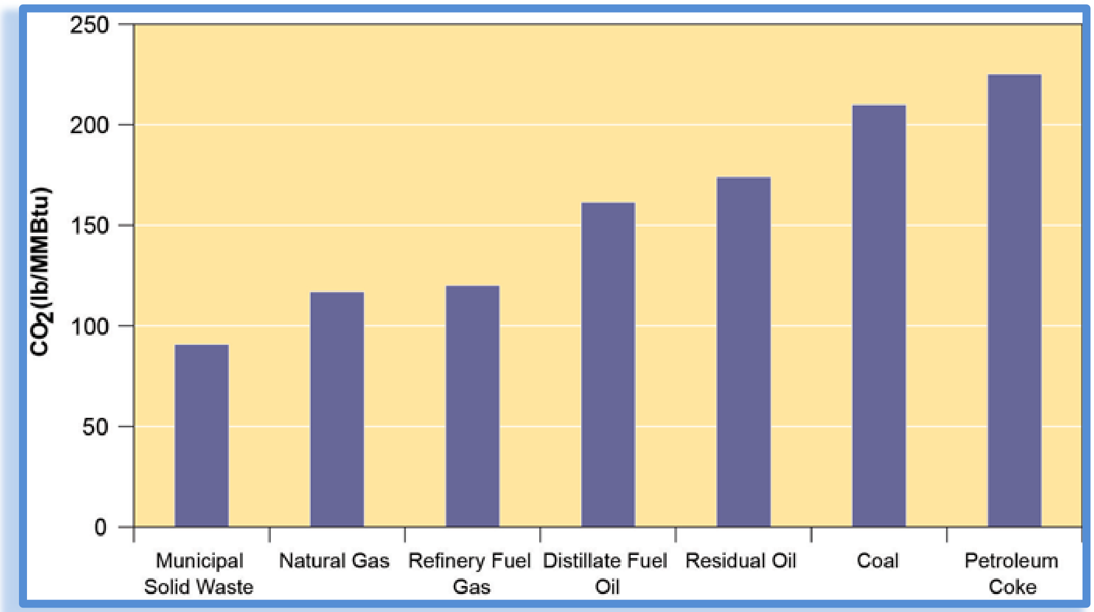
All fossil fuels, including both natural gas and coal, contain substantial amounts of fuel-bound carbon that is oxidized into carbon monoxide (CO) and CO_2 during combustion. CO_2 emissions from conventional coal combustion technologies amount to approximately one ton per MWh of electricity generated, compared to 0.4 to 0.6 ton per MWh from natural gas-fired generation (e.g., combined cycle/simple cycle gas turbines). Figure 5-17 shows the approximate level of CO_2 formed when combusting various fossil fuels.

[130] Nationally determined contributions under the Paris Agreement – Synthesis report by the secretariat, FCCC/PA/CMA/2021/8, unfccc.int/news/full-ndc-synthesis-report-some-progress-but-still-a-big-concern, last accessed September 21, 2021.

[131] sdg.iisd.org/news/governments-adopt-glasgow-climate-pact-operationalize-paris-agreement/.

While CO_2 emissions related to gas-fired plants are lower on a per-unit-of-energy basis relative to those generated from coal-fired plants, the increase in natural gas-fired power generation in Maryland highlights the fact that carbon emission mitigation cannot be limited to coal-fired plants. Furthermore, 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 the electric utility industry may be facing in upcoming years. See Section 5.1.5 for more information on regulatory considerations.

Figure 5-17 CO_2 Emissions from the Combustion of Fossil Fuels



Carbon dioxide emission mitigation for fossil fuel-derived power has been a debated topic in recent years and includes several alternatives. These CO_2 emission reduction strategies may include improvements to generation efficiency through the development of new plants or upgrades to existing facilities/equipment or substituting a fraction of the fossil fuel 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. One additional alternative that has received significant recent attention, especially at the federal level, is CO_2 capture, utilization and geological storage (CCUS).

CCUS is a term that encompasses the methods and technologies associated with removing CO_2 from flue gas (and therefore the atmosphere), followed by recycling the CO_2 for utilization, then the safe and permanent subsurface storage of the CO_2. Thus, the full CCUS process includes CO_2 capture, CO_2 transportation and the final use and storage of that CO_2. Recent federally funded projects and technological advances have proven that carbon capture from fossil fuel-fired plants is a viable technology that can be scaled for commercial application.

CO_2 Capture

Currently, three general methods are available to capture CO_2 from power plants before it reaches the atmosphere:

- 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 since 2000 for use in the food and beverage industry. 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 offsite via tanker trucks for beneficial use primarily in the food and beverage industry.

Outside of Maryland, several carbon capture demonstration projects are currently under various stages of development in the U.S., most of which are funded by the DOE's 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. Among 11 projects that received funding under DOE, three have been constructed to the point of commercial operation: one at a coal-fired power plant and two at chemical manufacturing facilities. The one project that was completed at the coal-fired power plant was discontinued in 2020 due to changing economic factors for the associated power plant.[132] 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 burdens.

Transporting CO_2

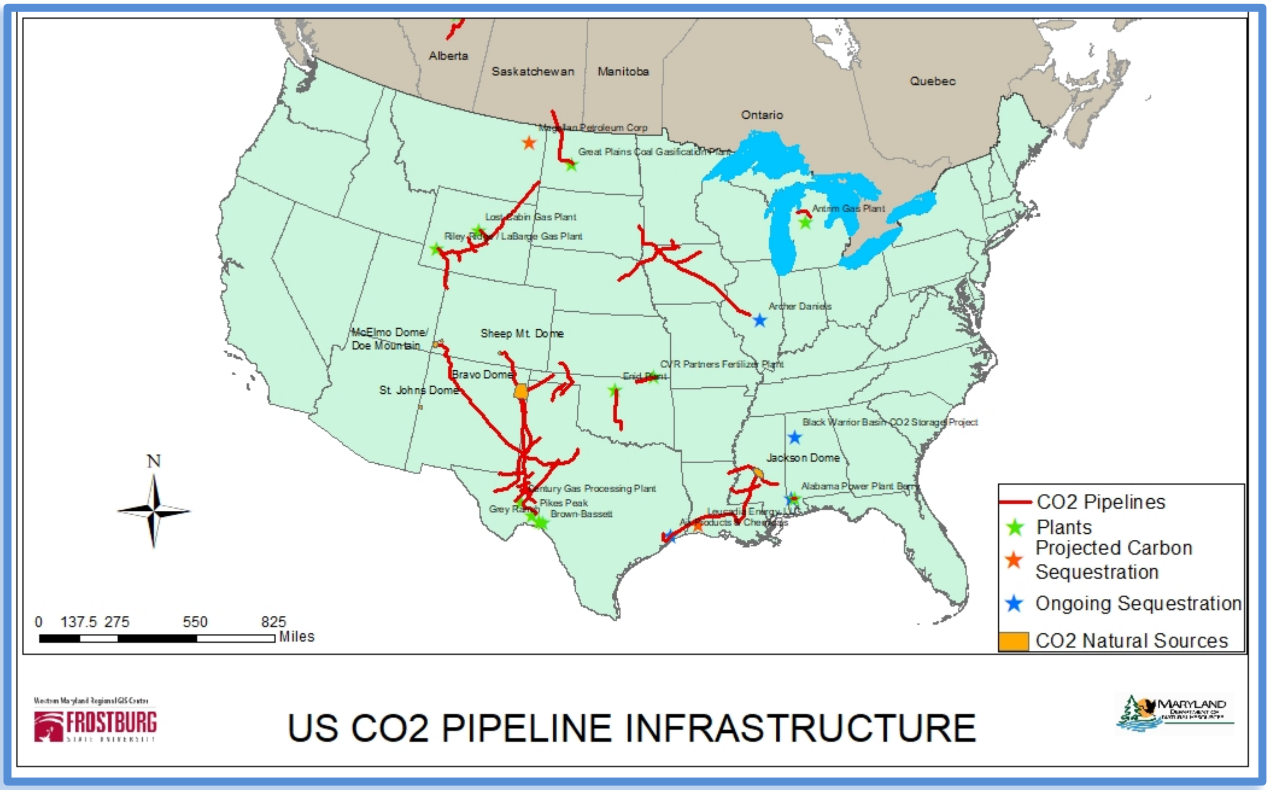
Typically, once CO_2 is captured, it must be highly pressurized and transported via one of several methods, including pipelines, trucks or shipping vessels. Despite potentially being more cost-effective than pipelines for small-scale applications, trucking and shipping transport methods have inherent limitations of volume constraints and intermittency. Thus, for larger-scale CO_2 projects, pipelines may be the most ideal transport method.

To implement carbon capture on the scale necessary to reduce atmospheric CO_2 concentrations, the transportation network of CO_2 from industrial sources to beneficial use or storage sites via pipeline must

[132] United States Government Accountability Office. Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects. Report to Congress GAO-22-105111. 2021. gao.gov/products/gao-22-105111

be greatly expanded beyond current capacities. The U.S. has over a 40-year history of transporting CO_2 via pipelines for CO_2 use in enhanced oil recovery (EOR) 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 (see Figure 5-18).

Figure 5-18 Existing CO_2 Pipeline Network in North America



While the pipeline 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 3-3) 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. These existing gas lines offer a potential opportunity for co-location of CO_2 pipelines should Maryland pursue carbon sequestration in the future.

CO_2 Use and Storage

Even in light of Maryland's multiple projects in the areas of carbon offsets, terrestrial sequestration, renewable energy and switching from coal firing to natural gas, further mitigation of atmospheric CO_2 emissions could be achieved via CCUS. While CO_2 is not a hazardous substance, it is an aggressive gas that carries certain risks and geological sequestration must be approached carefully to achieve the permanent, safe storage of this industrial gas.

Geological Storage and Use of CO_2

Geological sequestration involves injecting CO_2 into underground formations for permanent storage. Subsurface sequestration 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 reactions involving the chemical adsorption of CO_2 due to the potential for CO_2 leakage associated with structural storage. Chemical reactions involving injected CO_2 include capillary attraction in small fractures, physical adsorption of CO_2 known to occur on the surface of rock 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 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.

The primary types of target geological reservoirs are depleted oil and gas fields, unmineable coal seams and deep saline formations. Potential utilization of CO_2 occurs with geological sequestration in oil and gas fields when pressurized CO_2 can be used to displace residual oil and gas, allowing greater extraction volume. 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.

One additional promising means of storing (and using) Maryland CO_2 may be carbon mineralization using fly ash from power plants that do not meet the appropriate chemical specifications for industry use . 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.

Beneficial Use of CO_2

Large-scale regional CO_2 use, in addition to sequestration, could help offset the high costs associated with CO_2 capture and transportation, as demonstrated in many studies.[133,134,135,136] In response to its demonstrated effectiveness in EOR and enhanced gas recovery (EGR), the acceptance of CO_2 as a commodity has been encouraged by the DOE as well as the oil industry.

[133] Mikunda, Tom, Kober, Tom, Coninck, Heleen de, Bazilian, Margan, Rosler, Hilke, van der Zwaan, Bob. "Designing Policy for Deployment of CCS in Industry." Climate Policy. Vol 14, Issue 5. April 28, 2014. 665-676.

[134] Middleton, Richard S., Levine, Jonathan S., Bielicki, Jeffrey M., Viswanathan, Hari S., Carey, J. William, Stauffer, Philip H. "Jumpstarting Commercial-Scale CO2 Capture and Storage with Ethylene Production and Enhanced Oil Recovery in the US Gulf." Greenhouse Gases Science and Technology. Vol. 5, Issue 3: 1-13. June 2015. 241-253.

[135] Rubin, Edward S., Davison, John E., Herzog, Howard J. "The Cost of CO_2 Capture and Storage." International Journal of Greenhouse Gas Control Vol. 40. September 2015. 378-400 dx.doi.org/10.1016/j.ijggc.2015.05.018.

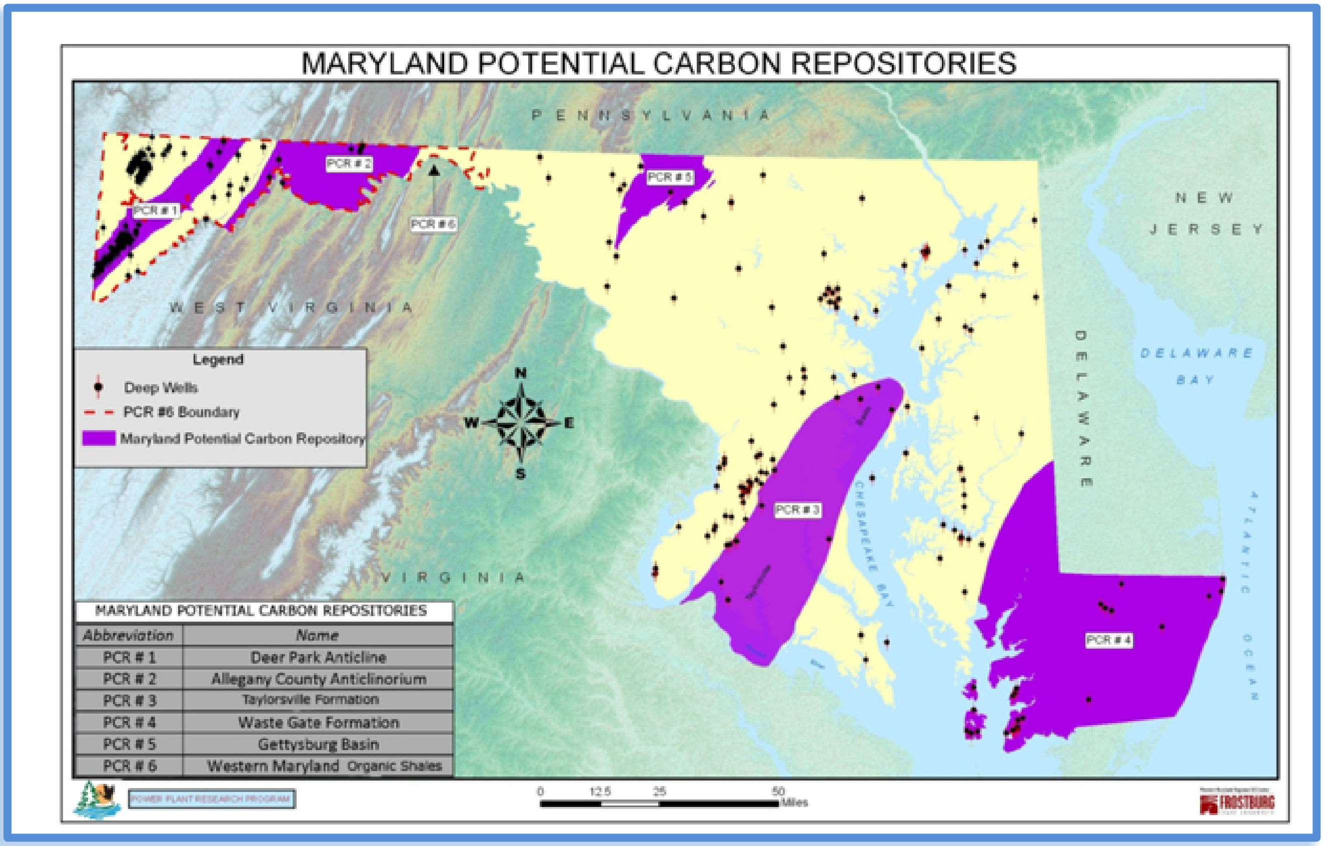
[136] International Energy Agency (IEA), Putting CO2 to Use: Creating Value for Emissions. September 2019. iea.org/reports/putting-co2-to-use.

Most proposed and existing CCUS projects in the U.S. involve EOR and are located in the southern and western states, where mature oil fields are prevalent. DOE has also recently funded extensive research and ongoing projects related to CCUS, also in EOR applications. These projects include new integrated gasification combined cycle (IGCC) facilities, a new oxy-combustion power plant and the retrofit of existing facilities with post-combustion capture technology. Although these projects have demonstrated great potential for CCUS, funding and other technical difficulties have often resulted in delayed start dates or modified project scopes. The single largest barrier to further expanded use of CO_2 in EOR continues to be the lack of available, affordable CO_2 supplies. Of the total CO_2 currently used in EOR, about 25 percent (about 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; therefore, CO_2 emissions are negligible if injected CO_2 is stored in the reservoir when production is complete.

Applicability to Maryland

Since long-term carbon use and storage potential is associated with several geological formation types found in Maryland, including deposits of "unconventional" natural gas, deep saline aquifers and Triassic-age sedimentary basins, Maryland could technically both use and store its power plant CO_2. PPRP has identified six potential formations that could serve as carbon repositories in Maryland (see Figure 5-19). Some geologic and geochemical information is known about these sites from previous oil and gas or other drilling activities. The characteristics of these formations in terms of their potential for adsorption storage of CO_2, however, requires further study. Many of the identified repositories are located in proximity to large natural gas-fired power plants that will remain in use in the future.

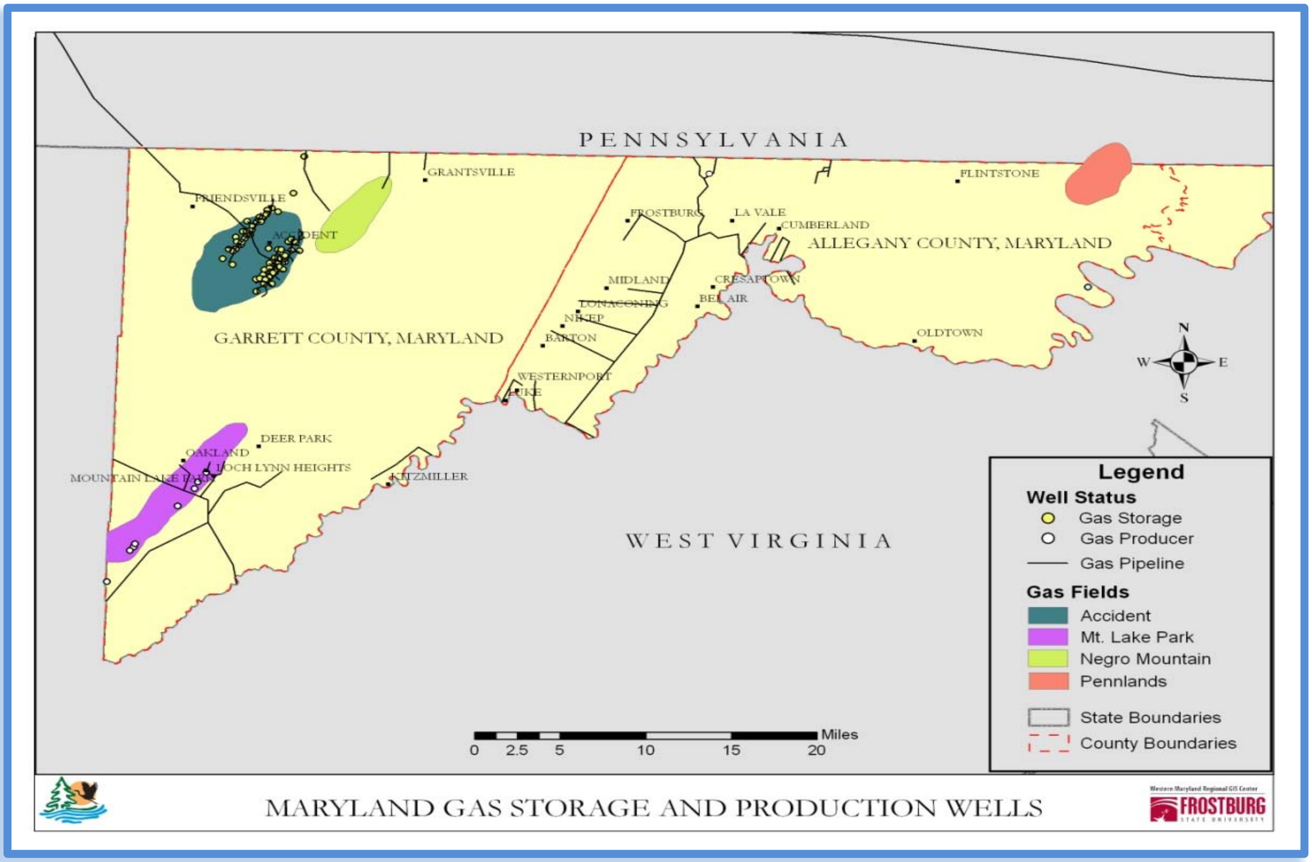
Figure 5-19 Maryland Potential Carbon Repositories



Source: Maryland Department of the Environment and Maryland Department of Natural Resources, “Marcellus Shale Safe Drilling Initiative Study,” December 19, 2014.

As shown in Figure 5-19, the geology of the western portion of Maryland is particularly attractive for the possible storage and use of CO_2. Figure 5-20 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 the western portion of the state that could potentially be used for enhanced recovery of coalbed methane and associated CO_2 storage.

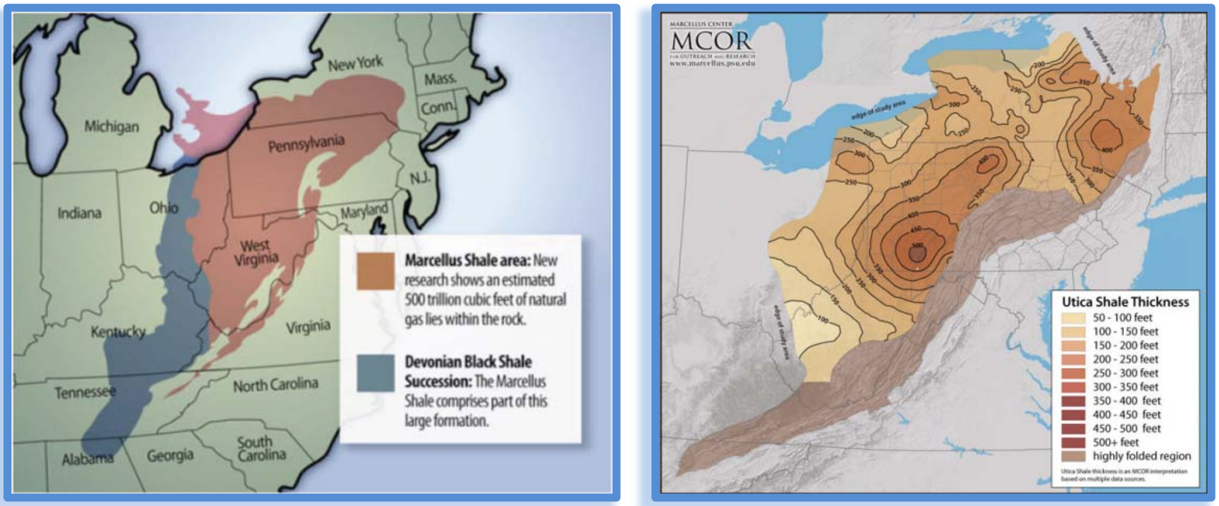
Figure 5-20 Maryland Gas Storage and Production Wells



Source: Maryland Department of the Environment and Maryland Department of Natural Resources, "Marcellus Shale Safe Drilling Initiative Study," December 19, 2014.

Other natural gas 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 Figure 5-21). Both of these 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 adsorption of CO_2 may displace additional natural gas. Although production wells will not be drilled into these formations in Maryland due to Maryland's 2017 law banning hydraulic fracturing, the potential could exist for pipelining Maryland-generated CO_2 to Pennsylvania, Ohio and West Virginia, states that are currently producing gas from these formations.

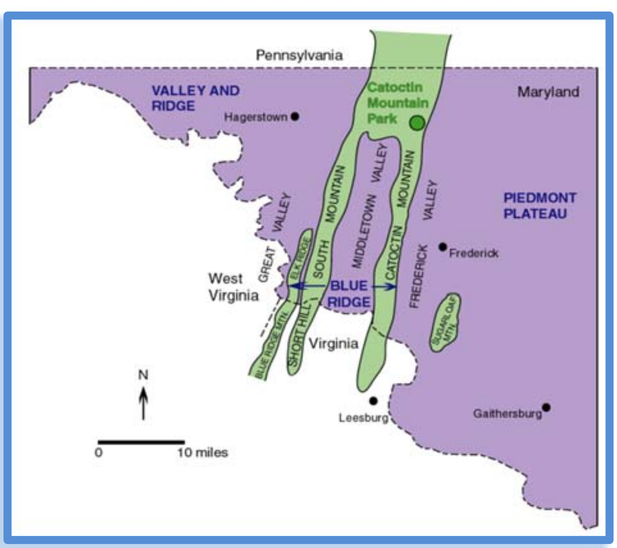
Figure 5-21 Location of the Marcellus and Utica Shale Formations



Source: Maryland Department of the Environment and Maryland Department of Natural Resources, "Marcellus Shale Safe Drilling Initiative Study," December 19, 2014.

Basalt formations in Maryland 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 U.S. and portions of Canada have the potential capacity in basalts to store as much as 5,700 years of CO_2. Figure 5-22 shows the location of the Catoctin Formation, comprised of a metabasalt breccia, which potentially could store CO_2 from Maryland's point sources.

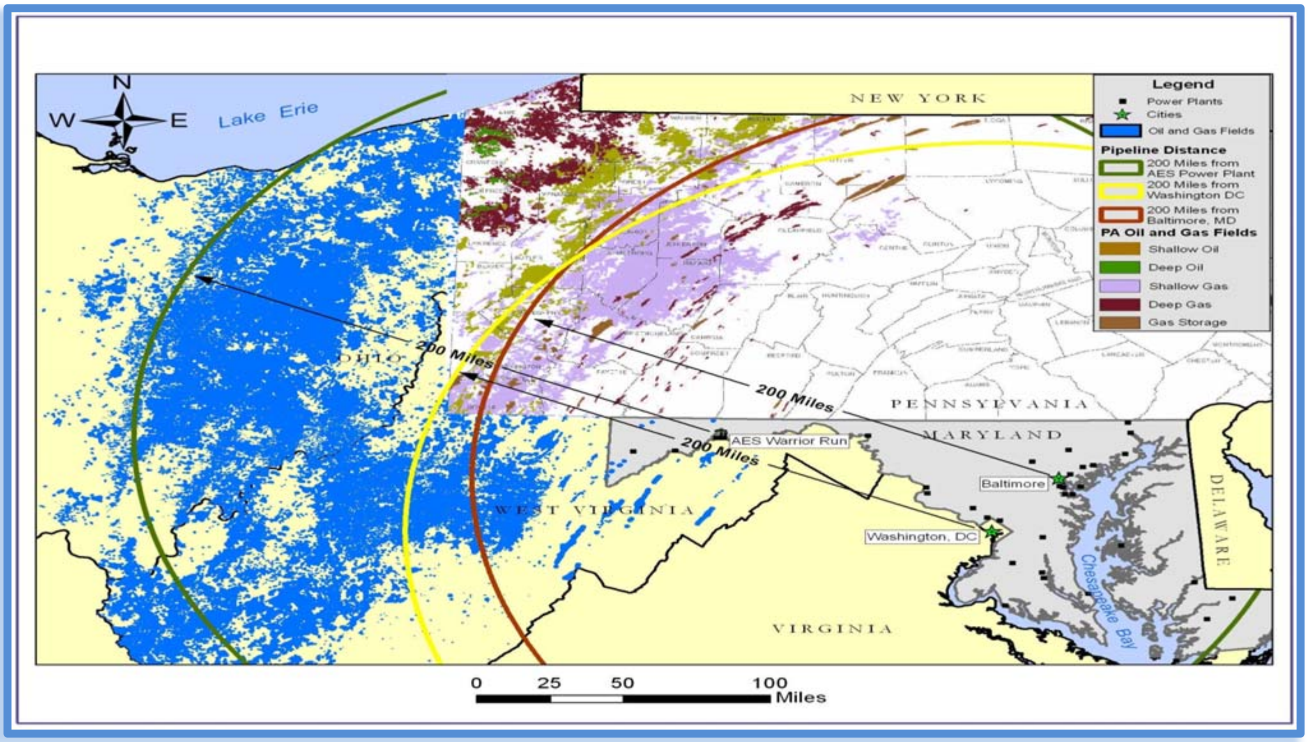
Figure 5-22 Location of the Catoctin Formation, a Regional Basalt Formation



Source: Maryland Department of the Environment and Maryland Department of Natural Resources, "Marcellus Shale Safe Drilling Initiative Study," December 19, 2014.

If and when the local CO_2 market develops, Maryland could also potentially consider pipelining its captured CO_2 to regional EOR projects a bit further away, such as those shown in Figure 5-23. 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. This oil field has the potential to produce significant additional oil via EOR using CO_2 flooding. 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.

Figure 5-23   Regional Oil and Gas Fields



Source: Maryland Department of the Environment and Maryland Department of Natural Resources, “Marcellus Shale Safe Drilling Initiative Study,” December 19, 2014.

Maryland Geological Survey Research

Regional Collaboration

The Maryland Geological Survey (MGS) of the DNR represents Maryland in the Midwest Regional Carbon Sequestration Partnership (MRCSP), which it joined in 2004 to expand its regional sequestration involvement. The MRCSP was established and funded by DOE to assess the technical potential, economic viability and public acceptability of carbon sequestration within a 10-state region—Delaware, Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania and West Virginia. Through its Phase I and Phase II research, the MRCSP determined the estimated carbon sequestration capacity of legacy oil and gas fields, black shales in the Appalachian Basin (from 2.2 to

29.68 billion tons) and assumed storage efficiencies of either saline aquifers (3 percent) or continuous coals (up to 40 percent).

The final phase of the MRCSP, Phase III, was completed in 2021. The phase was a multifaceted project involving large-scale injection of CO_2 for EOR and associated storage at the Core Energy oil field in northern Michigan. Over two million metric tons of CO_2 were successfully injected into the oil fields. The final technical report on the project was published by Battelle in December 2020.[137] A series of detailed reports on all phases of the MRCSP work are available at the Midwest Regional Carbon Initiative (MRCI)[138] website and multiple peer-reviewed papers have also been published. The publications are intended to disseminate research findings related to potential storage capacity, modeling of subsurface geology, formation monitoring techniques and information that provides a better understanding of similar rock formations throughout the region. Battelle reports that the findings of the MRCSP work are now being applied in multiple commercial applications.

Local Research

The MGS has performed local research related to geologic carbon sequestration and coordinates with its regional partners to frame the research into a broader context. Recently, MGS conducted a geologic investigation involving Triassic-age sedimentary basins. The Triassic basins were studied for sequestration potential and to determine internal characteristics of the basins and the capability of permanent seals that would contain injected carbon dioxide.

The study of the stratigraphic architecture, or layer characteristics, and the mappable subdivisions of these layers, within two Triassic Basins, the Culpeper and Gettysburg Basins, resulted in the identification of five distinct assemblages of rock types. These assemblages were formed by alluvial fans, braided and meandering streams, and marginal and distal lake depositional processes. These formation associations were then applied to the 8,000 feet of Triassic rocks that are concealed beneath the Cretaceous and Tertiary Coastal Plain sediments. Analysis of the rock assemblages indicates that the Taylorsville basin, one of several Maryland Triassic Basins buried beneath the Coastal Plain, was filled by fluvial processes to the east and alluvial fan processes to the west. The center of the basin was subject to extensive lake sedimentation. Only high-energy fluvial deposits, such as those found in the eastern side of the Taylorsville basin, appear to be consistent with the characteristics of an effective, conventional CO_2 reservoir.

The presence of thick, consistent intrusive and extrusive formations within the Triassic basins also serve as potential target locations for long-term CO_2 storage. These formations are potentially suitable for sequestration because they provide primary porosity in the form of lava flow top vesicles, are extensively fractured and contain mafic minerals, which may provide sequestration opportunities

[137] Battelle, 2020. Midwest Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase) – Final Technical-Report. December 2020. p9klp4q2un4xmhbtdnet10fu-wpengine.netdna-ssl.com/wp-content/uploads/MRCSP-Final-Technical-Report.pdf, last accessed September 1, 2021.

[138] midwestccus.org/.

through carbonate remineralization. Additionally, extrusive and intrusive igneous rocks are preserved within fine-grained lake deposits that could provide effective sealing potential.[139]

Summary

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. 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. Global policy issues involve the debate over CCUS as a worthwhile investment, and whether CO_2 used for economic gains, 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.

Additional regional economic and other market factors are important to consider for CCUS viability. Shell USA, Inc. is constructing a massive new polyethylene plant in Monaca, Pennsylvania that is expected to open in 2022, and it is difficult to predict the impact this plant could have on the CO_2 capture-and-use market in the Appalachian Basin. 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 continued fuel switching from coal to natural gas and other measures will continue to reduce CO_2 production in Maryland.

[139] Brezenski, David and Rebecca Kavage Adams, Exposed Triassic Basins as Proxies for the Understanding of Buried Rift Successions. Maryland Geological Survey Report of Investigations No. 88. January 2021.

5.2 Impacts on Water Resources

5.2.1 Physical and Chemical Impacts

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 groundwater withdrawals, consumption and discharges in Maryland from power plant operations. It also describes potential resource impacts and methods for minimizing any adverse impacts. Section 5.2.2 discusses the effects of generation facilities and transmission lines on aquatic resources.

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 into 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.[140] Together, these rivers and the Chesapeake Bay extend over a large geographic area and encompass a broad range of aquatic habitat types, including marine, estuarine and freshwater rivers and 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.[141] 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 usually met by onsite wells or municipal water systems.

Cooling water withdrawals at steam electric facilities represent the majority of surface water usage in Maryland. In 2020, combined water withdrawal for all steam generating power plants in Maryland was estimated at approximately 4.9 billion gallons per day. All other non-power plant users in the state had 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 18 billion gallons per day (actual daily flows in both the Susquehanna and the Potomac fluctuate greatly, both seasonally and from year to year).

Table 5-4 lists all major steam-generating power plants in Maryland (excluding self-generators) and quantifies their water withdrawals and consumption for 2019 and 2020. The plants are grouped into two categories: those that use once-through cooling, and those with closed-cycle cooling systems.

[140] The Youghiogheny is the one river that drains into the Ohio water basin.

[141] Combustion turbines have minimal water needs in comparison; however, they do consume water to control emissions and improve efficiency. This water must be high quality because it comes in direct contact with turbine surfaces. Therefore, it is generally sourced from groundwater or purchased water supply.

Table 5-4 Surface Water Appropriations and Use at Maryland Power Plants with Steam Cycles

Power Plant	Surface Water Appropriation (average, mgd)	2019 Actual Surface Withdrawal (average, mgd)	2020 Actual Surface Withdrawal (average, mgd)	Estimated Consumption (mgd)	Water Source
Once-Through Cooling					
Calvert Cliffs	3,500	3,339	3,348	18.22	Chesapeake Bay
Chalk Point	700	163 (a)	44	0.42	Patuxent River
Dickerson	400	106	61	0.34	Potomac River (nontidal)
H.A. Wagner	940	154	79	0.67	Patapsco River
Morgantown	1,500	940	694	1.74	Potomac River
Wheelabrator	50	40.3	34.3	0.15	Gwynns Falls
SUBTOTAL	**7,110**	**4,742.3**	**4,260.4**	**21.54**	
Closed-Cycle Cooling					
AES Warrior Run (b,c)	0.021	0.164	0.183	0.11	City of Cumberland
Brandon Shores	35	11.31	0.67	3.89	Patapsco River (Wagner discharge)
Chalk Point	20	- (a)	0.113	0.0002	Patuxent River
CPV St. Charles	N/A	859.4	806.5	514.4	Mattawoman WWTP
Montgomery Co. Resource Recovery Facility	1.342	0.79	0.33	0.36	Potomac River (Dickerson Station's discharge canal – nontidal)
KMC Thermo – Brandywine (c)	N/A	0.580	0.731	0.426	Mattawoman WWTP
Vienna	2.0	0.0117	0.0068	0.006	Nanticoke River
SUBTOTAL	**38.4**	**9.39**	**9.62**	**6.18**	
TOTAL	**7,189**	**3,291**	**4,948**	**25.5**	

Source: MDE Water Management Administration (WMA).
mgd = million gallons per day.
WWTP = wastewater treatment plant.

(a) Chalk Point has two units on once-through cooling and two on closed-cycle cooling. Through 2019, the appropriation of 720 mgd covered all four steam units; the plant did not report data to MDE WMA on each cooling system separately. The facility requested that the permits be separated beginning in 2020.

(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.

(c) 2019 and 2020 withdrawal data for AES Warrior Run and KMC Thermo – Brandywine is unavailable. Table reflects estimated annual withdrawals based on previously reported data.

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 typically consume 1.5 to 2 times more water per MWh than once-through systems. Values are shown in units of millions of gallons per day (mgd).

Six steam power plants in Maryland—AES Warrior Run, Brandon Shores, CPV St. Charles, Montgomery Co. Resource Recovery Facility, KMC Thermo 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. In Table 5-4, the estimated consumption values for closed-cycle systems are calculated assuming 65 percent of the surface water withdrawals are lost to evaporation. One more recently constructed steam power plant—Wildcat Point in Cecil County—also uses closed-cycle cooling, but it obtains water via direct withdrawal from the Susquehanna River in Pennsylvania and thus is not subject to Maryland appropriations permitting.

Nuclear power plants also fall within the steam generating category; however, they use nuclear reactions instead of fossil fuel combustion to create the needed 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 since nuclear stations generally operate at a lower steam temperature and pressure compared to fossil fuel-fired generating plants. This results in 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.

Calvert Cliffs Nuclear Power Plant (CCNPP) withdraws an average of 3.3 billion gallons per day directly from the Chesapeake Bay. This is the largest single appropriation of water in Maryland and is roughly 13 times larger than the municipal supply for the Baltimore City metropolitan area (250 mgd). While the majority of the water withdrawn by Calvert Cliffs is returned to the Chesapeake Bay, an estimated 18 mgd is lost to evaporation as a result of the heated discharge (see Table 5-4).

Although 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 groundwater 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 the allocation and under what conditions competing uses have to be curtailed or prioritized.

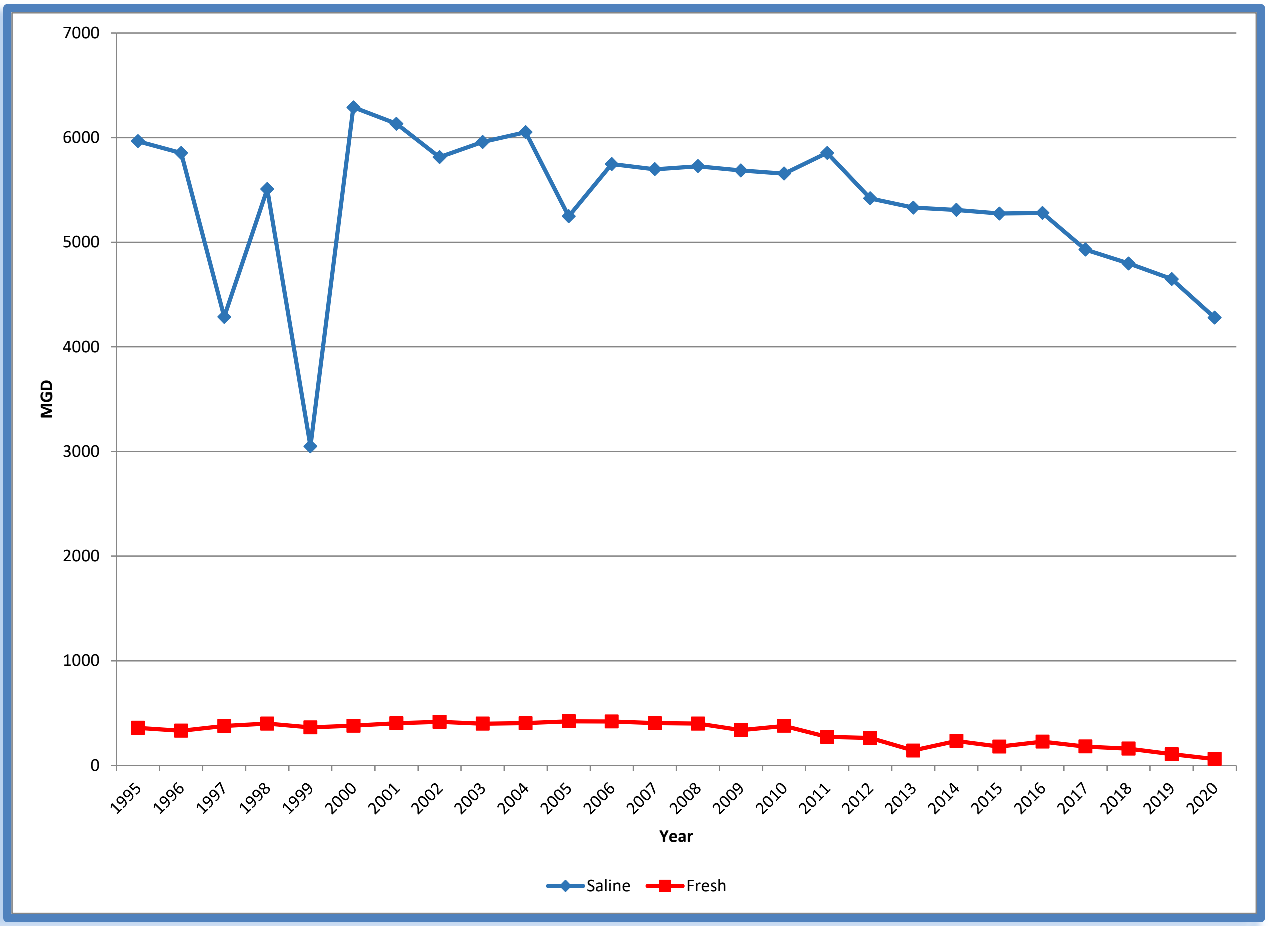
For power plants with closed-cycle cooling systems, the evaporative losses to the atmosphere can be calculated as the difference between water withdrawn and water discharged. However, most steam plants in Maryland use once-through cooling, in which cooling water is continuously drawn from a water source, used and then continuously returned to (usually) the same source. While water losses within the cooling system itself are negligible, the water discharged is at a higher temperature and this results in elevated evaporative losses in the receiving waters. 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 instream evaporative losses caused by heated discharges from 14 Maryland power plants. The ICPRB found that, on average, instream 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 Chesapeake 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 the consumptive loss is not a concern. By contrast, consumptive loss in nontidal riverine systems can adversely affect aquatic habitats and other users of the water body.

In addition to cooling systems, air pollution control systems at power plants can also require water appropriations. As a result of the Healthy Air Act, Maryland's three largest coal-fired power plants—Brandon Shores, Chalk Point, and Morgantown—operate wet flue gas desulfurization (FGD) systems. Morgantown uses surface water for its wet FGD system, Brandon Shores uses reclaimed wastewater, and Chalk Point uses groundwater. Over the past two years, as the generating output of coal-fired plants in Maryland has declined, the amount of water required for wet scrubbing has also declined; this trend is expected to continue. The Dickerson plant in Montgomery County used surface water from the Potomac River to operate its FGD system up until 2020 when its coal-fired units ceased operations. By 2025, all coal units in Maryland that are currently using wet FGD systems are scheduled to stop burning coal.

Figure 5-24 summarizes average surface water withdrawals in Maryland per year. Withdrawals are summed by freshwater and saline water sources, inclusive of all surface water sources used by the power plants in Table 5-4.

Figure 5-24 Average Daily Surface Water Withdrawals (1995-2020), in million gallons per day



Surface water withdrawals from saline sources far exceed those from freshwater sources in Maryland. The largest saline withdrawals come from the Chesapeake Bay and are associated with Maryland's one nuclear facility, Calvert Cliffs (see additional discussion of trends by fuel type). Other significant water sources include the Potomac, Patuxent and Patapsco rivers. For each of these water bodies, other than the Potomac, all withdrawals are from saline portions of the rivers. For the Potomac, typically more than 70 percent of the annual withdrawals are from saline portions of the river.

