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PPRP

Long-term Electricity Report for Maryland

December 2016

MARYLAND POWER PLANT RESEARCH PROGRAM

LARRY HOGAN, GOVERNOR
BOYD RUTHERFORD, LT. GOVERNOR

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

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

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Long-Term Electricity Report for Maryland

Prepared for the
Maryland Department of Natural Resources
Power Plant Research Program
Pursuant to Executive Order 01.01.2010.16

Prepared by
Exeter Associates, Inc.

December 2016

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Introduction

Executive Order 01.01.2010.16 (EO) was signed by then-Governor Martin O'Malley on July 23, 2010, directing the Maryland Department of Natural Resources' (DNR) Power Plant Research Program (PPRP) to prepare the Long-term Electricity Report for Maryland (LTER).[1] The purpose of the LTER is to provide a comprehensive assessment of approaches to meet Maryland's long-term electricity needs given the State's many challenges for providing a sustainable energy future through clean, reliable, and affordable power for all Marylanders. To address the issues set forth in the EO, PPRP assessed future electric energy and peak demand requirements for Maryland over the 20-year period from 2015 through 2035. Meeting those needs was assessed under an array of alternative future economic, legislative, and market conditions. Assessment of the alternatives is based on:

- Feasibility;
- Cost and cost stability;
- Reliability;
- Environmental impacts;
- Land use impacts;
- Consistency with the State's energy and environmental laws; and
- Consistency with federal energy and environmental laws.

To conduct the analysis, an LTER Reference Case was developed along with alternative scenarios to allow estimation of the implications of different economic, regulatory, and infrastructure conditions over the course of the 20-year study period. The Reference Case is based on a set of assumptions and projections assessed as a plausible view of the current situation. The alternative scenarios include specific assumptions and projections different from those contained in the Reference Case. These scenarios facilitate the isolation of the potential impacts of significant policy changes and external factors (such as natural gas prices and load growth) that could affect costs, emissions, the scheduling of new power plant development, fuel use, the types of power plants added to the capacity portfolio, fuel diversity, land use, and other results.

Table ES-1 summarizes the alternative scenarios considered for this analysis. The list of scenarios reflects PPRP's initial proposals to the Power Plant Research Advisory Committee (PPRAC), which provided comments and feedback on the initial proposals and suggestions for additional alternative scenarios. PPRAC is an advisory body to the Secretary of the DNR. PPRAC members are appointed by the Secretary and include representatives from State government agencies, environmental

[1] A copy of the Executive Order is included as Appendix A.

organizations, Maryland electric utilities, Maryland natural gas companies, independent power producers (IPPs), and others.

It should be emphasized that the fundamental purpose of this report is to provide Maryland policymakers with an assessment of estimated impacts on Maryland's electric power sector resulting from a wide range of possible future circumstances. The report should not be interpreted as a policy document or an integrated resource plan.

The outcomes of the Reference Case, as well as those of the alternative scenarios, are highly dependent upon the assumptions and projections used to develop the scenarios. While these assumptions and projections represent plausible scenarios, the outcomes (i.e., results) could change significantly if real-world experience differs from the projections. Additionally, the modeling scenario results represent a narrow evaluation focusing primarily on economic and environmental issues. There may be benefits that accrue to end-use customers (and Maryland residents at large) that are not fully captured by such a model. These benefits include, but are not limited to, overall economic development, and improvements in public health, welfare, and quality of life. In addition to unidentified and unquantified benefits, there may also be unidentified and unquantified costs. Those costs may include the costs of implementing energy conservation and efficiency initiatives, the cost of transmission system expansion, and the monetary costs associated with higher levels of renewable energy portfolio requirements.

Over the course of 20 years, there may also be substantial technological advances that would affect the modeling results in a variety of ways. Advances in renewable energy technologies, for example, could serve to significantly reduce the cost of renewable energy on a per-kilowatt-hour (kWh) basis over the life of the renewable project; advances in plug-in electric vehicles (PEVs) (or the supporting infrastructure) could provide for the use of PEVs as decentralized storage devices, and significantly increase growth in system load; and advances in emissions control technologies could result in lower rates of emissions at reduced cost. Speculation on potential technological advances over the 20-year study period, however, is beyond the scope of this analysis. As technological advances emerge, they will be captured in subsequent cycles of the LTER. The EO specifies that an LTER analysis be conducted not later than every five years.

Table ES-1 LTER Scenarios

Category	Scenario	Description
Reference Case	Reference Case Assumptions	See Table ES-2.
Natural Gas Price Alternative Scenarios	Low Price Natural Gas (LPNG)	Natural gas price assumption lowered so it reaches a price of approximately $3.45 per million British thermal units (MMBtu) in 2035, other Reference Case assumptions unchanged.
	High Price Natural Gas (HPNG)	Natural gas price assumption increased so it reaches a price of approximately $8/MMBtu in 2035, other Reference Case assumptions unchanged.
Load Growth Alternative Scenarios	Low Load Growth (LL)	Load growth rate lowered by 0.5 percentage points per year, other Reference Case assumptions unchanged.
	High Load Growth (HL)	Load growth rate increased by 0.5 percentage points per year, other Reference Case assumptions unchanged.
Climate Change Alternative Scenarios	Climate Change	PJM December 2015 Base Case Load Forecast adjusted for a 2.82°F increase for the summer months and a 2.65°F increase for the winter months by 2031, other Reference Case assumptions unchanged.
Alternative RPS Scenarios	Moderate Maryland Renewables	Maryland RPS reaches 25 percent by 2020 met with in-State renewable energy development, including a 2.5 percent solar carve-out, other Reference Case assumptions unchanged.
	High Maryland Renewables	Maryland RPS reaches 35 percent by 2030, including a 3 percent solar carve-out, other Reference Case assumptions unchanged.
	Moderate PJM Renewables	Each PJM state (including Maryland) reaches 25 percent renewable consumption by 2020, including a 2.5 percent solar carve-out, other Reference Case assumptions unchanged.
National Clean Power Plan Scenario	Clean Power Plan (CPP)	Reference Case assumptions modified to facilitate national compliance (including Maryland's compliance) with the current (though contested) version of the CPP, and rely on enhanced energy efficiency and conservation investment; enhancements to the transmission infrastructure to facilitate flows of renewable energy; increases in renewable energy capacity and production; enhanced emission controls; least-cost dispatch modification; and lower fuel prices (natural gas and coal).
Early Coal Plant Retirements	Early Coal Plant Retirements (ECPR)	Five coal plant units that submitted notifications of retirement to PJM, later rescinded, are assumed to retire in 2018, other Reference Case assumptions unchanged.
	NOx Emissions Compliance	MDE anticipates that eight coal plant units retire by 2020 based on the implementation of enhanced NOx regulations which were introduced in Maryland in 2015, other Reference Case assumptions unchanged.
PPRAC-Identified Additional Scenarios	Very High Maryland Renewables	Maryland reaches 50 percent renewable consumption by 2030, including a 5 percent solar carve-out, other Reference Case assumptions unchanged.
	Alternative CPP Scenario	This scenario is a modification to the CPP scenario that includes closure of several Maryland coal plants by 2020.