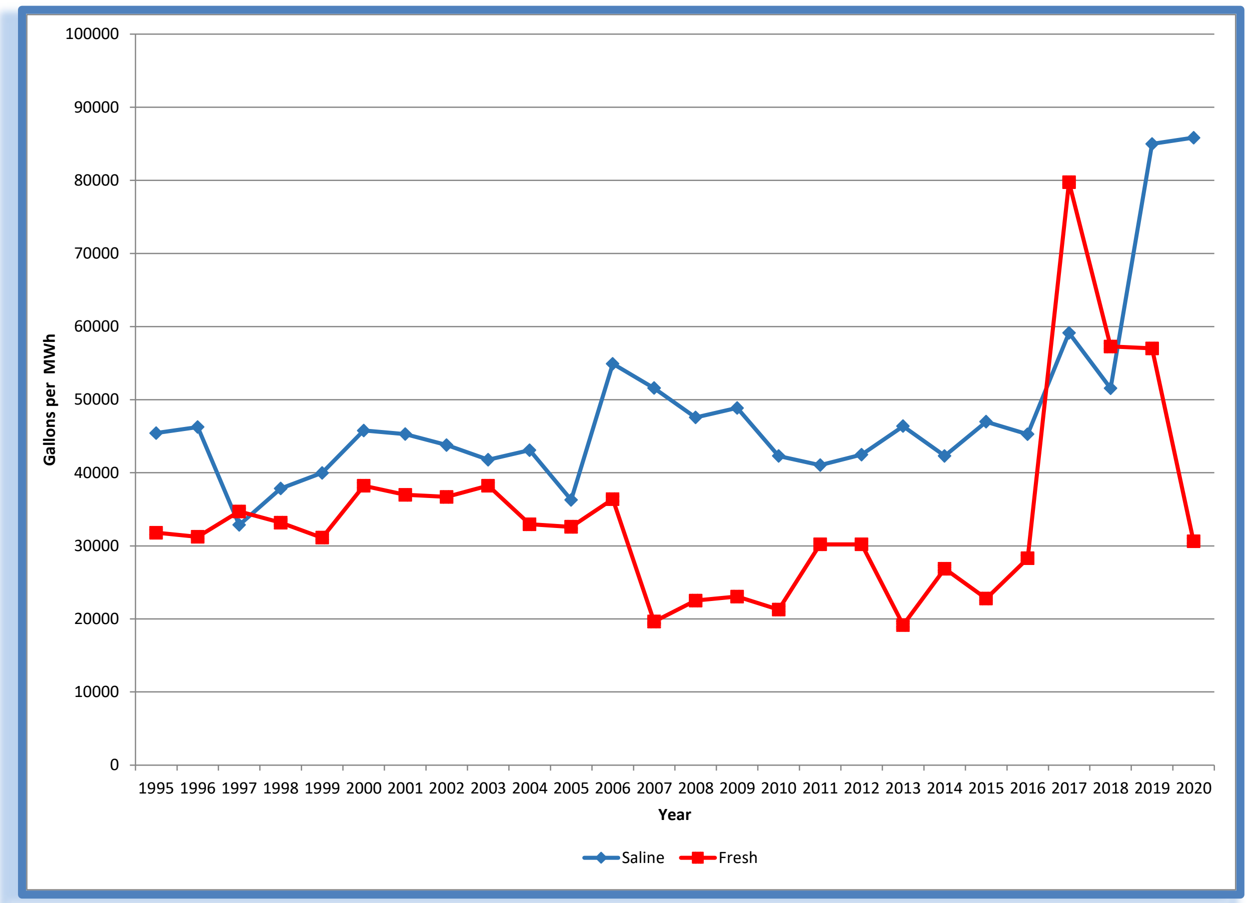
For those direct surface water withdrawals included in this section's evaluation, only two are fresh (nontidal) sources. Nontidal withdrawals from the Potomac River (which generally account for 30 percent or less of all Potomac withdrawals) are associated with the Dickerson plant and the Montgomery County Resource Recovery Facility.

Other water sources used by Maryland power plants include water from the City of Cumberland for the AES Warrior Run facility, and reclaimed water from the Mattawoman Wastewater Treatment Plant (WWTP) and the Cox Creek WWTP. In Figure 5-24, these sources have been grouped together with the freshwater withdrawals from the Potomac River.

Saline withdrawals have been more variable than freshwater withdrawals over the 25-year period. The most notable shifts in saline withdrawals occurred in 1997-1998, 2005 and 2012 (see Figure 5-24). The 1997-1998 and 2005 decreases in withdrawal volume are primarily related to temporary shutdowns at Morgantown during those periods. The 2012 decrease is primarily due to the shutdown of the R.P. Smith facility. Other than these dips, saline surface water withdrawals have shown a gradual decline over the last 25 years. The total annual volume of freshwater withdrawals has been less variable over the study period but has declined slightly over the past 15 years (2005-2018).

Another important consideration in evaluating Maryland's surface water withdrawals is to evaluate them relative to the net electricity generation of the associated power plants. Figure 5-25 shows the average surface water withdrawals per year, per MWh of net electricity generation.

Figure 5-25 Average Surface Water Withdrawals per MWh (1995-2020)



Far fewer power plants use freshwater sources, so after normalizing for net generation, the saline and freshwater withdrawals are more similar in magnitude.

Fuel Type Trends

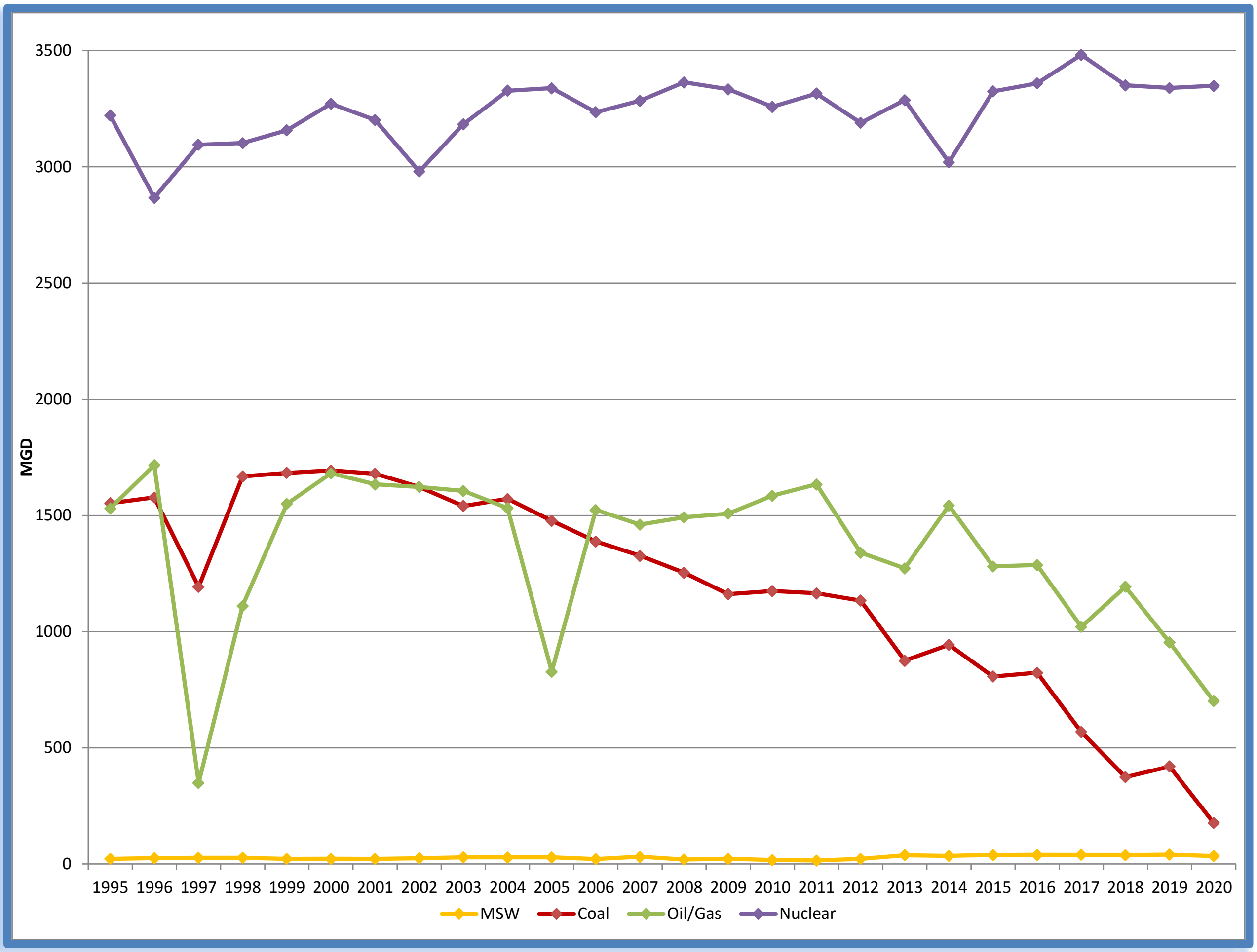
This section looks at trends relative to different fuel types, namely nuclear, coal, fossil (natural gas and fuel oil) and municipal solid waste (MSW). Table 5-5 summarizes average withdrawals per year by fuel source. Values are first shown in units of MGD and then on a percent basis. The withdrawals include only surface water.

Table 5-5 Average Surface Water Withdrawals by Fuel Type (1995-2020)

Year	Volume Rate (MGD)				Percent Contribution			
	Nuclear	Coal	Natural Gas/Oil	MSW	Nuclear	Coal	Gas/Oil	MSW
1995	3,221	1,553	1,530	23	50.92%	24.54%	24.2%	0.36%
1996	2,866	1,577	1,716	25	46.34%	25.60%	27.9%	0.41%
1997	3,095	1,192	349	27	66.36%	25.72%	7.5%	0.58%
1998	3,102	1,668	1,111	27	52.51%	28.36%	18.9%	0.46%
1999	3,157	1,683	1,550	22	49.24%	26.34%	24.3%	0.35%
2000	3,271	1,693	1,681	23	49.06%	25.48%	25.3%	0.34%
2001	3,201	1,680	1,633	22	48.98%	25.78%	25.1%	0.34%
2002	2,980	1,622	1,603	25	47.83%	26.14%	25.8%	0.40%
2003	3,183	1,541	1,605	29	50.06%	24.34%	25.4%	0.45%
2004	3,327	1,571	1,531	28	51.53%	24.43%	23.8%	0.44%
2005	3,338	1,476	827	29	58.87%	26.17%	14.7%	0.51%
2006	3,235	1,389	1,523	21	52.45%	22.60%	24.8%	0.34%
2007	3,284	1,326	1,461	31	53.81%	21.85%	24.1%	0.51%
2008	3,363	1,254	1,492	20	54.88%	20.52%	24.4%	0.32%
2009	3,333	1,162	1,508	23	55.32%	19.35%	25.1%	0.38%
2010	3,258	1,175	1,585	17	53.99%	19.52%	26.3%	0.28%
2011	3,315	1,165	1,633	15	54.09%	19.05%	26.7%	0.25%
2012	3,189	1,134	1,339	22	56.10%	20.02%	23.7%	0.39%
2013	3,287	875	1,272	38	60.06%	16.10%	23.4%	0.70%
2014	3,019	943	1,543	36	54.49%	17.13%	28.0%	0.64%
2015	3,324	807	1,280	39	60.99%	14.91%	23.7%	0.71%
2016	3,359	823	1,286	39	60.99%	15.05%	23.5%	0.71%
2017	3,482	568	1,021	40	68.12%	11.21%	20.1%	0.79%
2018	3,350	374	1,193	38	67.60%	7.60%	24.3%	0.78%
2019	3,339	420	953	41	70.24%	8.83%	20.06%	0.86%
2020	3,348	161	718	35	78.56%	4.16%	16.46%	0.81%

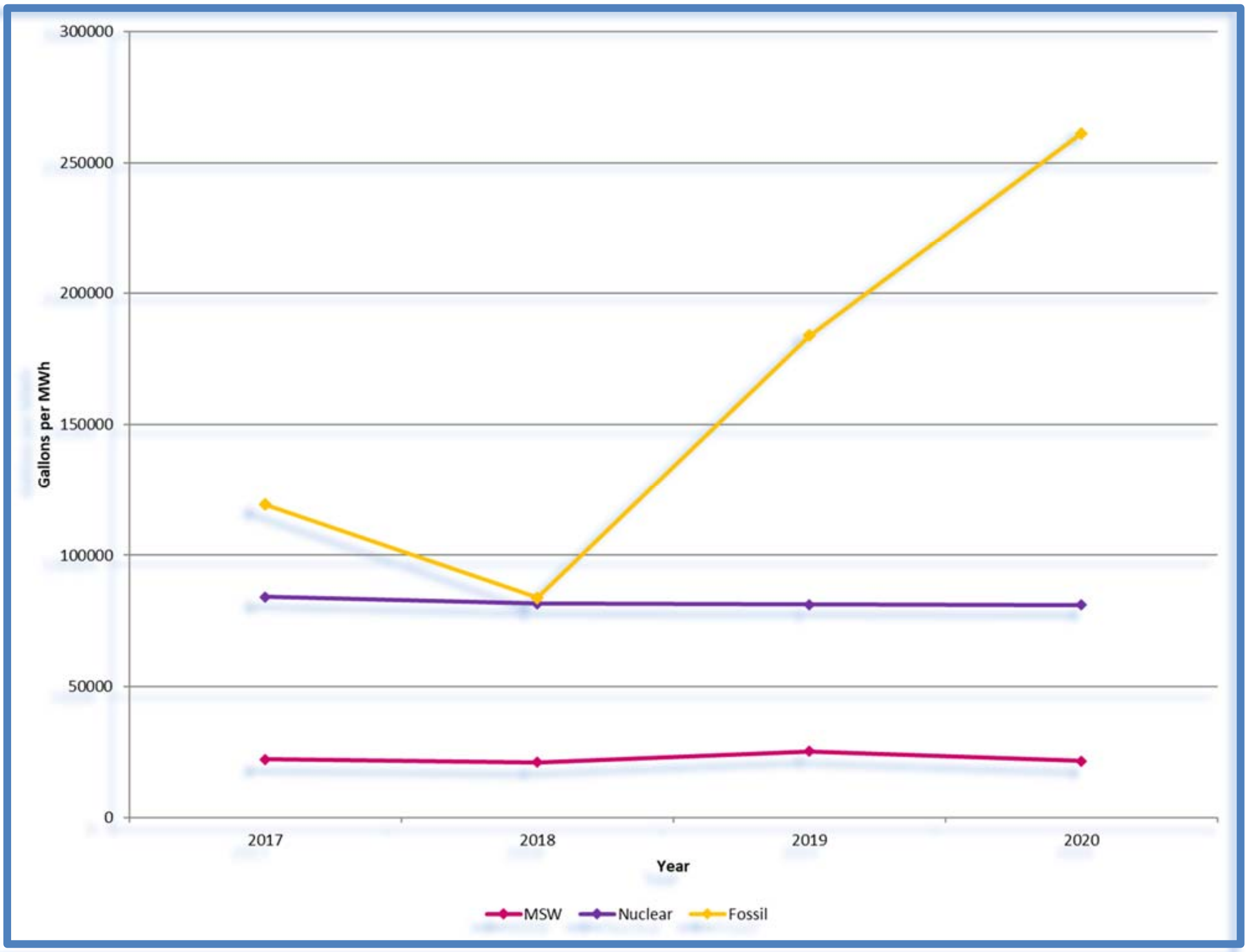
Figure 5-26 provides a visual depiction of the trends over time for power plant water withdrawals, broken down by fuel type. The notable decline in water withdrawals associated with coal-fired generation reflects the decreasing utilization of coal plants in Maryland.

Figure 5-26 Average Surface Water Withdrawals by Fuel Type (1995-2020)



These withdrawals can also be evaluated relative to the associated power plants' net electricity generation. Figure 5-27 shows withdrawals relative to net generation, in units of gallons per MWh. Nuclear withdrawals from Calvert Cliffs are significantly greater, in part because nuclear generation creates more waste heat than fossil fuel combustion, and also because the other fuel types in Figure 5-27 represent a combination of once-through and closed-cycle cooling systems.

Figure 5-27 Average Surface Water Withdrawals per MWh, by Fuel Type (2017-2020)



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 onsite 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 onsite water storage is to reduce the risk of curtailment, not eliminate it.

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 groundwater 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.

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 no longer 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 per MWh is higher than that of once-through cooling.

The reuse of effluent from wastewater treatment plants (WWTPs) is becoming an acceptable and viable water supply option. This grants some flexibility in siting

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—KMC Thermo 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, and in 2016, the guidelines were revised. 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 discharge permit from MDE before supplying Class IV reclaimed water;
- Requirement that a WWTP obtain a construction permit from MDE before constructing or expanding current facilities for the distribution of 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 Maryland PSC has included when approving new or modified facilities that use reclaimed water for cooling.

plants close to sources of reclaimed wastewater for cooling water supply, rather than relying on direct surface water withdrawals. The KMC Thermo combined cycle facility, located near Brandywine in Prince George's County (formerly owned by Panda), currently utilizes about 0.5 to 1 mgd of treated effluent from the Mattawoman WWTP for its cooling water needs. CPV Maryland in Charles County, another combined cycle gas-fired plant, began operating in 2018 and also utilizes Mattawoman WWTP effluent. 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.

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 water body.

Dry cooling systems, or the use of air-cooled condensers, are also making significant inroads in the power industry. 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. Dry cooling is a more viable technology option in the western United States compared to the East Coast. The Keys Energy Center combined cycle facility in Prince George's County became the first major power plant in Maryland to use dry cooling when it began operating in July 2018.

Groundwater Withdrawals

The use of groundwater for process cooling is severely restricted in Maryland, but some of Maryland's power plants are significant users of groundwater for other purposes. Groundwater 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 groundwater 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 groundwater are available in the Coastal Plain aquifers, withdrawals must be managed over the long term to ensure adequate groundwater supplies for the future.

The impact of these withdrawals has been a key issue in Southern Maryland, where there is a significant reliance on groundwater for public water supply. Currently, five power plants withdraw groundwater from Southern Maryland Coastal Plain aquifers for plant operations: Constellation Energy Corporation's Calvert Cliffs Nuclear Power Plant, NRG's Chalk Point and Morgantown power plants, NRG's combustion turbine facility (located at the Chalk Point plant and formerly owned by Southern Maryland Electric Cooperative (SMECO)) and KMC Thermo's combined cycle power plant. These five plants have historically withdrawn groundwater from three aquifers in Southern Maryland: the Aquia, the Magothy and the Patapsco. Chalk Point began withdrawing groundwater from the deeper Patuxent Aquifer in 2009.

Four additional power plants utilize groundwater, but these facilities withdraw groundwater from sources other than the Coastal Plain aquifers: Dickerson, located in Montgomery County (New Oxford Formation); Perryman, located in Harford County northeast of Baltimore (Talbot Aquifer); Rock

Springs, located in Cecil County (Baltimore Gabbro Complex); and Vienna, located in Dorchester County on the Eastern Shore (Columbia Group Aquifer).

Figure 5-28 shows the groundwater withdrawal rates expressed as daily averages from 2000 to 2020 for each of the power plants. The withdrawal rates and associated appropriation limits are also listed in Table 5-6.

Figure 5-28 Average Daily Groundwater Withdrawal Rates at Maryland Power Plants

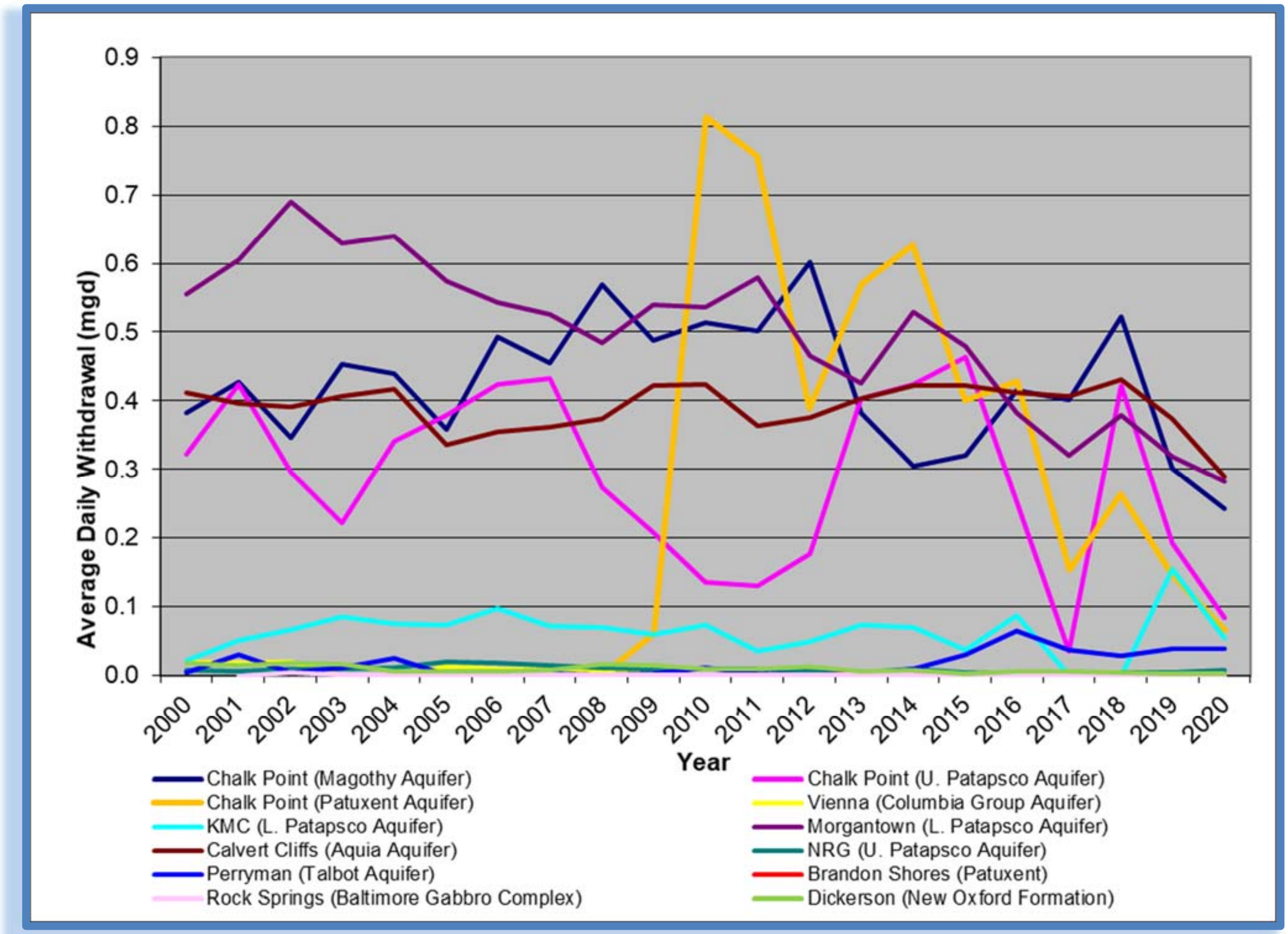


Table 5-6 Average Daily Groundwater Withdrawal Rates at Maryland Power Plants (in mgd)

	Chalk Point (Magothy Aquifer)	Chalk Point (U. Patapsco Group Aquifer)	Chalk Point (Patuxent Aquifer) See Note (a)	Vienna (Columbia Aquifer)	Panda (L. Patapsco Aquifer)	Morgantown (L. Patapsco Aquifer)	Calvert Cliffs (Aquia Aquifer)	SMECO (U. Patapsco Aquifer)	Perryman (Talbot Aquifer)	Brandon Shores (Patuxent)	Rock Springs (Baltimore Gabbro Complex)	Dickerson (New Oxford Formation)	Total Average Daily Withdrawal
Current Appropriation Limit	0.66	1.02	0.66	0.035	0.074[b]	0.7	0.45	0.02	0.942	0.0099	5.5 E-3	0.0055	3.9
2000	0.382	0.322		0.019	0.022	0.555	0.412	0.008	0.005			0.018	1.7
2001	0.427	0.425		0.018	0.051	0.605	0.396	0.007	0.031		0.00000	0.015	2.0
2002	0.346	0.296		0.020	0.067	0.689	0.392	0.009	0.004		0.00463	0.017	1.8
2003	0.454	0.222		0.023 See Note (b)	0.086	0.630	0.407	0.009	0.010		0.00070	0.017	1.9
2004	0.439	0.341		0.008 See Note (c)	0.075	0.641	0.416	0.011	0.025		0.00011	0.006	2.0
2005	0.359	0.379		0.013	0.074	0.574	0.336	0.020	0.001		0.00008	0.006	1.8
2006	0.494	0.425		0.009	0.097	0.543	0.354	0.018	0.002		0.00011	0.007	1.9
2007	0.454	0.432	0.000	0.009	0.072	0.526	0.362	0.015	0.002		0.00010	0.007	1.9
2008	0.570	0.274	0.000	0.008	0.069	0.485	0.375	0.011	0.001		0.00010	0.017	1.8
2009	0.488	0.209	0.060	0.005	0.059	0.540	0.422	0.010	0.002		0.00012	0.015	1.8
2010	0.514	0.135	0.813	0.000	0.073	0.536	0.423	0.010	0.011		0.00012	0.009	2.5
2011	0.502	0.131	0.756	0.000	0.035	0.579	0.364	0.010	0.002		0.00010	0.010	2.4
2012	0.601	0.178	0.389	0.001	0.049	0.465	0.375	0.006	0.000	0.00000	0.00011	0.014	2.1
2013	0.382	0.403	0.571	0.000	0.073	0.426	0.404	0.004	0.003	0.00384	0.00009	0.006	2.3
2014	0.304	0.425	0.626	0.000	0.070	0.530	0.423	0.010	0.010	0.00011	0.00005	0.009	2.4
2015	0.320	0.464	0.400	0.000	0.038	0.479	0.422	0.005	0.030	0.00015	--	0.003	2.2
2016	0.415	0.253	0.428	0.000	0.087	0.382	0.412	0.003	0.065	0.00009	--	0.006	2.1
2017	0.402	0.035	0.153	0.0002		0.320	0.406	0.003	0.037	0.00009	--	0.006	1.4
2018	0.522	0.423	0.264	0.000		0.379	0.431	0.005	0.029	0.00005	--	0.004	2.1
2019	0.301	0.193	0.145	0.000	0.154	0.318	0.374	0.005	0.038	0.00004	--	0.002	1.5
2020	0.242	0.084	0.065	0.000	0.054	0.282	0.289	0.007	0.038	0.00003	--	0.002	1.1

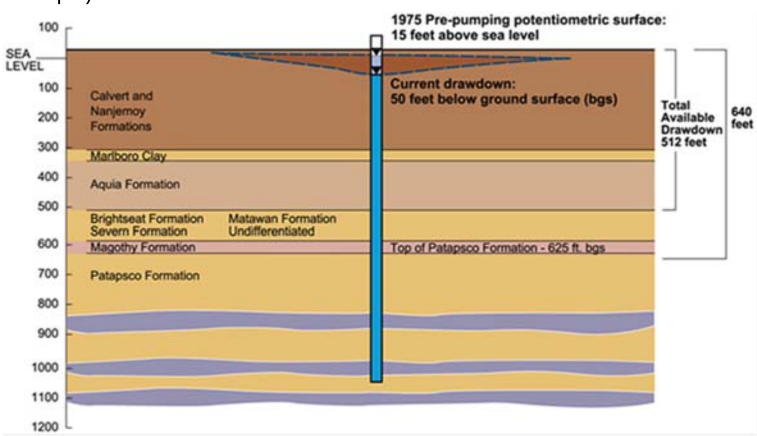
Source: U.S. Geological Survey, MDE WMA.
Note (a): Well was installed in 2007. Routine withdrawal did not occur until approximately 2009.
Note (b): No report was submitted to MDE for the period July – December 2003. The amount shown was estimated using the total volume withdrawn of 4,131,683 gallons reported for the period January – June 2003.
Note (c): 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 – December 2004.

As noted in Table 5-6, power plants typically withdraw groundwater at rates well below their appropriation permit limits. The average withdrawal for seven power plants in 2020 was 1.0 mgd compared to a combined daily appropriation limit of 3.9 mgd. The total amount of groundwater withdrawn by power plants has fluctuated between about 1.1 and 2.5 mgd over the past 40 years.

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

Evaluating Drawdown Impacts

Long-term monitoring data show how pumping from a groundwater aquifer affects the water level over time. MDE regulations define "available drawdown" in an aquifer as 80 percent of its historical 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).



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 historical 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.

Impacts to water quantity for each of the Coastal Plain aquifers are summarized below.[142,143]

- Aquia Aquifer at Calvert Cliffs – Water levels in the Aquia Aquifer at Calvert Cliffs declined approximately 82 feet from 1982 to 2019, with most of the decline occurring post-1990. This acceleration in water level decline is due to withdrawals from municipal well fields at Lexington

142 Andrew W. Staley, David C. Andreasen, and Stephen E. Curtin, Potentiometric Surface and Water-Level Difference Maps of Selected Confined Aquifers in Southern Maryland and Maryland's Eastern Shore, 1975-2015, Maryland Department of Natural Resources, mgs.md.gov/reports/OFR_16-02-02.pdf.

143 Andrew W. Staley, David C. Andreasen, and Elizabeth H. Marchand, Potentiometric Surface Maps of Selected Confined Aquifers in Southern Maryland and Maryland's Eastern Shore, 2019, Maryland Department of Natural Resources, mgs.md.gov/reports/OFR_20-02-01.pdf.

Park in St. Mary's County and Solomons Island in Calvert County. The water levels at Lexington Park and Solomons Island have declined nearly 115 feet and 101 feet, respectively, since 1982. The impacts from the water level decline are considered acceptable given the estimated 325 feet of available drawdown in the Aquia Aquifer at Calvert Cliffs (based on MDE's available drawdown criteria described above). Withdrawals from the Aquia Aquifer have increased from approximately 5 mgd in 1982 to 13 mgd in 2014 and 13.5 mgd in 2018.

- 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 groundwater withdrawals from the Magothy Aquifer from 1990 to 2015 by about 45 percent compared to its withdrawals prior to 1980. This reduction has resulted in a commensurate decrease in the rate of water level decline in the portion of the aquifer near the facility during this same period. However, water levels continue to decline in the aquifer as a whole due to its extensive continued use in Annapolis, Easton and Waldorf. The drawdown at Chalk Point has been approximately 41 feet between 1975 and 2015, and a total of about 81 feet since pumping at Chalk Point began in 1964. In 1962, prior to the start of pumping, the elevation of the potentiometric head in the Magothy Formation at Chalk Point 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 81 feet is small compared to the estimated total available drawdown of approximately 500 feet for the Magothy Formation in the vicinity of Chalk Point. Withdrawals from the Magothy Aquifer have increased from approximately 7 mgd in 1975 to 8 mgd in 2014 and 9.5 mgd in 2018.

- Upper Patapsco Aquifer at Chalk Point – The water surface level surface in the Upper Patapsco Aquifer has declined 51 feet in the vicinity of Chalk Point since 1990. This decline will not impact the approximately 550 feet of available drawdown for the Upper Patapsco Aquifer in the vicinity of Chalk Point. Withdrawals from the Upper Patapsco Aquifer have decreased from approximately 13 mgd in 2014 to 9.5 mgd in 2018.

- Lower Patapsco Aquifer at Morgantown – The water surface level of the Lower Patapsco Aquifer in the vicinity of the Morgantown power plant declined 30 feet between 1990 and 2014 and another 10 feet between 2014 and 2019. However, this decline is small compared to the available drawdown, which is approximately 600 feet. Withdrawals from the Lower Patapsco Aquifer have increased from 24 mgd in 2014 to 27.5 mgd in 2018.

- Patuxent Aquifer at Chalk Point & Brandon Shores – Between 2007 and 2014, the water surface level of the Patuxent Aquifer declined approximately 75 feet as a result of withdrawal at the Chalk Point power plant. Water levels in western Charles County have declined as rapidly as 10 feet per year between 2007 and 2014, which is one of the highest rates of water decline in the Coastal Plain aquifers of Maryland over that period. However, the overall decline noted is small compared to the approximately 1,450 feet of available drawdown in the Patuxent Aquifer at Chalk Point. The Brandon Shores power plant has only recently (i.e., since 2012) begun withdrawing water from the Patuxent Aquifer. This is a very small withdrawal quantity for emergency use only. Withdrawals in the Patuxent Aquifer have increased from 18 mgd in 2007 to 24 mgd in 2014 and 24.5 mgd in 2019.

Based on data from USGS monitoring well surveys from 2019 to 2020, the rate of drawdown is not changing significantly; thus, the impacts continue to be acceptable.

MGS Online Potentiometric Surface Maps

The Maryland Geological Survey (MGS) has now made available on its website the biannual reports that contain potentiometric surface maps for the Coastal Plain aquifers of Maryland. The reports include descriptions of the study areas of five different aquifers, their latest potentiometric contour updates, and well data that define the contours. The reports also provides summaries of the observations for the survey period. The most recent report, containing data collected during 2019, can be found at: OFR 20-02-01 (md.gov)

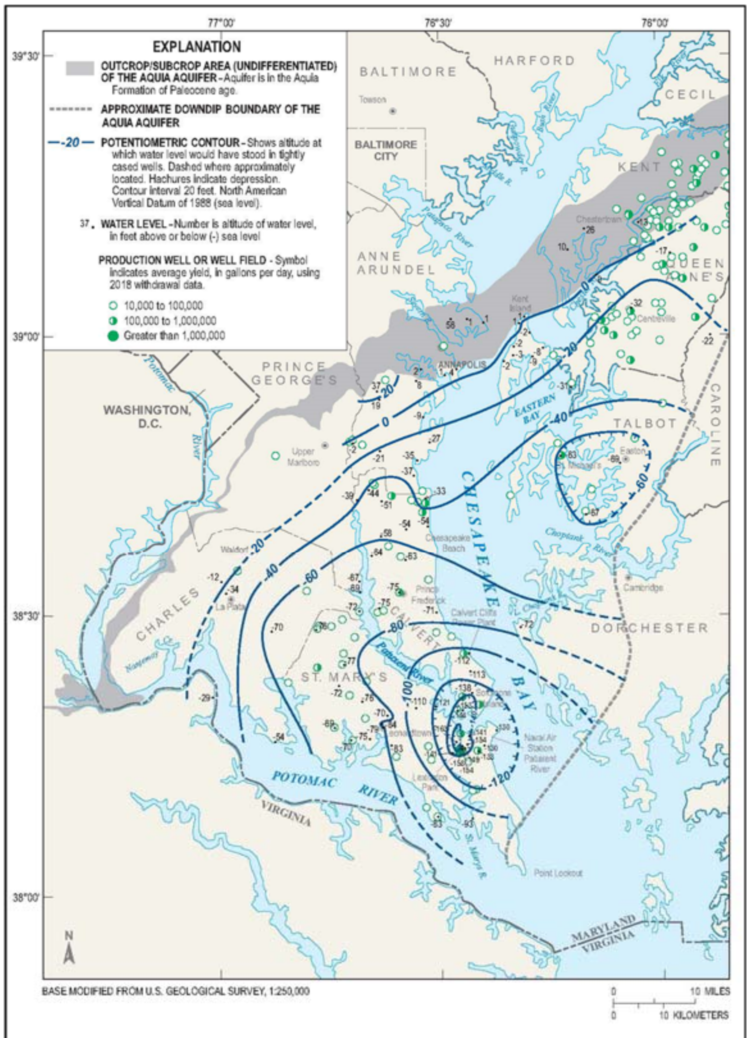
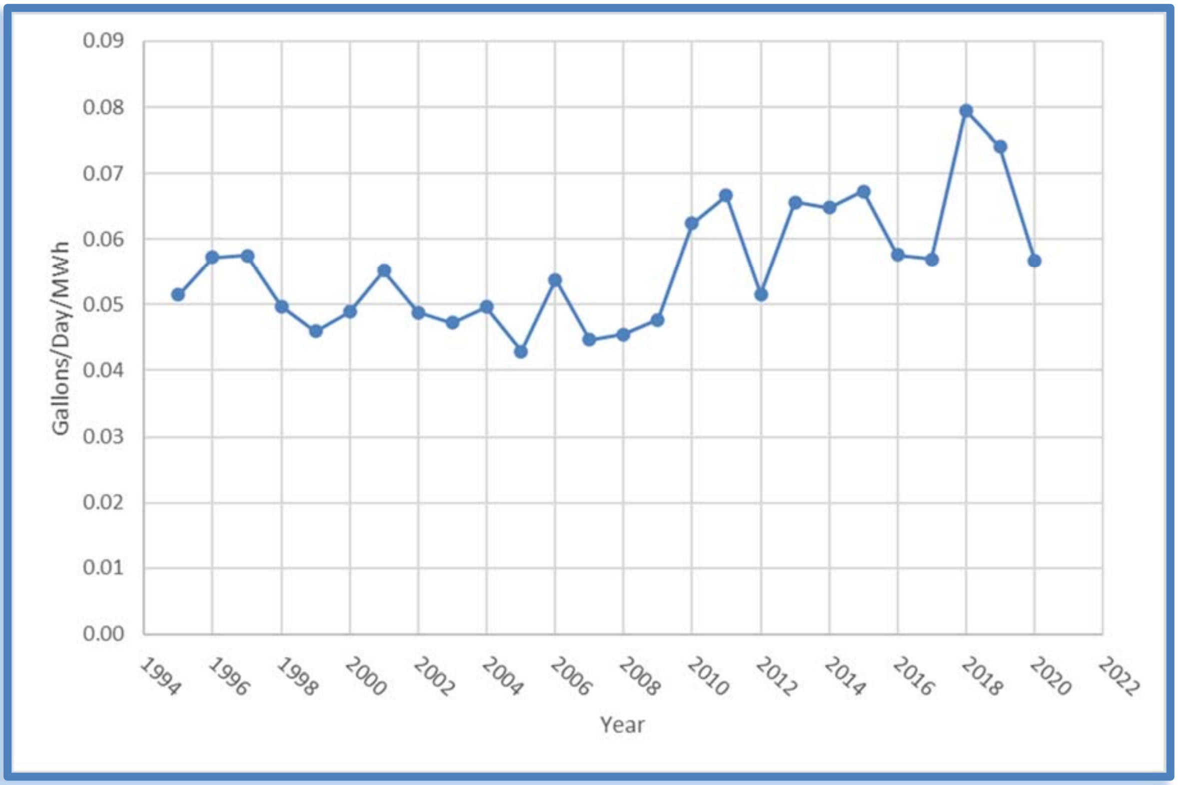


Figure 3. Potentiometric surface of the Aquia aquifer in Southern Maryland and Maryland's

Figure 5-29 shows the average groundwater withdrawals per year, per MWh. Values are shown in units of gallons per day per MWh.

Figure 5-29 Average Groundwater Withdrawals per MWh (1995-2020)



In general, groundwater withdrawals are less closely related to actual electricity generation (compared to surface water cooling system withdrawals). When electricity generation drops, groundwater demands do not decline nearly as much as cooling water demands.

Contaminated Groundwater Impacts

In some recent licensing cases, PPRP has worked with MDE to address issues related to groundwater 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.

One example is the Perryman licensing case. Groundwater 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 5 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, groundwater 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 groundwater is required for the operation of the Perryman Plant. However, pumping groundwater from the Upper Patapsco Aquifer has the potential to cause impacts to the groundwater quality if the reduction in the water table elevation or an alteration in the groundwater flow directions disperses the oil plume. Aquifer modeling results were used to evaluate the potential for these water quality impacts to be realized. Steady-state model results indicated that drawdown ranging from 0.1 to 0.15 feet could occur in the area of the oil plume. This slight drop in the water table would not alter the groundwater 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.

5.2.2 Impacts to Aquatic Biota

Conventional Facilities

Conventional electric power generation facilities have the potential to affect 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 because of entrainment in the cooling system, and impingement of larger organisms on cooling system intake screens. Elevated temperatures of receiving waters from a plant's discharge may also influence aquatic resources. Impacts to fish in streams include the potential loss of habitat due to lower water levels or altered water temperatures particularly during low-flow periods if a plant's use of cooling water significantly affects downstream flow. Various agencies and organizations have monitored water usage and the resulting environmental impacts. PPRP has monitored these issues since 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 5.2.4).

In addition to minimizing impacts, several power plants once 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 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 detail below. The impacts associated with cooling water withdrawals in the state are being reevaluated by MDE with technical assistance from PPRP for regulatory compliance over the next several years because of EPA's Section 316(b) regulations of the Clean Water Act (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 11 major power plants, with special emphasis on the Chesapeake Bay. Results of the studies showed that while power plant operations affected ecosystem elements, the cumulative impacts on Maryland's aquatic resources were not ecologically significant.

Measured entrainment losses of aquatic organisms did not reveal consistent depletions of populations. Even then, some power plants modified their operating procedures and one constructed onsite 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 CWA 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 EPA implemented a final rule in 2014 on requirements for CWIS at existing facilities (see sidebar).

Clean Water Act Section 316(b)

EPA's implementation of CWA Section 316(b) in 2014 has resulted in updated assessments of the impacts of cooling water withdrawals. Maryland has seven existing steam electric power plants with a National Pollutant Discharge Elimination System (NPDES) permit and a cooling water intake and discharge. Of these, two plants are below the 2 million gallons per day (mgd) design threshold for affected facilities (Warrior Run and Vienna); the remaining five (Calvert Cliffs, Chalk Point, Morgantown, Wagner-Brandon Shores and Wheelabrator/Baltimore Refuse Energy System Company [RESCO]) were required to conduct further evaluations based on the 2014 regulations. Two of these (Chalk Point and Morgantown) are being decommissioned in 2022 and no further evaluations are likely to be required.

The 2014 rule includes the following requirements, which facilities in Maryland that withdraw at least 2 mgd are addressing in the coming years; some facilities have started or completed studies to address these issues:

- Facilities are required to choose one of seven options to reduce fish impingement.
- Facilities that withdraw at least 125 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.
- Power plant owners must conduct one year of impingement studies and two years of entrainment studies (for facilities withdrawing greater than 125 mgd) 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 2014 rule are required to conduct economic and engineering studies to comply with the new rule as their NPDES permits are renewed.

Discharge Impacts

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 5.5 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 5-30). Below is a brief summary of the findings in those studies.

Mesohaline Habitat – The five largest power plants in the state by generating capacity (Chalk Point, Calvert Cliffs, Morgantown, Brandon Shores and H.A. Wagner) 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 and consider new technologies to reduce thermal discharges. More recently, PPRP studies have evaluated the potential effects of power plant discharges on diving ducks and their food resources.

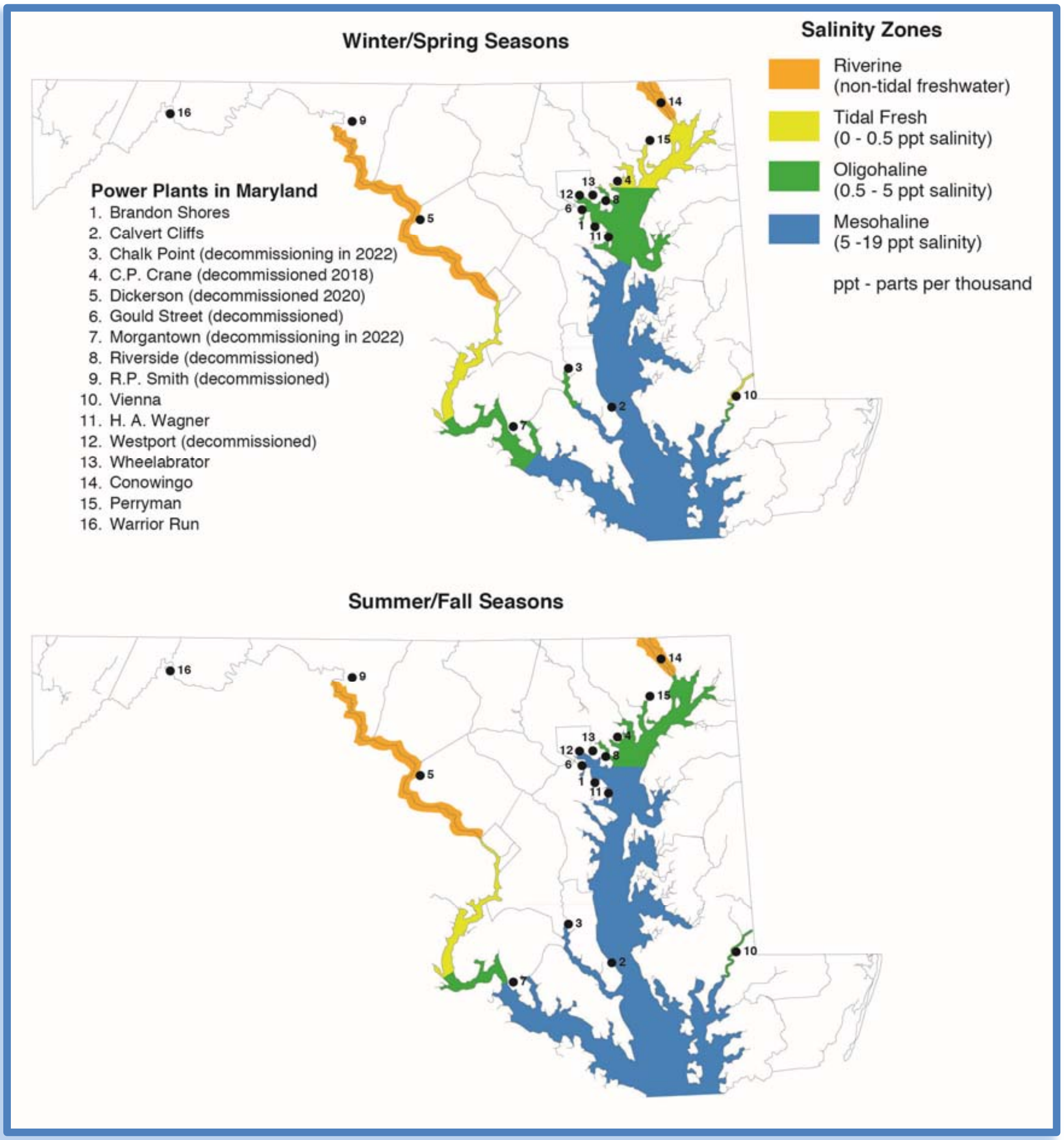
Tidal Fresh and Oligohaline Habitat – Two plants, Vienna and C.P. Crane, once discharged into tidal fresh (0-0.5 ppt) and oligohaline waters (0.5-5 ppt). Chalk Point, Morgantown, Brandon Shores and H. A. Wagner also discharge into the oligohaline zone during part of the year. PPRP studies showed that the thermal plume at Vienna was small and its discharge effects were negligible. The thermal plume at C.P. Crane (now retired) 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.