For each scenario, including the Reference Case, model simulations were run. The assumptions and projections required as inputs into the model include:

- Energy consumption and peak demand;
- Power plant operating characteristics [operating costs, capacity, fuel, heat rate, capital costs, and emission rates for carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury] for all existing power plants and generic power plant types that the model may select for addition to the portfolio of power plants on a least-cost basis;
- Data related to the configuration and carrying capacity of the electric transmission system;
- Quantitative reliability requirements;
- Regulatory environment [state renewable energy portfolio standards (RPS's), environmental restrictions on (or allowance prices for) specific pollutants];
- Fuel prices (natural gas, coal, oil, uranium);
- Power plant retrofit costs;
- Quantity, location, and type of renewable generating capacity constructed;
- Capacity factors for renewable generating facilities; and
- Certain other assumptions and projections.

A summary of the key assumptions and projections for the Reference Case is presented in Table ES-2. The key assumptions and projections for the alternative scenarios that differ from the Reference Case are included in the scenario descriptions contained in Table ES-1.

All of the key modeling input assumptions, for both the Reference Case and the alternative scenarios, were presented to the PPRAC and the PPRAC LTER Working Group (Working Group).

PPRP received comments from both PPRAC members and the Working Group members, which proved to be extremely helpful in developing the LTER. To the maximum extent possible, PPRP employed a transparent process in developing the LTER to facilitate meaningful input from PPRAC and the Working Group.

Table ES-2 Summary of Key Assumptions and Projections for the LTER Reference Case

Assumption/Projection Issue	Description
Energy and Peak Demand Forecast	PJM's December 2015 Base Case forecast for energy and peak demand was relied upon. The forecasts reflect adjustment for demand response, energy efficiency, and behind-the-meter solar generation.
Transmission Infrastructure	The transmission infrastructure includes all PJM transmission lines, and transmission lines in other regions, in place in 2015.
Natural Gas Prices	Average PJM natural gas prices are projected to increase from approximately \$2.00/MMBtu in 2015 (2015\$) to approximately \$5.50/MMBtu in 2035 (2015\$). (Note: Alternative scenarios address higher and lower natural gas price projections.)
Coal Prices	Coal prices (delivered) vary by transmission zone over the 20-year forecast period, but in general remain relatively flat, increasing, on average, by approximately \$0.75/MMBtu over the 20-year forecast period on an average base year price of approximately \$2.35/MMBtu.
Wind Power Capacity Factors	On-shore and off-shore wind turbines are assumed to operate at a 30 percent capacity factor and a 40 percent capacity factor, respectively.
Solar Power Capacity Factor	Photovoltaic (PV) systems are assumed to operate at a 15 percent capacity factor.
Wind Power Construction Costs	On-shore and off-shore wind projects are assumed to have an overnight construction cost in 2015 dollars of \$1,800 per kilowatt (kW) and \$4,260/kW, respectively.
Nuclear Power Plant Construction Costs	New nuclear generation facilities are assumed to have an overnight construction cost of \$5,800/kW (2015\$).
Financial Assumptions	The debt/equity ratio for new power plants is assumed to be 50 percent debt and 50 percent equity; the nominal cost of debt is assumed to be 7 percent; the nominal cost of equity is assumed to be 12 percent; and the annual inflation rate is assumed to be 2.5 percent.
Renewable Energy Portfolio Standard	It is assumed that Maryland will meet its solar, Tier 1, and Tier 2 RPS requirements through the retirement of Renewable Energy Credits.
Environmental Regulations	EPA's existing regulations (the Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard, and New Source Performance Standards) are integrated into the model. Additionally, the model recognizes the Regional Greenhouse Gas Initiative and Maryland's Healthy Air Act.

Key Results

The results of the model runs include, but are not limited to, information on power plant additions and retirements; fuel consumption by fuel type; emissions from Maryland generation and, alternatively, by Maryland energy consumption; wholesale energy and capacity prices; REC prices; and net imports of energy for each of the transmission zones. The modeling was conducted using the ABB Energy Portfolio Management (EPM) Integrated Power Model (ABB Model), developed by ABB. The ABB Model is a set of models designed to reflect the market factors affecting power prices, emissions, generation, power plant development (and retirements), fuel choice, and other power market characteristics. The ABB Model is a zonal model, which separates the PJM region (and other regions in North America) into distinct zones based on transmission paths and electric utility service territories. In the ABB Model, different portions of Maryland are in three different zones—PJM Mid-Atlantic Southwest (PJM-SW), PJM Mid-Atlantic East (PJM-MidE), and PJM Allegheny Power Systems (PJM-APS).[2] Some of the modeling results, therefore, are at the zonal level.

General Results

Several conclusions can be drawn from the body of results over all of the scenarios analyzed in the LTER. The general findings include:

- For all scenarios, no new generation capacity is needed in PJM to meet reliability requirements until 2019, including the High Load Growth scenario.

- For most scenarios, no new generation capacity is needed in Maryland to meet reliability requirements until 2020. The most rapid load growth assumption entails new generation needed in Maryland by 2019.

- Based on least-cost criteria, all new plants added by the model for reliability are fueled by natural gas under all scenarios.

- The price of natural gas is the most important factor affecting energy prices.

- Under most scenarios, fuel diversity in PJM increases over time as more natural gas plants and renewables are added to the supply mix. Under the High Load Growth scenario, the large increases in natural gas generation to meet reliability under assumptions of higher load levels actually result in a reduction in diversity as the percentage of generation from natural gas increases (which also reflects the loss of certain nuclear capacity). Similarly, under the Low Price Natural Gas scenario, we have the same result for the same reasons, that is, lower fuel diversity due to much higher reliance on natural gas generation.

- With respect to criteria air emissions (NOx, SO_2, and mercury), the PJM fleet as a whole slightly increases emissions over time in most scenarios. The most significant exception to this is the Low Price Natural Gas scenario, in which emissions remain flat or slightly decrease.

[2] PJM-SW includes Baltimore Gas & Electric Company (BGE); Potomac Electric Power Company (Pepco) (both Maryland and Washington, D.C. service territories); and the Southern Maryland Electric Cooperative (SMECO). PJM-MidE contains all of New Jersey; Delmarva Power & Light (DPL) (both Maryland and Delaware territories); Old Dominion Electric Cooperative (ODEC); and PECO Energy Company. PJM-APS covers the entire Allegheny Power System footprint which includes Western Maryland, West Virginia, and parts of Pennsylvania and Virginia.

- For all scenarios but one, the Maryland Healthy Air Act (HAA) limits for SO_2, NOx, and mercury are met. For the High Price Natural Gas scenario, NOx emissions exceed the HAA limits in 2029 and mercury emissions exceed the cap in 2030.
- Consumption-based CO_2 emissions are most importantly affected by the price of natural gas and the aggressiveness of the RPS.
- Increases to the Maryland RPS on a stand-alone basis do not result in significant reductions in emissions from fossil-fuel plants in the State or in PJM as a whole. The reason for this is that Maryland's generation fleet is operated to serve PJM loads, not exclusively Maryland loads. Increases in Maryland's RPS, therefore, do not materially affect the generation from Maryland's power plants.
- Increases to the Maryland RPS in conjunction with corresponding increases to the RPS's in place in other PJM states results in significant reductions to emissions from fossil fuel-fired generation in PJM.

LTER Reference Case Results

- No new generating capacity is added in PJM to meet reliability requirements before 2019. Between 2015 and 2035, PJM adds approximately 44,000 MW of new natural gas-fired capacity and 8,700 MW of renewable generating capacity.
- Based on least-cost criteria, all new generating capacity projected to be constructed to satisfy reliability requirements will be fueled by natural gas. Renewable generating capacity is also added during the 20-year study period to meet RPS requirements in Maryland and other states.
- Emissions of SO_2, NOx, and mercury from Maryland power plants subject to Maryland's HAA remain below the HAA caps for those pollutants throughout the 20-year study period.
- Emissions of CO_2 exceed Maryland's budget under the Regional Greenhouse Gas Initiative (RGGI) beginning in 2020, which will require some Maryland generation facilities to purchase RGGI emissions allowances from other RGGI states and/or purchase offsets in order for the State to comply with its RGGI commitments.[3]
- Real energy prices are projected to increase approximately 3 percent per year through 2035. The most rapid growth in prices occurs between 2016 and 2022, after which growth slows until the end of the projection period. The growth in electricity prices corresponds to the growth in natural gas prices. The most rapid growth in electric prices occurs in the PJM-MidE zone, due to an apparent increase in electric transmission congestion at the very end of the analysis period.

[3] RGGI is scheduled to expire in 2019. The LTER includes the assumption that RGGI will be extended (at 2019 levels) through the end of the 20-year analysis period.

- Capacity prices can increase or decrease significantly from year to year and vary by transmission zone. In PJM-SW and PJM-MidE, capacity prices generally decline after 2020, following sharp increases between 2018 and 2020. Prices appear to converge at the end of the period at about $220 per megawatt, per day (MW-day) for PJM-APS and PJM-MidE. Capacity prices in PJM-SW, which approach $275/MW-day in the final year of the analysis, exhibit low capacity prices (below $120/MW-day) for several years in the early 2030s. The increase in capacity prices in PJM-SW may be related to localized tightening of reserves given that no new natural gas capacity is constructed in that zone after 2020.

ALTERNATIVE SCENARIO RESULTS

Capacity Additions

- Under assumptions of High Load Growth over the study period, PJM adds approximately 67,000 MW of new gas-fired generating capacity compared to 44,000 MW in the Reference Case.
- Under assumptions of Low Load Growth over the study period, PJM adds approximately 24,000 MW of new gas-fired capacity compared to 44,000 MW in the Reference Case.
- The Climate Change scenario assumptions result in PJM natural gas plant additions of 55,000 MW.
- The scenarios based on the assumption of Maryland's adoption of a more aggressive RPS only have a minor impact on new natural gas generating capacity in PJM.
- Under the Early Coal Plant Retirement and NOx Emissions Compliance scenarios, net imports into PJM-SW are modestly higher than in the Reference Case, as plants outside the region help to compensate for the early coal plant retirements.

Energy Prices

- Wholesale energy prices under most alternative scenarios are generally consistent with the Reference Case energy prices with two exceptions—the natural gas price scenarios and the CPP scenario. Under the other alternative scenarios, wholesale energy prices vary only marginally from the Reference Case energy prices.
- Under assumptions of High Price Natural Gas, all-hours wholesale energy prices by 2035 are approximately $16.50 per megawatt-hour (MWh) (2015$) higher across the Maryland zones than in the Reference Case.
- Under assumptions of Low Price Natural Gas, all-hours wholesale energy prices by 2035 are approximately $14/MWh (2015$) lower across the Maryland zones than in the Reference Case.

- Under the CPP assumptions, all-hours wholesale energy prices are approximately equal to the Reference Case energy prices in 2035, but are lower by up to $5/MWh compared to the Reference Case prices during some years of the second half of the 20-year forecast period.

Maryland Emissions Based on Maryland Generation

- Under almost all of the scenarios considered, in-State emissions of SO_2, NOx, and mercury are below the caps imposed by Maryland's HAA. The exception is the High Price Natural Gas scenario, which results in NOx and mercury emissions exceeding the HAA limitations in the last five to six years of the analysis period.

- In-State CO_2 emissions vary by scenario. In general, CO_2 emissions exceed Maryland's budget under RGGI during the course of the study period starting in 2020.

- The introduction of the CPP reduces CO_2 emissions in Maryland by approximately 20 percent (relative to the Reference Case emissions) averaged over 2015 to 2017. For several years, CO_2 emissions in Maryland increase as Maryland coal plants run more intensively to compensate for plants in other zones running less or retiring. Beginning in 2024, CO_2 emissions in Maryland decline under the CPP scenario relative to the Reference Case. Between 2020 and 2035, CO_2 emissions in Maryland are above the RGGI budget in all but five years.