Data collected in 2003-2005 and in 1979-1980 studies reflect long-term changes in the upper Chesapeake Bay fish community and were not suggestive of a plant discharge effect. The results also suggest that the thermal discharge did not consistently affect the fish community's composition or distribution.

Nontidal Freshwater Habitat – Dickerson was the only Maryland power plant that used once-through cooling that was in nontidal riverine habitat; it ceased operation in 2020. PPRP conducted a long-term freshwater benthic study over eight years in the 1980s and assessed the thermal impact of power plant discharges on the Potomac River ecosystem. 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 was 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 multiyear study of the growth and condition of several fish species near the plant. Based on data on fish conditions collected over 21 years near the plant discharge and at a reference location eight miles above the discharges, there was no indication that the localized discharge effects on benthic communities affected fish near the plant.[144]

[144] Loos, J.J. and E.S. Perry. Dickerson Station graphical analysis of fish distribution relative to the Dickerson Station thermal discharge. 1979-2000. Permit Compliance Support, Mirant Mid-Atlantic. 1991.

Figure 5-30 Salinity Zones of the Maryland Chesapeake Bay



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, four additional small-scale facilities also generate electricity within the state and an additional one (Jennings Randolph Hydroelectric Project) has received a license from the Federal Energy Regulatory Commission (FERC) but is not yet constructed (see map and table in Section 3.1.5). Hydroelectric facilities may present special environmental concerns that operators do not encounter at steam electric power plants. Development and operation of hydroelectric facilities cause 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 hydroelectric dam. In addition, because dams slow moving water, suspended sediment often drops out and settles on the bottom behind the dam rather than continuing downstream, as would occur if the dam were not present. Normally, these materials would be carried and deposited throughout the entire river system. Downstream of dammed rivers, it is common to see receding riparian zones and wetlands due to the loss of transported sediment. This change and other effects influence the types of organisms that can live there. In addition, the river channel or path a river takes can be changed as a result of the existence of a dam. Habitats downstream from a dam are in general less diverse than those of free-flowing rivers and streams. Absent the dam, the river would be guided by the surrounding landscape.

The existence of a dam fundamentally alters water quality and aquatic life upstream of the dam (i.e., in the reservoir). The creation of a reservoir essentially replaces a flowing, dynamic and varied aquatic habitat with a lake with a fundamentally different habitat that in turn results in a different assemblage of aquatic species than would otherwise be present without the dam.

The change from a riverine system to a lentic system also changes the fate and transport of pollutants such as sediment and nutrients. The existence of a dam often alters species diversity and the number of fish in the water behind the dam as well as the types of fish there, with riverine species of fish being replaced by reservoir-adapted fish that like slow-moving warm water and insects that like silt and sandy bottoms. The slow-moving warmer water in a reservoir combined with inputs of nutrients from upstream sources and/or from project lands can also contribute to algal blooms, particularly during the summer, which can impact aquatic life as well as drinking water and recreational uses.

When reservoirs contain deposited sediment, large storm events can scour the deposited sediment and nutrients from the reservoir floor and move them downstream, adversely impacting water quality and aquatic life. In some cases, this material has been shown to impact water quality 40 miles or more from a dam.

Changes to flow regime and resultant changes to aquatic life and habitat downstream – The flow regime downstream of a hydroelectric dam plays a large role in defining the physical and biological characteristics of the river below the dam. Hydroelectric operations alter the flow regime of a river and disrupt the cycles on which many aquatic organisms depend. Accordingly, without the hydroelectric dam, one would expect increased biodiversity and population densities of native aquatic species downstream.

Hydroelectric facilities operating in a peaking mode (in response to peak electrical demand) produce unnatural and frequently extreme water level fluctuations in impoundments and the river downstream of the impoundment. Additional small-scale projects may also divert some flow away from the natural streambed. Fluctuations in water level and flow can reduce fish abundance as well as important food sources essential to fish growth and survival. In addition, as discussed in the section above on water quality, 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.

Susquehanna River Migratory Fish Restoration

Historically, the Susquehanna River supported large spawning runs of migratory species such as American shad (shad), river herring, striped bass and American eel. The massive diadromous 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 Pennsylvania's Holtwood, Safe Harbor and York Haven dams).

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 reopening 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 the hydroelectric licensees on the Susquehanna River are conducting additional studies at several of the lower river projects to address these issues as part of their federal license requirements.

Growth of the Susquehanna River shad stock in response to the restoration efforts and installation of fish passage devices has been problematic. Upstream passage peaked in 2001, when nearly 200,000 American shad were passed over the Conowingo Dam; however, the annual passage has declined since then for reasons that are the subject of ongoing studies and potential mitigation measures (see Figure 5-31). The 2019 fish passage data showed less than 6,000 American shad passed Conowingo and less than 12 percent of what passed Conowingo passed the next upstream dam (Holtwood). The Holtwood numbers have historically been low, but improvements to their fish passage system that were made in conjunction with recently added generation capacity were expected to result in an increased percentage of fish passing Holtwood. Long term (2000-2019), Safe Harbor has passed 74 percent of what passed Holtwood, but York Haven only passed 13 percent of what passed Safe Harbor. PPRP, working with the hydroelectric dam owners and other state and federal agencies, is continuing efforts to enhance upstream migratory fish passage, as well as the safe downstream passage of juveniles through operational and/or engineering modifications. Fish passage in 2020 was halted due to COVID-19 precautions and due to the threat of invasive species including Northern snakehead (*Channa argus*) and blue catfish (*Ictalurus furcatus*). Fish passage in 2021 was limited to trap and transport of American shad and river herring from the west fish lift to preclude passage of invasive species into Conowingo Pond from below the dam.

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 in the early 1900s. 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 due to these manmade impoundments. The loss of American eels, one of the most abundant fish in the watershed historically, has had additional effects on the Susquehanna River ecosystem. The native 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 (e.g., 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.

From 2009 to 2016, the U.S. Fish and Wildlife Service (USFWS) operated an eel ramp to capture juvenile eels below Conowingo Dam and move them upstream. [145] The goal of this program was to move 1 million eels to designated locations within the watershed to not only help restore mussel populations 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 (see Table 5-7), then decreased from 2014 to 2016. The decline in elvers could be related to the unusual weather conditions in 2015 and 2016, or this trend could be related to natural variability in eel numbers. However, as part of its settlement agreement with USFWS, and as a condition of the Clean Water Act Section 401 Water Quality Certification for the Muddy Run facility in Pennsylvania, Exelon (the plant owner at the time) was required to construct a new eel ramp and transport system at Conowingo in 2017. Numbers increased greatly in 2017 compared with 2016, although numbers declined in 2018, possibly due to high river flows that year, but rebounded in 2019 through 2021.

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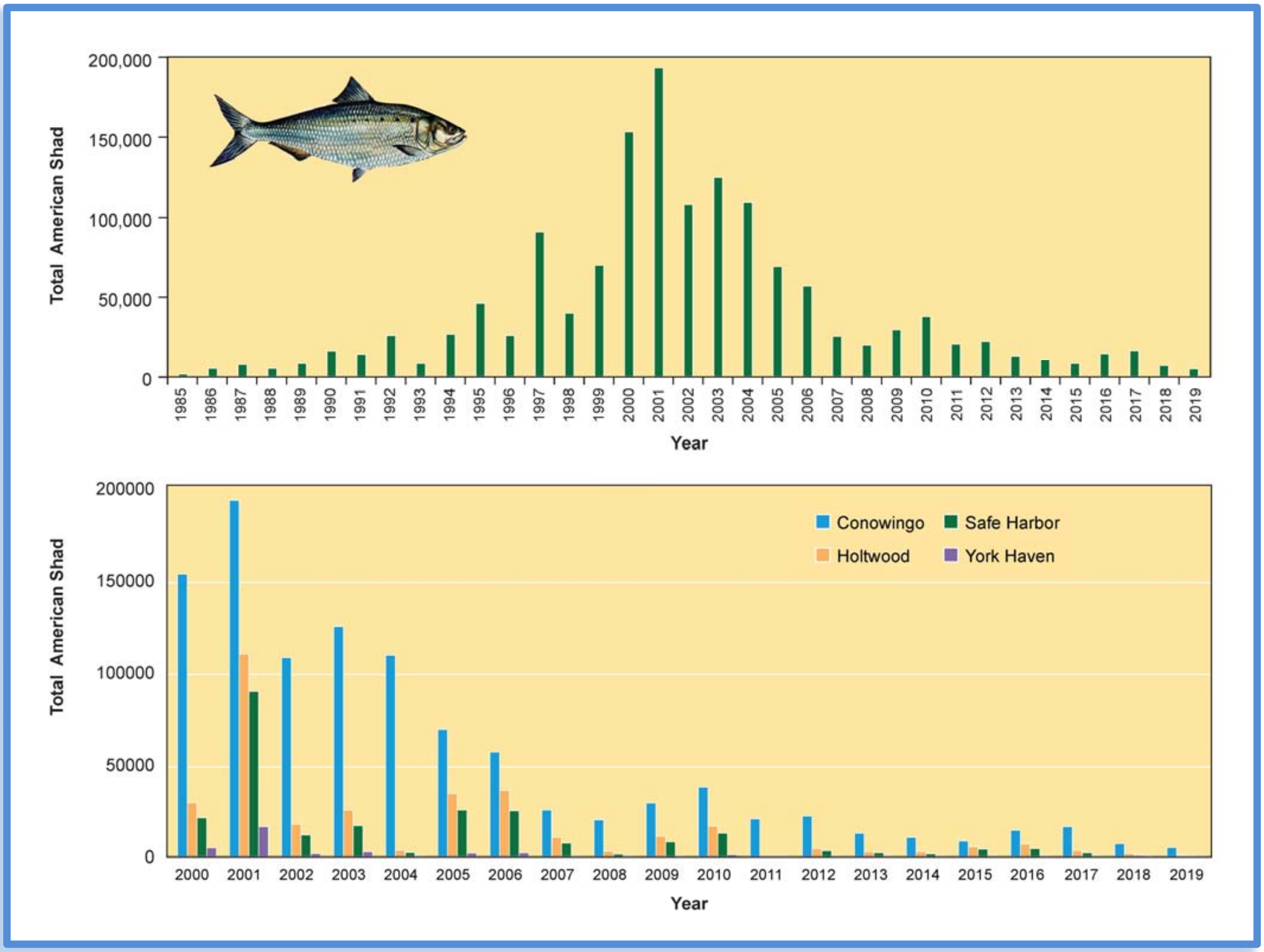
[145] Chris Reily, Steve Minkkinen, American Eel: Collection and Relocation – Conowingo Dam, Susquehanna River, Maryland, 2016, U.S. Fish and Wildlife Service, srbc.net/srafrc/docs/2016/Conowingo%20Eel%20Collection%202016.pdf.

Table 5-7 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
2016	2,684
2017	122,300
2018	67,949
2019	126,181
2020	254,651
2021	607,743

Sources: USFWS, 2016. American Eel: Collection and Relocation Conowingo Dam, Susquehanna River, Maryland. 2016; Normandeau Associates, Inc. and Gomez and Sullivan Engineers, D.P.C. 2018. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility; Normandeau Associates, Inc. 2019. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility. Normandeau Associates, Inc. 2021 and 2022.

Figure 5-31 Number of American Shad Passed at Conowingo Dam from 1985-2019 and at Conowingo, Holtwood, Safe Harbor and York Haven Dams from 2000-2019**



Source: fishandboat.com/Fish/PennsylvaniaFishes/Pages/SusquehannaShad.aspx.

* Fish passage did not occur in 2020 and 2021 due to COVID-19 precautions and because of invasive species concerns.

The FERC licenses for Muddy Run and York Haven were renewed in 2015. The license for Conowingo was renewed in 2021 (see further discussion below). Holtwood and Safe Harbor project licenses expire in 2030.

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 current capacity of 572 MW at the 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, as well as periodic dewatering downstream of the dam. The Conowingo Pond supports other generating facilities nearby in Pennsylvania, including the

2,770 MW Peach Bottom Atomic Power Station (units 2 & 3), the 1,072 MW Muddy Run Pumped Storage Project and the 1,100 MW York Energy Center, as well as the municipal water supply for Baltimore City and Chester, Pennsylvania. The 1,000 MW Wildcat Point facility in Cecil County also withdraws water from the Conowingo Pond, at a withdrawal point in Pennsylvania.

The federal license (first issued by FERC in 1980) to operate the Conowingo Project (now owned by Constellation Energy Corporation) expired in August 2014. The Conowingo Project operated under annual licenses until FERC issued a new license in March 2021. Exelon, the plant owner at the time, submitted to FERC a Pre-Application Document in 2009 for the continued operation of the Conowingo Project. PPRP coordinated all Maryland agency reviews of the FERC Pre-Application Document 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 multiyear studies based on recommendations from PPRP and other state and federal agencies 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. Under Section 401 of the CWA, before relicensing can occur, MDE must certify that the operation of and discharges from the Conowingo Project under the new license will meet Maryland Water Quality Standards and Requirements. MDE issued a Water Quality Certification (WQC) under Section 401 in 2018. MDE and Exelon in 2019 reached a settlement agreement that laid out licensing conditions for Conowingo, resolving issues between them. The settlement includes several protection, mitigation and enhancement measures, including fish passage, attraction flows, eel passage, invasive species management, a revised downstream operating flow regime, trash and debris removal, dissolved oxygen monitoring, shoreline management, turtle management, a waterfowl nest plan, sturgeon monitoring, mussel restoration, water quality project funding and other measures.

Fishway prescriptions issued by the USFWS were the subject of negotiations between the USFWS and Exelon. In 2016, the USFWS issued a fishway prescription that was the subject of extended negotiations between the USFWS and Exelon. 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 Conowingo Project to provide American shad and river herring a zone of passage to the fish passage facilities; and
- 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 with 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 has already started design work to implement many of the fish passage improvements required in the USFWS prescription.

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

Other Generation Facilities

Offshore Wind

The first U.S. offshore wind generation facility, the Block Island Wind Farm, began commercial operations offshore of Rhode Island in December 2016. Several additional U.S. projects have been proposed, most in shallow waters (< 30 m. depth) off the Atlantic coast, including two that would serve Maryland. Effects on avian and bat populations from the construction and operation of these offshore generation facilities are likely, based on the fatalities observed from collisions with turbines at land-based wind-energy projects. This could affect bird migration routes as well as breeding and feeding areas. While offshore turbine foundations may expand desirable habitat, environmental risks to marine resources include exposure of fish and other aquatic organisms to hazardous chemicals released into the ocean by accidental spills.

The development of large offshore wind farms will also require underwater transmission infrastructure, which also has the potential to cause impacts to natural resources in this region. Both lead lines from individual projects to shore substations and a large submarine "backbone" line parallel to the coast have been proposed. Burying cables in either configuration will create disturbed swaths across the seabed, which will become warmer than the surroundings during transmission operations from heat dissipated by the cables. Underwater electric transmission cables within and from wind farms also generate electromagnetic fields (EMF) that are known to affect the behavior of some fish, such as eels, rays and sharks.

In 2013, the Maryland Legislature passed the Maryland Offshore Wind Energy Act, which provides economic incentives to develop offshore wind facilities that benefit Maryland. The Maryland Public Service Commission (PSC) evaluates and approves or denies applications for these Offshore Renewable Energy Credits (ORECs). Under the Act, applicants must affirm plans to conduct an environmental review in compliance with applicable statutes, such as the National Environmental Policy Act (NEPA). Because of the potential for impacts to sensitive resources, these plans are also required to demonstrate compliance with the Endangered Species Act, Migratory Bird Treaty Act, and Marine Mammal Protection Act; applicable U.S. Bureau of Ocean Energy Management (BOEM) regulations and guidelines for surveying natural resources (including, but not limited to, avian species, benthic habitats, fish, marine mammals and sea turtles); local/state regulations; and the Coastal Zone Management Act.

The PSC received applications for ORECs under the Maryland Offshore Wind Energy Act from US Wind, Inc. and Skipjack Offshore Wind Energy in November 2016. After review, the PSC approved both applications, with conditions, in May 2017 (PSC Order No. 88192). Before construction starts, PPRP may conduct studies to identify potential environmental impacts from any submarine transmission cables that cross Maryland's offshore waters. BOEM approved Site Assessment Plans in 2018 and the applicants are currently conducting site assessments for these projects.

In Maryland's 2019 Legislative Session, additional offshore wind project ORECs were authorized through the Clean Energy Jobs Act. These ORECs are to support the development of at least an additional 1,200 MW of wind energy by 2030 from applications for "Round 2" of offshore wind development (which started as of July 1, 2017). In December 2021, the PSC accepted bids for two additional offshore wind projects from US Wind and Skipjack, representing an additional 1,654 MW. The two projects are slated to come online by 2026. This amount of offshore wind energy will more than quintuple the offshore wind contribution to the state's renewable energy portfolio.

Solar

Although solar generation facilities are generally not constructed near large bodies of water, there are instances when the facility is located on property containing a freshwater stream or in an area where drainage to the facility may impact a stream or the Chesapeake Bay. Construction of a solar facility may change the drainage pattern of the site, requiring the installation of appropriate best management practices (BMPs) based on the design of the facility. In some cases, this may reduce runoff to local streams and improve the water quality over time. In other cases, such as the Great Bay Solar Facility in Somerset County, construction occurred in nonjurisdictional drainage ditches, leading to flooding both on- and offsite. In addition, consideration must be made to the interconnection process as well. For example, PPRP evaluated a proposed horizontal directional drilling (HDD) line at the proposed Casper Solar Facility that would have been installed under a Tier II stream and may have caused heat transfer to the stream, affecting the quality of life for aquatic biota. However, the proposed Casper Solar project was withdrawn in 2019.

Transmission Facilities

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. 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 transmission 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 5-32, includes six towers in the river. All of Maryland's major rivers, both tidal and nontidal, are crossed by transmission lines. At present, only SMECO's transmission line between St. Mary's County and Calvert County near the mouth of the Patuxent River avoids the visual and physical impacts of towers by employing 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 small streams located in the upper parts of watersheds. Any effects that propagate downstream, such as warmer water temperatures or increased sediment load, will also be detrimental. 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 5-32 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 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. Good practices can minimize these effects. 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 the 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 root wads present in the stream system. This may result in increased water temperatures and a reduction in habitat and food sources that threaten the survival and reproduction of coldwater species, including brook trout. While studies have not documented a strong effect of a single transmission line ROW on average stream temperature, protection of cool water or coldwater habitat is advisable as a cautionary measure. In most cases, placing transmission line towers sufficiently far enough from the stream that the wires span the stream and associated riparian area can minimize long-term effects. 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. 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 utilities use EPA-approved substances for vegetation management that degrade quickly and that have minimal side effects.

Impacts to Groundwater

Transmission line structures have a small potential to affect groundwater resources, particularly in areas where the water table is close to the surface. Potential impacts to groundwater 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 SMECO Holland Cliffs to Hewitt Road project 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 groundwater is much less in some areas, such as the Eastern Shore, where many utility upgrade projects are being conducted. Higher-voltage overhead transmission lines require deeper drilling depths; therefore, PPRP must carefully compare the tower foundation design with the depth to groundwater for these projects.

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 groundwater 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 groundwater 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 groundwater.

5.2.3 Impacts to Rare, Threatened and Endangered Species

Generation Facilities

The potential effects of the construction and operation of generation facilities on Maryland's rare, threatened and endangered (RTE) species 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 Harford and Cecil counties, which is the eastern edge of its range. Impacts from habitat modification and human recreation are of special concern for map turtles in Maryland. The generation of electricity from the Conowingo Hydroelectric Project influences the flow of the lower Susquehanna River, which citizens use for recreational activities. Given the potential impacts of the Conowingo Hydroelectric Project 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.[146] Article 424 of the new Conowingo operating license requires Exelon to develop a Northern map turtle protection plan within one year of the license issuance.

Additionally, while solar facilities are generally not located on or near large bodies of water, the construction and operation of these facilities may impact aquatic RTE species. For example, the proposed Bluegrass Solar Facility will drain entirely to tributaries of Southeast Creek, known to contain the federally endangered dwarf wedge mussel. Dwarf wedge mussels require very high, sediment-free water quality. If disturbance were to occur to this stream from construction, or due to increased erosion or poor runoff control during operations, the population of mussels in that stream could be imperiled.

Offshore generation facilities could potentially affect federally listed threatened and endangered species that occur in the Chesapeake Bay and coastal waters of Maryland, including fish, whales and sea turtles. Except for sea turtle nesting habitat, the National Oceanic and Atmospheric Administration Fisheries Service has principal responsibility for these species.

For a complete list of federally threatened or endangered species in Maryland, see ecos.fws.gov/ecp/report/species-listings-by-state?stateAbbrev=MD&statusCategory=Listed&s8fid=112761032792&s8fid=112762573902.

[146] R. Seigel, T. M. Richards, K. Anderson, and N. Byer, Interim Report: Nesting and Basking Ecology of Northern Map Turtles in the Susquehanna River: Impacts of Human Disturbance and Effectiveness of Mitigation Measures, Department of Biological Sciences, Towson University, December 2012.

Transmission Facilities

RTE 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 RTE species, time-of-year restrictions may be applied to activities within the ROW to avoid times when the species is breeding or especially active.

The 115 kV Five Forks to Windy Edge project is an example of a project that cannot avoid impacts to RTE species. The ROW crosses Broad Creek in a sensitive wetland area, upstream of a Tier II stream segment, that contains suitable habitat for RTE species. A full RTE species survey for potential wetland area species, such as bog turtles, was not practical. As a result, PPRP included a licensing condition to address RTE species protections. PPRP's licensing condition in the CPCN required enhanced sediment and erosion control measures, fencing, flagging, third-party monitoring and time-of-year constraints on construction activities.

5.2.4 Cumulative Effects on Biological Resources

Although permit requirements and regulations may not require an assessment of cumulative effects, the impact of multiple influences determines the health of the contiguous ecosystem. PPRP has conducted aquatic impact assessment studies at all of Maryland's existing conventional power 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 the continued performance of power plants to minimize these impacts. Cumulative effects of additional generation facilities such as offshore wind and solar will need to be considered.

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 without BMPs. 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°C (71.6°F) 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 nonnative species such as the brown trout (*Salmo trutta*) to compete for 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 on that resource. It is also necessary to minimize such effects if they occur. For example, Maryland's Scenic and Wild Rivers Act applies to the natural resources of state-designated Scenic Rivers and their tributaries, thus limiting any combination of activities within the watershed that would degrade the condition and quality of the designated river.

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 the 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.

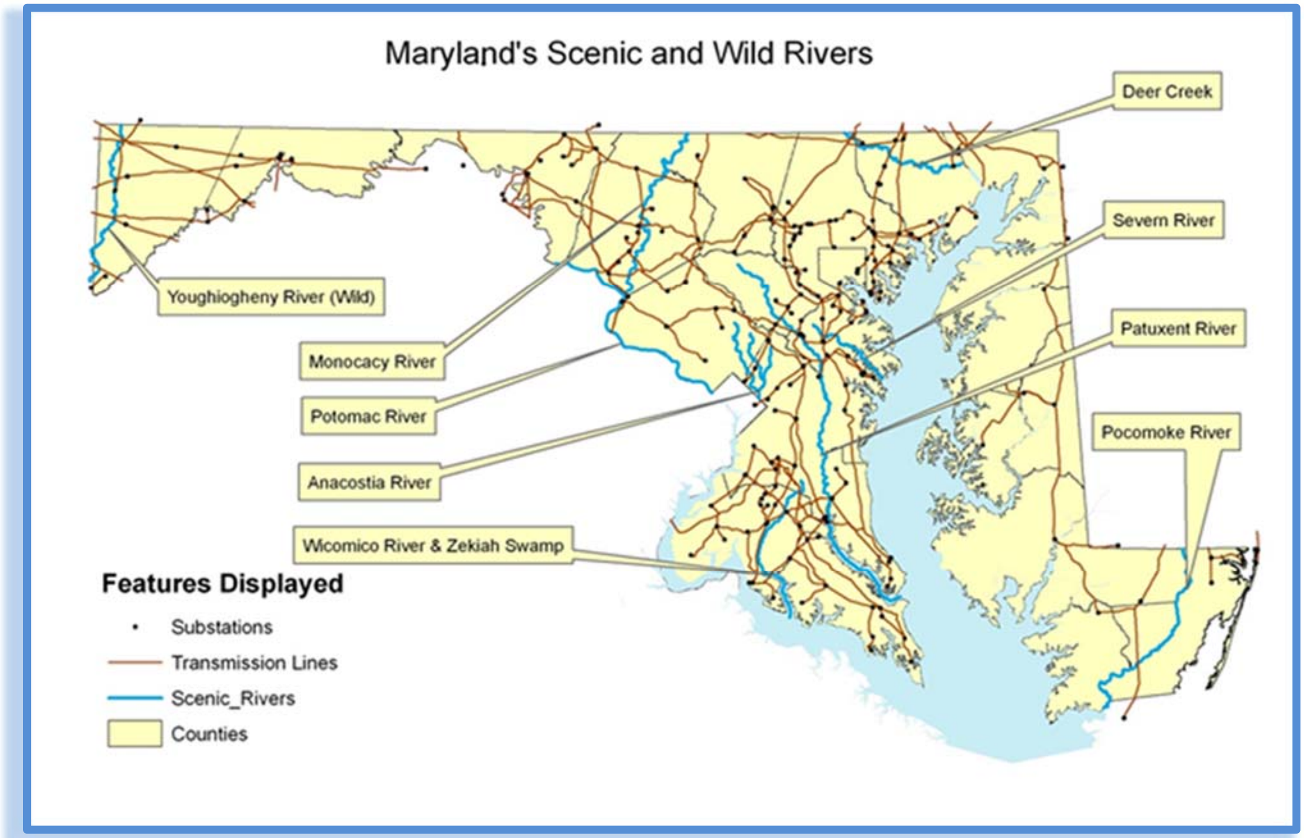
Impacts to High-Quality Waters

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. Figure 5-33 illustrates Maryland's Scenic and Wild Rivers and the transmission line corridors in the state. During the CPCN review, PPRP evaluates the potential impacts of proposed transmission lines to ensure that projects avoid or minimize impacts on these resources.

Scenic and Wild Rivers

Maryland's Scenic and Wild Rivers Act defines a Scenic River 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 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 5-33 Scenic and Wild Rivers and Transmission Line Corridors in Maryland



Recent transmission projects that cross Maryland Scenic Rivers and their watersheds include Delmarva Power and Light Company's (DPL or Delmarva) Piney Grove to Wattsville new 138 kV line (Pocomoke River), the portion of the Transource project located in Harford County (Deer Creek), and the rebuild of the Ringgold to Catoctin project (Monocacy River). In January 2021, Baltimore Gas and Electric Company (BGE) filed for a CPCN to rebuild the existing Five Forks to Windy Edge 115 kV line which crosses the Deer Creek Scenic River in Harford County. PPRP's reviews of such projects include focused attention to all river and stream crossings in the associated watersheds, with particular attention to the potential for riparian buffer vegetation loss and erosion leading to downstream sedimentation.

In addition, transmission structures may significantly degrade the visual environment along the river. Several Maryland designated Scenic Rivers, including the Pocomoke River, the Patuxent River, the Monocacy River and portions of the Potomac River, have incurred viewshed impacts from existing transmission line crossings. Where possible, underground crossings may eliminate or minimize such visual impacts (see Section 5.4.2 for additional details).

Tier II Streams

Maryland's antidegradation policy protects particularly high-quality streams from impacts that would degrade them. 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 the 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. Tier I waters meet only the minimum standards. There are Tier II streams in every county (23), but they are not evenly distributed throughout the state, and there are none located in Baltimore City. Maryland has no designated Tier III waters to date.

Maryland regulations provide Tier II designated streams with 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 effects Tier II waters, including transmission line and solar project 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 Piney Grove to Wattsville upgrade (Nassawango Creek) and the portion of the Transource project located in Harford County (Island Branch). In addition to the protection of water quality and habitat by stringent BMPs for sediment and erosion control, PPRP recommended specific Integrated Vegetation Management (IVM) plans in areas upstream of Tier II waters in these cases. PPRP also recommended relocating poles that are in sensitive areas such as wetlands or riparian buffers.

The recently approved Fairview Farm Solar Facility in Harford County (CPCN granted in July 2021) is located directly upstream of a Tier II stream segment; thus, the entire project is in a Tier II catchment (Bynum Run UT1). The project did not require any forest cutting or direct impacts to streams, wetlands or their associated buffers. Therefore, MDE determined the project adequately addressed avoidance and minimization alternatives analysis and satisfied the antidegradation Tier II review.

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 lines across (under) large expanses of the Chesapeake Bay or the waters off Maryland’s Atlantic coast. Technological advances have significantly improved the feasibility and cost-effectiveness of long-distance submarine cable installations that are required for such projects. Underwater cables already exist 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, PPRP must compare these advantages to the impacts to the biological communities that inhabit the bottom, and the food chains that depend on them. A submarine transmission line will cause multiple short-term, acute impacts resulting from installation activities, and long-term impacts from construction disturbance, maintenance activities and, ultimately, the operation of the electric power line.

Impact of Transmission Structures in Waterways

Where overhead transmission lines cross lakes, estuaries or wide rivers, it may be necessary to place supporting structures in the water, anchored to the bottom of the waterbody. These structures may have both positive and negative environmental impacts. Constructing the foundations for towers within the waterbody may resuspend contaminated sediments, disrupt benthic habitats and species, temporarily smother habitat for fish and other aquatic species and affect waterfowl that use the waterbody. Above the waterline, the towers and conductors may present collision dangers to birds, or alternatively offer new nesting locations and hunting perches. If properly designed, the underwater structures can provide hard surface habitat for species such as oysters and mussels and create niches that improve fish habitat.

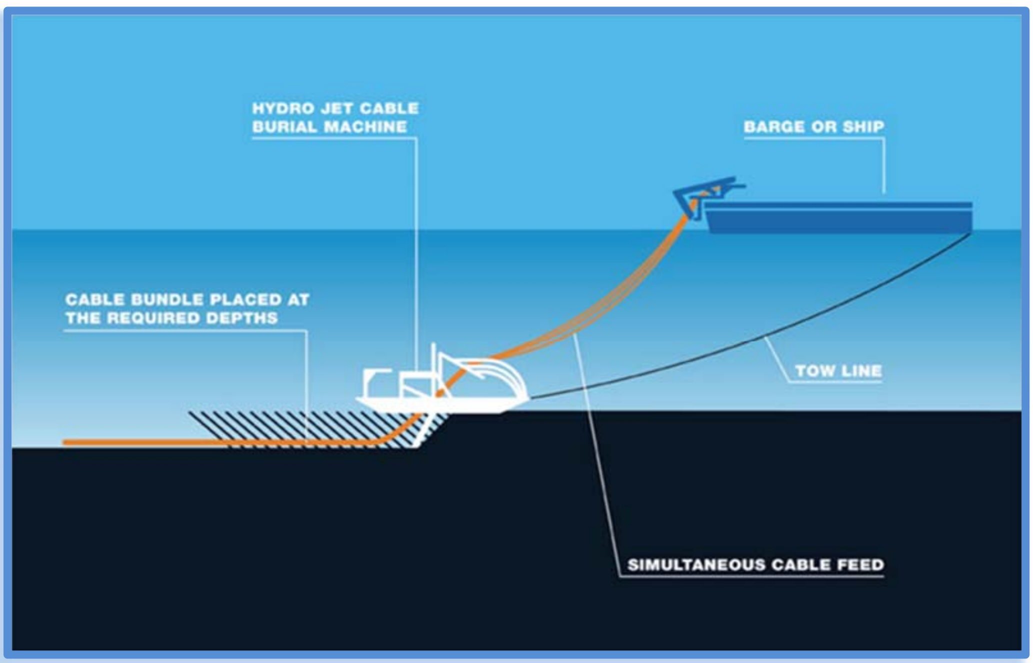
Overhead transmission lines cross most of the major rivers in Maryland, with in-water transmission towers found in the Potomac River (six structures near Quantico), the Patuxent River (eight structures near Chalk Point), and Bear Creek (five structures, near Sollers Point). Direct impacts include loss of bottom habitat and altered current flow. Although the actual bottom area occupied by each tower is relatively small, scouring by currents flowing around the tower foundations may increase the area of disturbed bottom and could alter the benthic community in a wider surrounding area. In some cases, the underwater structures are a concern for navigation and are surrounded by larger protective barriers that further modify the aquatic and aerial environment. Each river is unique and PPRP recommends that the potential effects be quantified through sediment sampling and hydrodynamical modeling prior to construction.

Recently, BGE proposed and had approved a modification and rebuild of an overhead transmission line across the Bush River, near Aberdeen Proving Ground's Edgewater Facility (CPCN was issued in May 2021). This project will Include removal of one existing structure and construction of a new transmission structure in the River, with potential effects similar to those described above. The new tower will be located in the center of the River channel at a slightly more northern location to avoid a sewer main near the existing tower. PPRP carefully evaluated the potential loss of bottom habitat and the effects of these proposed structures on natural resources, including aquatic vegetation, shellfish, fish and birds.

Utilities typically install underwater transmission cables several feet deep in the bottom sediments. Under some circumstances, such as a rocky hard bottom, a utility will place the cable directly on the bottom. This latter technique affords the least protection from currents and manmade disturbance, such as being hooked by an anchor or damaged by commercial fishing operations. There are several methods for installing cables, including HDD, the use of a jet plow, trench excavation or a combination of these techniques. The HDD technique can accidentally release pressurized drilling muds if there are 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 before 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 utility contractor can place the cable in the trench. Figure 5-34 illustrates a jet-plow installation, where a large 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 the 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 using HDD under the riverbed. The crossing is parallel to and upriver from the Rt. 4 Bridge between Johnstown and Town Creek, Maryland, with endpoints at Point Patience and Patuxent Beach Road. A portion of the line also traverses the Navy Recreation Center in Solomons through underground duct banks (concrete-lined trenches used to place power cables underground, then covered with vegetation or pavement). Because the termination point is within the Chesapeake Bay Critical Area, SMECO selected a previously developed site. 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, including a sampling plan to establish the river bottom baseline conditions using geotechnical and biological surveys of the river bottom with provisions for additional sampling if an inadvertent release of drilling fluids ("frac-out") occurred during the HDD process. CPCN licensing conditions recommended by PPRP required SMECO to develop a Contingency Plan using both pollution history and sampling data to help protect the living resources of the Patuxent River in the event of a frac-out. SMECO completed the HDD under the Patuxent River without incident in October and November 2013.

Figure 5-34 Illustration of an Underwater Cable Installation Using Jet Plow Technology



Source: 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 project that directly or indirectly affects the Critical Area in the state, including transmission line ROWs, is required to seek and obtain approval from the Critical Area Commission (buffer zone) or MDE (tidal waters).

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 (194°F) nd may create zones of elevated sediment temperature above ambient conditions, depending on sediment thermal characteristics. The 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*.[147,148] Oysters and other shellfish that ingest these bacteria pose a human health risk.

Aquatic habitats may be affected by the resuspension of sediments during construction or maintenance of the cables by the release of contaminants or nutrients into the water column. Depending on the depth profile and tidal influences, disturbances that resuspend 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.

Considering 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.

[147] Jacobs, J.M., M. Rhodes, C.W. Brown, R.R. Hood, A. Leight, W. Long and R. Wood. "Predicting the Distribution of Vibrio vulnificus in Chesapeake Bay." NOAA Technical Memorandum NOS NCCOS 112. NOAA National Centers for Coastal Ocean Science, Center for Coastal Environmental Health and Biomolecular Research, Cooperative Oxford Laboratory. Oxford, MD. 2010.

[148] Blaustein, R. A., Y. Pachepsky, R. L. Hill, D.R. Shelton and G. Whelan. "Escherichia coli survival in waters: Temperature dependence." Water Research. Vol. 47, Issue 2, February 1, 2013, 569-578.

5.3 Impacts on Terrestrial Resources

Maryland's physiographic diversity, geology and climate have produced a variety of ecoregions that foster numerous, and sometimes unique, habitats ranging from ocean barrier islands in the east through salt marshes, fields and forests on 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 these areas to some extent, the majority of the landscape still consists of 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 (RTE) species.

The State of Maryland enforces a suite of regulations (COMAR Titles 08, 26 and 27) that protect habitats and species in terrestrial and wetland environments, including regulations governing:

- 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 particulate matter (PM) and other air pollutants; and
- Degrade habitats by the permitted discharge of pollutants or from accidental spills.

Impacts from new generation projects on Maryland's landscape depend on the mode of power production. Power plants using traditional resources such as coal and natural gas are generally confined to relatively small, intensively developed installations and their associated linear facilities, whereas renewable energy projects using wind turbines or solar panel arrays may occupy hundreds of acres.

PPRP has reviewed more than 40 proposed solar generation facilities. These projects are located throughout the state and raise several environmental issues, many related to their size. For example, projects located near the Chesapeake Bay may include development in the Critical Area, and projects in agriculturally zoned areas may remove designated prime farmland out of production. Many of the projects require mitigation under Maryland's Forest Conservation Act, either for clearing trees or for developing land previously used for agriculture. The locations of utility-scale solar projects are frequently restricted by county zoning regulations, comprehensive development plans and designated preservation areas. Several Maryland counties, including Frederick, Prince George's and Caroline have revised their solar facility approval processes and laws to limit development impacts, particularly in agricultural and environmentally sensitive areas.

New traditional fossil fuel generation facilities have varied from being constructed entirely within an area that was already developed to one that required clearing a significant amount of natural habitat. Examples highlighting the scope of impacts to terrestrial resources include two projects in Prince George's County – Keys Energy Center, which began operating in July 2018, and Mattawoman Energy Center, which received a CPCN but was canceled by the Applicant in January 2021.

Keys Energy Center is a combined cycle, natural gas-fired plant on a 180-acre parcel of land formerly used for a sand and gravel mining operation. The permanent electric power generation and support facilities require approximately 30 acres of the parcel. The site is adjacent to Potomac Electric Power Company's (Pepco's) existing 500 kV transmission line right-of-way (ROW) located on the western side of the property. The associated gas pipeline, which is situated on the previously vegetated side of the existing 500 kV transmission line, required clearing many acres of forested habitat. The gas pipeline route also crosses sensitive areas such as wetlands and streams, including the headwater streams of Zekiah Swamp.

The proposed, but now canceled, Mattawoman Energy Center project site was an industrially zoned previously cleared 88-acre plot on Brandywine Road in Prince George's County. Linear facilities associated with the project initially included an approximately 10-mile-long reclaimed wastewater pipeline to bring treated effluent from Piscataway Wastewater Treatment Plant (WWTP), an approximately 7.4-mile-long natural gas pipeline, and a 2.3-mile-long generation lead line extending from the power plant site north to Pepco's Burches Hill to Talbert 230 kV transmission line. The developer subsequently modified plans to include a dry cooling system, eliminating the reclaimed water pipeline. The proposed substation site was located on Cherry Tree Crossing Road, adjacent to the Pepco 230 kV transmission line corridor on a site containing approximately 8 acres of predominately upland forest. The gas pipeline would have widened the existing corridor of the Pepco/SMECO transmission line ROW, requiring clearing many acres of forest. A portion of the ROW, at the Mattawoman Creek crossing, ran directly adjacent to the proposed gas pipeline route for the Keys Energy Center. The last 1-mile segment of the new ROW required for the gas pipeline ran parallel to Jordan Swamp, a sensitive wetland area.

Maryland has more than two thousand miles of electric power transmission line and natural gas pipeline ROWs. Constructing and maintaining these ROWs create 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 appropriate oversight and opportunity for public input, and to ensure that environmental and other concerns are addressed, new transmission line corridor construction or modifications in existing corridors require applications to the Maryland PSC to issue a CPCN.

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 ROW 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 are 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 balance compliance with Maryland's environmental regulations and natural resource management objectives with the public's need for additional power facilities. Environmental laws affecting waterways construction, water quality and water pollution control, and erosion and sediment control require the use of 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 conditions to avoid, minimize or mitigate specific impacts on natural resources. Under these circumstances, conditions placed on a CPCN to mitigate impacts to wetlands, forests and sensitive species and their associated habitats may often be more stringent than requirements under the individual statutes.

5.3.1 Impacts on Forests and Maryland's Green Infrastructure

Generation Facilities

The Maryland 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. This 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. Larger forest patches contain more forest interior habitat and often support unique niches for RTE species.

Forest resources are important in numerous ways in addition to providing habitat for wildlife. Forests filter nutrients and other pollutants from stormwater and help prevent erosion. They also filter out air pollutants, sequester carbon dioxide and produce oxygen. Carbon removed from the atmosphere is stored in above-ground plant tissue and below-ground roots as a forest grows and is added to soils as dropped leaves and branches decay. Forests are also important commercial resources, providing construction materials and renewable fuel supplies. Given these important ecosystem services and compelled by the significant losses of Maryland's forest resources over time, the Maryland Legislature enacted the Forest Conservation Act (FCA) in 1991. All construction development that disturbs more than 40,000 square feet must comply with the FCA in accord with county implementation statutes (Forest Resource Ordinances). Heavily forested Allegany and Garrett counties are exempted from implementing County Forest Resource Ordinances under the FCA.

Under the FCA, evaluating existing forest conditions and character is an integral component of power plant and transmission line facilities siting and development. 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 actions must be considered before any development disturbs forest resources. The Maryland Forest Preservation Act of 2013 amended the state's forest conservation policy to specify that the state's no-net-loss policy requires maintaining a statewide tree canopy cover of 40 percent. 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.

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

Maryland's agricultural land is an attractive option for siting solar generation facilities. More than 40 solar generation facilities are currently under construction or review by PPRP. Almost all of these facilities have been located on agricultural lands. 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 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 development triggers FCA mitigation requirements, even if no trees are being removed (afforestation). 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 project developers to meet the state's (or county's, if more restrictive) requirements for any afforestation, reforestation or mitigation that may apply to the project.

Taken together, 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 non-forested 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 the development of agricultural land has to meet 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 is 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.

As the license conditions are developed in the CPCN process; the quality of the natural resources that will be affected by the project is also considered. For example, the CPCN to construct the Rock Springs generating facility in Cecil County included restoration conditions to compensate for the ecological value of mature forest lost and to compensate for some of the nitrogen deposition caused by the facility's emissions. Specifically, the removal of 20 acres of mature forest required the applicant to plant 50 acres of young trees elsewhere in Maryland. The reforestation effort, initiated in 2002 at two DNR-owned sites, was focused on fields adjacent to streams to increase the likelihood that deposited nitrogen would be intercepted before reaching Chesapeake Bay tributaries. Follow-up studies at these sites, however, showed that at one reforestation site, 18 acres in size, 80 percent of the planted trees died by the summer of 2013. At the other site, 32 acres in size, no individuals of many of the planted species were found, while 60 percent of the trees present were non-planted species seeded from nearby forest areas. Based on these results, PPRP plans to reevaluate the efficiency of such restoration projects.

Transmission Facilities

Transmission line ROW 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 ROW. This approach allowed easy access to the transmission line but was frequently detrimental to natural habitats.