- Under the High Load Growth assumptions, emissions of CO_2 in Maryland increase relative to the Reference Case by approximately 14 percent by 2035. Under the Low Load Growth assumptions, there is a significant reduction in CO_2 emissions in Maryland relative to the Reference Case beginning in 2018; by 2035, that decrease reaches 12 percent.

- The High Renewables scenarios, which entail increased RPS obligations on Maryland only, result in virtually no difference in Maryland CO_2 emissions from Maryland power plants relative to the Reference Case.

Maryland Emissions Based on Maryland Consumption

- Emissions of SO_2, NOx, mercury, and CO_2 are highest (relative to the Reference Case) under the High Load Growth scenario and the High Price Natural Gas scenario.

- The lowest levels of assumption-based emissions are associated with the aggressive RPS scenarios and the CPP scenario.

Fuel Diversity

- For most scenarios, Maryland's fuel diversity increases over the course of the 20-year study period as the share of coal-fired generation declines and the proportion of generation relying on natural gas increases. For the High Load Growth scenario, fuel diversity decreases as natural gas generation assumes a larger share of total generation. The same result emerges under the Low Price Natural Gas, ECPR, and NOx Emissions Compliance scenarios.

- The greatest increases in fuel diversity are related to the scenarios that include high levels of renewables development.

Capacity Prices

- In general, capacity prices increase when capacity becomes tight in a zone, and decline following the introduction of a new power plant.

- Capacity prices tend to be relatively low in the early years of the study period, which reflects actuals through 2019. Capacity prices then increase as the need for new generating capacity increases and plants begin to be built within the model. For both the PJM-APS and PJM-MidE zones, the capacity prices tend to flatten after 2020, though there is substantial year-to-year variation. In PJM-SW, capacity prices peak in 2021 and then generally decline throughout the period. This pattern is consistent with the Reference Case, the High and Low Price natural gas scenarios, the High and Low Load Growth scenarios, the Climate Change scenario, the alternative RPS scenarios, the CPP scenario, the ECPR scenario, and the NOx Emissions Compliance scenario. There is a general tendency for the capacity prices among zones to converge towards the end of the study period, and gravitate towards values that approximate the cost of new power plant entry.

- The CPP scenario, which entails significantly reduced levels of new plant construction in conjunction with high renewable capacity development and reduced loads due to more aggressive energy efficiency initiatives in certain states results in substantially lower capacity prices in all three zones over much of the middle years of the analysis period.

- The Low Load Growth scenario, while following the same general trends as the Reference Case, exhibits capacity prices that tend to be well below the Reference Case capacity prices in all zones for significant portions of the analysis period.

Land Use

- Land-use requirements on a per-MW-of-installed-capacity basis are significantly higher for on-shore wind and solar than for nuclear and natural gas-fired capacity.

- Land-use requirements for on-shore wind capacity on a per-MW basis including setback and spacing requirements are approximately ten times higher than for solar capacity.

- Maryland land-use requirements for most scenarios are below 20,000 acres for all new generating capacity over the 20-year study period, assuming that 25 percent of new land-based wind generation needed to meet the Maryland RPS is located in Maryland, all solar generation needed to meet the Maryland RPS located in Maryland, and both the solar and wind generation require five acres of land per MW of installed capacity. For the 35 percent Maryland RPS scenario (with 3 percent solar carve-out) and the 50 percent Maryland RPS scenario (with 5 percent solar carve-out), between 23,000 and 33,000 acres are required.

- Maryland land-use requirements for most scenarios are below 100,000 acres for all new generating capacity over the 20-year study period, assuming that 25 percent of new land-based wind generation needed to meet the Maryland RPS is located in Maryland, all solar generation needed to meet the Maryland RPS is located in Maryland, solar requires eight acres of land per MW of installed capacity, and wind generation facilities require 60 acres of land per MW of installed capacity (which includes separation and setback requirements). For the 35 percent Maryland RPS scenario (with a 3 percent solar carve-out) and the 50 percent Maryland RPS scenario (with a 5 percent solar carve-out), between 137,000 and 198,000 acres are required.

Renewable Energy Credit Prices

- Under the Reference Case, the High and Low Load Growth scenarios, the aggressive RPS scenarios, the ECPR scenario, and the NOx Emissions Compliance scenario, Tier 1 Renewable Energy Credit (REC) prices (not specific to Maryland) are estimated to range between less than $1 per REC to $22 per REC (2015$). RECs prices increase from current market values through 2021, then gradually decline to less than one dollar at the terminal year of the study period. The maximum REC prices correspond to the time that the maximum RPS requirements tend to be reached in PJM states having RPS requirements.

- For the High Price Natural Gas scenario, which entails significantly higher energy prices than projected for the Reference Case, the projected REC prices (2015$) are lower than in the Reference Case REC prices and drop to less than one dollar toward the end of the study period. The maximum REC price under the High Price Natural Gas scenario is just below $17 in 2019 and 2020 compared to over $20 under the Reference Case set of assumptions. The reason for this result is that the estimation of RECs prices is based, in part, on the residual revenue required by a new renewable energy project to cover all costs of ownership and operation. Revenue sources include energy revenue, capacity revenue, and the federal Production Tax Credit (PTC). Higher market prices for energy, therefore, result in a smaller residual revenue requirement that would need to be recovered through REC prices.

- The Low Price Natural Gas scenario results in the highest projected REC prices due to the low energy prices projected for this scenario. REC prices under this scenario reach almost $28 in 2021, then gradually decline over the analysis period. By the end of the period, however, RECs prices remain above $11.00.

Summary

Table ES-3 ranks the emissions, fuel diversity, and generic natural gas capacity builds across the scenarios. Table ES-3 ranks the total NOx, SO_2, and CO_2 emissions from PJM generation units in each scenario (columns 1, 2, and 3). The ranking of the emissions across the three pollutants is generally stable, and scenarios with relatively high CO_2 emissions typically also have high NOx and SO_2 emissions. The fourth column in Table ES-3 ranks the fuel diversity indices across scenarios. The fuel diversity index is a measure of the mix of fuels used to generate electricity in PJM. A higher fuel diversity index (which has a maximum value of 1.0) indicates greater fuel diversity.

The last column of Table ES-3 ranks the total generic natural gas capacity (in MW) that was added by the model in PJM to satisfy load and reliability requirements. The two scenarios that entail higher load levels (the High Load Growth scenario and the Climate Change scenario), as well as the CPP, ECPR, and NOx Emissions Compliance scenarios (which entail significant coal plant closures) involve high levels of generic natural gas capacity additions.

Table ES-4 provides the same ranks for Maryland as Table ES-3, which is applicable to PJM as a whole. While the two sets of rankings are not identical, the same factors affect the rankings to provide similar results.

Table ES-3 PJM-wide Summary Statistics by Scenario

	Total SO_2 Emissions	Total NOx Emissions	Total Mercury Emissions	Total CO_2 Emissions	2035 Fuel Diversity Index*	Total Gas Capacity Built
LTER 2016 Reference Case	●	●	●	●	◑	●
High Price Natural Gas Price	●	●	●	●	◑	●
Low Price Natural Gas Price	○	○	○	○	○	◑
High Load Growth	●	●	●	●	○	●
Low Load Growth	◑	◑	◑	○	●	◑
Climate Change	◑	●	●	●	○	●
MD Moderate Renewable (25% RPS)	◑	●	◑	●	◑	◑
MD High Renewable (35% RPS)	●	◑	●	◑	●	○
MD Very High Renewable (50% RPS)	◑	◑	◑	◑	●	○
PJM Moderate Renewable (25% RPS)	○	○	○	○	●	○
Clean Power Plan	○	○	○	○	●	○
Early Coal Plant Retirement	●	◑	◑	◑	◑	◑
NOx Emissions Compliance	○	○	○	◑	○	●
	● = top third		◑ = middle third		○ = bottom third	

* Fuel diversity indices are ranked as follows:
● = < 0.965
◑ = ≥ 0.966 and ≤ 0.977
○ = > 0.978

Table ES-4 Maryland-wide Summary Statistics by Scenario

	Total SO_2 Emissions	Total NOx Emissions	Total Mercury Emissions	Total CO_2 Emissions	2035 Fuel Diversity Index*	Total Gas Capacity Built
LTER 2016 Reference Case	●	●	●	●	◑	◑
High Price Natural Gas Price	●	●	●	●	○	◑
Low Price Natural Gas Price	○	○	○	○	●	◑
High Load Growth	●	●	●	●	○	●
Low Load Growth	○	◑	◑	○	○	○
Climate Change	●	●	●	●	◑	●
MD Moderate Renewable (25% RPS)	●	●	●	●	◑	◑
MD High Renewable (35% RPS)	◑	◑	◑	◑	◑	◑
MD Very High Renewable (50% RPS)	◑	◑	◑	◑	●	○
PJM Moderate Renewable (25% RPS)	◑	◑	◑	◑	○	○
Clean Power Plan	○	○	○	◑	●	●
Early Coal Plant Retirement	◑	○	○	○	●	●
NOx Emissions Compliance	○	○	○	○	●	●
	● = top third		◑ = middle third		○ = bottom third	

* Fuel diversity indices are ranked as follows:
● = < 0.884
◑ = ≥ 0.885 and ≤ 0.893
○ = > 0.894

1. INTRODUCTION

1.1 Purpose of Report

Executive Order (EO) 01.01.2010.16 directs the Maryland Department of Natural Resources' (DNR) Power Plant Research Program (PPRP) to develop a long-term electricity report (LTER) for the State of Maryland, and then update it at least every five years. The principal purpose of the LTER is to provide a comprehensive assessment of approaches to meet the long-term electricity needs of Marylanders through clean, reliable, and affordable power. The LTER does not present policy recommendations, and the scenarios developed for analysis should not be interpreted as recommended policies. The LTER provides policymakers with the anticipated effects of both alternative policies and external (non-policy-related) factors such as high and low natural gas prices, high and low growth in electric loads, and climate change. The LTER should be viewed neither as an energy plan for the State nor as an integrated resource planning document.

This report represents the first full update to the original LTER, which was published in December 2011. To satisfy the purpose of the EO and to meet the requirements set forth therein, PPRP assessed future electricity and peak demand needs for Maryland over the 20-year period from 2015 through 2035. Various methods to meet these needs were assessed under an array of alternative future economic, legislative, and market conditions. PPRP's assessment of the identified alternatives is based on:

- Feasibility;
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- Consistency with the State's energy and environmental laws; and
- Consistency with federal energy and environmental laws.

There are inherent trade-offs among certain evaluation criteria elements. For example, enhancing reliability typically entails increased costs due to either increased generation capacity for a given level of peak demand or increased transmission capacity to permit greater importation of power. Similarly, minimizing adverse environmental impacts may also entail higher costs in the short term, as renewable energy generation tends to be more expensive than conventional generation (fossil fuels). Policymakers may determine, however, that any short-term cost impact from renewable energy generation may ultimately be balanced by the long-term benefits of improved health, price stability, energy diversity, and reduced emissions.

To develop this report, including the identification of the input assumptions needed to conduct the technical analysis, PPRP consulted with a spectrum of interested parties, principally through interactions with the Power Plant Research Advisory committee (PPRAC). The committee includes representation from the following:

- State agencies and offices including the Maryland Energy Administration (MEA), the Maryland Department of the Environment (MDE), and the Maryland Office of People's Counsel (OPC);
- PJM Interconnection, LLC;
- Maryland's electric distribution companies;
- Competitive retail electricity suppliers;
- Wholesale electricity suppliers;
- Natural gas companies;
- Renewable electricity generators;
- Energy service companies specializing in demand response;
- Organizations representing environmental interests; and
- Organizations representing consumer interests.

The input provided by these organizations was valuable throughout the scoping and analysis phases of modeling and also throughout the process of drafting the LTER. A list of PPRAC members and interested parties is provided in Appendix B.

1.2 Approach Overview

The steps taken to fulfill the EO are outlined below. A more detailed description is contained in later chapters of this report.

Step 1. Identify current and planned electric generating capacity and transmission system capabilities. The data developed for this step were used to assess the magnitude of the gap between electric energy and peak demand requirements for Maryland and the amount of electric energy and capacity available to meet those requirements. Current aggregate generating capacity is defined herein as the portfolio of power plants presently operating or available to operate within Maryland (i.e., existing plants) and those projects for which all air permits have been obtained and construction has begun as of mid-2015 (i.e., planned capacity). Current generating capacity is also adjusted downward to reflect announced retirements of specific power plants.

The transmission system infrastructure included in this analysis represents the PJM system as of 2015. The transmission system is represented as transmission transfer capabilities between transmission zones.[4]

Energy and demand requirements were based on the most recent PJM annual forecast of peak demand and energy, which was published in December 2015. PJM adjusts its peak demand and energy forecasts to reflect the expected impacts of behind-the-meter solar generation and state-level energy conservation and efficiency programs.