Over 50 years ago, the Working Committee on Utilities of the President's Council on Recreation and Natural Beauty prepared an extensive report on "actions required assuring 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:

- ROW clearing should be kept to the minimum width necessary to prevent interference from trees and other vegetation. Selective tree cutting and removal should target trees that could cause damage to the line.
- The ROW edges through forests or timber areas should have undulated boundaries, not straight "walls" that create a "tunnel" effect.
- Small trees and plants should be allowed in the ROW to "feather" the height of the ROW vegetation from grass and shrubbery near the center to larger trees at the edges.

ROWs that are constructed through Green Infrastructure hubs and corridors fragment habitats and diminish their ability to function as integrated habitat units. While the area of the removed forest may not be significant, 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 ROWs and can spread into the forest interior, limiting the growth of native species. Careful vegetation management in the ROW can minimize potential impacts. For existing transmission line ROWs in Green

Infrastructure areas, expansions of the ROW 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 preexisting disturbed and degraded areas.

5.3.2 Impacts to Wetlands

Generation Facilities

Wetlands are important components of the environment, forming the interface between terrestrial and aquatic ecosystems. Wetland communities often comprise diverse plant species, several of which may be species of concern. Wetlands also provide numerous ecosystem services that benefit human 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 its land area); 220 years later, in 2009, Maryland had only about 287,420 acres of nontidal wetlands (4.6 percent of its land area),[149] 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 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.

PPRP's CPCN analysis includes assessing potential wetland impacts and developing appropriate mitigation equal to or greater than that required by the state's wetland regulations. While wetlands are present at nearly all of Maryland's power facilities, impacts to these wetlands can usually be avoided. Where especially valuable wetlands are present, PPRP's process, in consultation with MDE, identifies specific CPCN 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.

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149 mde.state.md.us/programs/Water/WetlandsandWaterways/DocumentsandInformation/Documents/www.mde.state.md.us/assets/document/WetlandsWaterways/classification.pdf.

Generation facilities often require associated linear facilities including gas and water pipelines and transmission lead lines. Construction of gas and water linear facilities may affect streams and wetlands through vegetation removal or ground disturbance. Impacts to wetlands can be minimized through advanced construction techniques such as horizontal directional drilling (HDD). For example, in the Keys Energy Center (KEC) case, PPRP developed CPCN licensing conditions recommending HDD along portions of the natural gas pipeline corridors to the Keys facility to avoid impacts to Wetlands of Special State Concern.

Transmission Facilities

Wetlands are among Maryland's most valuable natural resources. The Critical Area Act protects land within 1,000 feet of tidal waters and tidal wetlands, while nontidal wetlands—including wetlands in utility ROWs—fall under the Nontidal Wetlands Protection Act. Maryland's overall goal is no net loss of nontidal wetlands acreage or function. To achieve this goal, the state requires that any unavoidable wetland losses be replaced at least acre per 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, the U.S. Army Corps of Engineers or both. While new routes are usually planned to avoid wetlands, ROWs constructed prior to the Nontidal Wetlands Protection Act were often less favorably sited, and many undesirable wetland impacts occurred. For example, the Burtonsville to Takoma Park transmission line route in Prince George's County (CPCN approved in 2014) traverses sensitive wetlands and streams including Little Paint Branch Creek, which has one of the state's last American brook lamprey populations. Another example is provided by the Bush River Crossing in Harford County (CPCN approved in 2021). This project to rebuild a segment of an older 115-kV transmission line across the Bush River fell entirely within the Critical Area. On the eastern shore of the river, the project required developing a new ROW within a Resource Conservation Zone of the Critical Area Buffer, including tree clearing in two Habitat Protection Areas with numerous non-tidal wetlands. Mitigation for both forest and wetland impacts was required.

Wetland impacts result when vegetation, soil or water flow is altered by a transmission line ROW, either directly or indirectly. Transmission line access roads within wetlands were often particularly damaging in the past 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. Without proper management practices, invasive plants tend to colonize areas on and directly adjacent to a dry elevated roadbed and compete with the adjacent wetland plants for sunlight and water. Because 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. Matting is often placed over wetland areas to minimize damage from equipment and activities when upland access is not possible, without building permanent roads.

Indirect construction and maintenance impacts to wetlands are caused primarily 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 the use of appropriate BMPs. 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 nonnative 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.

5.3.3 Impacts to Wildlife

Generation Facilities

New generation facilities primarily affect wildlife by removing habitat during the construction of the project. An example is provided by the impacts of the Cove Point liquefied natural gas (LNG) expansion project (which included new gas-fired generators) that was developed to produce LNG for export. Construction of the facility required that 97 acres of the forested area be cleared for construction laydown and staging areas. The loss of habitat from this area affected 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 also affected properties adjacent to the cleared area. In addition to this loss of habitat, wildlife was affected by light, noise and activity during the construction period.

Land-based wind energy projects can also have a substantial impact on wildlife during construction and operations, especially on 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 laydown areas during assembly. The loss of habitat can lead to the eradication or displacement of species in these areas.

All of the land-based wind power facilities developed in Maryland have been in the predominantly forested habitats of Garrett and Allegany counties. The forests of Western Maryland are a southern extension of the northern hardwood forests that spread 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 (WHS) have reviewed and commented on Bird and Bat Conservation Strategies (BBCS) for wind power projects. An Avian Protection Plan or BBCS for a project is a project-specific document that outlines a program to reduce the potential risks of avian and bat mortality that may result from the project’s construction and operation. The ultimate goal of these plans 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 of Maryland Nongame and Endangered Species Conservation Act.

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, there has been some increase in mortality in areas of the western United States. Conversely, bat mortality rates at some wind power projects along the Appalachian Mountains have been among the highest reported in the U.S. 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 obtaining 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. Furthermore, an exempted project must undergo permitting review administered at the county level, and satisfy all local planning and zoning requirements.

Solar facilities are the most space-consuming type of generation plants. Approximately 5 to 7 acres of solar panels are required for each MW of power that is produced. Generally, larger solar projects in Maryland have been in the 100- to 300-acre range on previously cleared agricultural land, but in April 2019 an 1,100-acre, 200 MW project was approved for Caroline County. Such farmed lands usually offer little existing wildlife habitat, since they have been intensively managed, limiting nesting by birds or occupancy by other wildlife. Common species of wildlife that are compatible with agricultural environments may be present (e.g., mourning dove, groundhog), but overall biodiversity is limited. However, these large open areas often provide forage spaces for species that live in peripheral and adjacent areas, including raptors. When the farmland is lost to large solar arrays, population sizes may be reduced or the species composition may change, e.g., birds that hunt in large open spaces may be replaced by birds that favor the narrow, confined areas between solar panels.

Solar projects can also be developed and maintained in a way that provides benefits to wildlife. Following the installation of the solar panel arrays, PPRP recommends that the areas below and between the solar panels be planted with native, warm season grasses and low-growing pollinator friendly species to encourage ground-nesting birds and pollinators. PPRP promotes, on behalf of DNR, practices that support native Maryland pollinators and expand their habitat (see sidebar). One recent project has proposed to turn the entire area beneath the solar panels into grassland habitat suitable for ground-nesting birds.

Promotion of Native Pollinators

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

Picture above and below from: xerces.org/wp-content/uploads/2014/09/NortheastPlantList_web.pdf

In June 2014, President Obama issued a memorandum establishing a Pollinator Health Task Force, cochaired by the U.S. Department of Agriculture (USDA) and EPA, to create a National Pollinator Health Strategy to promote the health of honeybees and other pollinators (including birds, bats, butterflies and other insects). Overall, eastern monarch butterfly populations have declined by more than 80 percent over the past two decades. Despite this decline, the monarch did not make the federal listing of Endangered species in 2020 and is currently awaiting further consideration.

The loss of native bees, which also play a key role in pollination, 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, parasites, pathogens, lack of genetic diversity and exposure to pesticides.

During Maryland's 2017 legislative session, a bill passed creating a pollinator habitat certification for solar facilities meeting specific criteria. This legislation was enacted in March 2020. In June 2020, the retrofitted solar facility at the Perdue headquarters in Salisbury received the first solar-friendly pollinator certification. Several other utilities are also working with PPRP to be certified. Information concerning the pollinator-friendly solar certification program can be found on PPRP's website (dnr.maryland.gov/pprp/Pages/pollinator.aspx). Pollinator habitat replaces frequently mowed herbaceous or crop areas (but never replaces forested habitats) on a project site. The pollinator habitats consist of native herbaceous plants that are known to attract a variety of pollinator species (a list of suggested seed mix suppliers can be found on PPRP's website.). These habitats are relatively maintenance-free, and once established, often only require an annual or semiannual mowing. They generally do not require herbicides or fertilizers and are friendly to native birds and other wildlife. Pollinator habitats can also be managed in electric transmission ROWs 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.

Transmission Facilities

A large portion of the transmission line ROWs in Maryland are in 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 ROW through a forested area creates cleared areas with abrupt edges that are not desirable habitat for 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 ROW 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 that are on each side of the ROW from each other. 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, 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. FIDS, 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 avian FIDS generally requires several hundred acres. According to the Natural Heritage Program, the populations of many avian FIDS are declining in Maryland, often because of the loss of suitable amounts of habitat. Thus, the effect on FIDS 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 riparian areas.

Another potential impact of transmission lines is bird collisions and electrocutions. Bald eagle and osprey nests are occasionally found on transmission line towers (see Figure 5-35). One tower in the Bush River supported a double-crested cormorant colony with 37 nests. The U.S. Fish and Wildlife Service (USFWS) and the Avian Power Line Interaction Committee cooperatively developed guidelines to help prevent injuries to birds that contact power lines. The state uses the voluntary guidelines, as updated in 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. As older power lines are rebuilt, utilities typically use newer structure designs that minimize nest construction opportunities.

Figure 5-35 Bald Eagle Nest in a Transmission Tower

5.3.4 Impacts to Rare, Threatened and Endangered Species

Generation Facilities

Rare, threatened or 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 specific habitats. Generation projects proposed in Maryland must undergo an RTE species review by the DNR's Wildlife & Heritage Service (WHS) to identify RTE species known to occur in or near the affected area. Table 5-8 lists, by category, the number of protected plant and animal species that are considered when evaluating potential adverse effects of a generation project. Recommendations made by the WHS during the review usually form the basis for protective recommended license 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 5-8 Number of State-Listed Rare, Threatened and Endangered Species by Category

Summary of State Listed Species*		
Category	**Plants**	**Animals**
Endangered	248	98
Threatened	75	19
In Need of Conservation	n/a	36
Endangered Extirpated	67	32
Total	390	175

* Only includes species listed in COMAR 08.03.08.
Source: Maryland DNR: dnr.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx .

Although few proposed traditional power generating facilities affect listed RTE species, the large footprint of solar and wind facilities often includes or borders potential RTE habitat areas. Several individual CPCN cases have considered potential impacts to protected species such as the Northern long-eared bat and the Indiana bat, and In Need of Conservation bird species. An example is the recently approved Jade Meadows Solar Facility (CPCN issued in May 2021) located on a reclaimed mine site in Allegany County, close to known records for an In Need of Conservation Species, the Henslow's sparrow (*Ammodramus henslowii*) that could also potentially occur on the project site. The grassland habitat required for this species has nearly vanished due to development, and much of the remaining grassland occurs in limited settings, such as reclaimed mine sites. Solar development on such reclaimed mines may eliminate potential grassland habitat for this species. Additionally, the potential presence of bats, specifically the Northern long-eared bat and the Indiana bat, was a concern due to the amount of tree clearing proposed for this project. Though no official records for these bat species existed on the project site, nearby old growth forest and old mining structures likely serve as habitat for these species. PPRP's recommended CPCN license conditions included a suggested wildlife habitat and protection area to promote wildlife and pollinators on site and also included a condition to initiate further review and/or mitigation in the event any RTE species were encountered before, during or after construction of the facility.

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 several wind power facilities in the U.S. and abroad, there is evidence that the numbers of bird fatalities are minimal 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.[150,151,152] It is currently believed that most of the bat fatalities occur during the late summer to fall migration period as bats move to their overwintering habitat.

Wind energy facilities in the Midwest have killed several federally Endangered Indiana bats. Western Maryland provides year-round habitat to the Indiana bat, as well as 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.

[150] Kerns, J. and P. Kerlinger. A Study of Bird and Bat Collision Fatalities at the Mountaineer Wind Energy Center, Tucker County, West Virginia: Annual Report for 2003. Technical report prepared by Curry & Kerlinger, LLC. for FPL Energy and Mountaineer Wind Energy Center Technical Review Committee. 2004.

[151] Kerns, J. Patterns from daily mortality searches at Backbone Mountain, West Virginia. National Wind Coordinating Committee. Onshore Wildlife Interactions with Wind Developments: Research Meeting V. November 3-4, 2004.

[152] Erickson, W. Patterns from daily mortality searches at Meyersdale, Pennsylvania. National Wind Coordinating Committee. Onshore Wildlife Interactions with Wind Developments: Research Meeting V. November 3-4, 2004.

The discovery that white-nose syndrome was severely affecting bat populations in caves of the northeast resulted in even greater concern about the risks to cave-hibernating bat species, including the Indiana bat, the Northern long-eared bat and the more common little brown bat. 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 USFWS 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 restricted, such as tree removal. The Northern long-eared bat is found in a variety of forested habitats in summer. Incidental take resulting from tree removal is prohibited if it (1) occurs within a 0.25-mile (0.4-kilometer) radius of known Northern long-eared bat hibernacula; or (2) cuts or destroys known occupied maternity roost trees, or any other trees within a 150-foot (45-meter) radius from the known maternity tree during the pup season (June 1 through July 31). Within the White-Nose Syndrome Zone, Allegany County is designated as a county with known white-nose syndrome infected hibernacula.

Transmission Facilities

Most RTE species occupy specific environmental niches that only support small populations. 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 existing transmission line ROWs sometimes create an ideal niche for a threatened or endangered species. For example, the federally threatened bog turtle is known to occur in numerous locations in northern Harford County. WHS noted potential occurrences of this species that would be affected by the proposed rebuilding of the Five Forks to State Line transmission line. The utility was required to conduct a Phase 1 Bog Turtle Study following protocols set forth by the USFWS. Once this survey was performed and potential habitat was located, DNR's bog turtle expert made specific recommendations regarding time-of-year restrictions and potential distance from bog turtle hibernacula for construction impacts. Of special importance was avoiding vibration disturbance from heavy equipment use in the vicinity of hibernacula, as that could wake turtles prematurely and lead to loss from exposure to winter weather conditions.

Rare floral species were a concern for the Ringgold to Catoctin transmission line rebuild in Frederick and Washington counties. At least eight floral species were identified along this ROW, including a population of white turtlehead, the preferred host species for the endangered Baltimore checkerspot butterfly. In circumstances like this, specific coordination must occur with WHS to protect each species. The Ringgold to Catoctin CPCN license conditions included not only flagging and/or fencing known RTE areas, but the presence of an onsite third-party environmental monitor during construction activities to help avoid or minimize impacts to sensitive species. In some other cases, PPRP also recommended a license condition that required the utility to assist in an invasive species control program for a period of time after construction to ensure that construction activities did not introduce invasive species that would outcompete native RTE species or degrade their habitat.

The WHS Natural Heritage Program maintains a database of all known observations of the state's designated RTE 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 to identify habitat that may be suitable for any other RTE species. If the appropriate habitat is available, certain species could be present without documentation because site-specific surveys have not yet been conducted. PPRP and WHS work together to make specific recommendations for each species when habitats and potential habitats are identified near a proposed project. Recommendations include field surveys and protecting or mitigating impacts to any populations present, such as avoiding disturbances during breeding seasons or migrations, controlling hydrologic 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.

5.3.5 Cumulative Effects on Biological Resources

Generation Facilities

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. At present, bird fatalities are 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 (USFWS), in practice, only requires that good faith efforts be employed to avoid fatalities.

The cumulative impact on bat species is of greater concern. The high level of recorded bat fatalities includes 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 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 that 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.

Transmission Facilities

In general, overhead transmission line corridors in Maryland range in size from approximately one hundred to three 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, 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. Utilities have proposed several new transmission lines across Maryland in response to PJM’s transmission planning and federal studies indicating that the northeastern

U.S. is in critical need of increased transmission capacity and reliability. Furthermore, proposed offshore wind power facilities near the Maryland coast may require both offshore transmission and additional large capacity transmission lines on the Delmarva Peninsula. 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 and other urban areas.

Impacts imposed by transmission line ROWs may 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 ROW 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.

There are several ways to assess cumulative effects. The effect of multiple stressors 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 either restricts or requires mitigation for development in all sensitive habitats within Maryland's Chesapeake Bay and its tidal tributaries. Individual resources, on the other hand, are addressed 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 Nontidal Wetlands Protection Act.

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

Another transmission line ROW in Southern Maryland, which was evaluated in response to a CPCN application to upgrade the capacity of the line, illustrates the multiplicity of impacts that must be considered. The ROW crosses more than 20 streams, traverses 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 ROWs can have on some of Maryland's most critical natural resources.

5.3.6 Vegetation Management

In existing transmission line ROWs, 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 5-36 shows an example of typical transmission line vegetation management practices in Maryland. Many of the species present in the ROW may be nonnative 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 ROW has not been frequent, taller vegetation may be present, but generally, the ROW 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 ROW boundaries) can also be degraded to some degree when the vegetative community within the ROW has been significantly disturbed or altered by construction and maintenance, such as in forested areas.

Figure 5-36 Example of Typical Transmission Line Vegetation Management in Frederick County

Trees in or near power line ROWs 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, vegetation contact caused 22 percent of the total electrical outages throughout Maryland.[153] New PSC vegetation management standards for lower-voltage power lines, known as RM43, went into effect as of 2014. 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. Although there are fewer tree-fall events that cause outages of higher-voltage transmission lines that are regulated by the Federal Energy Regulatory Commission (FERC), DNR has joined with the Maryland Electric Reliability Tree Trimming (MERTT) Council, which typically focuses on the lower-voltage lines, to develop a clear picture of trees

[153] Maryland Public Service Commission Staff, Engineering Division Review of 2014 Annual Performance Reports on Electric Service Reliability, Case No. 9353, August 17, 2015.

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. PPRP 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 PPRP to evaluate whether there are changes following the implementation of RM43.

NERC Regulations

Improperly maintained vegetation in a transmission line ROW can disrupt the integrity of the system and cause power outages. The North American Electric Reliability Corporation (NERC), operating under the oversight of FERC, develops and enforces reliability standards for transmission lines. The NERC Reliability Standard FAC-003-4 (Transmission Vegetation Management), approved by FERC in 2016, codifies current best practices and requirements for reliability 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 ROW. The TVMP must identify and document clearances between vegetation and overhead conductors, considering voltage, sag under maximum load, and wind velocity on conductor sway. Alternating-current voltages require minimum vegetation clearance distances (MVCD). 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 ROW inspections.

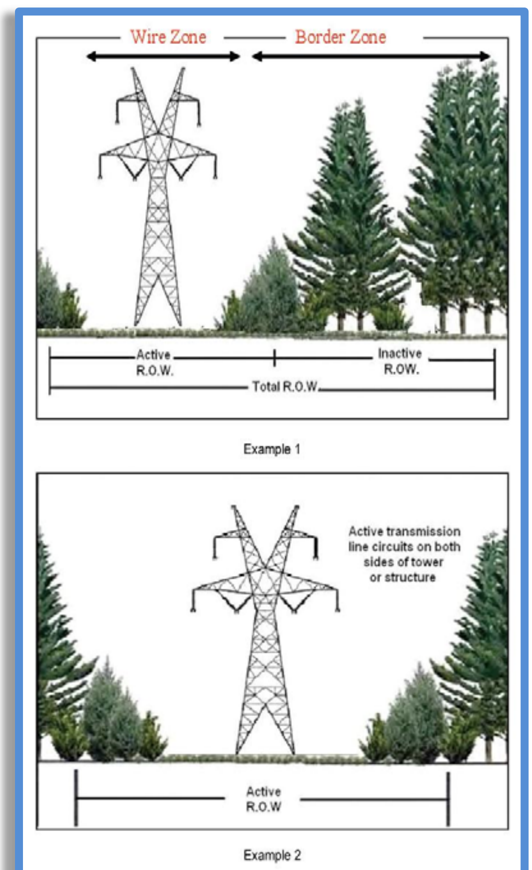
Current Practices

Transmission companies are required to maintain ROWs 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 ROW, 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 of the President's Council on Recreation and Natural Beauty, and other advanced techniques such as the Integrated Vegetation Management approach recommended by the International Society of Arboriculture, can be implemented providing the required clearances are maintained. In general, most Maryland utilities use uniform, systemwide practices that may be more aggressive than NERC requirements. After forested land is cleared to create a transmission line ROW, several methods to maintain a low stature vegetative community within the ROW 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. ROW 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 ROW 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 in Section 5.3.3).

Leaving the ROW in a natural state to the maximum extent possible is the best alternative for protecting wildlife in sensitive areas. Creating curved or wavy ROW boundaries and piling brush from the cleared ROW so that it provides wildlife habitat would help mitigate impacts from ROW clearings in forested areas. Figure 5-37 illustrates feathered, or soft, edges in a transmission ROW, which 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 ROW is recommended for ROWs 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 5-37 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 ROWs, PPRP has, through its membership in the MERTT 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 ROWs in limited areas. The introduction of desirable species into the ROW 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 saved thousands of dollars in annual maintenance costs.

Some research indicates that planting "connecting corridors" in the ROW 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 ROW fragments habitat used by forest interior dwelling species or crosses riparian areas and wetlands. PPRP continues to research the benefits of innovative BMPs for power line ROWs vegetation management.

PPRP reviews the TVMPs of all applicants for CPCNs for new or modified transmission lines for compliance with the required standards and BMPs. As necessary, PPRP recommends license conditions for implementing such practices and for developing detailed vegetation management plans for sensitive locations along the ROW. PPRP maintains a library of these ROW license conditions, locations and detailed vegetation management plans, and follows up with in-field assessments to evaluate the efficacy of the license condition requirements.

5.4 Socioeconomics and Land Use Issues

5.4.1 Generation Technologies and Socioeconomic Focus

Solar Photovoltaic – Generation Technologies and Agricultural Land Use

Siting utility-scale solar energy generating systems (SEGS) on agricultural land does not come without costs, and PPRP's role has been to weigh these costs against the benefits of renewable energy generation in its environmental reviews. Some of the issues PPRP has addressed are discussed below.

Loss of Prime Farmland

A recurring issue in the siting of SEGS on productive agricultural land is the loss of prime farmland. Prime farmland is land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber and oilseed crops, and is also available for these uses (the land could be cropland, pastureland, rangeland, forest land or other land, but not urban built-up land or water). These soils are of the highest quality and can economically produce sustained high yields of crops when treated and managed according to acceptable farming methods.[154] Farmland is defined as prime where 50 percent or more of the soils in a map unit composition is prime. Farmland is of statewide importance where less than 50 percent of the components in the map unit is prime, but a combination of lands of prime or statewide importance is 50 percent or more of the map unit composition. Excluding federal land, urban land and water areas, about 23 percent of Maryland's soils are prime.[155] Counties with the highest amount of prime farmland are found either in the upper part of the Eastern Shore, including Kent, Caroline, Queen Anne's and Talbot counties, or along the Pennsylvania border, such as Washington, Carroll and Cecil counties. Counties with the least prime soils tend to be in Southern or Western Maryland and include Garrett, Allegany, Calvert and Charles counties.

Maryland places few restrictions on the siting of solar photovoltaic (PV) facilities on agricultural land. The state's primary policy instrument for conserving prime farmland is the Maryland Agricultural Land Preservation Foundation (MALPF), a unit within the Maryland Department of Agriculture (MDA). Created by the General Assembly in 1977, MALPF purchases agricultural preservation easements that forever restrict development on prime farmland and woodland. Through FY 2020, MALPF had purchased easements on a cumulative total of 2,413 properties, permanently preserving about 326,650 acres.[156] MALPF's policy on solar facilities is codified in COMAR 15.15.14, which explains the Foundation's criteria to approve an authorized renewable energy source (ARES) for commercial profit on a farm subject to an agricultural land preservation easement.[157] The Foundation may only accept applications to approve an ARES on a farm subject to an agricultural land preservation easement before June 30, 2018. The Foundation may not approve an ARES on a farm subject to an agricultural land

[154] U.S. Department of Agriculture. 1993. Soil Survey Manual. Soil Conservation Service. U.S. Department of Agriculture Handbook 18. Soil Survey Division Staff. 1993.

[155] nrcs.usda.gov/wps/portal/nrcs/detail/md/technical/dma/nri/?cid=nrcs144p2_025681.

[156] Maryland Agricultural Land Preservation Foundation. Annual Report Fiscal Year 2020. mda.maryland.gov/malpf/Documents/!MALPF%20Annual%20Report%20FY20.pdf Last accessed January 21, 2022.

[157] COMAR § 15.15.14.01.

preservation easement after June 30, 2019. No other regulations at the state level address development on prime farmland.

Farmland Critical Mass

The direct loss of prime farmland acreage is just one aspect of the concerns regarding SEGS. There are also fears that solar PV development could reduce acreage below a critical mass of farmland needed for the agricultural economy in an area to remain viable.[158] This issue is not specific to SEGS. Between 2007 and 2012, for example, 14,700 acres of agricultural land, 19,100 acres of forest land and 2,700 acres of other rural land in Maryland were converted to developed land.[159] Even greater rates of conversion before 2000 prompted public concern about the loss of farmland. However, the concern is not what the land is converted to, but whether the rate of farmland conversion to other uses will increase after agricultural acreage drops below a critical level. This argument was advanced by the Kent Conservation and Preservation Alliance in opposition to the Mills Branch Solar application to construct a 60 MW solar facility in Kent County. As stated in testimony, "Kent County intentionally zoned approximately 72 percent of the farmed land for agricultural use to create a 'critical mass' of protected land [to insure] the viability of a progressive and profitable agricultural industry."[160] Although the critical mass argument was disputed in testimony, the application was subsequently denied.[161]

Post-Solar Restoration of Farmland

In Maryland and elsewhere, once the operating life of a solar facility ends (typically 30 years), the facility must be decommissioned and land returned to its original condition. PPRP recommended licensing conditions include a requirement for a detailed decommissioning plan and surety agreement to be filed with the PSC. While decommissioning plans generally aim to remove all project components, plans include contingencies for structures, such as below-ground piles and buried underground cables, to be cut and abandoned in place. For example, Maryland Solar's decommissioning plan would remove below-ground portions of supports in their entirety or otherwise at least two feet below ground surface and left in place. Underground collection lines would be cut off two feet below ground surface and left in place. Great Bay's decommissioning plan would cut below-ground piles three feet below grade, and any underground cables buried at least 30 inches would be cut at the ends and remain in place.

Particularly for agricultural land, the abandonment of below-ground structures is a concern. A recurring problem in agriculture is soil compaction.[162] The intensity of operations and the use of larger equipment used in modern agricultural practice have made soil compaction more common. It has been shown, for

[158] Janet Carpenter and Lori Lynch, Critical Mass of Agricultural Land Report. Prepared for the Maryland Center for Agro-Ecology Inc., Queenstown, Maryland. January 2003.

[159] farmlandinfo.org/statistics/Maryland.

[160] Direct Testimony of Francis J. Hickman on behalf of Keep Kent Scenic, Inc. Maryland Public Service Commission, Case No. 9411.

[161] Maryland Public Service Commission, Order No. 88021.

[162] Wolkowski, Richard and Lowery, Birl. "Soil compaction: Causes, concerns, and cures." A3367. Cooperative Extension Publishing, University of Wisconsin-Extension. Madison, WI. 2008.

example, that the effect of equipment weight can penetrate down to 24 inches when soils are moist.[163] The problem can be exacerbated during solar facility installation when excavation and construction equipment is deployed. Deep tilling, where soils are ripped at least one foot below the surface, is the primary method for relieving compaction. Although most implements can penetrate to a depth of about 20 inches, tilling depths of two to three feet can be achieved with heavy tracked machinery.[164] Even no-till "rippers" perform tillage to depths of 12 to 18 inches while maintaining a smooth soil surface.[165] PPRP requires the removal of all below-ground structures and cabling to ensure safe agricultural operations after a site has been restored.

Energy Sprawl and Suburban Sprawl

Another issue for solar development on agricultural land is the conflict with neighboring homeowners of single-family homes on large lots or subdivisions in rural areas. The years between 1970 and 2000 saw an explosion of residential development in Maryland outside of town and city boundaries. From 1982 to 1997, the amount of developed land in Maryland increased by 35 percent, while the state's population grew by only 19 percent.[166] The resulting sprawl was one of the main drivers in the state's introduction of its Smart Growth and Neighborhood Conservation land use reforms in 1997. Loopholes still exist, particularly in agricultural zoning.[167]

View degradation is probably the most cited reason for opposition to solar facilities because open views of agricultural landscapes will be replaced by solar panels or, at best, a vegetated buffer. Even with a buffer, elevated views from multi-story structures may be dominated by a broad expanse of solar panels. Public comments are usually prefaced by statements to the effect that a family located to a rural area, in part for the views. There is some irony in this argument. From recent cases (Biggs Ford, LeGore Bridge, Casper) most opponents are homeowners living in single-family homes on lots of 5 acres or less, most built within the last 20 years. Building on subdivided farmland, these homes have, themselves, altered the landscape, making it far less "agricultural-looking" than in the past.

The Casper Solar Center is a case in point. As proposed, the project would have been located in an unincorporated part of Queen Anne's County near the Town of Church Hill. The northern part of the project was within Church Hill's Planning Area boundary, but outside of the Town's Growth Area boundary. The project parcel was in an area of farmland cultivated in commercial crops and pasture, with many nearby parcels also containing stables, oval tracks and other elements associated with equine breeding and training.

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[163] McKenzie, Ross. "Agricultural Soil Compaction: Causes and Management." Agdex 510-1. Agri-Facts, Government of Alberta. October 2010.

[164] Dane County, Wisconsin Land and Water Resources Department. Dane County Erosion Control and Stormwater Management Manual. Appendix 1: Deep Tilling. Second Edition. January 2007.

[165] Virginia Cooperative Extension. "Deep Tillage Prior to No-Till Corn: Research and Recommendations." Publication 424-053, 2009.

[166] E. Ridlington, B. Heavner and D. Algoso, Sprawl in Maryland: A Conversation with the Experts. MaryPIRG Foundation. Summer 2004.

[167] Letter from Richard S. Altman, Queen Anne's Conservation Association, to Joseph Tassone, Maryland Department of Planning. RE: Queen Anne's County Zoning. May 25, 2009.

Residential development extends south from Church Hill and is slowly overtaking the area's rural character. This is partly a consequence of Queen Anne's less stringent zoning regulations governing the Agricultural and Countryside district. Two subdivisions, Condor Manor and Eagle Manor, are just north of the project site, while another, Patchwork Knoll, is west of the southern project parcel. Also adjacent to the southern parcel, Starfield Farms was granted final subdivision approval by the county's Planning Commission in 2007 but had not been developed when the application was considered.

PPRP's analysis of property data found 96 parcels within one-quarter mile of the project, 85 of which are residential, 51 built after 1999.[168,169] These are mostly two-story homes on lots of one acre or more. A nearly 260-foot communications tower constructed in 2001 overlooks the project site and surrounding area. The result is a complex visual landscape of built residential clusters, sometimes referred to by locals as "cornfield villages," overlaying a setting that portrays less of a cohesive agricultural region than before. This contrasts significantly from the region's historical setting, described in 2000 as "a complexly interrelated rural historic landscape with agricultural and architectural resources which communicate the economic and social changes that occurred in Queen Anne's County from circa 1800 to circa 1950."[170,171]

This is a recurring issue in the permitting of SEGS in Maryland. Residential encroachment into rural lands has constrained the siting of solar facilities due to fears by homeowners that views will be degraded and/or property values will fall. These attitudes, however, are based on the expectation that nearby agricultural properties which contribute to the rural landscape will never change. The reality is that views from any property are not static, nor should they be expected to remain so unless nearby properties are protected by a conservation or other preservation easement, or purchased by neighboring landowners with the intent to preserve their current use. Unencumbered properties are vulnerable to change—within constraints dictated by local zoning laws or other regulation.[172]

Another consideration is the landowner who has sold or leased a property to solar developers. These landowners have rights, too, and it is in their interest to maximize a parcel's return on investment. Furthermore, the agricultural economy is changing from a sole proprietorship to corporate ownership model, where the emphasis is on near-term profit maximization and diversification to buffer commodity

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[168] Maryland Department of Planning. MdProperty View, Queen Anne's County, 2015.

[169] Since 2013, more homes have been built or are under construction.

[170] Maryland Historical Trust NR-Eligibility Review Form. Fincastle-Prickett Rural Historic District. Inventory Number: QA-522. Prepared by KCI Technologies, Inc. February 2001.

[171] Since the National Register eligibility review was undertaken, as of January 2018, 10 homes had been built within the boundaries of the district, and 11 more within a quarter-mile.

[172] With respect to the Casper Solar Center, the list of permitted and conditional uses in the AG zone is quite extensive. In addition to agriculture, permitted uses include: commercial and noncommercial forestry, effluent disposal, institutional residential, kennels, large-lot agricultural subdivision, major and minor single-family cluster subdivision, migrant labor camp, minor extraction and dredge disposal uses, etc. Conditional uses include: campgrounds, commercial apartments, major extraction and dredge disposal, institutional residential, organic fertilizer storage and transfer operations, private airports, public heliports and airports, shooting clubs and, of course, solar arrays. Many of these uses have far less stringent setback and buffering requirements than utility-scale solar arrays. Furthermore, zoning bylaws provide no recourse in the AG district against the effects of any normal farming operations conducted in accordance with standard and acceptable best management practices. Normal agricultural effects include, but are not limited to, noise, odor, vibration, fumes, dust, spray drift or glare.

price swings. A traditional farm's wealth is almost completely tied up in the land, which in the past was passed on to succeeding generations. But given a declining interest in family farming from one generation to the next, plus rising costs and smaller profits,[173] this wealth is being extracted to pay for retirement or other expenses. Utility-scale solar offers an attractive end game for farmers owning lands suitable for development.

Agricultural Operations Near Solar Facilities

Solar arrays have a low vertical profile that, even in the absence of buffering, creates a small visual footprint. SEGS do not emit significant traffic, noise, air or water pollutants, or generate any hazardous waste that could potentially affect public health. As such, operational solar facilities would not appear to have the potential to affect nearby agricultural operations. However, there was concern in the Casper Solar Center case that glare from the project could potentially impact nearby equine operations. Reportedly, horses were being spooked by glare from the nearby Church Hill Solar facility, and equine facilities near the project site were concerned the proposed facility would add to the problem.

PPRP identified three equine training facilities near the Casper project site, but only one that could potentially be affected by glare. Windswept Farm is wedged between the northern and southern project parcels, although equine operations would be potentially affected by glare only from the southern parcel. Its training oval, however, would be nearly 900 feet from the nearest solar panel. Because the Casper Solar Project would use a tracking system, PPRP concluded glare would not affect equine operations in this case.

Cultural and Heritage Resources

Cultural and heritage resources define Maryland in many respects. They comprise historic properties and archeological sites listed on the Maryland Inventory of Historic Properties (MIHP) and National Register of Historic Places (NRHP), heritage areas, scenic byways and many other programs and properties in the public and private domain. Many of these resources are defined by their setting, or cultural landscape, which is sensitive to incompatible development. Historic preservation laws require state and federal government agencies to consider the direct or indirect effects of their projects on historic and archeological resources. The Maryland Historical Trust (MHT) is the primary state agency charged with preserving and interpreting Maryland's cultural resources. Other agencies involved include the Maryland Department of Transportation (MDOT) State Highway Administration (SHA) through its Scenic Byways Program, DNR (Scenic Rivers, Rural Legacy), county historical and preservation organizations, private land trusts and citizen groups. As Maryland's State Historic Preservation Office (SHPO), MHT may also coordinate its reviews with the U.S. Army Corps of Engineers, National Park Service, Federal Communications Commission, Federal Energy Regulatory Commission, state-recognized Native American tribes and others.[174]

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[173] Dorchester County Planning Commission. Minutes – March 4, 2015. secureservercdn.net/104.238.71.109/c4d.327.myftpupload.com/wp-content/uploads/2017/06/PC-Meeting-3-15.pdf, last accessed November 20, 2021.

[174] Maryland Historical Trust. Participants in the Section 106 Process. mht.maryland.gov/documents/PDF/projectreview/Section-106.pdf, last accessed July 20, 2019.

Although most impacts from the construction of solar facilities are temporary, ground disturbance or structure demolition can permanently erase the historic or prehistoric record from a culturally significant site. Thus, MHT requires sites determined to have a high archeological potential to undergo archeological surveys within a project's limit of disturbance or to be avoided if possible. If avoidance is not feasible, additional mitigation measures must be undertaken by developers before construction can begin. As noted earlier, most solar facilities constructed or proposed in Maryland are sited on agricultural land, much of which has been disturbed through years of tilling and where the archeological potential is low. As a result, few archeological protection measures have been required following initial surveys of properties carried out by qualified cultural resources consultants.

Once operational, SEGS have relatively benign effects on cultural resources compared to other generation technologies, with the primary effect being visual. Visual impacts may include views of structures within the project's limit of disturbance, or reflections off array surfaces, the latter usually identified as glare. This can be important since solar projects, particularly those developed on agricultural properties, can alter a landscape's setting, and criteria for evaluation of a historic property include a property's "integrity of location, design, setting, materials, workmanship, feeling and association."[175] Conversion of a farm from an agricultural setting to a utility-scale solar project can diminish the integrity of a historic property's setting, association and feeling, which is considered an adverse effect upon a property eligible for listing in the NRHP.

Such is the case with the Baker Farm located on the proposed Biggs Ford Solar site. The property was determined eligible for listing in the National Register (NR) for its association with the agricultural development of Frederick County. As proposed, solar panels would surround NR-eligible structures and occupy all available land on the parcel except where farm buildings are located, which would remain. Not only would the project diminish the integrity of the property's setting, but MHT concluded structures might be demolished by neglect if left vacant. MHT, therefore, determined the installation of the solar array would constitute an adverse effect on historic properties. PPRP convened a historic preservation consultation meeting with the applicant, MHT and local organizations with cultural resource interests in the project area to resolve MHT's concerns over the farmstead on the proposed site. Further consultation with MHT resulted in conditions requiring the applicant to undertake additional documentation of the Baker Farm farmstead and to establish a farmstead protection zone around structures within the complex during construction.

Because of their potential to adversely affect the integrity of a property's setting, PPRP must consider the effects of solar projects on state and other programs where scenic resources are an important element. Scenic quality is an important amenity for residents, but is equally so for the tourism industry, particularly for attracting recreational and heritage visitors to a region. Research has shown that degradation of views can affect tourist perceptions of scenic vistas and visitation levels.[176] Scenic quality can therefore affect the economic well-being of a region.

[175] 36 CFR § 60.4.

[176] Leah Greden Mathews, Susan Kask and Steven Stewart. "The Value of the View: Valuing Scenic Quality Using Choice and Contingent Valuation Models." Presented to the American Agricultural Economics Association Annual Meeting. Denver, CO. August 2004.

Scenic quality is recognized in many of Maryland's programmatic designations. The Maryland Environmental Trust (MET), for example, accepts offers of conservation easements to protect natural, historic and scenic resources in the state. Maryland's Rural Legacy Program 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" through the establishment of Rural Legacy Areas (RLAs). The Maryland Heritage Areas Program preserves the state's historical, cultural, archeological and natural resources for sustainable economic development through heritage tourism by designating Certified Heritage Areas (CHAs), defined by a distinct focus or theme that makes a place or region, including its natural landscapes, different from other areas of the state. MDOT 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. State and local government units promote scenery in various recreational initiatives, such as bicycle, hiking and water trails.

Impact on Conservation Easements

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 Rural Legacy Areas (RLAs), RLA designation, in itself, affords no land use protection.

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 NRHP, historic landscape and national historic landmark designations, the National Heritage Area program and the Federal Highway Administration's National Scenic Byway Program, among others.

The degree to which these programmatic designations protect cultural and heritage resources varies. MDOT SHA funds the development of community-based corridor management plans (CMPs) 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.[177] Although Maryland's Scenic Byways program does not have regulatory authority over land development within scenic byway corridors, SHA coordinates with other state agencies, including DNR, and local governments to achieve its programmatic goals. The Maryland Department of Planning's Scenic Byways Resource Protection Application is an example of this.[178] A geographic information system (GIS) mapping tool that inventories and analyzes both protected and vulnerable byways, the Application helps local and state agencies decide which byways are in most need of immediate conservation action, allowing them to prioritize and protect their historic and natural resources.

[177] Maryland Department of Transportation, State Highway Administration. "Context Sensitive Solutions for Work on Maryland Byways." February 2008.

[178] mdpgis.mdp.state.md.us/BywayResourceTool/Map.html.

Consistent with the state's vision for making walking and biking an integral part of Maryland's transportation system,[179] MDOT SHA has designated bike routes on many state highways to create a Bike Spine Network. By Maryland law, bicycles are vehicles.[180] Traffic laws require a vehicle overtaking another vehicle, including a bicycle, to proceed with due regard for the other vehicle on the approach, overtaking and clearance of the overtaken vehicle, and to yield to an overtaken bicycle before making any turns.[181] MDOT SHA does not otherwise regulate development of any kind along designated bike routes.

Although heritage areas do not impose regulatory controls on land use, impacts on scenic resources associated with the Stories of the Chesapeake Heritage Area contributed to the PSC's denial of the Mills Branch Solar project in Kent County. When carrying out activities in a CHA, a state agency must (1) consult, cooperate and, to the maximum extent feasible, coordinate their activities with the entity responsible for the management of each CHA; (2) ensure that the activities are consistent with the CHA's management plan; and (3) ensure that activities will not have an adverse effect on the resources of the Heritage Area unless there is no prudent and feasible alternative. In this case, there was concern that by changing the character of the historic and cultural landscape and interjecting a modern intrusion of considerable scale and alteration in the landscape's visual character, the project would impose an adverse effect on the Chesterville/Morgan Creek landscape district and on the Stories of the Chesapeake Heritage Area as a whole. It was further argued that impairment to the viewshed could harm the county's tourist industry due to the change it would make to the natural setting currently in place. Damage to the viewshed to a nearby Scenic Byway was also cited in the Utility Law Judge's decision.

In most cases, consultation results in mitigation to address adverse effects of solar projects sited on agricultural land. As was done for Mills Branch, PPRP consults numerous stakeholders in its environmental reviews of solar projects to understand concerns and propose remedies. For example, extensive coordination with the Heart of the Civil War Heritage Area as part of the review of the Citizens UB Solar project led to a recommended license condition requiring additional mitigation beyond buffering to enhance the entrance to the Town of Union Bridge. Conditions were added to the state's review of the Cherrywood Solar Project in Caroline County to satisfy the concerns of MDOT SHA regarding views from the Harriet Tubman Underground Railroad (HTUR) Byway, a National Scenic Byway.

Mitigating Solar Impacts on Agricultural Land

With the state's 50 percent RPS Tier 1 solar carve-out increasing to 14.5 percent of instate solar generation in 2028, development pressure on agricultural land in Maryland for siting utility-scale energy facilities is expected to continue. Because of solar PV land requirements, there are few alternatives to agricultural tracts, particularly in Maryland and the rest of the eastern U.S. where less land is barren or unproductive. Concern about energy sprawl in agricultural landscapes is not confined to Maryland, however, and the potential of strategic renewable energy siting to mitigate environmental trade-offs is beginning to receive serious attention across the U.S. These mitigation strategies do not necessarily

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[179] Maryland Department of Transportation. Maryland Twenty-Year Bicycle & Pedestrian Master Plan. January 2014.

[180] COMAR § 11-176.

[181] mdot.maryland.gov/tso/pages/Index.aspx?PageId=139.

remove utility-scale solar in its entirety from agricultural land, but attempt to reduce the impact through land-sparing, dual use and buffering.