Step 2. Define an LTER Reference Case (Reference Case) and alternative scenarios to estimate the implications of different economic and regulatory conditions over the course of the 20-year study period. The Reference Case represents current regulatory and economic conditions, including existing renewable energy portfolio requirements, energy conservation and efficiency programs, and environmental legislation. For the Reference Case, forecasted inputs such as load levels and fuel prices are based on projections assessed to be the most plausible. The alternative scenarios were developed to assess the impacts and implications of potential policy changes or external factors that could emerge over the 20-year study period and affect projected costs, emissions, scheduling of new power plant development, fuel-use, types of power plants that are added to the capacity portfolio in future years, fuel diversity, Renewable Energy Credit (REC) prices, and other results. The alternative scenarios reflect conditions that differ from those in the Reference Case. Alternative scenarios analyzed in this report include: (1) high natural gas prices; (2) low natural gas prices; (3) high load growth; (4) low load growth; (5) high and moderate renewables development in Maryland; (6) moderate renewables development throughout PJM; (7) rising temperatures due to climate change; (8) implementation of the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan (CPP); and (9) early coal plant retirements.

Step 3. Specify input assumptions for the Reference Case and all alternative scenarios. A wide range of input assumptions is required to fully and precisely define each of the scenarios considered (i.e., the Reference Case and all of the alternative scenarios). These assumptions include, but are not limited to: future fuel prices (natural gas, fuel oil, coal, and nuclear); plant variable and fixed operating costs; plant capital costs (including financing costs); load growth; the types and locations of renewable energy projects to be constructed in future years; the extent to which energy efficiency and conservation goals will be attained in terms of energy reductions and reductions in peak demand; power plant heat rates (the efficiency with which power plants convert the energy in fuel into usable electricity); power plant emission rates (for sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, and carbon dioxide (CO_2)); power plant outage rates due to maintenance and forced outages; and electric transmission system transfer capabilities between transmission zones.

Step 4. Obtain input and feedback from the PPRAC. The PPRAC was provided with the preliminary specifications of the Reference Case and the alternative scenarios, as well as the preliminary

[4] The method by which transmission system capabilities are reflected in the analysis is discussed in detail in Chapter 2, "Model Description."

modeling assumptions anticipated to be used for the analysis. To facilitate PPRAC's involvement, several meetings and webinars were held to explain the scenarios and the input assumptions. All comments from PPRAC members on the draft LTER were addressed and written responses to those comments are provided on the PPRP website.[5]

A subset of the PPRAC, referred to as the LTER Working Group, was formed to review and comment on the development and the results of the various scenario runs. The LTER Working Group included representatives from Maryland State agencies, environmental groups, Maryland electric distribution utilities, and electric generation owners. Input from the LTER Working Group was highly valuable in identifying additional alternative scenarios for analysis.

<u>Step 5. Conduct modeling test runs and evaluations</u>. After all of the scenarios were specified and the modeling input assumptions developed, preliminary modeling results were obtained on a scenario-by-scenario basis. The results were carefully reviewed to ensure that the models were appropriately handling the inputs and scenario specifications in the manner intended. This step involved a degree of iteration and some refinement of the input assumptions and scenario specifications to ensure proper coordination of the inputs with the requirements of the models.

<u>Step 6. Conduct modeling runs</u>. Once it was determined that the models were operating properly and correctly employing the input assumptions provided, the Reference Case and the alternative scenario runs were performed, outputs were analyzed and compared, summary tables and charts were developed, and a draft report was prepared.

<u>Step 7. Obtain public input and modify the analysis/report as needed</u>. Upon completion of the initial draft and draft final report, a notice of availability for public comment was placed in the *Maryland Register*. Further, public informational meetings were held to obtain input and feedback from as large an audience as possible. The comments received through the public review process were addressed and written responses were posted on the PPRP website. Where warranted, modifications were made to the draft report based on the comments received.

The following chapter, "Model Description," describes the model used, the inputs required by the model, and the outputs provided by the model. The chapter also discusses the limitations specific to the model.

[5] All presentation materials, comments, and responses are available at http://esm.versar.com/pprp/PPRAC/default.htm. Comments and responses are also included in Appendix M.

2. MODEL DESCRIPTION

2.1 Introduction

The results presented in this report are based on modeling conducted using the ABB Energy Portfolio Management (EPM) Integrated Model (ABB Model), developed by ABB. The ABB Model is an interpreted set of modules designed to reflect the market factors affecting power prices, emissions, generation, power plant development (and retirements), fuel choice, and other power market characteristics. This chapter describes the ABB Model and explains how it operates. In particular, this chapter explains how the model estimates energy and capacity prices, determines when new plants will be constructed and old plants retired, estimates electric energy production by fuel and by region, and estimates power plant emissions (CO_2, NOx, SO_2, and mercury).

2.2 Model Description

2.2.1 Overview of ABB Model

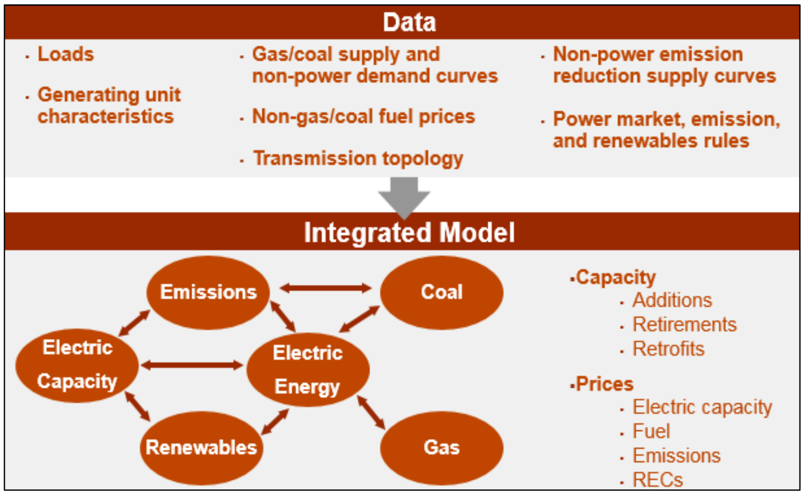
The ABB Fall 2015 Midwest Reference Case is the platform used for modeling the various scenarios in the LTER. The ABB Reference Case includes market-based forecasts of North American power,[6] fuel, emissions allowances, and Renewable Energy Credit (REC) prices that are internally consistent with one another as described below:

- Carbon allowance prices are internally consistent with the costs to control carbon emissions;
- Natural gas and coal prices are internally consistent with the carbon allowance prices, and the associated power-sector consumption of each fuel;
- Capacity additions, retirements, and retrofits are internally consistent with the allowance and fuel prices;
- Electric energy and capacity prices are internally consistent with the capacity additions, emission allowance costs, and fuel prices; and
- REC prices are internally consistent with state and multi-state renewable portfolio standards (RPS's) (if specified as a policy condition) and electric energy and capacity prices.