Land-Sparing Alternatives

Land-sparing alternatives refer to the use of nonproductive rather than agricultural land on which to site solar facilities. Although not all alternatives apply to Maryland, research has shown the energy potential of these land-sparing alternatives is quite high nationwide. For example, a study of the land-sparing potential of solar PV energy development sited on four nonconventional land cover types in the Great Central Valley of California—built environment, salt-affected land, contaminated land and water reservoirs (floatovoltaics)—estimated these areas comprise a capacity-based energy potential of nearly 13 times California's 2025 projected energy demand.[182] National Renewable Energy Laboratory (NREL) researchers estimate that floating solar PV on the more than 24,000 built reservoirs in the U.S. could generate about 10 percent of the nation's annual energy production.[183]

Land-sparing alternatives to agricultural lands for siting renewable energy projects in Maryland has primarily focused on brownfields.[184] The EPA's RE-Powering America's Land Program has identified 279 sites in Maryland—totaling 103,000 acres—that contain contaminated lands, former mines and landfills that could potentially host renewable energy projects.[185] However, EPA's list ignores development considerations such as slope and risk associated with constructing and operating facilities on federally regulated (i.e., Resource Conservation and Recovery Act [RCRA] and Superfund) sites. After 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,[186] particularly since MDE has a Voluntary Compliance Program for brownfields that could potentially mitigate liability concerns.[187] As of September 2021, PPRP is reviewing an application to construct and operate a 175-MW PV facility in Garrett County on 1,189 acres in an area that was deep-mined prior to 1950 and then surface-mined in several locations starting in 2002.

In order to provide easily accessible information to assist in smart siting decisions, the Maryland Energy Administration (MEA) and PPRP sponsor SmartDG+, an online screening tool for distributed generation and renewable energy projects between 1 and 10 MW. SmartDG+ focuses on infrastructure proximity, land suitability and other factors that could help developers and officials identify promising areas from the RE-Powering America's Land Program.

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[182] Madison K. Hoffacker, Michael F. Allen and Rebecca R. Hernandez. "Land-sparing opportunities for solar energy development in agricultural landscapes: a case study of the Great Central Valley, CA, United States." Environmental Science & Technology, 2017, 51, 14472-14482.

[183] DOE/National Renewable Energy Laboratory. "Great potential for floating solar photovoltaics systems: Technology already in widespread use overseas, especially in Japan." ScienceDaily. January 8, 2019. sciencedaily.com/releases/2019/01/190108125422.htm.

[184] While not a brownfield, Spectrum Solar filed an application with the PSC in 2019 to construct a 5.6 MW solar PV facility on an idle, partly-developed property containing asphalt parking lots and an unstabilized excavation site in Prince George's County.

[185] geopub.epa.gov/repoweringApp/.

[186] EPA's Re-Powering America's Land Program identified 181 brownfield sites in Maryland, which is approximately 24,000 acres, and 25 closed landfill sites in Maryland, equivalent to 6,000 acres.

[187] Maryland's brownfields and closed landfills represent a capacity potential of 3,750 MW, assuming 8 acres per megawatt.

Dual-Use Solar Development

Dual-use development installs solar PV on farm fields without taking the fields out of production. It is sometimes called low-impact solar development. In other parts of the world, agriculture and solar facilities coexist reasonably well. Throughout Europe and the United Kingdom, small livestock (sheep, chickens) are grazed on utility-scale, ground-mounted solar facilities. In North Carolina, solar energy companies have started leasing flocks from farmers to control ground cover,[188] while sunflowers for oil production are grown under panels in Wisconsin.[189] Other productive options, such as beekeeping, could complement PPRP's promotion of pollinator habitats at CPCN-licensed solar facilities.

Not all agricultural applications are suitable for collocating with solar panels. For livestock, horses can be picky about what they eat, cows require a lot of grazing space, and goats tend to chew on wires and climb on panels, which are traditionally mounted close to the ground.[190] In addition, most utility-scale solar facilities do not have an onsite water supply which can increase production costs for farmers using the land for agricultural purposes. For crops, traditional panel placement and spacing can inhibit vegetation growth. However, innovative installation and structure design, including no-disturbance structure installation, panel spacing to minimize shading, and raised solar panels, are being tested in Massachusetts to address many of these constraints, which may someday enable the use under panels for a wide range of grazing animals or for vegetable and field crops.[191]

Setbacks and Buffering

By far, the most common form of mitigation for SEGS in Maryland is setbacks and buffering. In agricultural areas, mitigation can be quite robust where projects abut residential properties, scenic resources or cultural landscapes. For SEGS, a setback is the minimum distance from a property line, right-of-way (ROW) or other feature to a solar component such as a panel or inverter within a project's limit of disturbance. A buffer is a vegetated strip or other landscaped feature such as a berm that is designed to mitigate views or other externalities of the project, such as noise. Typically, a solar project's perimeter road, security fence and buffer are within its setback.

For counties that address SEGS in their zoning bylaws, setback and buffer requirements are usually included in special exception conditions or in general setback and buffer requirements for zoning districts where SEGS are a permitted use, although the specifications vary throughout Maryland. For example, for utility-scale solar facilities, Queen Anne's County requires setbacks of 75 feet from any lot line, 100 feet from any road and/or ROW, and 150 feet from any residential use or zoning district, plus a vegetated 50-foot buffer around the perimeter of the site.[192] Design standards for SEGS in Washington

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[188] cals.ncsu.edu/news/got-sheep-want-a-solar-farm/.

[189] Jordan Macknick. "Overview of opportunities for co-location of agriculture and solar PV." National Renewable Energy Laboratory. Clean Energy Economy Conference. Utica, NY. June 14, 2016.

[190] nrel.gov/state-local-tribal/blog/posts/solar-sheep-and-voltaic-veggies-uniting-solar-power-and-agriculture.html.

[191] Stephen J. Herbert, Phaedra Ghazi, Kate Gervias, Emily Cole and Sara Weis. "Agriculture and Solar Energy Dual Land Use." Stockbridge School of Agriculture, University of Massachusetts Amherst. ag.umass.edu/sites/ag.umass.edu/files/research-reports/Agriculture%20and%20Solar%20Energy%20Dual%20Land%20Use.pdf, last accessed July 22, 2019.

[192] § 18:1-95.S Queen Anne's County Code.

County require SEGS to adhere to setback, height and coverage requirements of the district in which they are located.[193] Section 5A.6 of the county's Zoning Ordinance, for example, requires nonresidential lots in the Agriculture - Rural zone to have a minimum setback of at least 50 feet for "Other Principal Permitted or Conditional Uses." Landscaping requirements, including plant material specifications, maintenance and other conditions are applied to any development requiring site plan review,[194] although buffer widths are not specified.

Where SEGS are not addressed or are inadequate for addressing project impacts, PPRP includes additional project-specific setback and buffer requirements in license conditions. PPRP also adds buffer maintenance and surety requirements when not addressed by counties. Such conditions were attached to the licensing of the Rockfish Solar facility in Charles County to shield the project components from nearby residential properties and accommodate the planned future widening of a road fronting the facility.

Most buffering conditions require landscaping to be installed before the project becomes operational and to be effective in blocking views of and glare from the project after three to five years. However, PPRP has in some cases required developers to install temporary, opaque buffers prior to construction, primarily to mitigate glare impacts upon surrounding public roads. For example, for Jones Farm Lane Solar, PPRP's concern about glare trespassing onto two roads bypassing the project site was related to motor vehicle safety. The National Highway Traffic Safety Administration, in a study on the risks of glare to oncoming vehicles, found nighttime glare from headlights was associated with decreasing visibility distance, increasing reaction times and increasing recovery time, with the risk increasing on two-lane highways.[195] Daytime glare has been found to increase situational identification time from 0.8 to 2.7 seconds,[196] while analysis of data from signalized intersections of Tucson, Arizona shows some evidence that sun glare affects intersection crash occurrence.[197] Even though Queen Anne's County landscaping requirements are robust, they require a landscape buffer to provide an opaque visual barrier once the vegetation reaches maturity or within five years. As such, offsite glare would not be fully mitigated during the early years of the project. While PPRP concluded the project's site plan satisfied the county's proposed setback and landscaping requirements, it added a license condition requiring the developer to mitigate glare impacts on nearby public roads prior to construction until the proposed landscape buffer matures enough to completely block the sun's reflections.

The effectiveness of landscaped buffers around solar projects in Maryland has been mixed so far. Setback and buffers requirements were not even included in the recommended license conditions for the Maryland Solar project, one of the first utility-scale solar facilities granted a CPCN by the PSC. In the absence of county landscaping requirements, license conditions in subsequent cases generally specified a 25-foot or less buffer within a 50-foot setback, but without plant maintenance and surety guarantees.

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[193] § 4.26 Washington County Zoning Ordinance.

[194] § 22.11.1 Washington County Zoning Ordinance.

[195] National Highway Traffic Safety Administration. Nighttime Glare and Driving Performance. Report to Congress. February 2007.

[196] R.L. Saur and S.M. Dobrash. "Duration of afterimage disability after viewing simulated sun reflections." Applied Optics, Vol. 8, Issue 9, September 1969, 1799-1801.

[197] S. Mitra. "Sun glare and road safety: An empirical investigation of intersection crashes." Safety Science, Volume 70, December 2014, 246-254.

This was coupled with a condition to allow neighboring property owners to obtain relief from visual impairment or unwanted reflections through arbitration, which was assumed would be rectified by additional targeted landscaping.

PPRP's experience with the Great Bay Solar (GBS) project in Somerset County is an example of how visual mitigation conditions for SEGS have changed over time. PPRP's recommended license conditions associated with buffering, as proposed in late 2015, are shown below.

- GBS shall set back its facilities, defined as facilities within 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, GBS shall design a landscape buffer within the setback and outside the fence line that will effectively screen, to a minimum of eight (8) feet above ground level, views of the solar facility. The landscape screening requirements may be waived by the Somerset County Department of Technical and Community Services where GBS can demonstrate that conditions on adjacent land are present, such as forest, woodland, wetlands, open fields or cropland such that the landscaped buffer serves no purpose. The plan must be submitted to the Public Service Commission, PPRP and the Somerset County Department of Technical and Community Services for review and approval prior to construction.

- GBS shall develop a process to document and address admissible complaints related to potential solar reflections. An admissible complaint shall be one formally submitted to GBS within one year of an array within a Project parcel being energized. If it is determined that the complaint is justified, GBS shall prepare a screening plan to mitigate impacts from reflective glare upon the affected property.

Note that PPRP's buffering condition resulted from the fact that SEGS were not recognized in Somerset County's zoning ordinance and thus there were no local standards to regulate their development. PPRP further concluded that Somerset County's general buffering requirements for new industrial installations were insufficient for mitigating visual impacts upon nearby residences. Following public comment that the 50-foot setback was insufficient to protect residential properties and the local viewshed in general, the PSC order approving the project increased the setback from 50 to 75 feet from all roads and highways and required that the views of local residences be fully buffered by planting appropriate trees and shrubs.[198]

Because GBS requested the PSC to extend and amend CPCN construction deadlines, effectively dividing the project into two phases, PPRP was able to revisit the project's visual mitigation requirements and strengthen them considerably in 2019, as follows.

- GBS shall set back its facilities, defined as facilities within perimeter fencing, *at least 75 feet from any public roads and 50 feet from adjacent non-participating properties*. Where the Project abuts a primarily residential property, or a public or private road, GBS shall design a landscape buffer within the setback and outside the fence line that will effectively screen *for the life of the project*, to a minimum of eight (8) feet above ground level *year-round and within five years of project completion*, views of the solar facility. *The amount and extent of the required screening will be determined by the Somerset County Department of Technical and Community Services as*

[198] Maryland Public Service Commission, Order No. 87321, Case No. 9380.

part of the site plan review process. The landscape buffer design must be submitted to the PSC, PPRP and the Somerset County Department of Technical and Community Services for review and approval prior to construction. *Due to seasonal planting restrictions, no more than twenty percent of the site shall be installed with solar panels until the vegetative buffer is installed*.

- GBS shall develop a process to document and address admissible complaints related *to visual impacts associated with Project structures, such as panel arrays and inverters within the Project's perimeter fence*, and solar reflections (glare). An admissible complaint shall be one formally submitted to GBS within *two (2) years* of an array within a Project parcel being energized. *GBS shall provide to the PSC, PPRP, and the Somerset County Department of Technical and Community Services, both a copy of the complaint and its response to the complaint. GBS's response to any written complaint shall clearly inform the aggrieved party that if not satisfied with GBS's response, the aggrieved party may seek relief by filing a complaint with the PSC. If the PSC determines that the complaint is justified*, GBS shall prepare and implement a screening plan to mitigate impacts from reflective glare upon the affected property. *The screening plan shall be in conformance with all applicable state and local laws and regulations*.

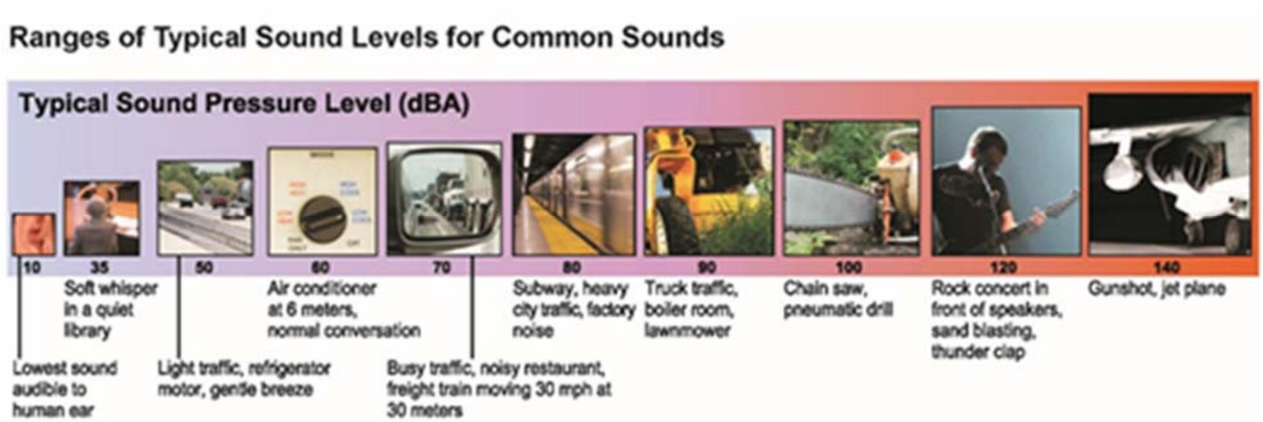
The revised conditions apply to the entire project, where applicable, meaning inadequate buffering around Phase I of the project will be replaced or supplemented. Somerset County is currently in the process of revising its zoning ordinance, which will include standards for solar projects.

Regardless of the robustness of landscaping, there are limitations to buffering as mitigation for visual impacts from SEGS, particularly in agricultural areas where solar PV facilities present a stark visual contrast. Although the angularity of arrays can be compared to other agricultural structures, such as greenhouses or poultry barns, the spatial scale of these facilities sets them apart, covering tens or hundreds of acres instead of just a few. Without screening, solar arrays are unmistakably industrial to the eye and may emit additional visual (glare) and audible externalities onto nearby properties. Landscape screening does offer visual relief as the Rockfish Solar facility in Charles County demonstrates, but does not restore prior views of the landscape, nor is the effect very natural, particularly in rural areas, sometimes creating a visual contrast to viewers due to their linearity and uniformity of design. Visual impacts can be reduced by landscaping, but not eliminated.

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 are 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.



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 versus 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. With the increasing number of renewable energy projects in the state, PPRP has studied noise impacts from wind and solar projects over the past decade.

- Solar power inverters emit a noticeable "electrical hum," but this is only audible at relatively short distances and is generally not heard over background noise at a distance of 150 feet. PPRP has encouraged developers to position inverters at the interior of solar arrays, which allows noise to attenuate before reaching the property boundary.
- Wind turbines generate noise in two primary ways—from the motion of the turbine blades and from mechanical equipment inside the turbine nacelle. Low frequency noise should also be considered when evaluating the effects of wind turbines. PPRP has used modeling software, as well as literature research into recent scientific studies, to assess noise levels and potential impacts from proposed wind turbines. To mitigate both audible and low frequency noise, windpower facility design should incorporate adequate buffer distances between wind turbines and residences.

Property Value Impacts

As the economy transitions to clean, renewable energy, utility-scale solar projects are becoming a common feature of the landscape and, although ground-mounted solar facilities can occupy significant acreage, solar panels, racking and associated components have a vertical profile that rarely exceeds 12 feet. Still, concerns about alterations to views and other externalities lead to questions about changes to property values and reduced demand for residential properties near solar energy facilities.

Residential property value is dependent on many factors, including the size and amenities of the property itself, improvements made to the property, and the attributes of the surrounding neighborhood. Previous research has suggested that distance to “environmental disamenities” is a contributing factor in adversely affecting property value, although property value declines have been more consistently observed in residential properties that are near higher-risk disamenities (e.g., hazardous waste facilities) or facilities that lack adequate land or vegetation buffers.

Most research into property value impacts has derived its conclusions from appraisal studies or econometric techniques. Most appraisal studies use a comparison sales approach, which is largely dependent on the appraiser’s expert judgment in locating and refining a set of comparable sales for analytical purposes. Although appraiser studies often use records of sales prices or assessments from a large number of properties, the analysis is usually confined to descriptive statistics from which only limited inferences can be made. Econometric models attempt to statistically account for factors that influence property values, such as lot size, structural attributes, neighborhood amenities, etc. Econometric studies are data-intensive and often combine data from several distinct sources such as tax rolls, real estate sales records and survey data. PPRP has sponsored research on property value impacts from power plants and comparable large industrial facilities, transmission lines and wind energy facilities in Maryland using econometric models.

> **Econometric Models and Property Value Impacts**
>
> In property value studies, econometric models estimate the marginal contribution of property attributes and neighborhood externalities to property values. Distance from a property to a disamenity is a neighborhood externality, one of the explanatory variables in what is known as a hedonic model. Econometric methods are used to estimate the relative contribution and statistical significance of the explanatory variables and the model as a whole to explain residential

Examples of appraisal studies from published literature include a past siting case in North Carolina for a 21-acre solar facility in an Agricultural-Residential district, which concluded that utility-scale PV energy systems that are not visible from surrounding properties would have no impact on their market values,[199] and a paired comparison of market values of residential and agricultural properties near operating solar facilities in North Carolina that came to a similar conclusion.[200] While findings from the Franklin County study were based on expert opinion drawn from market valuations of a limited sample of properties near other types of industrial disamenities, the Kirkland

[199] Franklin County 2014. Commissioner’s Agenda Information Sheet. Item: Request for Special Use Permit – Sarah Solar, LLC, Parts 2 and 3. June 16, 2014.

[200] Letter from Richard C. Kirkland, Jr., Kirkland Appraisals, LLC to Mr. Louis Iannone, Strata Solar, July 24, 2014.

study compared adjoining with non-adjoining residential sales prices at three comparable solar facilities in the state, as well as a survey of builders, developers and investors, which led it to conclude the project would have no impact on home values due to the adjacency and no impact to adjacent vacant residential or agricultural land. Neither has more recently published literature found a significant relationship between proximity to utility-scale solar facilities and nearby residential property values. This includes evidence gathered from a widely circulated independent survey of home appraisers from multiple states, including Maryland,[201] a study of utility-scale PV solar installations abutting residential land parcels in the seven-county Twin Cities Metro Area,[202] and a paired sales analysis of properties adjacent to operating solar projects in Indiana.[203]

However, comparability with appraisal studies discussed above is unclear due to the geographic scope of potential effect (three miles), range of generating capacities (1 MW and above), non-recognition of visual encumbrances and absence of a proximity measure.

There is little direct evidence from Maryland licensing cases supporting or rejecting the property value impact argument. In support of two applications to build solar PV facilities in Frederick County,[204,205] a real estate appraisal study was commissioned by the project developer to investigate the potential impact of the project on neighboring property values using paired sales analysis of properties within and outside a half-mile radius of selected operational solar facilities in Maryland.[206] Although the methodology and limited sample size do not allow one to draw a statistical inference from the data, the study concluded the values of properties in proximity to solar facilities are not impacted by the presence of the solar facilities. Still, as evidenced in the Biggs Ford Solar case, where the applicant's study concluded that the

[201] Leila Al-Hamoodah, Kavita Koppa, Eugenie Schieve, D. Cale Reeves, Ben Hoen, Joachim Seel and Varun Rai. "An Exploration of Property-Value Impacts Near Utility-Scale Solar Installations." Policy Research Project, LBJ School of Public Affairs, The University of Texas at Austin. May 2018. emp.lbl.gov/sites/default/files/property-value_impacts_near_utility-scale_solar_installations.pdf, last accessed August 30, 2020.

[202] Benjamin Marin. "Solar Installations and Property Values: An Examination of Ground Mounted, Primary Land Use, Two Plus Megawatt Solar Installations on the Total Estimated Market Value of Abutting Residential Parcels." The Hubert H. Humphrey School of Public Affairs. The University of Minnesota. April 29, 2019. conservancy.umn.edu/bitstream/handle/11299/208704/Solar%20Installations%20and%20Property%20Values.pdf?sequence=1&isAllowed=y. Last accessed February 7, 2021.

[203] CohnReznick, LLP. "Property Value Impact Study: Proposed Solar Farm, McClean County, IL." August 7, 2018. mcleancountyil.gov/DocumentCenter/View/13192/Patricia-L-McGarr--Property-Value-Impact-Study?bidId=. Last accessed February 7, 2021.

[204] Maryland Public Service Commission, Case No. 9429. In the matter of the application of LeGore Bridge Solar Center LLC for a Certificate of Public Convenience and Necessity to construct a 20.0 MW solar photovoltaic generating facility in Frederick County, Maryland.

[205] Maryland Public Service Commission, Case No. 9439. In the matter of the application of Biggs Ford Solar Center, LLC for a Certificate of Public Convenience and Necessity to construct a 15.0 MW solar photovoltaic generating facility in Frederick County, Maryland.

[206] Treffer Appraisal Group. "An External Obsolescence Study Related to Proposed Solar Farms in Frederick County, Maryland." Prepared for Coronal Development Services. January 18, 2016.

project was not expected to impact adjacent property values and one commissioned by an adjacent property owner predicted a negative impact,[207] appraisal studies are not without bias.[208]

Statistical evidence in Maryland is thin because few projects granted a CPCN by the PSC are operational (see Table 5-9). Since the first CPCN for a utility-scale PV project was issued (Maryland Solar), only 11 projects, totaling 262.6 MW, are online. PPRP estimates 3,776 occupied residential parcels are within one mile of the project parcels containing these facilities, and 1,173 are within one-half mile (see Table 5-10). On a project-by-project basis, only areas within one mile of three project parcels have seen enough residential sales to statistically analyze with any degree of confidence. This is because most projects have been sited on rural land with few nearby residential parcels. Furthermore, one of the three, Maryland Solar, is located on the grounds of the Maryland Correctional Institution – Hagerstown that has likely had its influence on surrounding property values, which cannot be readily distinguished from the solar facility.

[207] Six & Associates Inc. Letter to Jack Stern, Walkersville MD. January 22, 2016. Maryland Public Service Commission Case No. 9439, ML 226957.

[208] In that case, the Public Utility Law Judge (PULJ) found that both the applicant's appraisal and the appraisal submitted by the property owner had deficiencies, and contained no evidence to support the claim that property values would be impacted. Maryland Public Service Commission Case No. 9439, Phase II. Proposed Order of Public Utility Law Judge. Issued August 27, 2020.

Table 5-9 Operational Solar Facilities in Maryland (as of July 2021)

Name	PJM GATS Name	County	Limit of Disturbance (Acres)	PSC Case No.	Filing Date	GATS Nameplate Capacity (MW)	Date Online
Maryland Solar	AP MARLOWE 1 SP	Washington	270	9272	5/26/2011	29.1	11/1/2012
Cambridge Solar	DPL BUCKTOWN 1 SP	Dorchester	25	9348	4/1/2014	4.3	5/1/2015
Rockfish Solar	Rockfish Solar, LLC	Charles	82.5	9351	3/16/2014	13.1	6/1/2015
LS-Egret Solar	DPL HEBRON 1 SP	Wicomico	108	9366	10/20/2014	17.8	2/1/2016
Church Hill Solar	DPL CHURCH HILL 1 SP	Queen Anne’s	42	9314	1/23/2013	7.3	5/1/2016
Wye Mills Solar	DPL WYE MILLS 1 SP	Queen Anne’s	95	9375	2/2/2015	13.7	8/1/2016
Great Bay Solar I	DPL GREAT BAY KINGS CREEK 1 SP	Somerset	562	9380	5/11/2015	99.9	9/1/2017
Great Bay Solar II	DPL GREAT BAY KINGS CREEK 2 SP	Somerset	167.13	9380	5/11/2015	43.0	6/1/2020
Baker Point Solar	AP BAKER POINT 1 SP	Frederick	56	9399	10/8/2015	10.9	10/1/2017
Gateway Solar	DPL WORCESTER NORTH 1 SP & SOUTH SP	Worcester	120	9409	12/1/2015	10.0	3/1/2019
Blue Star Solar	OneEnergy Bluestar Solar, LLC Parcel #2 & #3	Kent	45	9387	7/10/2015	7.8	1/1/2020
Pinesburg Solar	AP PINESBURG 1 SP	Washington	55	9395	9/4/2015	5.8	5/1/2020

Source: PJM Environmental Information Services. Generation Attribute Tracking System (GATS). Renewable Generators Registered in GATS. Through July 4, 2021.

Table 5-10 Residential Parcels in Proximity to Operational Solar Facilities

Name	County	Date Online	Res. Parcels < 1 mi	Res. Parcels < 0.5 mi	Post Online Res. Sales < 1 mi.	Post Online Res. Sales < .5 mi.	% Res. Sales < .5 mi.
Maryland Solar	Washington	11/1/2012	1,040	339	325	64	19.7%
Cambridge Solar	Dorchester	5/1/2015	23	11	2	1	50.0%
Rockfish Solar	Charles	6/1/2015	1,445	311	399	71	17.8%
LS-Egret Solar	Wicomico	2/1/2016	600	170	99	23	23.2%
Church Hill Solar	Queen Anne's	5/1/2016	107	3	21	1	4.8%
Wye Mills Solar	Queen Anne's	8/1/2016	53	2	6	0	0.0%
Great Bay Solar I	Somerset	9/1/2017	212	83	14	5	35.7%
Baker Point Solar	Frederick	10/1/2017	106	63	10	4	40.0%
Gateway Solar	Worcester	3/1/2019	61	23	2	2	100.0%
Blue Star Solar	Kent	1/1/2020	61	52	2	1	50.0%
Pinesburg Solar	Washington	5/1/2020	199	156	2	1	50.0%

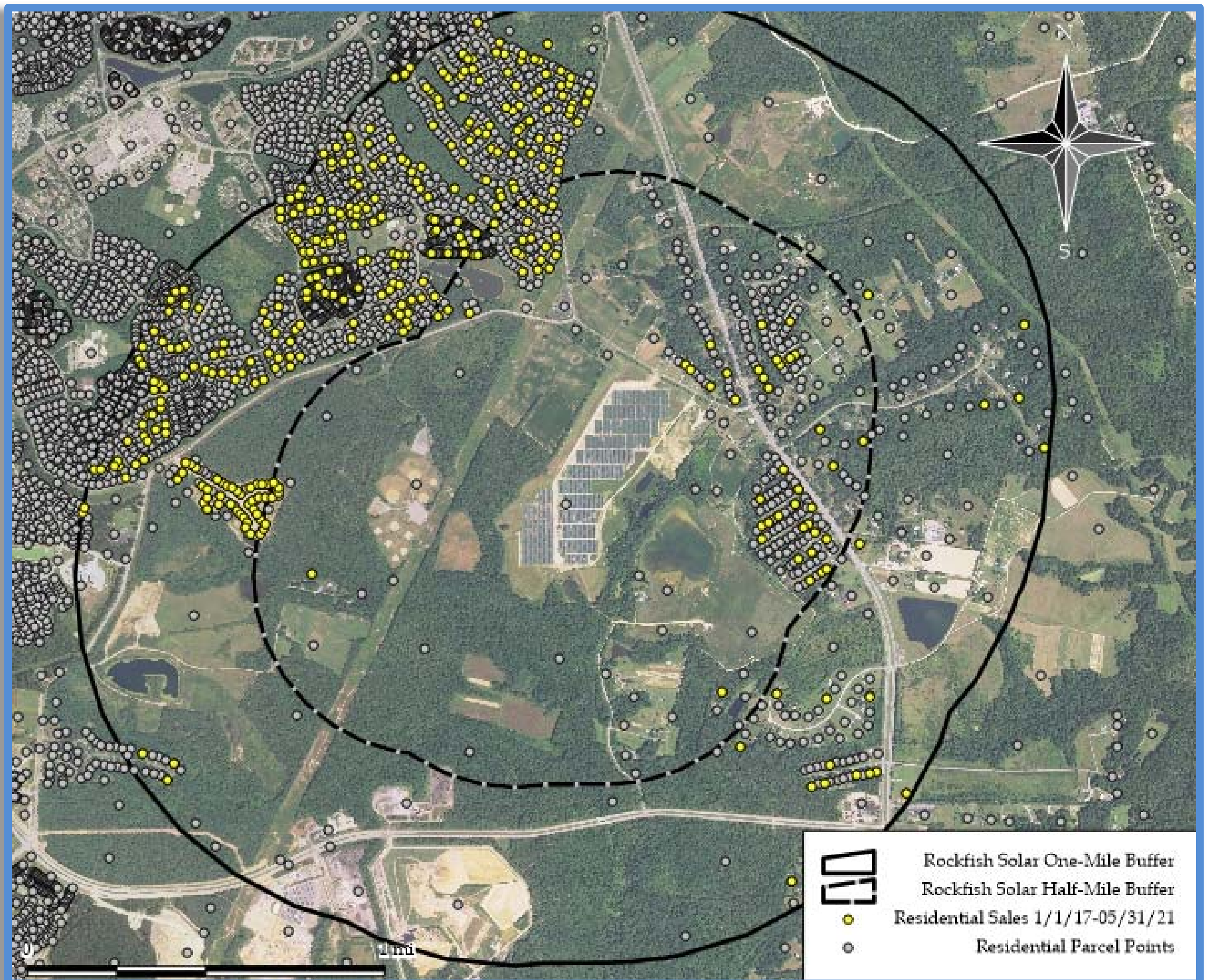
Source: Maryland Department of Planning, Sales Data, January 1, 2017 – May 31, 2021.

To date, PPRP's analysis of the Rockfish Solar facility in Charles County has yielded the most information on property value impacts. The facility, which came online in June 2015, is located off Renner Road, approximately 2.3 miles southeast of the communities of St. Charles and Waldorf, on nearly 90 acres of a 165-acre parcel formerly cultivated for agricultural use after being reclaimed from a sand and gravel surface mine. The site is generally flat land with minimal topographical variation. Land use near the facility is within a Rural Residential district, a designation intended to allow for rural development at one unit per three acres while preserving the rural character and open space whenever possible. Other surrounding land uses are Residential (St. Charles), Employment & Industrial Park and Rural Conservation Districts.

Views toward the project are limited because there are few adjacent residential properties and solar arrays have a minimal vertical profile. Homes in the St. Charles planned unit development north of Piney Church Road (west of the facility) are separated by distance and forest, as are homes in the Cedar Pines and Broadview Farm subdivisions to the south. A transmission corridor and mature woodland buffer views toward the project from playing fields within the nearby Robert D. Stethem Memorial Complex. The only "near" views are from a small number of residences along Renner Road opposite the property and from Renner Road itself. PPRP conditioned the project on a landscaping plan in substantial conformance with Charles County's buffering requirements for large solar energy systems. It also required a setback greater than Charles County's minimum 50-foot setback from any property line due to the planned future widening of Renner Road. Solar panels are about 150 feet from Renner Road at their closest point, and views are mitigated by a 50-foot landscaped buffer of trees and shrubs that appears to be largely effective.

According to MD Property View residential sales data, between January 1, 2017 and May 31, 2021, 399 residential properties within one mile of the project parcel, or 27.6 percent of all residential parcels within a mile, changed hands in arms-length transactions. Within half a mile, 71 arms-length residential sales were recorded. The average sale price for all transactions within one mile was $306,145, and $316,779 within one-half mile (see Figure 5-38). While the sale price difference does not take property attributes into account, it suggests proximity to the solar facility may not have been a major factor in homebuyer decision-making, which could be attributable to visual mitigation from mature woodlands surrounding much of the project and effective landscaping along the northern edge of the parcel. PPRP is continuing to gather residential sales and property attribute data to better understand the relationship between property values and proximity to utility-scale solar PV facilities to help guide its project assessments.

Figure 5-38 Residential Parcel Sales Near Rockfish Solar Facility



Source: Maryland Department of Planning.

Transmission Lines

Proximity to high-voltage transmission lines has been associated with changes in property values due to visual intrusion and perceived risk. Most evidence, however, has been based on impacts upon residential properties in urban and suburban settings. There have been relatively few studies that address the impact on rural land used for agricultural or recreational purposes.[209,210]

Most studies have, however, shown little to no effect on sales price from transmission lines, beyond the loss associated with ROW acreage. A regression analysis on sales of farm land in the Canadian province of Saskatchewan between 1965 and 1970, for example, found that the relationship of land value to the number of power line structures was not statistically significant and that the lines did not negatively affect property value.[211] In another study, a hedonic price model of sales data from several hundred rural land transactions in Wisconsin found a small difference (< 2.5 percent) in sales prices of online and offline properties, but the difference was not statistically significant. An analysis of transactions involving agricultural properties in Montana found that on productive agricultural lands (cropland and range lands), there was no evidence supporting a transmission line effect on the sales price.

Some exceptions do exist in the literature.[212] A sales comparison study of farmland in Minnesota found price effects ranging from zero to 20 percent where transmission lines were highly intrusive on farm operations, although the latter finding was from a single appraiser study.[213] Another study of transactions involving agricultural land in rural Alberta found a decrease in property values on parcels with irrigation potential hosting multiple transmission lines. In general, however, the findings of the most recent research suggest that a transmission line crossing an agricultural parcel has either no effect or an effect in the range of several percentage points that is not statistically significant.

County Ordinances

While CPCNs are required for generating stations over 2 MW, generating stations under 2 MW are subject to county ordinance and permitting. With the increase in renewable energy projects in Maryland, particularly solar and wind, many counties have established ordinances pertaining to the approval and siting of generation. Although the PSC has the regulatory authority to approve electric generating stations above 2 MW, it takes into consideration a county's ordinances, if applicable, and concerns when reviewing an application for a CPCN.

[209] Thomas Jackson. "Electric Transmission Lines: Is There an Impact on Rural Land Values?" Right of Way. November/December 2010.

[210] Thomas Priestley. "Transmission Lines and Property Values: Briefing Paper." Prepared for Clean Line Energy Partners LLC. CH2MHill. Houston, Texas. April 2015.

[211] D.J.A. Brown. "The effect of power line structures and easements on farm land values." Right of Way. December/January 1975-1976.

[212] Julia Haggerty. "Transmission Lines and Property Value Impacts: A Review of Published Research on Property Value Impacts from High Voltage Transmission Lines." Produced for Mountain States Transmission Intertie (MSTI) Review Project by Headwaters Economics. July 2012.

[213] C.A. Kroll and T. Priestley. "The Effects of Overhead Transmission Lines on Property Values." Report to Edison Electric Institute Siting & Environmental Planning Task Force. 1992.

Ordinances related to renewable energy can be found within a county's zoning documents. The level of detail and extent of ordinances vary based upon the county, with some counties adopting ordinances specific to certain renewable energy technologies, such as wind or solar. In 2017 and 2018, some counties issued moratoriums on the siting of renewable energy projects while they reevaluated or established ordinances related to renewable energy. As of 2021, all county moratoriums had expired. Some of the ordinances currently in effect include:

- Limit on the number of acres that can be utilized by commercial solar systems;
- Maximum capacity per renewable energy project;
- Height restrictions on wind turbines;
- Limitations on which zoning areas renewable energy projects may be sited within; and
- Bans on certain renewable energy projects (e.g., Charles County zoning prohibits large-scale wind energy projects with turbines and towers exceeding 150 feet in total height).

To ensure that a renewable energy project does not negatively impact existing operations, such as radar, a county may include a zoning provision requiring approval from multiple county agencies and/or an entity besides the county. For example, St. Mary's County requires wind and solar developers to receive permission from the U.S. Department of the Navy for projects they wish to site within a certain area around the Naval Air Station Patuxent River to prevent radar interference. A comprehensive list of county ordinances is provided as part of the SmartDG+ tool, located on the PPRP website. The SmartDG+ tool and accompanying resources are designed to guide developers as they begin the process; however, developers should contact county planning/zoning offices when planning their project to ensure that a site meets county ordinance requirements.

SmartDG+

MEA and PPRP developed a free, online, map-based screening tool, SmartDG+, to assist developers and officials in identifying areas to locate new wind and solar projects. The tool maps 1- to 4-mile-wide corridors surrounding electric distribution and transmission lines that are likely able to handle renewable energy projects that are 2 MW or higher. Users can choose from the following screen factors/data layers to find potential project siting areas:

- Infrastructure Proximity
    - Electricity lines
    - Gas lines
- Renewable Resource Availability
    - Viable wind speeds
- Land Suitability
    - Protected areas
    - Flood zones
    - Land cover/land use
    - Airports
    - DOD no-go zones
    - County zoning
- Installed wind and solar projects

Source: dnr.maryland.gov/pprp/Pages/SmartDG.aspx

5.4.2 Historic and Scenic Resources in Transmission Assessments

Scenic Resource Assessment

Transmission lines are an enduring feature of the rural landscape in Maryland. Virtually all transmission line corridors in the state have been in existence for more than 50 years. Most transmission line projects that have been proposed to the PSC in recent years have therefore involved reconductoring existing transmission lines to service projected increases in electricity demand and improve reliability throughout the state. [214]

Reconductoring has typically required new structures, but in many cases, lattice structures have been replaced by monopoles which, while taller, have a lower visual profile and require less real estate on the ground. As a result, PPRP has generally concluded the visual landscape will be mostly unchanged by these projects and therefore will have few direct effects on nearby land uses, even on parcels under agricultural production.

The Independence Energy Connection (IEC) project proposed by Transource Maryland LLC, however, presented this issue in a different context as it would require a new "greenfield" corridor through agricultural lands in Harford County, and a new corridor roughly parallel to an existing transmission line ROW through mostly agricultural land in Washington County. Based on the project's design and location, PPRP concluded the transmission lines would add visually conspicuous, linear features to landscapes within small areas of Harford and Washington counties, with structures adding a major source of vertical contrast.

For transmission line structures, the size, vertical visual character and geometry all contribute to their contrast against the landscape. Yet a range of factors can influence the perceived visual impact of the physical infrastructure. These factors include screening elements such as landforms, vegetation, structures, earth curvature and atmospheric refraction, viewer perceptions, lighting, atmospheric conditions, viewing geometry, the visual backdrop of the viewed object (e.g., sky, ground or vegetation) and the distance between the viewer and the viewed object.[215]

Both landscape setting and distance moderate the visual impact of transmission lines on viewers. In general, more visually complex landscapes, such as lands with greater vegetative and topographical complexity, reduce the prominence of transmission structures.[216] For an evidence-based study of Ireland's transmission grid,[217] landscapes were characterized by specific landscape character types, where the lowest visual effects were found within urban, lowland lake-land, river valley farmland, lowland plain and upland forested landscapes, and the majority of the sites with lowest visual effects were found to be lowland agricultural landscape types. The highest visual effects were found within high

[214] Reconductoring is the process of replacing the current-carrying conductors in a transmission line.

[215] Robert G. Sullivan et al. "Electric Transmission Visibility and Visual Contrast Threshold Distances in Western Landscapes." Conference: National Association of Environmental Professionals 2014 Annual Conference, Saint Petersburg, Florida. April 2014.

[216] I. Bishop and R.B. Hull. "Visual Simulation and Assessment of Electricity Transmission Towers." Landscape Australia, March 1985.

[217] EirGrid. EirGrid Evidence Based Environmental Studies. Study 10: Landscape & Visual – Main Report. June 2016.

drumlin and low drumlin esker landscapes, a finding consistent with an analysis of visual contrast threshold distances in landscapes in the western U.S., where skylined structures were visible to the unaided eye at greatest distances. The magnitude of potential visual impacts from transmission lines is strongly related to distance from the viewer, with scenic impact declining with increasing distance to structures (although also increasing with structure size).[218] Visual contrast threshold distance is the distance at which an object becomes visible or attracts visual attention and is used to determine the area of potential effect in visual impact assessments.

Scenic values associated with landscape settings can be difficult to define, particularly when scenic resources are not systematically or consistently identified. Maryland, for example, has not conducted a statewide scenic landscape inventory, although comprehensive scenic resource assessments have been conducted for some regions of the state.[219] As a result, general planning decisions for transmission line siting, in addition to other growth policy decisions, are tempered by the lack of a scenic landscape data layer based on uniform visual resource assessment guidelines. Therefore, PPRP visual impact assessments are largely discretionary, based on incomplete scenic resource data and multiple standards among scenic preservation interests for classifying visual resources.

Impacts on Heritage and Recreational Tourism

Many federal, state and local land preservation and heritage overlays of Maryland contain scenic elements. For example, the Maryland Heritage Areas Program focuses on the preservation of the state's historical, cultural, archeological and natural resources for sustainable economic development through heritage tourism. The program designates Heritage Areas, defined by a distinct theme that makes a place or region different from other areas of Maryland. The Maryland Heritage Areas Authority (MHAA) certifies and governs Heritage Areas. A management plan sets forth the strategies, projects, programs, actions and partnerships that will be involved in achieving each Heritage Area's goals. Once certified, a Heritage Area management entity becomes eligible for state-matching grants for operating assistance and marketing activities. Local jurisdictions and nonprofit organizations in a Heritage Area may also qualify for state-matching grants for planning, design, interpretation and programming. There are 13 Certified Heritage Areas (CHAs) in Maryland. Maryland Heritage Area law requires state agencies to carry out certain actions when considering a project located in a CHA. Specifically, when a state agency is carrying out activities in a CHA, it must consult, cooperate and, to the maximum extent feasible, coordinate its 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. Other designation programs include Maryland's Rural Legacy Program and MDOT SHA's Scenic Byways Program which were described earlier.

At the federal level, scenic quality is 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

[218] Sullivan et al., op. cit.

[219] John Milner Associates, Inc. "Maryland's Eastern Shore: Stories of the Chesapeake Heritage Area: Cultural Landscape and Scenic Resource Assessment." Chestertown, Maryland. 2004.

Administration's National Scenic Byway Program, among others. Local governments promote scenery in various recreational initiatives, such as bicycle, hiking and water trails.

While these federal, state and local land preservation and heritage overlays contain scenic elements, landscapes are not uniform within them. Many views have low scenic value or are compromised by contrasting elements, such as commercial establishments, cell and transmission towers and rural subdivisions. Because of this, land preservation and heritage overlays are poor proxies for characterizing scenic quality.

Furthermore, the relationship between scenic quality and heritage and recreational tourism is unclear. As noted earlier, degradation of views has been found to affect tourist perceptions of scenic vistas and visitation levels.[220] However, it has also been shown that perceptions drawn from views within a landscape or of objects within a landscape can vary depending on whether the landscape is an economic resource, tourism or recreational asset, family home or other identity.[221] The visual impact of a wind turbine on a tourist may be quite different from that on a nearby resident, for example. Even when landscapes are highly disturbed, they often retain a pastoral quality to urban or suburban visitors to rural areas.[222] Perceptions may also change over time. Evidence from a Finnish study, for example, suggests residents living in close proximity can adapt to transmission lines being part of the landscape.[223] Similar findings have been suggested in property value studies.[224] Still, the findings of the majority of studies seeking to relate perception and aesthetics are far from certain given their lack of scientific rigor.[225] As a result, PPRP's estimation of impacts of transmission lines on heritage and recreational resources is largely based on visibility and distance from these resources.

For example, in PPRP's environmental review of the IEC West project, three corridor segments were found to be within the Heart of the Civil War CHA, and the project was also within the programmatic boundary of the Journey Through Hallowed Ground National Heritage Area (JTHG NHA). No Maryland scenic byway intersected the transmission corridor, but the ROW was estimated to be within 1.7 miles of the Appalachian National Scenic Trail (AT) at its nearest point. Views to the west along most of the AT in Maryland are limited, but views of the Cumberland Valley from two overlooks, High Rock and Pen Mar, are regarded as among the most notable east of the Rocky Mountains. PPRP also identified an MDOT SHA-designated bicycle route crossing the IEC West ROW.

However, in consultation with reviewing state agencies, PPRP concluded adverse effects on scenic and heritage resources, to the extent they occur, were expected to be confined largely to the transmission line ROWs and be primarily associated with construction. Therefore, even though the IEC West corridor

[220] Greden, et al., op. cit.

[221] EirGrid Evidence Based Environmental Studies. Op. cit.

[222] Andrea M. Slusser. "Transmission Lines in Wildland Landscapes: Gauging Visual Impact Among Casual Observers." University of Washington. 2012.

[223] Soini, K. et al. "Local residents' perceptions of energy landscape: The case of transmission lines." Land Use Policy. 28. 2011. 294-305.

[224] Des Rosiers, F. "Power Lines, Visual Encumbrance and House Values: A Microspatial Approach to Impact Measurement." Journal of Real Estate Research, Vol 23, No. 3. 2002. 275-302.

[225] Tikalsky, S. and Willyard, C. "Aesthetics and Public Perception of Transmission Structures: A Brief History of the Research." Right of Way. March/April 2007.

passes through the Heart of the Civil War Heritage Area, key heritage resources would not be adversely affected by the project, nor was the project expected to have an adverse effect upon the Journey Through Hallowed Ground National Heritage Area. A visibility assessment conducted by PPRP did find that although the elevated overlooks of the Cumberland Valley from the AT are more than 2.5 miles from the IEC West centerline, structures might still be visible when atmospheric conditions permit. However, structure detection from these locations would be limited due to the complexity of a Cumberland Valley landscape that includes other transmission facilities, roads and other built forms. As a result, PPRP concluded the IEC West transmission line would not have an adverse effect on the many trail systems, driving and bicycle tours, and other cultural and recreational attractions in the area.

5.4.3 Renewable Technology Supply Chains

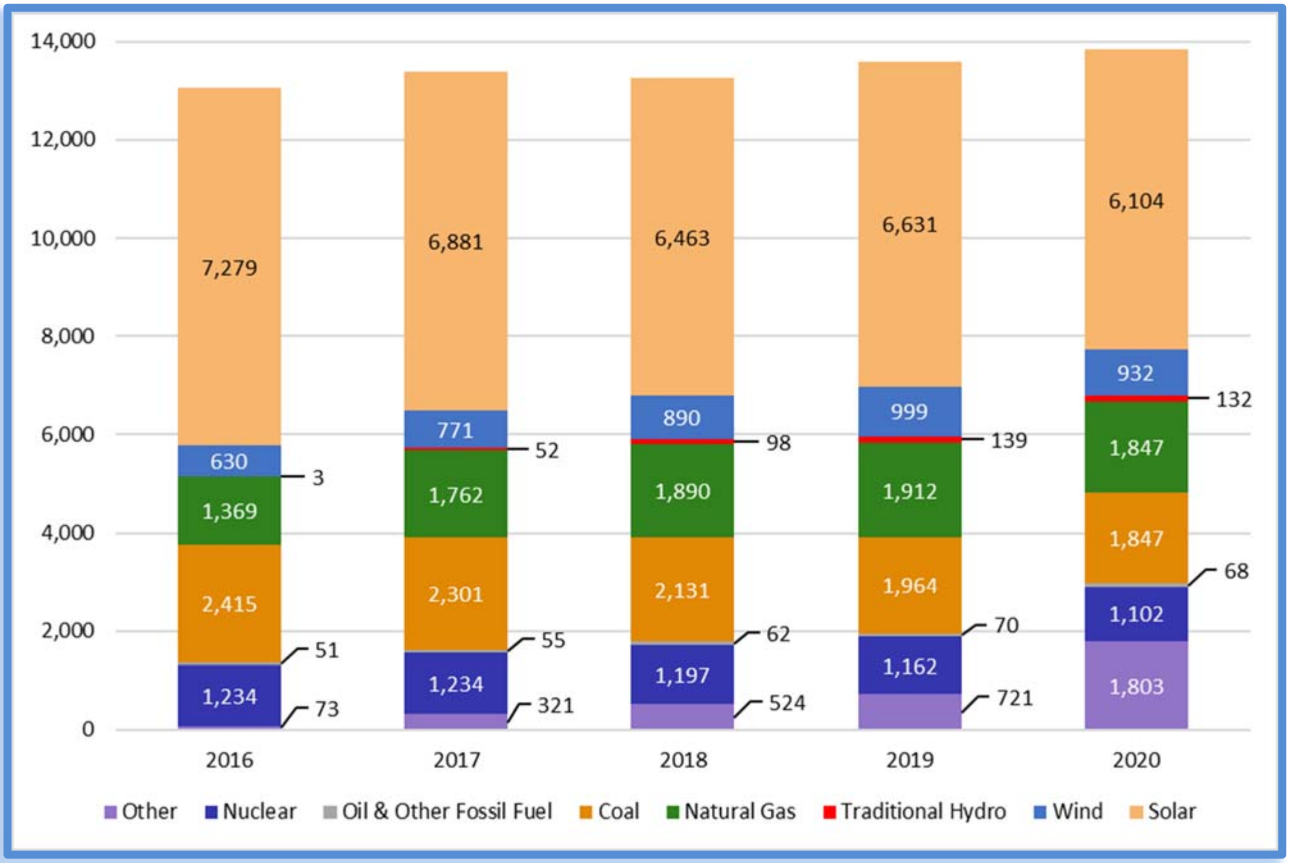
Energy Employment

In 2020, the electric power generation sector employed 13,835 workers in Maryland.[226] The majority of the jobs were construction-related (43.5 percent), followed next by the utility industry (22.8 percent). As noted in Figure 5-39, approximately 7,170 of Maryland's electric power generation jobs focused on renewable energy (solar, wind and hydropower), with 85 percent attributed by the solar industry (including full time and part time). Based on a forecast by the Energy Futures Initiative and the National Association of State Energy Officials, Maryland's electric power generation sector is expected to grow by approximately 6.3 percent.[227] In addition to the electric power generation industry, there were approximately 850 jobs in the transmission, distribution and storage sector related to energy storage in Maryland in 2020 (this number is not reflected in Figure 5-39).

[226] Energy Futures Initiative and National Association of State Energy Officials. U.S. Energy and Employment Report: Energy Employment by State: 2021, energy.gov/sites/default/files/2021-07/USEER%202021%20State%20Reports.pdf.

[227] Ibid.

Figure 5-39 Electric Power Generation Sector Employment in Maryland by Fuel Type (2016-2020)



Note: "Other" includes other biofuels and all other fuels, including employers that cannot assign employment to a single technology/fuel type.

Source: Energy Futures Initiative and National Association of State Energy Officials, 2020 U.S. Energy and Employment Report: Energy Employment by State.

The instate solar carve-out requirement of the RPS is partially responsible for existing solar jobs in Maryland; however, despite increases in the carve-out, Maryland experienced a decline in solar jobs between 2016 and 2020. As shown in Figure 5-39, full-time, solar-related employment in Maryland peaked in 2016 with 7,729 jobs, but has since declined despite the instate solar carve-out increasing from 0.7 percent in 2016 to 6 percent in 2020.[228] One explanation for this shift, as put forth by industry participants, is that the initial RPS requirement levels, coupled with federal and other state incentives, created significant demand that the industry met and exceeded.[229] A resultant glut in solar generation resulted in early compliance with the solar carve-out of the RPS and put downward pressure on solar renewable energy credit (SREC) prices, making it less economic for the continued development of new solar projects. COVID-19 also played a role, as companies were unable to conduct door-to-door marketing and sales, and local governments were less able to process building permit applications.

[228] Full-time, solar-related employment is defined as a worker who spends more than 50 percent of its hours working on solar projects.

[229] MDV-SEIA, ccanactionfund.org/media/MD-Solar-Jobs-Losses-Press-Release.pdf.

Solar PV

The National Renewable Energy Laboratory (NREL) estimates that about 60-70 percent of utility-scale PV installation costs are for hardware (i.e., module, inverter, structural balance-of-system (BOS) and electrical BOS), with the remaining costs evenly split between construction and services. For distributed systems, less of the project cost goes to manufactured components and more to services. Operations and maintenance (O&M) costs, which include warrantied and non-warrantied parts replacement, monitoring and property maintenance, are weighted toward services, which are usually fulfilled locally. O&M costs vary by technology, system size, location and other factors.

Solar PV systems are constructed of highly recognizable components like solar cells, modules, racking and inverters, but also hardware such as monitoring equipment, cabling, connectors, nuts and bolts and other manufactured products that knit the system together. Major components, such as modules and inverters, are largely imported. In comparison, there is a greater domestic presence of manufacturers of structural and electrical BOS. In 2020, approximately 89 percent of modules were imported.[230] According to Solar Power World, there are 22 domestic solar panel manufacturing facilities, although most of these manufacturers import key components from other countries for assembly in the U.S. or are vertically integrated companies that provide end-to-end services (i.e., design through installation).[231] Eight companies manufacture some, or all, of their solar panels in the U.S. (see Table 5-11).

Table 5-11 U.S.-Based Companies Involved in Manufacturing Solar PV Panels

COMPANY	MANUFACTURING LOCATION	HEADQUARTERS	NOTES
Heliene	Mountain Iron, MN	Canada	
Mission Solar	San Antonio, TX	Texas	
Seraphim	Jackson, MS	China	
Silfab Solar	Bellingham, WA	Canada	
Solaria	Fremont, CA	California	
SolarTech Universal	Riviera Beach, FL	Florida	
SunSpark	Riverside, CA	China	
Tesla/Panasonic	Buffalo, NY	California/Japan	Joint venture

Source: news.energysage.com/u-s-solar-panel-manufacturers-list-american-made-solar-panels/.

Inverters, which convert direct current (DC) output from a solar panel into utility frequency alternating current (AC), are an integral component of every solar PV system. Eight companies manufacture inverters domestically, ranging from standalone to grid-tie models,[232] but only three of the leading

[230] U.S. Energy Information Administration, eia.gov/todayinenergy/detail.php?id=49396.

[231] Solar Power World. "U.S. Solar Panel Manufacturers." solarpowerworldonline.com/u-s-solar-panel-manufacturers/. **Error! Hyperlink reference not valid.**Last accessed October 2021.

[232] solarpowerworldonline.com/global-inverter-manufacturing-locations/.

utility-scale inverter manufacturers are located in the U.S.[233,234] According to the National Solar Jobs Census 2017, U.S. inverter production declined after two major facilities closed at the end of 2016.[235] Some of these jobs may return under certain conditions. In particular, U.S. Section 301 tariffs on Chinese goods could shift inverter manufacturing from China to India, Mexico and the U.S.[236] The pandemic drove solar manufacturing jobs nationwide down by 9.3 percent in 2020.[237]

Other solar components are generally categorized as structural BOS and electrical BOS. Structural BOS includes racking, mounting and tracking systems plus any other materials needed to support the modules. ENF Solar, a consultancy, lists more than 100 solar-mounting manufacturers in the U.S.[238] Forty-six companies manufacture solar-tracking systems.[239] None of the companies listed by ENF Solar selling structural BOS components are located in Maryland. Electrical BOS comprises equipment that transports DC energy from solar panels through the conversion system that produces AC power. Components include conductors, conduits, combiner boxes, disconnects and monitoring systems. ENF Solar lists 37 solar charge controller manufacturers and 36 solar monitoring system manufacturers in the U.S.

Opportunities for manufacturing growth in Maryland from continuing solar PV deployment are likely limited to the structural and electrical BOS supply chains. This is because the solar installers tend to be vertically integrated, that is, they own or control manufacturing, sales and installation which limits opportunities for other companies to enter the market.

Onshore Wind

More than two-thirds of capital expenditures for a land-based wind power plant project are for turbines, with another 10 percent for electrical infrastructure.[240] Assembly and installation account for only 3 percent of construction costs, while site access and staging, foundation and engineering management account for another 7 to 8 percent. About 59 percent of O&M expenditures are for maintenance and 15 percent for land lease payments.[241]

As the cumulative capacity of U.S. wind projects has grown over the last decade, foreign and domestic turbine equipment manufacturers have localized and expanded operations in the U.S. There are more

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233 wiki-solar.org/company/inverters/index.html.

234 ABB acquired GE's inverter business in mid-2018.

235 The Solar Foundation. National Solar Jobs Census 2017. 2018. Available at SolarJobsCensus.org.

236 The Solar Foundation. National Solar Jobs Census 2018. 2019.

237 The Solar Foundation. National Solar Jobs Census 2020. May 2021. irecusa.org/wp-content/uploads/2021/07/National-Solar-Jobs-Census-2020-FINAL.pdf.

238 enfsolar.com/directory/component/mounting_system?country=187.

239 greenworldinvestor.com/2011/07/06/solar-tracker-manufacturers-usachinaindia-list-and-market-review-of-sale-price-and-cost/. Updated September 2016.

240 Tyler Stehly, Philipp Beiter and Patrick Duffy, 2019 Cost of Wind Energy Review. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-78471. December 2020.

241 Ryan Wiser, Mark Bolinger and Eric Lantz, Benchmarking Wind Power Operating Costs in the United States, Lawrence Berkeley National Laboratory, January 2019, eta-publications.lbl.gov/sites/default/files/opex_paper_final.pdf.

than 500 wind turbine and component manufacturing and assembly facilities in U.S. as of 2020,[242] although only three are located in Maryland.[243] Most manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers.

The trend in onshore wind turbines has been toward greater capacities, larger rotor diameters and higher hub heights. Wind turbines installed in the U.S. in 2018 had an average nameplate capacity of 2.4 MW, 116-meter rotor diameter and 88-meter hub height.[244] By 2020, the average capacity, rotor diameter, and hub height had all increased to 2.75 MW, 125 meters and 90 meters, respectively. In addition, 33 wind projects had been partially repowered with significantly larger rotors and power ratings in 2020.[245]

The domestic supply chain faces competitive pressures from foreign manufacturers. There continues to be increased industry concentration among top original equipment manufacturers and centralization of manufacturing operations to gain economies of scale. Despite its domestic presence, the U.S. wind industry remains reliant on imports, particularly on turbines and components.[246]

Offshore Wind

NREL estimates between 40-50 percent of offshore wind construction costs are for manufactured goods.[247] An additional one-third is for assembly and installation, with the remaining portion covering services and water transportation. More than half of O&M expenditures are for corrective maintenance parts and other machinery, with the balance for maintenance construction and miscellaneous services.

Although the majority of onshore wind turbine components (as a fraction of total equipment-related turbine costs) installed in the U.S. are domestically sourced, offshore wind installations require many specialized components that are not currently produced in the United States.[248] Even where facilities serving the U.S. onshore wind market may be capable of manufacturing offshore wind components, logistical concerns primarily related to the long-distance transport of large components may limit their ability to supply the offshore market. As a result, an offshore wind supply chain has not yet developed in the U.S.

Because of this, most near-term manufacturing opportunities for offshore wind are limited to upstream materials and subcomponents that can be easily transported. Upstream products include scaffolding,

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[242] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. 2020 Land-Based Wind Market Report. August 2021.

[243] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Land-Based Wind Market Report: 2021 Edition. emp.lbl.gov/sites/default/files/land-based_wind_market_report_2021_edition_final.pdf.

[244] Eric Lantz, Owen Roberts, Jake Nunemaker, et al. Increasing Wind Turbine Tower Heights: Opportunities and Challenges. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-73629. May 2019.

[245] Land-Based Wind Market Report: 2021 Edition, op. cit.

[246] Ibid.

[247] Tyler Stehly, Donna Heimiller and George Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-70363. December 2017.

[248] Navigant Consulting Inc. U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. February 22, 2013, 19.

coatings, ladders, fastenings, hydraulics, concrete and electrical components. Table 5-12 identifies some businesses in the Mid-Atlantic region that have the potential to support the offshore wind supply chain.[249,250]

Table 5-12 Number of Existing Companies and Firms Identified in the Mid-Atlantic Region with the Potential to Supply Offshore Wind Components

INDUSTRY	MD	DE	NJ	PA	VA
Electronics	**1**	0	3	15	2
Manufacturing & assembly	**17**	0	1	17	6
Installation, construction, materials	**13**	2	1	28	5
Maintenance, logistics, transportation	**16**	0	4	6	34
Services	**6**	2	6	4	34
TOTAL	**53**	**4**	**15**	**70**	**81**

Source: Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-61315. February 2015.

Both existing offshore wind renewable energy credit (OREC) applications (US Wind and Skipjack)[251] to the Maryland PSC allocate significant percentages of construction costs to Maryland and specifically target investment in a Maryland steel fabrication facility. Apart from these projects, however, there is considerable uncertainty about which industries in Maryland will benefit from offshore wind development. Both US Wind and Skipjack are attempting to develop relationships with instate businesses that traditionally have not participated in energy development projects and markets.[252] In May 2021, Maryland entered into a partnership with NREL, the Business Network for Offshore Wind, the New York State Energy Research and Development Authority, the National Offshore Wind Research and Development Consortium, and the U.S. Department of Energy for creating an offshore wind supply chain roadmap.[253] Separately, Maryland entered into a Memorandum of Understanding with the states of Virginia and North Carolina under the Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources for expanding offshore wind energy generation and to develop a supply chain.[254]

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[249] issues.nawindpower.com/article/maryland-prepares-offshore-wind-push.

[250] S. Tegen, D. Keyser and F. Flores-Espino, et al., Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios, National Renewable Energy Laboratory. Technical Report NREL/TP-5000-61315. February 2015.

[251] Maryland Public Service Commission, Case No. 9341.

[252] bizjournals.com/baltimore/news/2019/01/23/maryland-offshore-wind-developers-look-to-partner.html

[253] Maryland Energy Administration, "National Offshore Wind Research and Development Consortium Announces Offshore Wind Supply Chain Roadmap Project," May 13, 2021, news.maryland.gov/mea/2021/05/13/national-offshore-wind-research-and-development-consortium-announces-offshore-wind-supply-chain-roadmap-project/.

[254] Chris Carnevale and Heather Pohnan, "Regional Offshore Wind Agreement will Lead to more Smart Power for the South Atlantic," cleanenergy.org, November 2, 2020, cleanenergy.org/blog/regional-offshore-wind-agreement-will-lead-to-more-smart-power-for-the-south-atlantic/.

Some studies predict future opportunities for suppliers will be greatest in industries responsible for providing foundations and substructures, towers, blade materials, power converters and transformers.[255,256] NREL has taken this outlook further by estimating the share of critical offshore wind component manufacturing that could take place in the Mid-Atlantic region. These estimates are broken down into three investment scenarios (see Table 5-13).

Table 5-13 Regional Investment Paths for the Dynamic Components for Offshore Wind in the Mid-Atlantic

	LOW INVESTMENT		MEDIUM INVESTMENT		HIGH INVESTMENT	
YEAR:	2020	2030	2020	2030	2020	2030
Deployed capacity (MW)	366	3,196	1,912	7,832	4,100	16,280
Turbines	32%	68%	35%	95%	65%	100%
Blades & towers	13%	71%	25%	95%	30%	95%
Substructures & foundation	11%	30%	20%	50%	30%	85%

Source: Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-61315. February 2015.

However, while there exists domestic infrastructure for the manufacture of some offshore wind components (e.g., offshore oil and gas industry suppliers), a more complete domestic supply chain is unlikely to be built until sufficient demand exists to justify the investment in new, dedicated facilities. This is particularly the case because the offshore wind market faces rapidly changing technologies and continued regulatory uncertainty. Deployment has lagged to date and, as a result, installed offshore wind capacity projections have been consistently pushed into the future and, with it, the development of a domestic offshore wind supply chain. Demand along the Atlantic coast may not be sufficient to attract a wind turbine generator manufacturing facility until the mid-2020s or later.[257,258]

Onshore Hubs for Offshore Wind

Even though offshore wind has been slow to develop in the U.S., declining costs and state RPS policies have the potential to leverage the development of offshore wind resources and industries.[259] If offshore

[255] Navigant Consulting Inc. U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. February 22, 2013.

[256] Massachusetts Clean Energy Center. 2018 Massachusetts Offshore Wind Workforce Assessment., 46. files.masscec.com/2018%20MassCEC%20Workforce%20Study.pdf

[257] Navigant Consulting Inc. U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. February 22, 2013.

[258] BVG Associates Ltd. U.S. Job Creation in Offshore Wind. NYSERDA Report 17-22. October 2017.

[259] S&P Global Market Intelligence. "Offshore Wind Ready to Take Off in the United States." July 20, 2018. spglobal.com/marketintelligence/en/news-insights/research/offshore-wind-ready-to-take-off-in-the-united-states, last accessed February 27, 2019.

wind is developed to projected capacities, multiple U.S. ports will need to be improved to support staging and manufacturing operations.[260]

Known as onshore hubs for offshore wind, these facilities can generate significant economic impacts, potentially leveraging existing manufacturing competencies in a region and adding new ones. The Port of Bremerhaven on the North Sea is an example of a successful onshore wind hub. The harbor has attracted more than $325 million of investment to create a major onshore wind energy cluster.[261] Three turbine manufacturers, a blade manufacturer and a foundation manufacturer are located in the harbor area, and the region hosts over 300 suppliers, service providers and research institutions. An estimated 1,500 local jobs around Bremerhaven are directly attributable to offshore wind energy. With projected annual installation and repowering approaching 200 wind turbines in the North Sea, a 500-acre expansion of Bremerhaven's harbor was initiated in 2011 to accommodate Germany's offshore wind strategy.

Several Atlantic coastal states, including Virginia, South Carolina, Massachusetts and others, have identified potential onshore hubs for offshore wind. Onshore hubs may soon become a reality with plans by wind developer Ørsted to locate a factory for steel foundations in Paulsboro, New Jersey for its 1.1 GW Ocean Wind project.[262] Virginia took a step in October 2021 when Siemens Gamesa announced plans to build the nation's first offshore wind turbine blade factory at the Portsmouth Marine Terminal. The company will invest over $200 million in the facility and the facility will create over 300 jobs.[263]

In return for Round 1 ORECs, both US Wind and Skipjack are required to invest in a Maryland steel fabrication facility, use a port facility in the greater Baltimore region for marshaling project components, use Ocean City as the O&M port and invest in upgrades to the Tradepoint Atlantic shipyard. As such, Tradepoint Atlantic has positioned itself to potentially become a hub for offshore wind on the East Coast, with space for offshore wind laydown, manufacturing and vessel loading.[264] On October 14, 2020, Ørsted announced a $72 million deal with Crystal Steel Fabricators to construct state-of-the-art steel manufacturing facilities in Federalsburg, making Caroline County the first Maryland-based offshore wind facility.[265] US Wind plans to invest $150 million in a new monopole fabrication facility at Sparrows Point.

In December 2021, the PSC issued awards for Round 2 ORECs to US Wind and Skipjack for the 808 MW Momentum Wind and the 846 MW Skipjack projects, respectively. The PSC order had several

[260] GL Garrad Hassan. Assessment of Ports for Offshore Wind Development in the United States. Prepared for U.S. Department of Energy. March 21, 2014.

[261] BIS Economic Development Company Ltd. Offshore Terminal Bremerhaven: Information for Infrastructure Investors. Bremerhaven, Germany. January 2011.

[262] greentechmedia.com/articles/read/orsted-and-germanys-eew-plan-offshore-wind-factory-in-new-jersey?utm_medium=email&utm_source=Daily&utm_campaign=GTMDaily#gs.om3f12.

[263] Sarah Vogelsong and Virginia Mercury, "Siemens Gamesa chooses Virginia for offshore wind turbine blade factory," Energy News Network, October 25, 2021, energynews.us/2021/10/25/siemens-gamesa-chooses-virginia-for-offshore-wind-turbine-blade-factory/.

[264] Tradepoint Atlantic. Offshore Wind Factsheet. tradepointatlantic.com/downloads/.

[265] stardem.com/business/72-million-deal-establishes-maryland-s-first-offshore-wind-manufacturing-plant-in-federalsburg/article_4908fa31-dcb7-522d-bf8f-7380a6f0cc39.html.

conditions such as: the creation of at least 10,324 direct jobs during the development, construction and operating phases of the projects; committing to certain goals to engage small, local and minority businesses; passing 80 percent of any construction costs savings to ratepayers; and contributing $6 million each to the Maryland Offshore Wind Business Development Fund. The two projects are expected to contribute about $1 billion in instate spending.

5.5 Radiological Issues

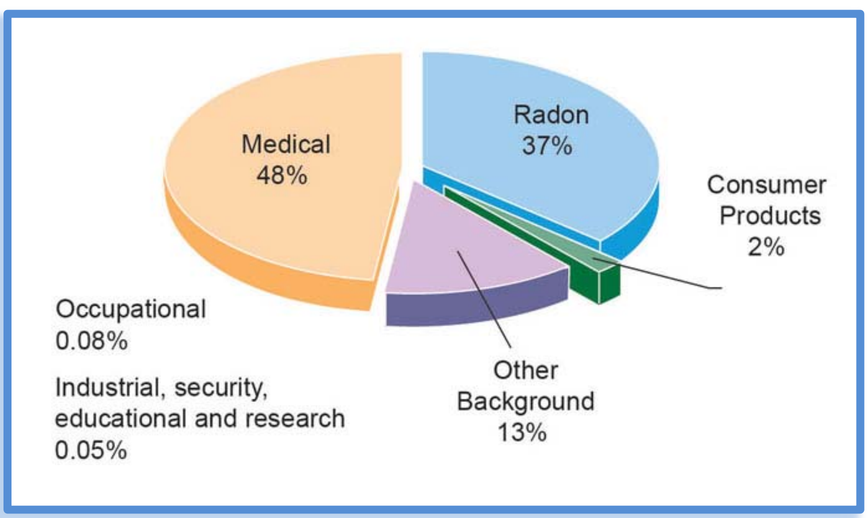
5.5.1 Pathways to Exposure

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 5-40 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 manmade sources, less than 0.05 percent is attributed to commercial nuclear power production.

Figure 5-40 Annual Estimated Effective Dose Equivalent (mrem) to the General Population from Natural and Manmade 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 from Calvert Cliffs and Peach Bottom consist of tritium to waterways and radioactive noble gases into the atmosphere, 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 cobalt, cesium, zinc, nickel 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.[266] Environmentally significant radionuclide releases have declined over the past two decades due to improvements in coolant water filtration technology.

5.5.2 Nuclear Power Plants in Maryland

Figure 5-41 shows the locations of nuclear power plants in and near Maryland. Calvert Cliffs Nuclear Power Plant (CCNPP) in Calvert County is the only nuclear power plant in Maryland. The next closest plant, Peach Bottom Atomic Power Station (PBAPS), is on the Susquehanna River just north of the Pennsylvania/Maryland border. Both facilities release very low levels of radionuclides into Maryland's environment.

Figure 5-41 Nuclear Power Plants in and Around Maryland

[266] McLean, R.I., T.E. Magette and S. G. Zobel. 1982. Environmental Radionuclide Concentrations in the Vicinity of the Calvert Cliffs Nuclear Power Plant: 1978-1980. PPSP-R-4. Maryland Power Plant Siting Program, Annapolis, MD.

Calvert Cliffs Nuclear Power Plant

Constellation Energy Corporation operates CCNPP on the western shoreline of the Chesapeake Bay. Both units are pressurized water reactors with a total generating capacity of approximately 1,756 MW. The units began service in May 1975 and April 1977, and the current NRC operating licenses will expire in 2034 and 2036.

Peach Bottom Atomic Power Station

Constellation Energy Corporation also operates PBAPS, which 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, with a combined generating capacity of approximately 2,770 MW.

Besides these plants, there are nine additional nuclear generating sites within 100 miles of Maryland (see Table 5-14).

Table 5-14 Out-of-State Nuclear Power Plants Near Maryland

Plant	Owner/Operator	Location	Generating Capacity (MWe)[267]
Salem Nuclear Generating Station	PSEG Nuclear, LLC	Hancocks Bridge, NJ	2,325
Hope Creek Generating Station	PSEG Nuclear, LLC	Hancocks Bridge, NJ	1,172
Oyster Creek Nuclear Generating Station*	Constellation Energy Corporation	Forked River, NJ	652
Three Mile Island Nuclear Station**	Constellation Energy Corporation	Middletown, PA	819
Susquehanna Steam Electric Station	PPL Susquehanna, LLC	Salem Township, PA	2,494
Beaver Valley Power Station	FirstEnergy Nuclear Operating Co.	Shippingport, PA	1,800
Limerick Generating Station	Constellation Energy Corporation	Limerick, PA	2,317
North Anna Power Station	Virginia Electric & Power Co.	Louisa, VA	1,892
Surry Power Station	Virginia Electric & Power Co.	Surry, VA	1,676

* Closed in 2018.
** Closed in 2019.

[267] Megawatts electric, referring to the electricity output capability of the plant.

5.5.3 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 near Calvert Cliffs and Peach Bottom to assess the radiological effects on the environment attributable to each of the power plants (see Table 5-15). PPRP has monitored radionuclide levels in the environment surrounding Calvert Cliffs since 1975 and Peach Bottom since 1979, and publishes its environmental assessments biennially.

Table 5-15 Nuclear Power Plant Environmental Monitoring Elements

Matrix	No. Stations	Locations	Analytes	Collection Frequency
1. Air Filter	8	Calvert County, Baltimore City, Cecil County, Harford County, Eastern Shore	a, b, ^{7}Be, ^{137}Cs	continuous (exchanged weekly)
2. Charcoal Filter	8	Calvert County, Baltimore City, Cecil County, Harford County, Eastern Shore	^{131}I	continuous (exchanged weekly)
3. Potable Water	7 1 1 1	Calvert County Baltimore City Patuxent River Potomac River	a, b, ^{3}H	quarterly monthly quarterly quarterly
4. Raw Water	1 1	Patuxent River Potomac River	a, b, ^{3}H	monthly monthly
5. Precipitation	1	Baltimore City	a, b, ^{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)	Γ	quarterly
9. Tray Oysters	2	Chesapeake Bay	Γ	quarterly
10. Sediment	19	Chesapeake Bay & Susquehanna River (near PBAPS)	Γ	semiannually
11. Finfish	1	Susquehanna River	Γ	semiannually
12. Submerged Aquatic Vegetation (SAV)	3	Chesapeake Bay & Susquehanna River	Γ	semiannually

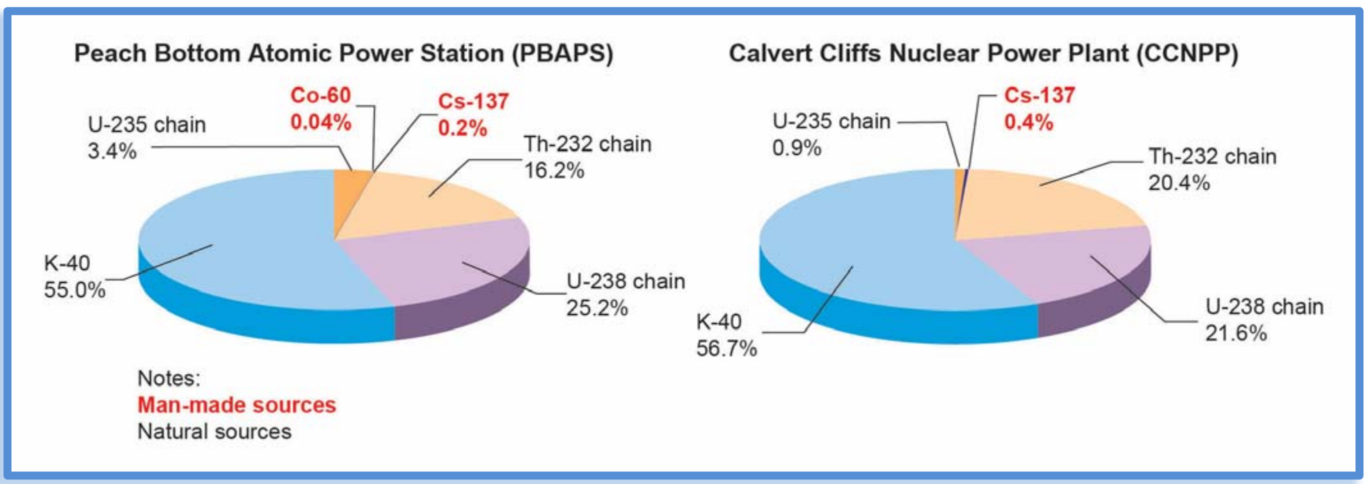
Monitoring by PPRP is conducted to satisfy NRC requirements to verify that any releases from normal plant operations result in potential doses to humans that are below regulatory limits. The monitoring also meets Maryland requirements to research the environmental effects of electric power generation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

The most recently compiled results (for 2018 to 2019) from weekly air and annual vegetation monitoring conducted by Exelon Generation Company, and independently by PPRP, indicate that releases of radioactivity into 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 Cobalt-60 (^{60}Co), were detected in Chesapeake Bay sediments near Calvert Cliffs during the 2018-2019 reporting period (see Figure 5-42).

At Peach Bottom, plant-related ^{60}Co was detected on two occasions (detection frequency of 2.6 percent) in sediments collected from Conowingo Reservoir and Upper Chesapeake Bay. As shown in Figure 5-42, the quantity of ^{60}Co in sediment samples, when detected, was proportionally far below the levels contributed by residual radioactive fallout and natural sources. The detection frequency of ^{60}Co in sediment samples from Peach Bottom during the 2018-2019 reporting period was slightly lower than the average for historical samples (15.2 percent since 1996).

Figure 5-42 Proportion of Natural Versus Manmade Radionuclides in Sediment Samples near CCNPP (2019) and PBAPS (2018)



Chesapeake 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. Radio-silver (^{110m}Ag) has historically been the principal plant-related radionuclide accumulated by test oysters and oysters on natural beds. Since Q4 2001, concentrations of ^{110m}Ag in oysters have fallen below analytical detection limits. The lack of detectible ^{110m}Ag reflects a downward trend in ^{110m}Ag releases, as well as other environmentally significant 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 semiannually by PPRP from the Conowingo Reservoir area near Peach Bottom. During 2018-2019, one finfish sample contained a trace amount of Chromium-51 (^{51}Cr) attributable to PBAPS. Finfish samples also contained small amounts of fallout-related Cesium-137 (^{137}Cs), which were incorporated into dose calculations to obtain a conservative figure.

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 5-16). As shown in Figure 5-43, 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 5-16 Comparison of CCNPP/PBAPS Radiation Doses to Humans and Applicable Regulatory Limits

Exposure Route	Maximum Dose Estimate (2018)	Maximum Dose Estimate (2019)	EPA Regulatory Limit (40CFR190 Subpart B)	NRC Regulatory Limit (10CFR50 Appendix I)
Ingestion (mrem)				
Oyster ingestion, whole body dose (from CCNPP)	< 0.002 (child)[a]		25	3
Oyster ingestion, other organ dose (from CCNPP)	< 0.009 (adult GI tract)[a]		25	10
Finfish ingestion, whole body dose (from PBAPS)	0.0145 (adult)[a]		25	3
Finfish ingestion, other organ dose (from PBAPS)	0.0231 (adolescent liver)[a]		25	10
Inhalation (mrem)				
Whole body dose (gaseous, from CCNPP)	0.00018 (child)[b]	0.000044 (child)[b]	25	3
Other organ dose (gaseous, from CCNPP)	0.00018 (child skin)[b]	0.000048 (child skin)[b]	25	10
Whole body dose (gaseous, from PBAPS)	0.292 (any age class)[b]	0.234 (any age class)[b]	25	3
Other organ dose (gaseous, from PBAPS)	0.380 (any age class skin)[b]	0.316 (any age class skin)[b]	25	10

[a] Source: PPRP biennial reports.

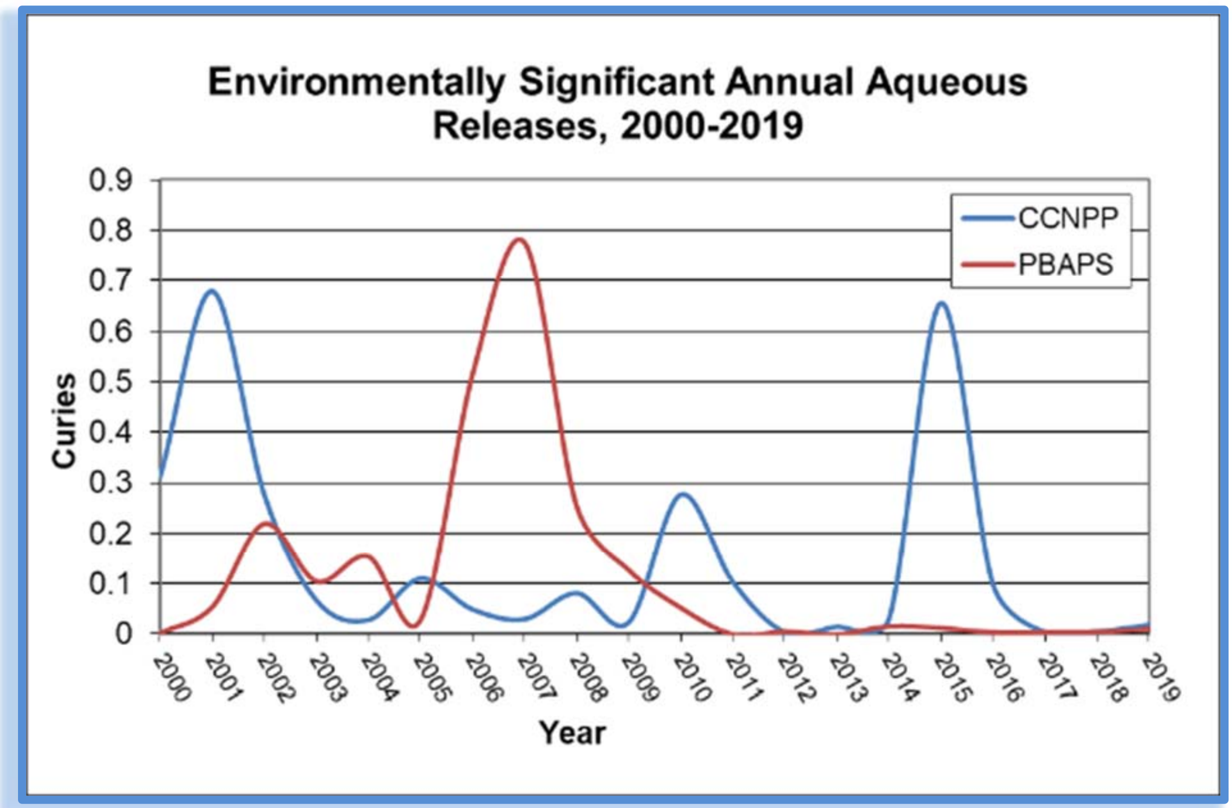
[b] Source: Exelon Generation Company, Annual Radiological Environmental Operating Reports for 2018 and 2019.

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 from 2018 to 2019 with historical levels shows the following:

- Plant-related radionuclides were rarely detected in seafood (i.e., oysters and finfish) from 2018 to 2019;
- Plant-related radionuclides were rarely detected in sediments from 2018 to 2019;
- 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 5-16).

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

Figure 5-43 Environmentally Significant Annual Aqueous Releases, 2000-2019*



* 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. A curie of any radioactive element disintegrates at the same rate as 1 gram of natural radium.

5.5.4 Emergency Response

Maryland state agencies (such as DNR, MDE and the Maryland Emergency Management Agency), local counties and Constellation Energy Corporation conduct emergency response exercises annually, and an in-depth, federally evaluated, ingestion pathway emergency response exercise approximately every six to eight years. The multi-agency exercises demonstrate and provide practice for Maryland's onsite and offsite response measures using simulated accidents at Calvert Cliffs or Peach Bottom. The exercises encompass the implementation of protective actions for all phases (e.g., plume, ingestion pathway, reentry) of the simulated accident, depending on simulated conditions at Calvert Cliffs or Peach Bottom and simulated impacts to the surrounding environment. The protective actions affect farm operations, drinking water supplies, and may include evacuation or sheltering in place for nearby populations. The exercises include taking simulated environmental samples in the area of the plant and delivering them to state-operated laboratories. The offsite portion of the exercise is evaluated by representatives from the Federal Emergency Management Agency.

5.5.5 Radioactive Waste

In addition to the production of atmospheric and liquid effluent releases as a byproduct 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, cartridge filters, equipment, oil 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 has 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.

High-Level Radioactive Waste (Irradiated Fuel)

Used (spent) nuclear fuel from both Calvert Cliffs and Peach Bottom is 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 each plant's protected area. Independent Spent Fuel Storage Installation (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. Onsite storage facilities, such as the ISFSI, are currently the only long-term storage facilities available for irradiated fuel [see sidebar].

Constellation Energy Corporation's dry cask storage facility at Peach Bottom is estimated to have used 65 percent of its currently installed storage pad space. Peach Bottom's ISFSI license will expire in 2040. The Calvert Cliffs ISFSI is estimated to have used 72 percent of its currently installed storage capacity. The Calvert Cliffs ISFSI license will expire in 2052. Future modules will be built as needed to continue to store spent nuclear fuel generated at each of the power plants.

"Waste Confidence" and the "Continued Storage of Spent Nuclear Fuel Rule" for U.S. Nuclear 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. Over the past decade, the ultimate fate of spent nuclear fuel has been the subject of regulatory activity and judicial review. The NRC issued the Continued Storage of Spent Nuclear Fuel Rule in 2014, adopting the findings of an NRC-prepared Generic Environmental Impact Statement, which concluded that used nuclear fuel can be stored for an indefinite period. The U.S. Court of Appeals, District of Columbia Circuit sided with the NRC in 2016 in response to a legal challenge brought by several states.

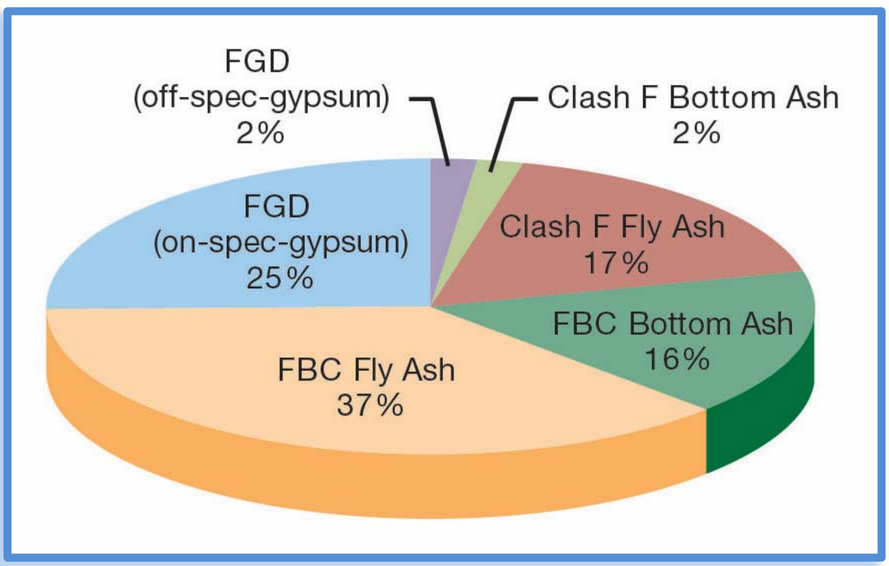
5.6 Power Plant Combustion Byproducts

The combustion of coal to produce electricity yields solid coal combustion byproducts (CCBs), also known as coal combustion residuals (CCRs). These materials are often disposed of in landfills, but there are also a variety of beneficial uses for CCBs that reduce disposal and the demand for virgin raw materials. This section of the report focuses on the generation of CCBs at coal-fired power plants in Maryland as well as beneficial use and disposal practices. Use of CCBs in ways that are environmentally beneficial protects Maryland's landscapes, groundwater and surface water.

5.6.1 CCB Generation and Characteristics

In 2020, coal-fired power plants in Maryland generated approximately 460,000 tons of CCBs, as reported to the 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 5-44.

Figure 5-44 CCBs Produced in Maryland in 2020



The chemical characteristics of CCBs depend upon the nature of the coal burned, the method of combustion and the use of any emission control processes. Most power plants in Maryland burn bituminous coal from the eastern United States and produce Class F fly ash and bottom ash. Fly ash is composed of very fine, 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 porous particles that are heavier and thus fall to the bottom of the furnace, where they are collected.

Class F fly ash and bottom ash are primarily composed of silicon, aluminum and iron oxides, making them excellent pozzolan material (meaning that they contribute to cementitious reactions when combined with water and free lime). They 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 into 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.

Fly ash and bottom ash composition may be affected by emission control technologies, such as low-NOx burners. These burners reduce the concentration of smog-producing nitrogen oxides from power plant emissions but also tend to result in CCBs with higher levels of unburned carbon (also known as loss-on-ignition or LOI). Excess unburned carbon reduces the quality of concrete and cannot be used by the ready-mix concrete industry. Maryland power plants have overcome this problem by adopting CCB beneficiation technologies. There are two fly ash beneficiation plants in Maryland, the Separation Technologies (ST) plant and the STAR plant. These two plants use different technologies to reduce the level of unburned carbon in fly ash, making it highly desirable for the ready-mix concrete industry.