[6] The ABB Reference Case is ABB's baseline national projection. This projection differs from the LTER Reference Case which is based on certain Maryland-specific and PJM-specific data developed by PPRP, current legislation, and the most plausible projections of other relevant factors. The specifications of the LTER Reference Case scenario are detailed in Chapter 3, "Reference Case Modeling Assumptions."

Figure 2.1 summarizes the relationships among the ABB EPM forecasting modules. The data inputs and the modules themselves are described in the following sections.

Figure 2.1 Forecasting Process

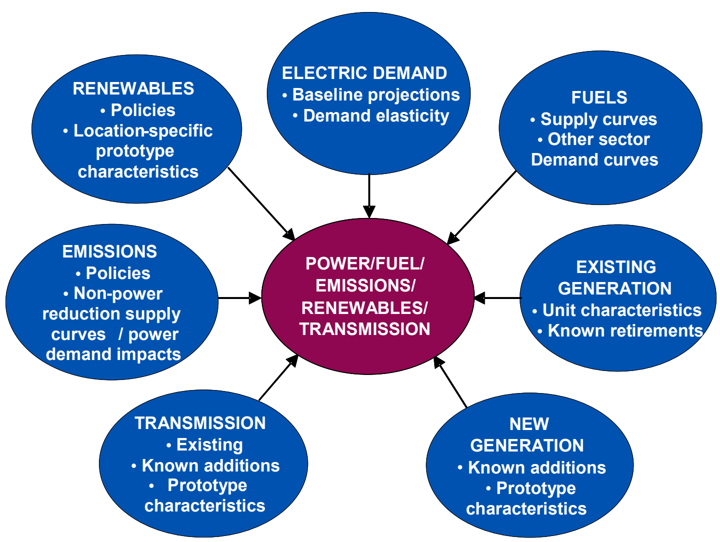


Source: ABB.

2.2.2 Data Inputs

The forecast process requires a significant amount of input data, as shown in Figure 2.2. The model is represented by the oval in the center; groups of data inputs are represented by the seven blue ovals in the periphery.

Figure 2.2 Forecasting Data Inputs



Source: ABB.

These data were assembled from the following sources:

- **Electric Demand** – The peak and energy forecasts are based on a combination of Federal Energy Regulatory Commission (FERC) Form 714 filings; Regional Transmission Organization (RTO) reports; and the U.S. Department of Energy, Energy Information Administration (EIA) *Annual Energy Outlook 2016* (AEO 2016). These forecasts are adjusted as necessary based on assumptions of new energy efficiency programs.[7]

- **Fuels** – The majority of the required data are drawn from ABB's EPM proprietary fuel forecasts. Information about pipeline expansion costs is from industry publications.

- **Existing Generation** – The majority of the required data are from ABB's Velocity Suite, a proprietary data set. Information about the costs to retrofit existing units with carbon capture and storage (CCS) capability, and the resulting impacts on plant operations, is derived from an engineering analysis conducted by ABB.

- **New Generation** – Data on planned additions are from ABB's Velocity Suite. Additional information on planned additions in Maryland was developed by PPRP. Information about the characteristics of prototype units is derived from industry research conducted by ABB and PPRP.

- **Transmission** – Data on the existing transmission system and proposed additions are based on industry research conducted by ABB and PPRP.

- **Emissions** – Information about policies is derived from publicly available literature.

- **Renewables** – Data on current generating plants are from ABB's Velocity Suite. Information about policies and the characteristics of prototype capacity additions is derived from publicly available literature and data, research conducted by ABB, and analysis conducted by PPRP.

With respect to generating resource additions, the ABB Model assumes that new generating capacity will enter the marketplace in two phases. In the first phase, called Initial Entry, all capacity that is currently under construction is assumed to be completed and brought online. Initial Entry for a renewable energy source is included if it is under construction or has received all permits. In the second phase, generic units are brought online to meet reliability needs. Renewable energy sources are added exogenously (i.e., input by the user) as necessary to meet state RPS requirements.

In order to meet future needs for new generating capacity, the ABB Model considers five types of generic conventional resources during the 20-year forecast period. New resources are added in

[7] For the LTER, PPRP substituted annual peak demand and energy forecasts created by PJM, as described in Chapter 3, "Reference Case Modeling Assumptions."

response to forecasted electric demand, whereby the added capacity is economically viable and the reserve margins are either in accordance with regional requirements or are sufficiently maintained to meet reliability standards. The five conventional resource types are: gas-fired combined cycle natural gas F-, G-, and H-Class (CCNG) and combustion turbine (CT) units; and nuclear.[8] In addition, renewable energy resources, including wind, photovoltaic (PV) solar, landfill gas, wood-fired biomass, and geothermal are added to meet expected state renewable energy requirements.[9] The model adds non-renewable capacity when doing so would result in a long-term equilibrium state for this capacity, based on expected profit opportunities. The "balanced" market that results is characterized by constant long-term reserve margins, relatively flat annual prices, and an annual profit level for new capacity sufficient to cover operational as well as fixed and financing costs.

Note that the ABB Model does not adjust electric loads for the price elasticity effects of changes in energy prices. Electric energy consumption and peak demand are model inputs and are not adjusted downward in response to increases in electric power prices or adjusted upward in response to decreases in electric power prices.