Alkaline CCBs, such as fluidized bed combustion (FBC) material and Class C fly ash, contain high levels of calcium and have high pH values. The AES Warrior Run power plant near Cumberland uses 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 released from the burning of the coal. FBC units can remove more than 95 percent of the sulfur produced from burning coal and the resulting FBC material byproducts contain both calcium sulfate (gypsum) and calcium oxide (free lime). The free lime content of these materials makes them self-cementing with the addition of water. None of the currently active coal-fired power plants in Maryland produce Class C fly ash.

The third major category of CCBs produced in Maryland is flue gas desulfurization (FGD) material. 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. In 2019, the Environmental Integrity Project published a report describing previously documented impacts to groundwater from CCB sites across the United States. Four of the sites mentioned in the report are located in Maryland: the Brandywine Ash Management Facility, the Fort Armistead Road Landfill, the Westland Ash Management Facility and the BBSS site.

5.6.2 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 their beneficial use and disposal. Figure 5-45 presents a timeline that shows milestones in the CCB industry and corresponding regulatory developments; Figure 5-46 presents a more detailed regulatory timeline, broken down by state versus federal actions.

Figure 5-45 Industry and Regulatory Activities Affecting CCBs

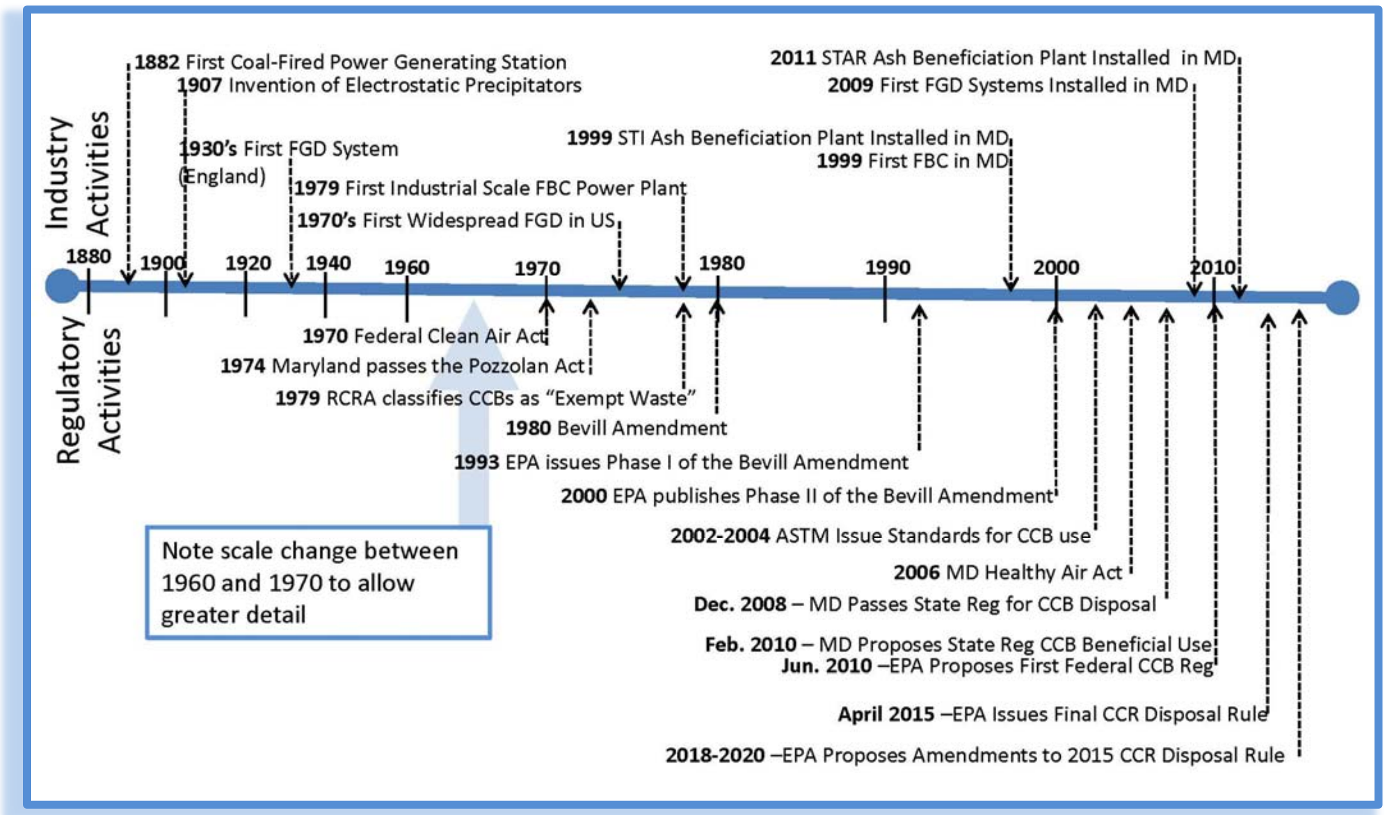
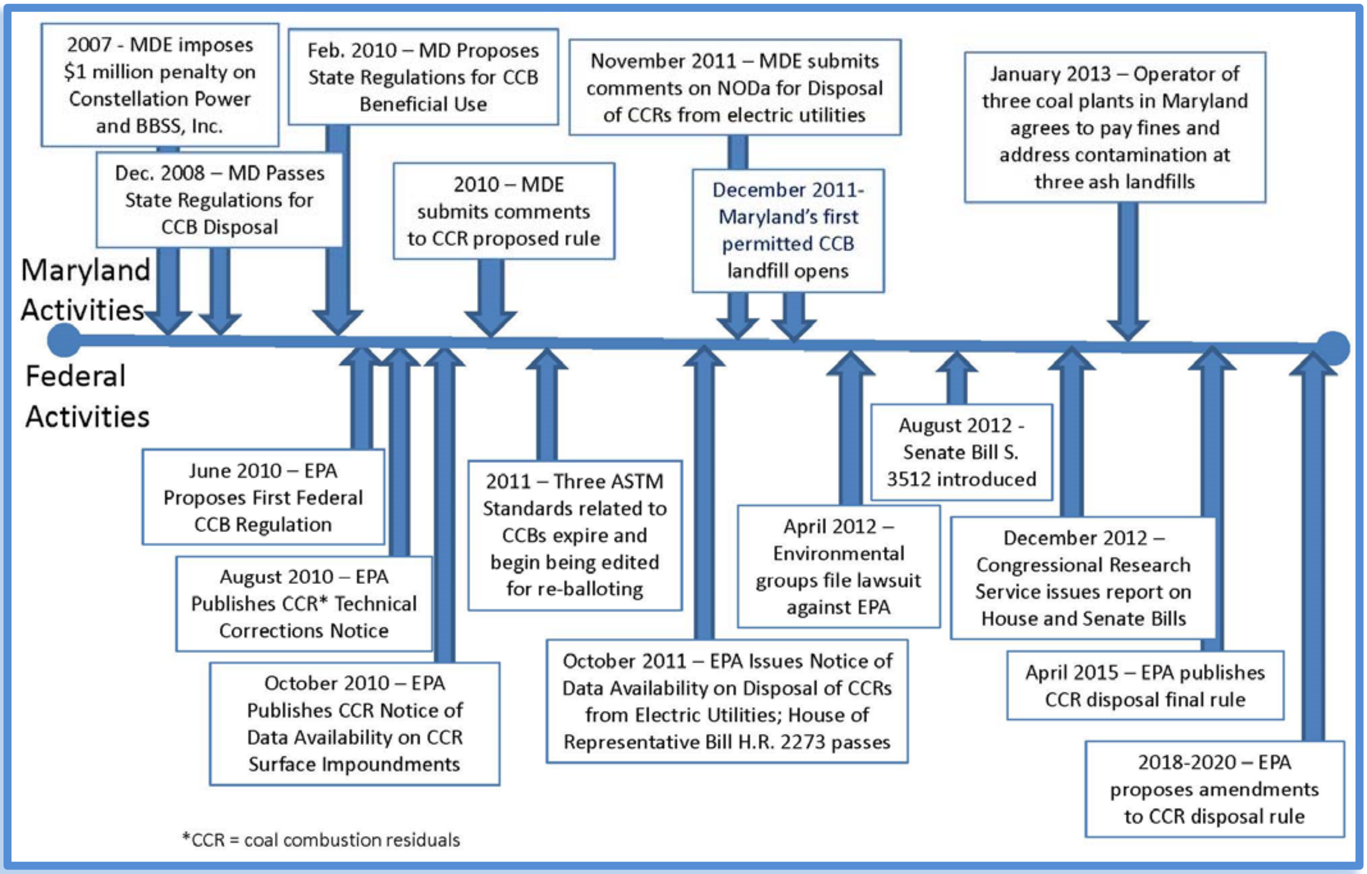


Figure 5-46 CCB Regulations in the U.S. and Maryland



Maryland Regulations

Historically, the 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 new CCB disposal facilities under the same regulations as industrial solid waste facilities. The regulation further extends the industrial solid waste landfill requirements to the reclamation of non-coal mines. CCBs used for coal mine reclamation are required to be alkaline. A second regulation was proposed and drafted in 2010 that would have governed the beneficial use and transportation of CCBs. Work on this second regulation was suspended following EPA's 2010 announcement that it would begin developing a new federal rule to govern CCB use and 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 cement, 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.

Between 2018 and 2020, a series of amendments to the 2015 federal regulation were proposed. Some of the amendments ultimately became final. The primary changes to the federal rule have to do with reporting and closure requirements for the CCB disposal sites covered under the original rule, as enacted in 2015. Also in 2018, a decision by the U.S. Court of Appeals for the District of Columbia Circuit (*Utility Solid Waste Activities Group, et al. v. EPA* or the *USWAG* decision) determined that the exclusion of CCR sites that closed prior to enactment of the 2015 federal rule was not lawful. While some of the proposed amendments did reference the *USWAG* decision, none of the amendments that were finalized, as of the date of this writing, addressed the issue of the CCB sites that closed prior to the 2015 federal rule (also known as legacy CCB sites).

In April 2021, the Ensuring Safe Disposal of Coal Ash Act (House Resolution (H.R.) 2396) was introduced in Congress. This bill includes two provisions that address legacy CCB sites. The first would require that all CCB units comply with Code of Federal Regulations Title 40, part 257 regardless of when they stopped receiving CCBs. The second would require that owners of closed CCB disposal sites identify and survey the locations of these sites within the public record. At the time of this writing, it is unknown whether H.R. 2396 will be passed.

5.6.3 Disposition and Beneficial Use

Beneficial Use

Manufacturing, civil engineering, mine restoration and agricultural applications can utilize CCBs when properly engineered and correctly applied. The beneficial use of CCBs as raw materials in applications that are environmentally sound, technically safe and commercially competitive leads to a reduction in the disposal. Various uses of CCBs can also reduce GHG emissions. When fly ash is used to replace a portion of the portland cement in concrete, the emission of CO_2 that is associated with the production of the portland cement (when Calcium Carbonate [$CaCO_3$] is converted to Calcium Oxide [CaO]) is avoided. A continued increase in the beneficial use of Maryland CCBs will further 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.

Beneficial use of CCBs in Maryland historically included large-scale fill applications as in highway embankments and mine reclamation. Over time, the use of CCBs in encapsulated forms, such as cement, concrete and wallboard, has become more prevalent (see Table 5-17). In 2020, all beneficial use of Class F fly ash was for cement and concrete production. The vast majority of FGD material was used for wallboard, though a very small amount was used for agriculture. Industry practice, technology, costs of natural materials, regulations and guidelines, public perception and demands for sustainability in the commercial marketplace drive these changes.

Table 5-17 CCBs Produced in Maryland and 2020 Use Types

CCB Type	Source in Maryland	Quantity Produced in 2020 (tons)	% Used	Use Types
Class F Fly Ash	Brandon Shores H.A. Wagner Morgantown Dickerson Chalk Point	78,407	83%	Cement, concrete
Bottom Ash	Brandon Shores H.A. Wagner Morgantown Dickerson Chalk Point	10,436	0%	--
FBC Fly Ash/Bottom Ash	Warrior Run	249,716	100%	Coal Mine Reclamation (as backfill and to offset acid production in mine pavement)
FGD Material	Brandon Shores, Morgantown, Dickerson, Chalk Point	124,825	93%	Wallboard, agriculture

The other beneficial use that was active in 2020 was coal mine reclamation. About 250,000 tons of alkaline FBC material were used to reclaim surface coal mines in Western Maryland. The FBC is used both as a backfill material and as a source of alkalinity to offset acid produced by the oxidation of pyrite in mine pavement. As the CCBs release acid-neutralizing constituents, however, the potential exists for trace metals to be released as well. This is the only large-scale unencapsulated use of CCBs currently active in Maryland.

Figure 5-47 shows the locations of Maryland's six active coal-fired power plants. In addition, the R. Paul Smith power plant (which closed in 2012) and the C.P. Crane power plant (which began converting from coal as a fuel source to natural gas in 2018) are also shown. The figure also highlights some of the beneficial use sites and disposal sites across the state that have been active over the last 20 years. Figure 5-48 highlights the quantity of CCBs generated versus CCBs disposed of by Maryland's coal-fired power plants in 2020.

Figure 5-47 Locations of CCB Generation, Use and Disposal in Maryland

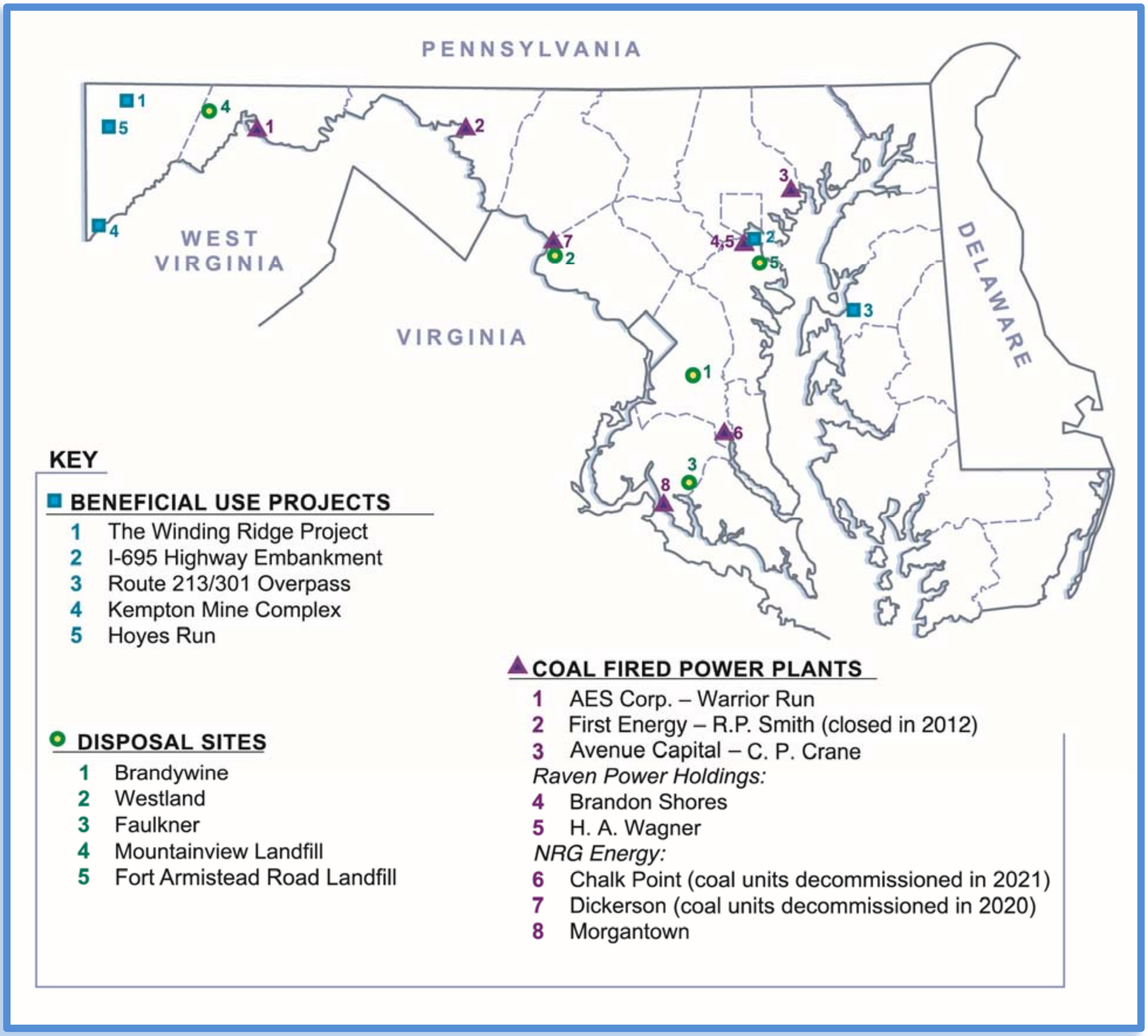
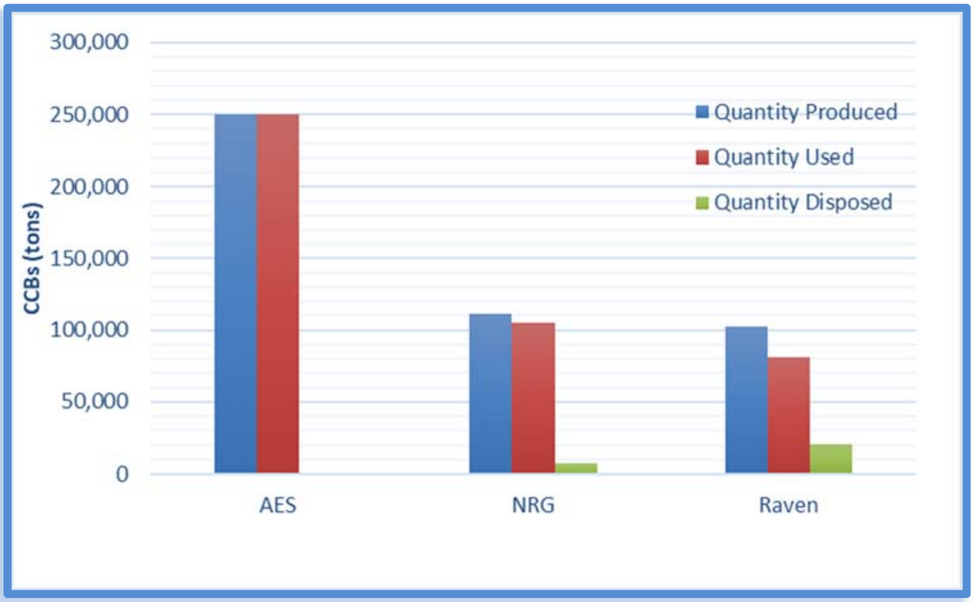


Figure 5-48 CCB Generation and Disposal (2020 Data)



Fly ash, bottom ash and FGD material have different primary beneficial uses because each type of CCB has distinct physical and chemical properties suited to specific applications. In Maryland, the sale of fly ash to the cement, grout and ready-mix concrete industries accounted for all of the beneficial use of Class F fly ash in 2020. 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 are also potential beneficial uses for bottom ash, although these uses did not occur in 2020. Nationwide, bottom ash is also used as road base/sub base, structural fill and snow and ice control. Since the first FGD scrubbers were installed in Maryland in 2010, the majority of FGD material generated in Maryland has been sold to wallboard manufacturers as a replacement for natural gypsum. This use accounted for over 91 percent of the total FGD material produced in Maryland in 2020. Agriculture accounted for a smaller portion of the beneficially used FGD material. The small percentage of FGD material that was disposed of is primarily comprised of “off-spec gypsum” that could not be sold because it did not meet industry standards for wallboard manufacturing.

Disposal

The first permitted and lined CCB landfill in Maryland (the Fort Armistead Road Landfill) began operations 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 5.6.2). CCBs were disposed of in unlined landfills and were sometimes stored or used as backfill 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 groundwater, these legacy ash disposal sites continue to have the potential to leach constituents into groundwater. One possible way to mitigate this impact is to “mine” the previously disposed CCBs for sale to commercial industries; this approach is further discussed in Section 5.6.4.

5.6.4 CCB Marketing Activities

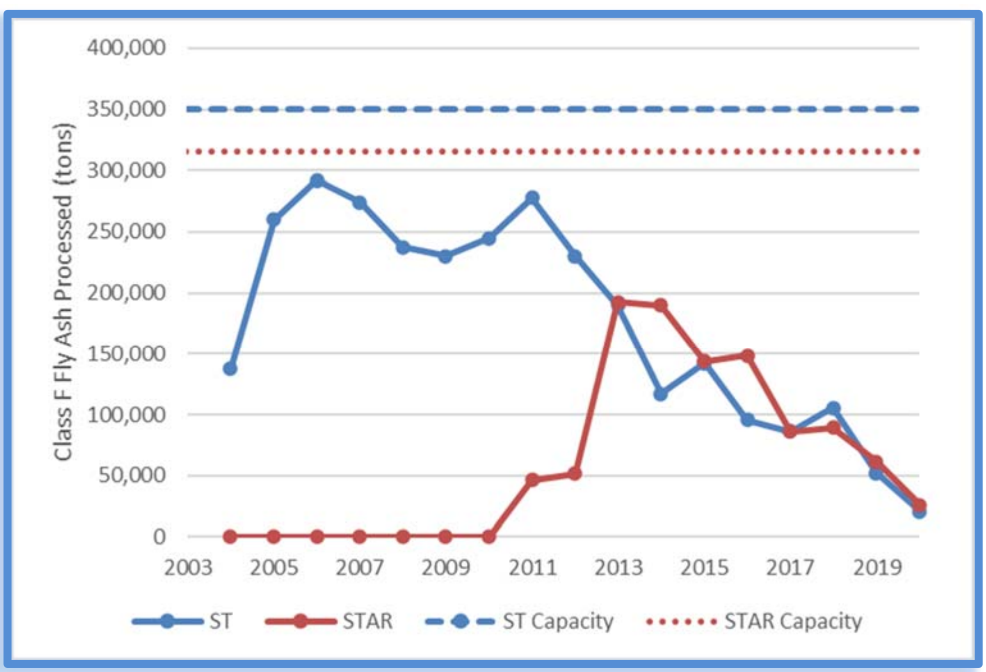
Demand

Class F fly ash provides a number of benefits to cement and concrete producers. Its pozzolonic properties improve the strength of concrete and grout while the fine-grained spheres that comprise this material improve concrete workability. As previously noted, the use of Class F fly ash to replace a portion of portland cement in concrete reduces GHG emissions associated with the production process.

Gypsum is fundamental to the production of wallboard and also has some utility in cement production. Use of FGD material by both of these industries reduces their reliance on mined gypsum. This not only conserves natural mineral resources, but may also allow avoidance of transportation costs if wallboard or cement manufacturers are located closer to coal-fired power plants than to gypsum mines.

The success of marketing freshly produced CCBs to cement manufacturers, the ready-mix concrete industry and wallboard manufacturers has produced a demand for these materials within each industry. As older coal-fired power plants are retired or replaced by gas-fired generating units, these companies are willing to consider, and pay for, previously disposed CCB materials. Beneficiation facilities like ST and STAR were designed to handle a certain volume of fly ash from their associated power plants. As these power plants are beginning to burn less coal each year, they are generating less fly ash, and the beneficiation plants have unused capacity available to accept more CCBs, if they were to become available (see Figure 5-49).

Figure 5-49 CCB Beneficiation Processing Versus Capacity (2004-2020)

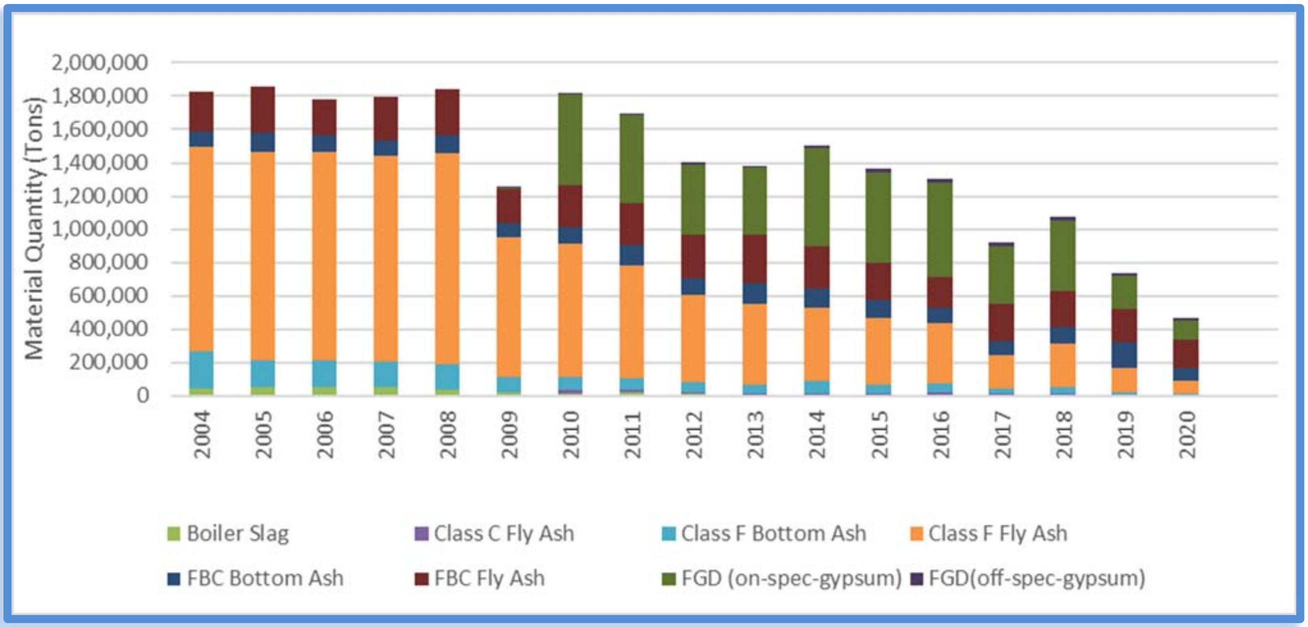


Supply

Annual CCB Production

The total tonnage of CCBs generated in Maryland has decreased in recent years from an average of 2.5 million tons in 2004 to just under 500,000 tons in 2020. Not only has the total tonnage decreased, but the proportion of that tonnage that is comprised of Class F fly ash has also decreased over time (see Figure 5-50). The closure or conversion of older coal-fired power plants (such as R. Paul Smith and C.P. Crane) has driven this change in part, but the coal-fired power plants that remain active are also burning less coal in recent years. As the generation of CCBs decreases, users have begun to consider using CCBs that have been recovered from former fill and disposal sites.

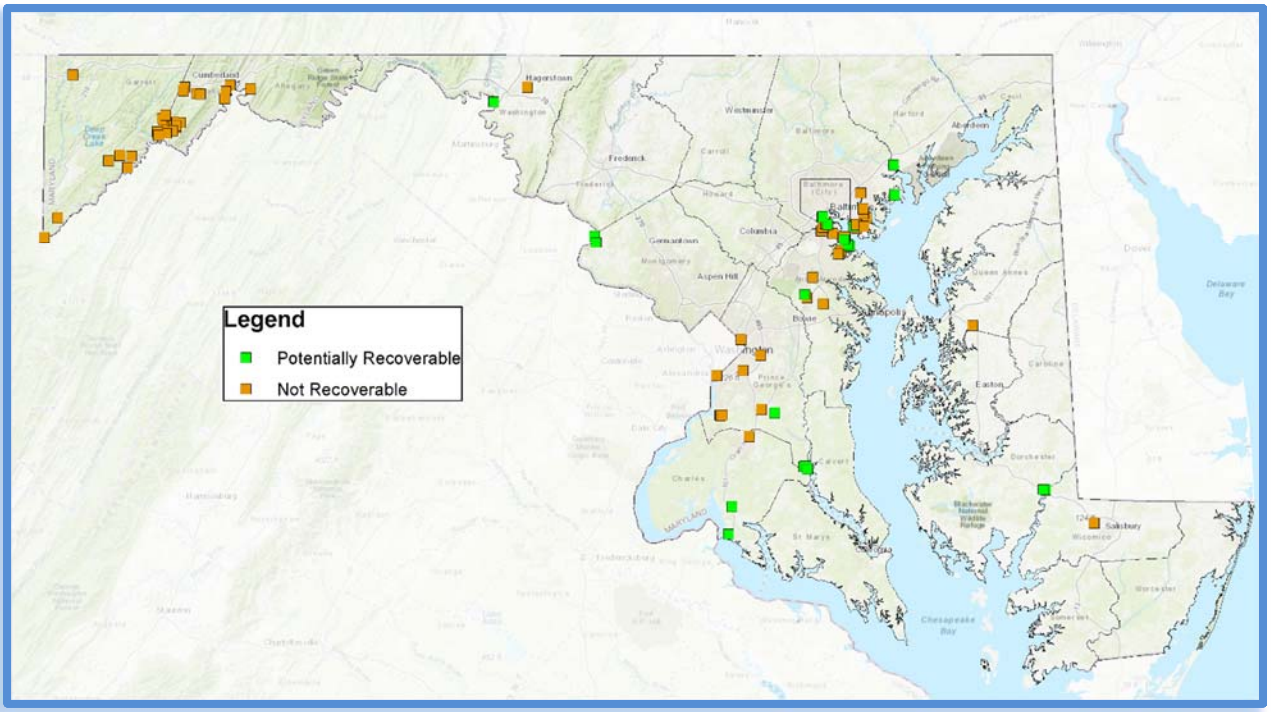
Figure 5-50 Quantity and Type of CCBs Produced in Maryland (2004-2020)



Legacy Ash Sites

In addition to the active CCB disposal sites currently operating in Maryland, there are several historic fill and disposal sites across the state (see Figure 5-51). In recent years, PPRP has been engaged in cataloging the locations of these sites as well as researching known information about them (i.e., period used, types of materials disposed and disposal practices, where available). It is estimated that 20-25 million tons of material is stored within these sites. Recovery of legacy CCBs from disposal sites for use in encapsulated form (such as cement, concrete and wallboard) removes them from situations where they can impact surface waters and groundwaters, and also supplies a raw material that these industries are willing to purchase.

Figure 5-51 Legacy CCB Sites in Maryland



There are a variety of challenges to overcome for recovery and beneficial use of previously disposed of CCBs to become commonplace. Not all of the disposal areas may be accessible for CCB recovery. Some have been redeveloped with buildings, roads or other infrastructure, making the CCBs essentially inaccessible as long as they are covered. A second challenge is the quality of material disposed. CCBs that were co-disposed with household garbage, industrial materials or construction and demolition debris are unusable without significant sorting efforts, which is cost-prohibitive for recovery and reuse at this time.

In many cases, even if only CCBs were disposed of, fly ash and bottom ash were combined and thus recovery would include a mixture of both, which may prove to be problematic for some users. In other cases, historic burning practices at the power plants could mean that the CCBs contain constituents that make them inappropriate for certain uses; in particular, some NOx and sulfate emission control practices can impact the chemical characteristics of CCBs. Finally, legacy CCBs generally contain more moisture than fresh CCBs and some users may require preprocessing of the materials before they can be used. Drying is the most common practice and a variety of companies are developing equipment to assist with this process. Other preprocessing needs may include crushing or grain size separation.

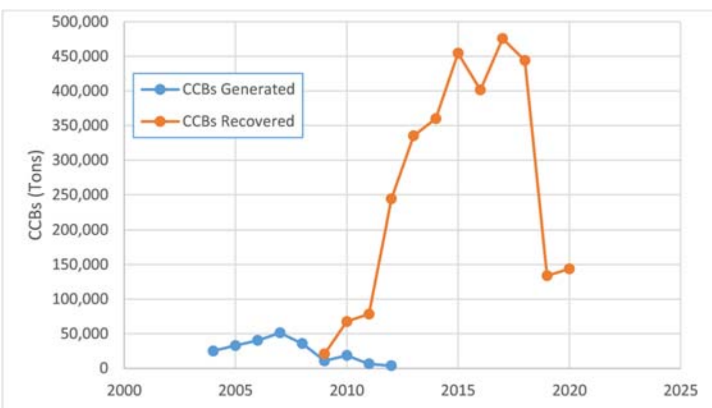
Lately, the subject of legacy CCB sites has been of significant interest in multiple states. As state and federal deadlines for closure of older CCB disposal sites approach, Virginia and North Carolina have made rulings requiring that CCBs be removed from unlined fill areas and either beneficially used or placed into lined landfills compliant with state and federal regulations. Virginia's ruling includes a requirement to recycle at least 25 percent of the removed CCBs. Virginia is further allowing CCB generators to recover a portion of the CCB excavation and removal costs via rate increases to customers. Similar allowances have also been discussed in North Carolina. Both rulings are expected to result in an increase in the marketing of these states' legacy CCBs to Maryland industries and could result in greater interest in recovery of CCBs from historic disposal sites in Maryland.

Recovery of CCBs from Former R. Paul Smith Ash Disposal Site

The R. Paul Smith power plant in Williamsport, Maryland generated up to 50,000 tons of Class F fly ash and bottom ash before it was decommissioned in 2012. The CCBs were conveyed by sluice across the Potomac River to settling ponds in West Virginia. After settling, the CCBs were transferred to an adjacent dry landfill. Beginning in 2009, in coordination with local cement manufacturers in West Virginia and Maryland, the landfill operators began to excavate CCBs from the landfill for sale to cement producers (see Figure 1). Between 2009 and 2020, the annual rate of CCB recovery exceeded the annual rate of CCB production when the plant had been in full operation (see Figure 2). At the end of 2020, more than 3 million tons of CCBs had been recovered from the landfill and beneficially used in cement production. The final material was removed from the landfill on the West Virginia side of the river in 2021. Additional material is present on the Maryland side of the river that awaits a deconstruction plan to allow recovery.

Figure 1 CCB Recovery at Former R. Paul Smith Landfill (2019)

Figure 2 CCB Production versus Recovery at Former R. Paul Smith Landfill



As mining of the R. Paul Smith landfill nears an end, cement manufacturers who have used this material have expressed interest in locating similar stockpiles of material for reuse. In 2019, a CCB recovery effort began at the Westland Ash Storage Site in Montgomery County. Several other CCB fill sites are known to exist in Maryland and efforts are currently underway to determine whether any of these sites may be accessible for CCB recovery and contain material of appropriate quality for use in cement production.

5.6.5 PPRP Demonstration Projects

With over 90 percent of the state's annual production of CCBs currently being beneficially used, Maryland is well above the national utilization rate of 52 percent, as reported by the American Coal Ash Association for 2019. PPRP has supported research and demonstration projects for more than 35 years regarding the beneficial use of CCBs, particularly those applications that could use massive quantities of CCBs in encapsulated form. 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 and restoration of disturbed lands.

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 percent CCBs into underground mines to reduce acid-producing reactions and to help restore natural groundwater 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 AMD were investigated as guidance for large-scale use of CCB grouts in mine applications. In addition, PPRP supported efforts of the MDE's Abandoned Mine Lands Division (MDE AMLD) to address a mine blowout at the McDonald Mine that overwhelmed the doser (i.e., water treatment system) treating its effluent (see Figure 5-52).

Figure 5-52 McDonald Mine Seep

Photo on left shows the post-blowout 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.

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 may lead to land subsidence with the potential to damage buildings and infrastructure. Quarry activities can create artificial sinks for groundwater that alter the natural direction of groundwater 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 (see Figure 5-53). Hoyes Run is a highly valued trout stream adjacent to the Key Stone Quarry in Garrett County. 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 5-53 Hoyes Run Project

Photos During and Shortly After 2007 CCB-Grout Injection at Hoyes Run. Stream flow was restored within hours of grout injection.

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 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 EPA authorizes to issue Part 70 Title V operating permits may also 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 groundwater 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).

Table A-1 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).

Table A-1 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 the 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 New Source Review (NA-NSR)[1]	Required for new or modified major sources that emit volatile organic compounds (VOCs) or nitrogen oxides (NOx); 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

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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 selective catalytic reduction (SCR) systems to control NOx
Cross-State Air Pollution Rule (CSAPR)	Uses a cap-and-trade system to reduce SO_2 by 73 percent and NOx by 54 percent from 2005 levels	MDE	Applies to 28 eastern states and the District of Columbia
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 is necessary
Maryland Coastal Zone Management Program	Balances development and protection in the coastal zone, which includes the Chesapeake Bay, coastal bays and the 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 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 full Critical Area Commission must review the project
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 Rivers Act can be found in the Maryland Code, Section 8-401 et seq. of the Natural Resources Article

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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
Stormwater Management Plan	Plan to prevent stormwater pollution associated with industrial activities	County	Required prior to discharging stormwater associated with industrial activity
Surface Water Discharge/ National Pollutant Discharge Elimination System (NPDES) Permit	Combined state and federal permit for industrial wastewater and possibly stormwater discharge to state water must meet applicable federal effluent guidelines, satisfy state water quality standards and comply with Clean Water Act (CWA) Section 316(b) regulations regarding surface withdrawals	MDE	Individual NPDES permits may include discharge of stormwater associated with industrial activities, or the facility must apply for a general permit for these activities; permit application is due 180 days before discharge commences
General Stormwater Permit (Industrial Activity)	For discharges associated with industrial activity	MDE/County Conservation District	MDE determines whether a facility can operate under a general stormwater 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	Publicly Owned Treatment Works (POTW) or County/ Municipality	Required to ensure 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 nonprocess water	MDE/USACE	640-acre drainage area, 20 foot or greater embankment, high hazard class, natural trout water

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Maryland Water Quality Certification	Section 401 of the CWA provides states with the power to either deny or impose restrictions on construction that might affect water quality. Generally, this has been applied to the construction or operation of hydroelectric projects under the jurisdiction of the Federal Energy Regulatory Commission (FERC)	MDE	Wetland impact determination is 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 CWA permits, State Historic Preservation Officer (SHPO) clearance, National Resource Conservation Program (NRCS) consultation, floodplain permitting and road boring permits	County/Municipality	
Tidal Wetland Permit	State/federal review and permitting for tidal wetland impacts	Board of Public Works (BPW)/ PSC/MDE Water Management Administration (WMA)/USACE	Wetland impact determination is necessary; BPW has the ultimate authority for issuing tidal wetland permits and licenses
Nontidal Wetlands Permit	State/federal review and permitting for nontidal wetland impacts	MDE WMA/USACE	Wetland impact determination is 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

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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 onshore 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 POTW	Municipal Authorities	
Health Department Permit	If septic tanks are used for sanitary waste, a Health Department Permit must be obtained	County	
Spill Prevention Control and Countermeasure (SPCC) / Storage tank regulations	Plan to prevent and manage accidental spills of petroleum products stored on site	MDE	Typical threshold quantities of petroleum products: 1,320 total above-ground gallons (for tanks 55 gallons or greater), and 4,200 gallons underground
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

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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 U.S. 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)	Thresholds (only one needs to be exceeded to trigger permit): 102 inches wide, 13 ft. 6 inches high, 70 ft. overall length, 150,000 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	MDOT SHA	Longitudinal occupancy of an MDOT SHA right of way (ROW) by electrical transmission lines greater than 98 kV is prohibited
Approval for Solid Waste Disposal	If waste, such as fly ash, is taken offsite, 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 a facility wishes to haul its regulated waste, an additional permit may be necessary
Notice of Proposed Construction or Alteration	For projects located near an airport or landing strip	Federal Aviation Administration (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 U.S. 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)

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
National Environmental Policy Act (NEPA)	Completion of an Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Federal entity, such as USACE or National Parks Service (NPS)	Triggered when a 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. The regulated utility provides electric service for consumers who do not select a supplier or are unable to receive service from a competitive supplier, and contracts with wholesale suppliers on behalf of its consumers, under the supervision and guidance of the Maryland 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 Interconnection LLC (PJM) regional transmission organization (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).[268]

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 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 and the Ancillary Services Markets). These markets are competitive

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

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, that is responsible for the sale of electricity to a retail customer. Along with electricity, LSEs must also purchase their proportionate share of the PJM system's peak capacity (to ensure reliability) and transmission services (to move the electricity from the generator to the distribution system).

Day-Ahead Market

The Day-Ahead Market is a spot market (deliveries are expected in a month or less at that day's quoted price) in which participants can purchase and sell energy for the next operating day. It provides the opportunity 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 the lowest to the 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 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 into the market at the real-time price. 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

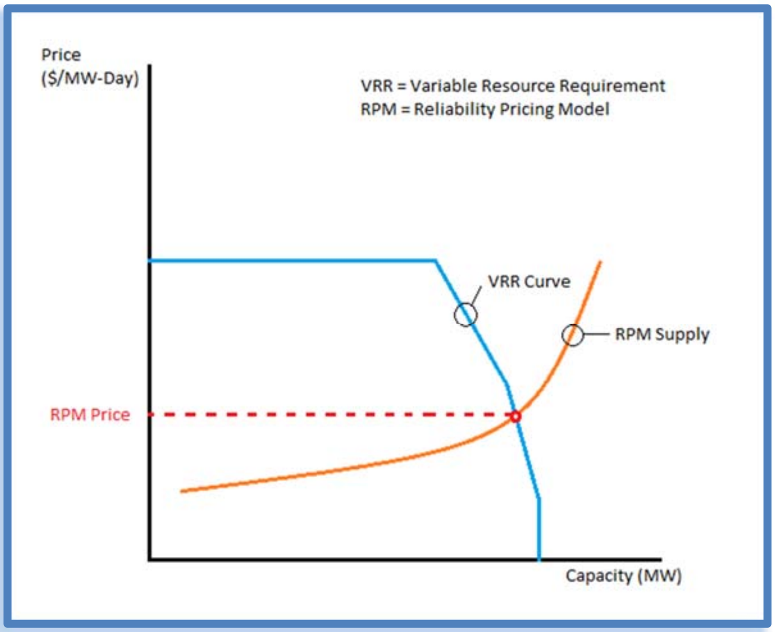
Capacity refers to the amount of electricity generation available at any given time. The capacity market is a forward market in which LSEs purchase supply-side and demand-side capacity resources. Each LSE is required to have available its share of the PJM system peak plus a planning reserve margin of an additional 14.4 percent of peak load, which changes annually depending upon the reserve requirement study. 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 (see Figure B-1).

Figure B-1 PJM Demand and Supply Curves



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).[269] 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.

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 or energy efficiency), 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.[270] The BRA is conducted three years in advance of the year for which the capacity will be committed.[271] 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

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[269] PJM divides the PJM region into deliverability areas based on transmission connections and constraints.

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

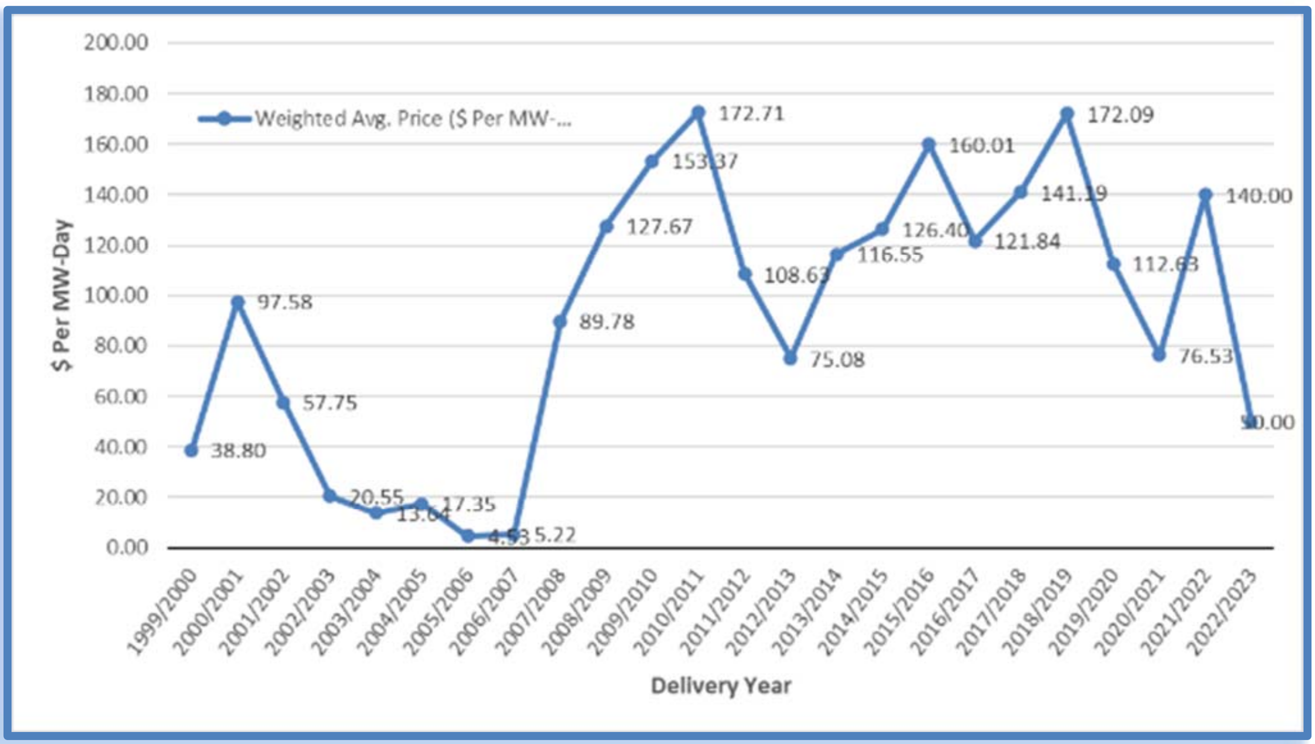
[271] The BRA for the planning year June 2022 through May 2023 was to be held in May 2019 but was delayed until June 2021 due to Federal Energy Regulatory Commission (FERC) review of the new Minimum Offer Price Rule (MOPR). The recent 2021 MOPR reform, approved as a result of a FERC deadlock, will allow certain state-subsidized resources such as wind farms, nuclear power plants, natural gas-fired power plants, as well as demand response and energy efficiency programs, to participate in BRAs without the threat of their bids being increased under the MOPR.

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.

The price for capacity in PJM has been more volatile in the past two auctions after the capacity clearing price fell significantly for the 2019/2020 delivery year due to changes in the products offered through the BRA. The capacity price in the 2021/2022 delivery year increased 83 percent over the prior delivery year due to the continued decrease in energy revenues. The 2022/2023 BRA resulted in a much lower clearing price for capacity, representing a 64 percent decline from the 2021/2022 auction. Figure B-2 shows historical capacity prices for PJM through the 2022/2023 delivery year.

Figure B-2 Average PJM Capacity Prices by Delivery Year, 1999/2000 – 2022/2023



Source: Monitoring Analytics, 2021 Quarterly State of the Market Report for PJM and PJM, 2022/2023 RPM Base Residual Auction Results.

Historically, demand response (DR) has been included in the PJM auctions as one of three resource types: limited, extended summer and annual. Delivery year (DY) 2017/2018 (i.e., June 1, 2017 through May 31, 2018) was the last year in which PJM permitted the use of these three DR capacity products. These products, detailed in Table B-1, allowed DR participants to bid into the auction in a limited annual capacity.

Table B-1 PJM Demand Response Capacity Products through DY 2017/2018

	Limited	Extended Summer	Annual
Eligible Auctions	Through DY 2017/2018	Through DY 2017/2018	Through DY 2017/2018
Availability	June - September	May - October	Any day during DY
Potential Event Hours	12:00 PM - 8:00 PM	10:00 AM - 10:00 PM	May - October 10:00 AM - 10:00 PM November - April 6:00 AM - 9:00 PM
Maximum Duration of Event	6 Hours	10 Hours	10 Hours
Annual Maximum Number of Events	10 Times or Less	Unlimited	Unlimited

For DY 2018/2019 and DY 2019/2020, PJM only accepted one type of DR capacity product, Base Capacity. Base Capacity was the same as the Extended Summer Project that expired in DY 2018/2019. Beginning with the auction for DY 2018/2019, PJM accepted bids for Capacity Performance, a DR capacity product that requires participants to respond year-round, with no limit on event duration or the number of events called per year. See Table B-2 for a summary of the two capacity products available beginning in DY 2018/2019. As a result of the changes, those that have bid into the auction have had to alter their bid strategies and amount of bids, ultimately impacting the clearing price of the BRA. Effective with the 2020/2021 Delivery Year, PJM will procure only a single DR capacity product, Capacity Performance.

Table B-2 PJM Demand Response Capacity Products Beginning in DY 2018/2019

	Base Capacity	Capacity Performance
Eligible Auctions	DY 2018/2019 & DY 2019/2020	Effective beginning DY 2018/2019
Availability	June - September	Any day during DY
Potential Event Hours	10:00 AM - 10:00 PM	May - October 10:00 AM - 10:00 PM November - April 6:00 AM - 9:00 PM
Maximum Duration of Event	10 Hours	No Limit
Annual Maximum Number of Events	Unlimited	Unlimited

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-ramp hours and 800 effective MW during on-ramp hours, with the on-ramp and off-ramp periods determined seasonally and based on system conditions. 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 capacity that is standing by ready for service in the event of a disruption on the power system, such as the loss of a generator. 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, e.g., 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 10 minutes of a request by PJM. Secondary reserves must be available within 30 minutes of a request. Synchronized or spinning reserves are typically the first primary resources called upon and are paid to be available, whether called upon to respond to an event or not. These are the reserve units that are either already running but idling in standby mode, or can be started up very quickly and synchronized with the grid, and can therefore supply energy within the 10-minute time frame.

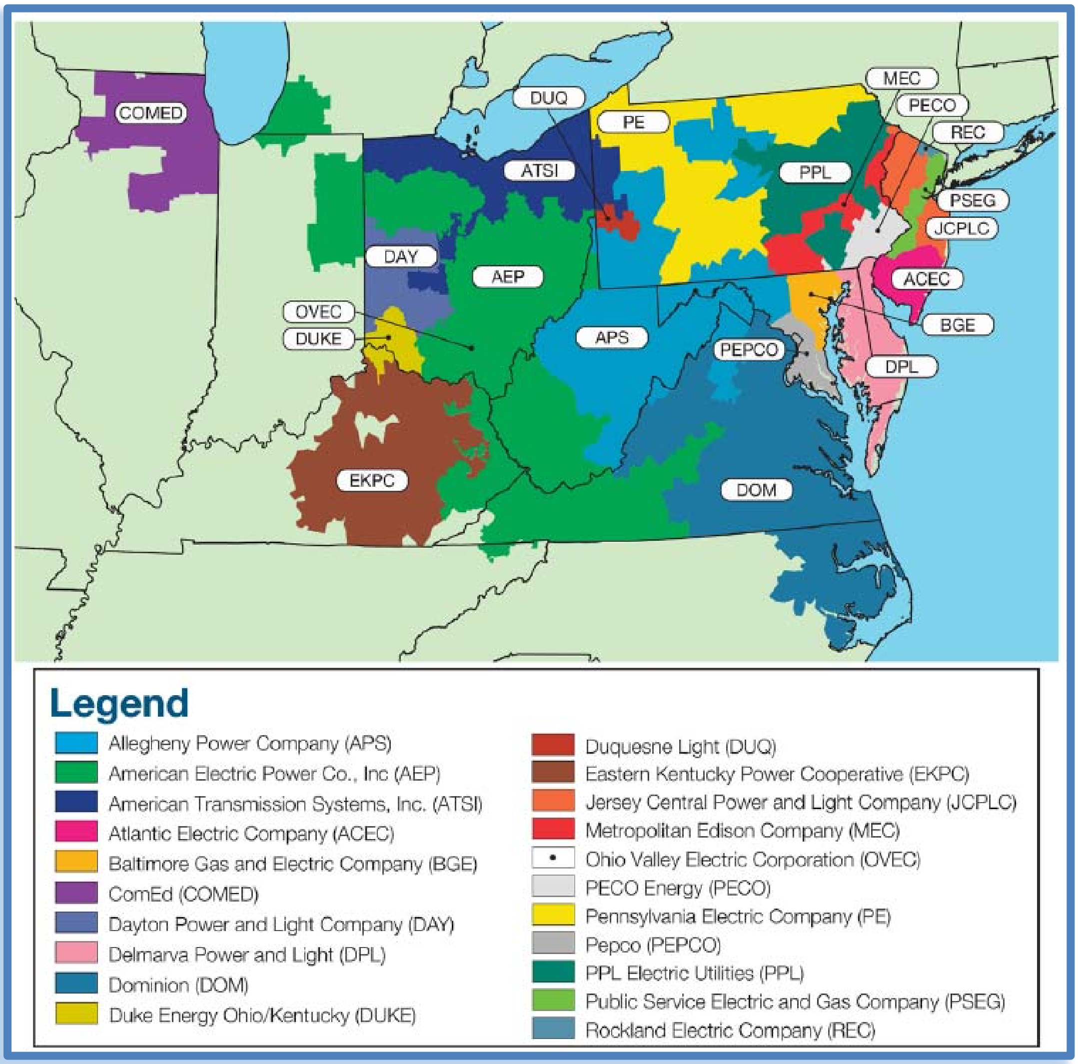
These operating reserves, the standby generation made available to serve load in case there is an unplanned event, are not the same as the 14.4 percent planning reserve requirement, which is an annual capacity obligation based on PJM's independent load forecast and other system planning assumptions and scenarios. The 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 14.4 percent.

Market Pricing

Factors Affecting Locational Marginal Prices

The PJM region is divided into different zones (see 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 electricity price 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: Monitoring Analytics, 2021 Quarterly State of the Market Report for 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-3 provides the PJM average and median prices experienced over the 2020 calendar year.

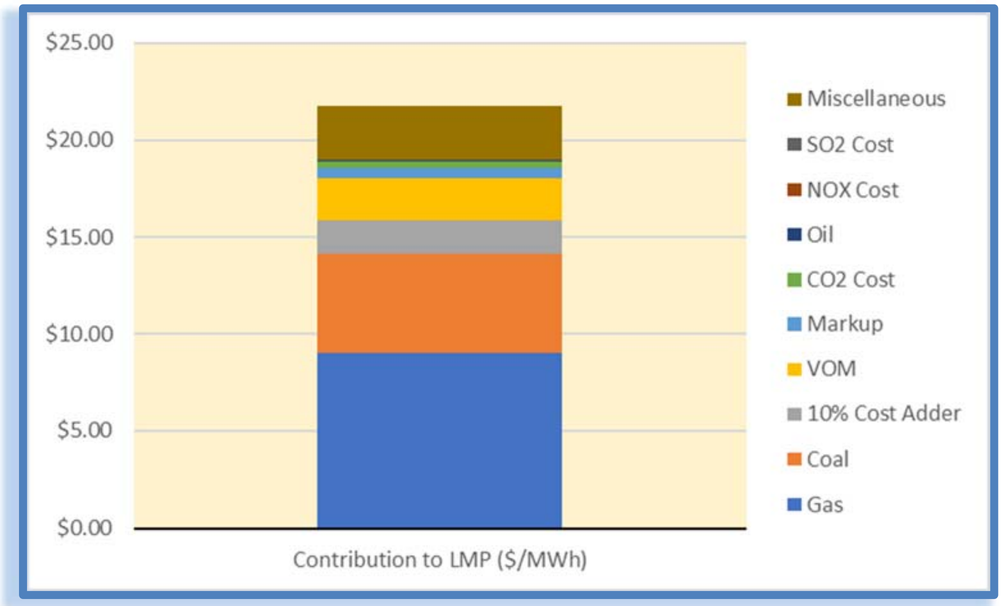
Table B-3 PJM Off-Peak and On-Peak Average LMPs for 2020

	Day-Ahead ($/MWh)		Real-Time ($/MWh)	
	Off-Peak	On-Peak	Off-Peak	On-Peak
Average	$17.39	$23.67	$17.64	$24.09
Median	$16.54	$21.64	$16.29	$20.52

Source: Monitoring Analytics, 2020 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 the 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 2020, the capital and fuel supply costs of gas-fired generators made up 41.5 percent of the annual average day-ahead LMP, while coal-fired generators made up 23.7 percent. Variable operating and maintenance costs (VOM) contributed 10.1 percent of the LMP and PJM's cost adder contributed 7.7 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), nonfuel operating costs and profit margins. Cost for compliance with CO_2 emissions regulations contributed approximately 1.7 percent to the total LMP with SO_2 and NOx emissions regulations contributing 0.1 percent. All generators, however, are paid the LMP of their zone; the PJM Market Monitor estimates these cost factors for informational purposes only.

Figure B-4 Components of Real-Time, Load-Weighted Annual Average LMP (2020)



Source: Monitoring Analytics, 2020 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-4). 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. Since then, LMPs have fallen by over two-thirds from 2008 levels, due in large part to declining natural gas prices. Although natural gas prices have increased in 2021, nearing pre-COVID-19 pandemic levels, they are still well below the highs experienced in 2008. The primary driving factor leading to lower natural gas prices is increased domestic gas production. The technological breakthrough of horizontal drilling provided domestic producers access to low-cost shale gas. This increase in fracking and subsequently natural gas supply, combined with low load growth as well as increased penetration of energy efficiency and renewable energy projects, have acted to put downward pressure on LMPs. Figure B-5 depicts fuel costs for electricity suppliers between 1999 and 2020 across the entire U.S.

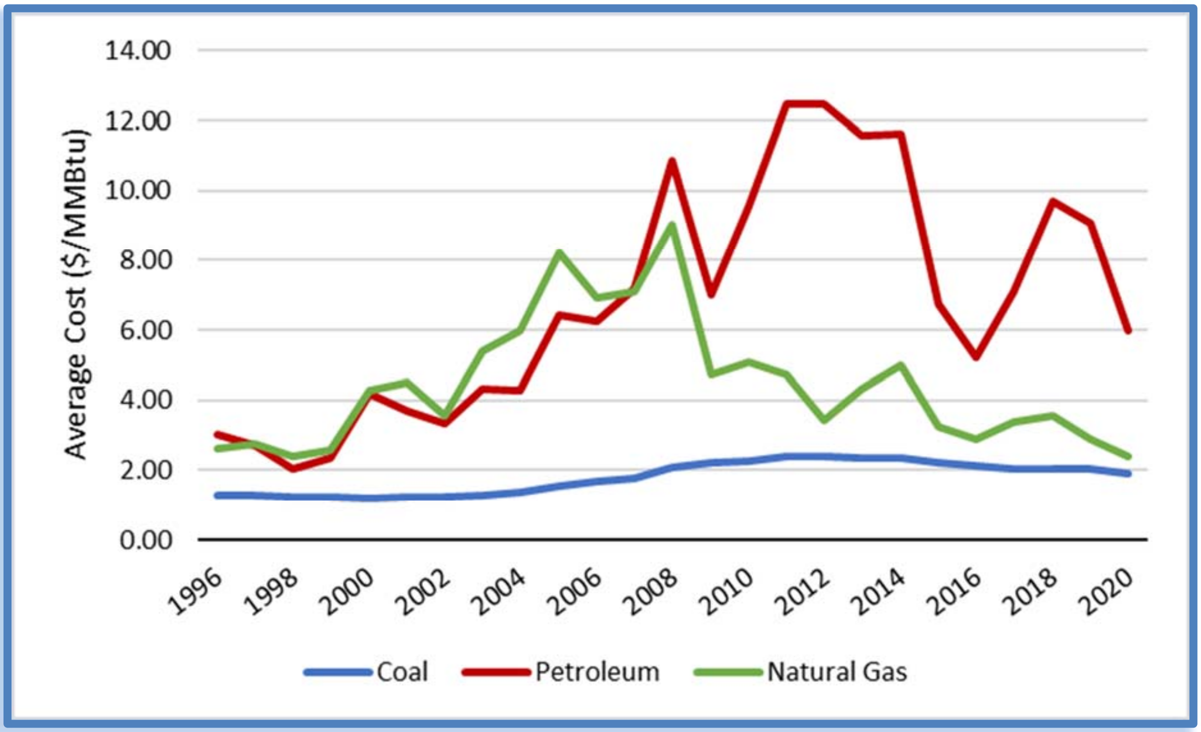
Table B-4 PJM Real-Time, Load-Weighted, Day-Ahead Average LMPs, 1999-2020

Year	LMP ($/MWh)	Change from Previous Year ($/MWh)	Percent Change
1999	34.07	9.91	41.02%
2000	30.72	(3.35)	-9.83%
2001	36.65	5.93	19.30%

2002	31.6	(5.05)	-13.78%
2003	41.23	9.63	30.47%
2004	44.34	3.11	7.54%
2005	63.46	19.12	43.12%
2006	53.35	(10.11)	-15.93%
2007	61.66	8.31	15.58%
2008	71.13	9.47	15.36%
2009	39.05	(32.08)	-45.10%
2010	48.35	9.30	23.82%
2011	45.94	(2.41)	-4.98%
2012	35.23	(10.71)	-23.31%
2013	38.66	3.43	9.74%
2014	53.14	14.48	37.45%
2015	36.16	(16.98)	-31.95%
2016	29.23	(6.93)	-19.16%
2017	30.99	1.76	6.02%
2018	38.24	7.25	23.40%
2019	27.32	-10.92	-28.6%
2020	21.77	-5.55	-20.3%

Source: Monitoring Analytics, 2020 State of the Market Report for PJM.

Figure B-5 Fuel Costs for the Electric Power Industry, 1996-2020



Source for 2010 through 2020: U.S. Energy Information Administration, Electric Power Annual 2020, October 2021. eia.gov/electricity/annual/?src=emaill, Table 7.1.
Source for 2008 and 2009: U.S. Energy Information Administration, Electric Power Annual 2018, October 2019. eia.gov/electricity/annual/html/epa_07_01.html, Table 7.1.
Source for 1996 through 2007: U.S. Energy Information Administration, Electric Power Annual 2007, January 2009. 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. 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-5).

As seen in Table B-5, the differences in LMPs in 2020 between the Western Region and Eastern Region decreased compared to the differences in LMPs between the Western Region and Mid-Atlantic Region in 2019. This can be attributed to lower amounts of congestion in 2020 driven by mild winter weather and reduced electricity demand due to the COVID-19 pandemic. PJM reported a 9.4 percent decrease in total congestion costs in 2020 compared to 2019. In Table B-5, the PJM zones that impact Maryland are highlighted in green. Additional information on congestion is provided in Chapter 4 of this CEIR.

Table B-5 Real-Time, Annual, Load-Weighted Average LMPs for 2019 and 2020

Zone	2019 LMP	2020 LMP	Variance (Percent Change)
Eastern PJM Zones			
AECO	$25.07	$19.72	5.35
AP	$28.21	$22.14	6.07
BGE	$30.82	$25.78	5.04
Dominion	$27.71	$22.90	4.81
DPL	$27.69	$22.79	4.90
JCPL	$25.40	$20.05	5.35
Met-Ed	$26.34	$21.16	5.18
PECO	$24.75	$19.29	5.46
PENELEC	$26.17	$20.84	5.33
Pepco	$29.68	$23.59	6.09
PPL	$24.85	$19.42	5.43
PSEG	$25.28	$19.69	5.59
RECO	$25.72	$20.74	4.98
Western PJM Zones			
AEP	$28.21	$22.14	6.07
ATSI	$28.06	$22.55	5.51
ComEd	$24.72	$20.18	4.54
Day	$29.52	$23.23	6.29
DEOK	$28.49	$22.37	6.12
DLCO	$29.08	$23.05	6.03
EKPC	$28.18	$22.14	6.04
OVEC	$26.23	$20.75	5.48

Source: Monitoring Analytics, 2020 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 noneconomic 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; noneconomic 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.

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 summary.

Table C-1 Principal Regions in Maryland

Region	Counties	Predominant Electric Distribution Utility
Baltimore	Anne Arundel Baltimore Baltimore City Carroll Frederick Harford Howard	Baltimore Gas and Electric Company
Washington Suburban	Montgomery Prince George's	Potomac Electric Power Company
Southern Maryland	Calvert Charles St. Mary's	Southern Maryland Electric Cooperative
Western Maryland	Allegany Garrett Washington	Potomac Edison Company
Upper Eastern Shore	Caroline Cecil Kent Queen Anne's Talbot	Delmarva Power and Choptank Electric
Lower Eastern Shore	Dorchester Somerset Wicomico 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 the demand are those to which the producers of goods and services are sensitive.

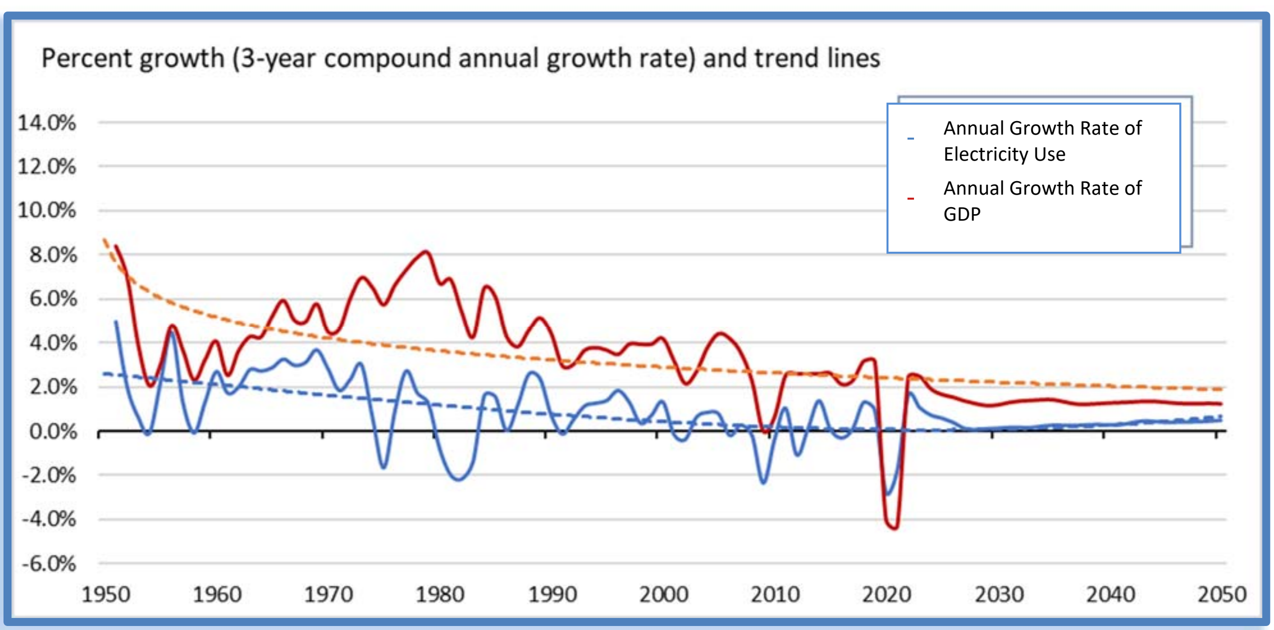
The residential demand for electricity is assumed to result from the exercise of choice by which the consumer maximizes their usage, subject to a budget constraint. Consumer demand for electricity is taken to be a function of its price, consumer income, weather and the price of related commodities (i.e., 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 nonresidential 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, employment is used 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 the gross domestic product (GDP) in the 1950s 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 1990s when growth in electric use fell below GDP growth. Similar to the recession in the early 1980s, the differential between GDP growth and growth in electric use during the Great Recession of the late 2000s is minimal.

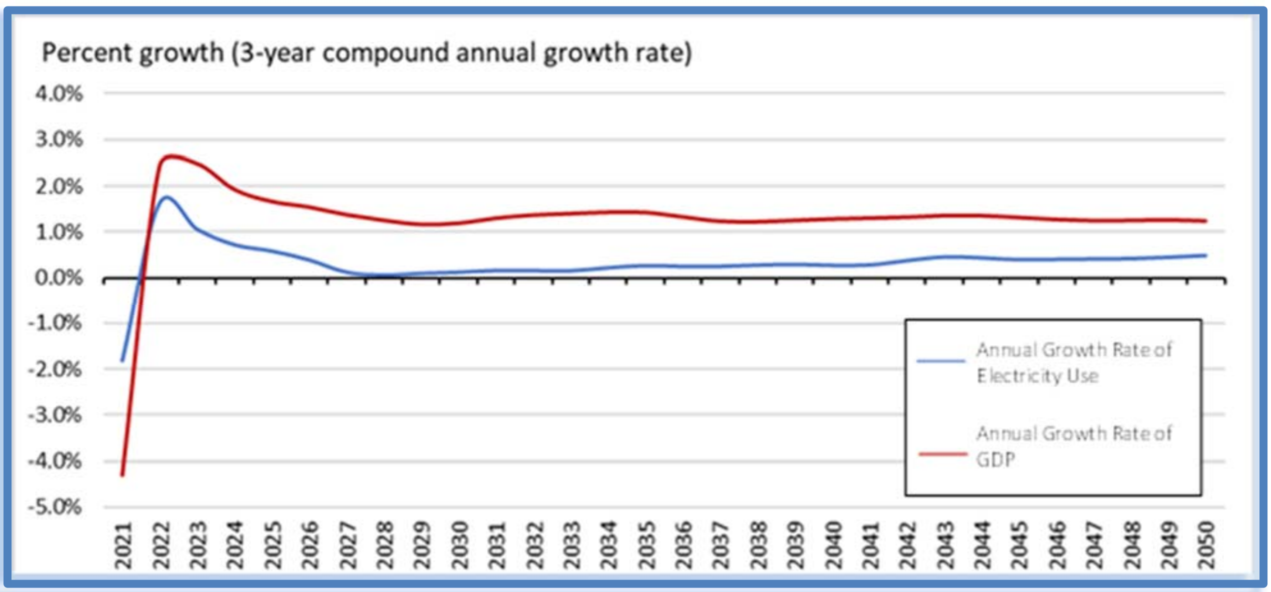
Figure C-1 U.S. Electricity Use and Economic Growth, 1950-2050



Source: U.S. Bureau of Economic Analysis; U.S. Energy Information Administration, Annual Energy Outlook for 2021 and Bureau of Economic Analysis Historical GDP.

The U.S. Energy Information Administration (EIA) reports in its 2021 Annual Energy Outlook (AEO) that energy consumption declined further than GDP in 2020 because of COVID-19 and there is uncertainty of the rate at which both will return to 2019 levels. AEO projects that the industrial sector will return the quickest to 2019 energy demand levels, compared to other sectors (residential, commercial and transportation). In the long term, average electric use is projected to grow around 0.5 percent per year from 2020 through 2050, compared to average real GDP growth of 2.1 percent over the same period (illustrated in Figure C-2). Over the next three decades, EIA projects that electricity use will continue to grow; however, the rate of growth will slow over time. EIA does not expect the growth in electricity use to equal or exceed real GDP growth for any sustained period due to efficiency standards for lighting and other appliances continued downward pressure on electricity consumption.

Figure C-2 Projected U.S. Electricity Use and Economic Growth, 2021-2050



Source: U.S. Energy Information Administration, Annual Energy Outlook for 2021.

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 reevaluate 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 the 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 electricity demand will rise or fall.

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, except for 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 prepared 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

	Per Capita Income (2009 $)						Average Annual Growth Rates				
Region	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

Nonresidential 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 consistently, hence, a proxy for output needs to be used. Nonfarm employment has typically been relied upon for this purpose. Under 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

	Total Jobs (thousands)						Average Annual Growth Rates				
Region	2000	2005	2010	2015	2020	2025	'00-'05	'05-'10	'10-'15	'15-'20	'20-'25
Maryland	3,065	3,316	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%	1.56%	1.06%	0.58%
Washington Suburban	1,088	1,186	1,197	1,252	1,324	1,372	1.68%	0.18%	0.92%	1.15%	0.72%
Southern Maryland	124	148	156	162	174	184	3.43%	1.06%	0.84%	1.43%	1.18%
Western Maryland	130	138	136	143	149	156	1.08%	-0.27%	0.98%	0.88%	0.89%
Upper Eastern Shore	99	115	115	123	133	140	2.90%	0.07%	1.40%	1.53%	1.05%
Lower Eastern Shore	110	120	114	118	126	130	1.70%	-0.90%	0.62%	1.29%	0.64%

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 2000s 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 3.5 percent in 2007 to 7.65 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 growth between 2005 and 2010. Now well out of the recession, the unemployment rate for the nation and Maryland was down to 3.9 percent in 2018. The state's downward trend in unemployment continued in 2019, falling to 3.5 percent before nearly doubling year over year to 6.8 percent in 2020 due to the COVID-19 pandemic. Despite the sharp increase in unemployment in Maryland and the nation in 2020, total employment is projected to increase at an average annual rate of 0.7 percent through 2030 according to the Bureau of Labor Statistics.[272]

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

[272] bls.gov/news.release/pdf/ecopro.pdf.

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 the 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, population increases 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 2010-2035. The population growth rates have been positive since 2000 for every region of Maryland except the western region which decreased slightly between 2010 and 2020. The state's population growth slowed from 2015 to 2020 to 0.31 percent per year, compared to the first half of the decade which experienced an annual growth rate of 0.71 percent. The state's population is projected to experience a slight uptick in growth from 2020 to 2025 and is projected to maintain a similar annual growth rate going forward. While following these trends generally, the outer regions of the state, including Southern Maryland and the Upper and Lower Eastern Shore are projected to experience a more rapid population growth than that of the rest of the state from 2020 onward. The rates of population growth are uneven across the state. Historically, the largest growth rates were reported for Southern Maryland and the smallest rates for Western Maryland. However, Baltimore's growth rate is projected to be significantly lower than that experienced for Western Maryland over the 2020-2025 period.

Table C-4 Historical and Projected Population for Maryland, 2010-2035

	Total Population (thousands)						Annualized Growth Rates				
Region	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**'10-'15**	**'15-'20**	**'20-'25**	**'25-'30**	**'30-'35**
Maryland	5,774	5,983	6,075	6,245	6,414	6,589	0.71%	0.31%	0.55%	0.53%	0.54%
Baltimore	2,663	2,738	2,763	2,814	2,864	2,915	0.55%	0.19%	0.37%	0.35%	0.35%
Washington Suburban	2,069	2,183	2,228	2,299	2,366	2,440	1.09%	0.41%	0.63%	0.58%	0.61%
Southern Maryland	340	358	373	394	414	433	0.99%	0.85%	1.10%	0.98%	0.91%
Western Maryland	253	252	252	259	267	276	-0.03%	-0.05%	0.55%	0.67%	0.64%
Upper Eastern Shore	240	241	245	254	267	281	0.09%	0.32%	0.76%	0.96%	1.03%
Lower Eastern Shore	209	211	215	225	235	245	0.19%	0.31%	0.95%	0.92%	0.78%

Source: Projections for the Baltimore region based on Round 9 from the Baltimore Metropolitan Council of Government's Cooperative Forecasting Committee. Projections for the Washington suburban region based on Round 9.0 of the Metropolitan Washington Council of Governments Cooperative Forecasting Committee. Aggregated data prepared by the Maryland Department of Planning, August 2020.

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 2010-2035. Household growth rates differ from population growth rates 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 2015, household size in five of the six Maryland regions has been declining or flat, and the decline is forecast to continue through 2025, at which point most household sizes remain static. For the state, the average household size was level at 2.68 people in 2015; however, household size is expected to decrease slightly to 2.61 people by 2035.

Table C-5 Historical and Projected Number of Households and Average Size of Households in Maryland, 2000-2035

	Number of Households (thousands)						Annualized Growth Rates				
Region	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**'10-'15**	**'15-'20**	**'20-'25**	**'25-'30**	**'30-'35**
Maryland	2,156	2178	2,334	2,315	2,392	2,461	0.20%	0.51%	0.71%	0.66%	0.57%
Baltimore	1,021	1,020	1,046	1,071	1,098	1,120	-0.02%	0.51%	0.48%	0.50%	0.40%
Washington Suburban	746	766	782	816	845	871	0.53%	0.43%	0.83%	0.70%	0.62%
Southern Maryland	120	125	133	143	151	158	0.88%	1.28%	1.38%	1.14%	0.96%
Western Maryland	97	95	96	100	103	106	-0.33%	0.22%	0.65%	0.70%	0.63%
Upper Eastern Shore	91	92	94	99	104	110	-0.04%	0.50%	0.98%	1.04%	1.12%
Lower Eastern Shore	82	80	82	87	91	95	-0.33%	0.44%	1.14%	0.97%	0.73%
	Household Size						**Annualized Growth Rates**				
Maryland	2.61	2.68	2.65	2.63	2.61	2.61	0.53%	-0.22%	-0.15%	-0.15%	0.00%
Baltimore	2.54	2.62	2.57	2.56	2.54	2.53	0.62%	-0.38%	-0.08%	0.16%	-0.08%
Washington Suburban	2.73	2.81	2,80	2.77	2.75	2.75	0.58%	-0.07%	-0.22%	-0.14%	0.00%
Southern Maryland	2.80	2.82	2.76	2.72	2.70	2.69	0.14%	-0.43%	-0.29%	-0.15%	-0.07%
Western Maryland	2.43	2.47	2.43	2.42	2.42	2.42	0.33%	-0.33%	-0.08%	0.00%	0.00%
Upper Eastern Shore	2.58	2.58	2.56	2.53	2.52	2.50	0.00%	-0.16%	-0.24%	-0.08%	-0.16%
Lower Eastern Shore	2.42	2.48	2.47	2.45	2.45	2.45	0.49%%	-0.08%	-0.16%	0.00%	0.00%

Source: Historical data from the U.S. Census. Forecasts prepared by the Maryland Department of Planning, August 2020.
planning.maryland.gov/MSDC/Documents/popproj/AVGHHSizeProj.pdf

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 nonresidential, as well as into economic and noneconomic 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 noneconomic explanatory variables affecting residential electricity consumption. This appendix also shows trends in employment, which affect the nonresidential demand for electricity. Selected data on these determinants of demand are reported and trend analyses are presented. The broad conclusion to emerge from these trends is that electricity demand should continue to grow in Maryland.

Glossary

The following list provides definitions of selected terms that are commonly used in the electricity generating industry.

Advanced Metering Infrastructure (AMI)
Technology deployed at end user locations in conjunction with a smart grid, allowing for a new, dynamic rate structure for electricity prices.

Anadromous
Anadromous fish are those that ascend rivers from the sea for breeding.

Aquifer
An underground layer of water-bearing permeable rock or unconsolidated materials from which groundwater can be extracted using a water well.

Attainment area
Area in the country where National Ambient Air Quality Standards are being met.

Best Available Control Technology (BACT)
Level of pollution control required for sources that trigger PSD air quality requirements (see Prevention of Significant Deterioration, PSD).

Biomass
Biological material (such as wood, agricultural, and animal wastes) that can be used as fuel for transportation, steam heat and electricity generation.

Black Liquor
Black liquor is a thick, dark liquid that is a byproduct of the process that transforms wood into pulp, which is then dried to make paper. One of the main ingredients in black liquor is lignin, which is the material in trees that binds wood fibers together and makes them rigid, and which must be removed from wood fibers to create paper.

BMPs
Best management practices.

Bottom ash
A coal combustion byproduct that is collected from the bottom of the furnace after combustion and is composed of coarse, angular, porous or glassy particles.

British thermal unit (Btu)
A unit of thermal energy equivalent to 252 calories; serves as the base unit for measuring the heat content of a fuel source.

Capacity
The capability to generate electrical power. The generating capacity of a power plant is the maximum amount of power it can instantaneously supply to the grid and is measured in megawatts (MW).

Carbon capture and storage (CCS)
A range of technologies used to prevent large quantities of CO_2 from being released into the atmosphere, mainly from large point sources such as fossil fuel-fired power plants.

Certificate of Public Convenience and Necessity (CPCN)
Issued by Maryland's Public Service Commission to an electric company planning to construct or modify a generation facility or transmission line; grants permission to construct the facility subject to certain conditions.

Class F Fly Ash
As classified by the American Society for Testing and Materials (ASTM), Class F fly ash is distinguished from Class C fly ash by having less than 10 percent calcium (expressed as CaO) by weight.

Closed-cycle cooling
Type of cooling that involves recirculating water in cooling towers.

Coal combustion byproducts (CCBs)
Solid byproducts consisting of components of coal not consumed during combustion, such as fly ash and bottom ash.

Conduit hydropower
Hydropower produced by water-carrying structures (tunnels, canals, pipelines, etc.) fitted with electric generating equipment without the use of a dam or reservoir.

Congestion
Describes a situation where power cannot be moved from where it is being produced to where it is needed because the transmission system does not have sufficient capability to carry the electricity.

Conservation
A conscious choice that a person makes to change behavior solely to use less energy (or other resources).

Consumptive water use
Use of water in such a way that it does not return to its source following use, such as water that evaporates from cooling towers at power plants.

Cross-State Air Pollution Rule (CSAPR)
EPA's cap-and-trade program that is designed to reduce interstate transport of PM2.5 and ozone.

Curtailment Service Providers (CSPs)
Grid members that act as demand response providers.

Demand
The amount of power that must be supplied to a customer (i.e., a load).

Demand response
Refers to shifting demand for electricity to nonpeak periods or reducing electricity use during periods of peak demand.

Distributed generation
Generating resources located close to or on the same site as the facility using the power.

Distribution
The process of delivering electricity received from transmission providers to local customers.

Electric company
The company that delivers electricity to a customer’s home or business through its system of poles, power lines, and other equipment.

Electric cooperative
An electric company that is owned by, and operated for the benefit of, those using the system.

Electricity supplier
An entity that sells electricity to customers (and, in Maryland, is licensed to do so by PSC).

EmPOWER Maryland
A state energy initiative that began in 2008 designed to reduce Maryland’s per capita energy consumption and peak demand by 15 percent by 2015.

Energy efficiency
Finding ways to accomplish the same amount of work using less energy.

Energy use
A measure of electrical power used over a period of time usually expressed in kilowatt-hours or megawatt-hours.

Federal Energy Regulatory Commission (FERC)
An independent commission responsible for regulating wholesale electric power transactions and interstate transmission and sale of natural gas for resale. FERC is the federal counterpart to state utility regulatory commissions.

FIDS
Forest interior dwelling species.

Flue gas desulfurization (FGD)
Technology that introduces sorbent into the exhaust gas after combustion to remove sulfur compounds from power plant emissions, thereby reducing air pollution.

Fluidized bed combustion (FBC)
Technology that uses a heated bed of sand-like material suspended (or fluidized) within a rising column of air to burn many types and classes of fuel, including waste-type fuels. Typically has higher efficiency and lower emissions than conventional power plant combustion technologies.

Fly ash
A coal combustion byproduct made up of finely divided residue or ash that is transported from the furnace along with emission gases. Composed of very fine, and generally spherical, glassy particles.

Flywheel
A system that uses a large rotational mass to store energy and to provide regulation services to smooth output fluctuations from a local solar or wind facility.

Fuel cell
A device that converts the chemical energy from a fuel into electricity through a chemical reaction with oxygen or another oxidizing agent.

Generation
The process of producing electrical energy. Electricity generation is the amount of power supplied through time (energy) and is measured in megawatt-hours (MWh).

Generation Attribute Tracking System (GATS)

GATS is a database maintained by PJM that lists the generation attributes (e.g., time, facility, fuel type) for all MWh generated in the PJM territory and outside the PJM territory if the generator is eligible for a state's RPS and has registered as such with PJM.

Greenfield
Area of land that has not previously been developed.

Greenhouse gases (GHGs)
Gases that occur both naturally and from human activities that trap heat in the atmosphere, such as carbon dioxide and methane.

Hazardous air pollutants (HAPs)
List of pollutants identified by EPA as having the potential to cause an adverse impact to human health or the environment.

Independent Power Producer (IPP)
Private company that develops, owns, or operates an electric power plant.

Independent spent fuel storage installation (ISFSI)
Long-term storage facility for spent nuclear fuel located at a nuclear power plant site and regulated by the NRC.

Investor-owned utility
A for-profit company in the business of supplying electric power to end users.

Landfill gas (LFG)
Gas produced when organic solid wastes decompose in a landfill. LFG is a combination of methane and carbon dioxide.

Load
Kilowatt or megawatt demand placed on the electric system by consumers of power.

Locational Marginal Price (LMP)
Electricity price that varies by time and geographic location; provides the basis for the regional market for buying and selling electricity.

Maryland Healthy Air Act (HAA)
Requires substantial reductions in emissions of NOx, SO_2 and mercury from coal-fired generating units in the state. Also requires Maryland to participate in the Regional Greenhouse Gas Initiative to reduce emissions of pollutants that contribute to climate change.

Maryland Public Service Commission (PSC)
Government agency that regulates public utilities and certain passenger transportation companies doing business in Maryland, including gas, electric, telecommunications, water, sewage disposal, passenger motor vehicle, railroad, and taxicab companies.

Maximum Achievable Control Technology (MACT)
An EPA standard designed to reduce emissions of HAPs, such as heavy metals, acid gases and organics, from coal- and oil-fired power plants.

Municipal utility
An electric company owned and operated by a municipality serving residential, commercial and/or industrial customers usually within the boundaries of the municipality.

National Ambient Air Quality Standards (NAAQS)
Ambient air quality standards developed by EPA to represent the maximum pollutant concentrations that are allowable in ambient air.

New Source Review (NSR)
A complex set of EPA regulations that govern the construction of new pollution sources and modifications or expansions of existing sources.

Nuclear Regulatory Commission (NRC)
The federal agency that regulates nuclear power plants in the United States, particularly focused on reactor safety, nuclear waste management and license renewal of existing plants.

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. Defined by particle size: PM10 = particles smaller than 10 microns in diameter and PM2.5 = particles smaller than 2.5 microns.

Peak demand
The maximum demand on an electric system in a designated period of time (e.g., over a year, a month, or a season).

Peaking plants
Power plants that operate for a relatively small number of hours, usually during peak demand periods. Such plants usually have high operating costs and low capital costs.

PJM Interconnection, LLC (PJM)
A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states, including Maryland, and the District of Columbia.

Power Plant Research Program (PPRP)
A subdivision of the Maryland Department of Natural Resources, PPRP functions to ensure that Maryland meets its electricity demands at reasonable costs while protecting the state's valuable natural resources. It provides a continuing program for evaluating electric generation issues and recommending responsible, long-term solutions.

Pozzolan
A type of material that, when added in the process of mixing cement, improves the strength of the resulting solid. Fly ash, a coal combustion byproduct, has pozzolanic properties making it suitable for beneficial use in certain cement industry applications.

Prevention of Significant Deterioration (PSD)
In attainment areas, EPA's New Source Review program is referred as PSD.

Processed refuse fuel (PRF)
Fuel derived from residential, commercial and nonhazardous industrial waste, which can be burned to produce energy.

Radionuclides
Naturally occurring or manmade atoms with an unstable nucleus that undergoes radioactive decay, emitting gamma rays or subatomic particles.

Regional Greenhouse Gas Initiative (RGGI)
The first cap-and-trade regulatory program to reduce greenhouse gas emissions in the United States. (See Section 5.1.5)

Reliability councils
Regional organizations formed by the electric utilities to coordinate utilities' generation and transmission systems and monitor the availability of electric services.

Renewable energy
Sources of energy that are continually being replaced such as energy from the sun (solar), wind, geothermal and hydroelectric.

Renewable Portfolio Standard (RPS)
A standard adopted in Maryland requiring that a portion of the electricity supply comes from renewable resources.

Retail competition
Permitting end-use customers to contract directly with suppliers for their electric or gas service, while transmission and distribution companies provide for delivery of the service.

Reserve margin
Total system generating capacity minus annual system peak demand, divided by the annual system peak demand, expressed as a percent.

Right-of-way
A defined pathway owned or legally established for the use of utilities, vehicles or pedestrians, such as for transmission lines or roadways.

Self-generator
A generating facility that consumes most or all of the electricity it produces to meet onsite power demand.

Shale gas
Natural gas trapped in deep, fine-grained rock formations; recovered using horizontal drilling and hydraulic fracturing methods.

Smart grid
A type of electrical grid system that attempts to predict and intelligently respond to the behavior of electric power users connected to it in order to supply reliable and economically viable electricity.

Soil Compaction
Physical consolidation of the soil that destroys structure, reduces porosity, limits water and air infiltration, and increases resistance to root penetration, usually resulting in reduced crop yield.

Solar photovoltaic (solar PV)
Type of renewable energy created by converting solar radiation into electricity using semiconductors.

Standard offer service (SOS)
Electricity service that is provided to customers who do not choose an electricity supplier. Maryland's SOS service is based on competitive wholesale market rates.

Time of use rates
A utility rate structure that charges higher rates during peak hours of the day to shift peak period demand to off-peak hours.

Transmission
The process of delivering electricity from generation plants to entities that serve loads.

Volt
A unit of electrical pressure; 1 kilovolt (kV) = 1,000 volts.

Waste-to-energy (WTE)
An electricity generating facility that combusts municipal solid waste in order to heat boilers and create high pressure steam.

Watt
The electrical unit of power or rate of doing work; 1 kilowatt (kW) = 1,000W; 1 megawatt (MW) = 1,000,000 watts; 1 gigawatt (GW) = 1,000,000,000 watts.

Watt-hour
An electric energy unit of measure that is equal to 1 watt of power supplied or taken steadily from an electric circuit for 1 hour; 1 kW-hour (kWh) = 1,000 watt-hours.

Wetlands
Areas of land that form the interface between terrestrial and aquatic ecosystems.

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