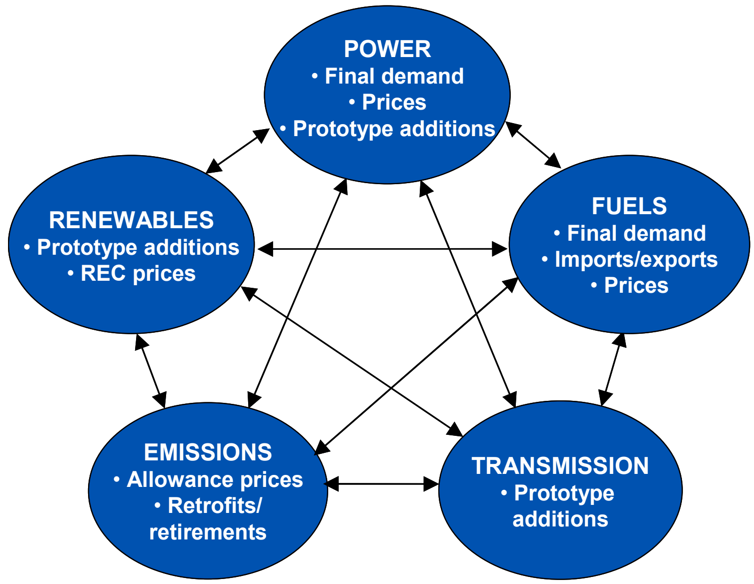
2.2.3 Module Descriptions

An overview of the ABB Model is provided in Figure 2.3. As the figure shows, the process comprises five modules, which iterate within the model on an annual basis. For example, the operations component of the Power Module simulates power plant dispatch, preliminary power prices, fuel consumption, and emissions for each month of 2017 based on values from the prior iteration for: (1) power plant capacity and natural gas pipeline decisions; and (2) inputs from the other modules. For the first iteration, the Power Module applies the previous year's natural gas forecast values. The simulated power sector demand for natural gas is passed to the operations component of the Fuel Module, which simulates natural gas prices for all months of 2017 in the current iteration.

[8] The ABB Model does not permit new coal plants to be constructed.

[9] For the LTER, new renewable power additions are restricted to be either land-based wind, off-shore wind, or solar.

Figure 2.3 Forecasting Process Modules



Source: ABB.

Once the operations components of the Power and Fuels Modules are simulated for all 12 months of 2017 in the current iteration, the 2017 power and fuel prices, emissions, and other intermediary outputs are passed to the Investment Component. The Investment Component of the Power and Fuel Modules is then simulated for 2017, producing updated values of conventional power plant capacity additions, retirements, and retrofits; annual electric capacity prices; and annual CO_2 prices. The decisions made in the Investment Component are then passed into the Operations Module as an additional iteration. If the updated values for 2017 of any of these variables are different than those from the prior iteration, i.e., outside a predetermined tolerance, the updated values are passed back to the Investment Component, which will produce a refined schedule for additions, retirements, and retrofits. This iterative process continues until convergence is achieved.

The following text describes the key aspects of each of the modules comprising the forecasting process.

Power Module

The Power Module is a zonal model of the North American interconnected power system covering 74 ABB-defined transmission zones. The Module simulates separate hourly energy and annual capacity markets in all zones. The Module simulates the operations of individual generating units, as opposed to aggregations of units. As indicated above, the Power Module comprises two components which simulate: (1) operations; and (2) conventional power plant capacity additions, retirements, and retrofits.

Operations Component. For given values of the variables simulated by the other modules from the prior iteration, and for a variety of fixed input assumptions such as generating unit characteristics described in detail in Chapter 3, "Reference Case Modeling Assumptions," the Operations Component simulates a constrained least-cost commitment and dispatch of all the power plants in the system. This simulation takes into account hourly loads, operating parameters and constraints of the units, system constraints such as spinning reserve requirements, and transmission constraints. (Note: No transmission constraints are assumed to exist within transmission zones; transmission constraints are applicable only to power flows between zones.)

Investment Component. For a given set of the values of variables from the Operations Component, such as hourly electric energy prices, and from the other modules, the Investment Component simulates the conventional power plant capacity additions, retirements, and retrofits expected to occur in the market.

Capacity Addition Decision. The investment decision for capacity additions is a multi-step process that identifies both energy and capacity revenue associated with potential new resources. The Investment Component identifies in each forecast year the list of technology types that are available for generation expansion in each zone. The profitability of each technology for each zone is based on whether energy market revenues are greater than the sum of: (1) expenses for fuel, emissions allowances, and variable and fixed operations and maintenance (O&M); and (2) amortized capital costs.

In determining reserve margins, the Investment Component considers: (1) thermal, hydro power, and intermittent resources within the zone; (2) the coincident peak less interruptible demand response resources; and (3) transmission transfers into and/or out of the zone. Intermittent resources, such as wind and solar power, are de-rated for capacity addition decisions based on their availability at time of peak.[10] The objective of the transmission transfers is to equalize the capacity prices within a planning region. A planning region is defined by the markets where there are developed capacity planning regions, such as PJM, or, if there is not a developed capacity planning region, where there are North American Electric Reliability Corporation (NERC) defined capacity planning regions.

The capacity addition decision is an iterative process that gathers intelligence from the markets before the decision is finalized. The iterative process steps are outlined below:

1. Identify the capacity price before additions, which is characterized as the CONE within a zone;
2. Identify the most profitable incremental capacity additions given the energy price for that iteration;

[10] Through the 2019/2020 planning year, PJM credits new solar projects with 38 percent of nameplate capacity; new wind projects are credited with 13 percent of nameplate capacity.

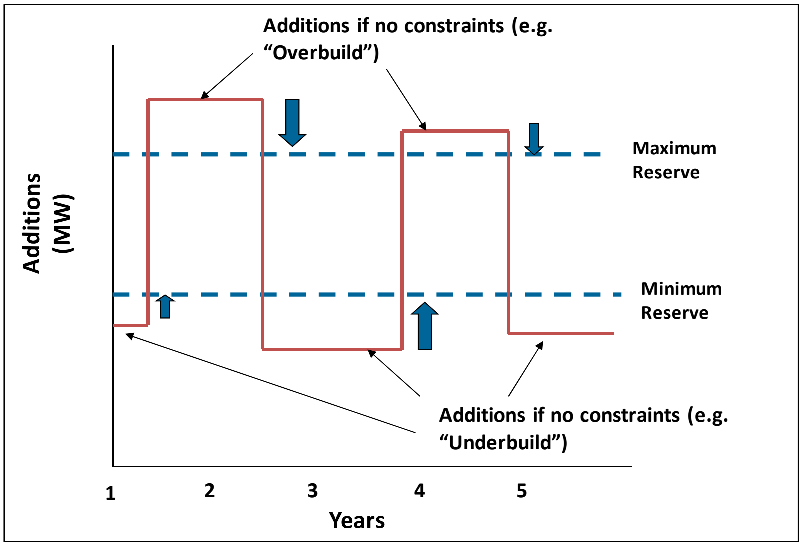
3. Perform another iteration given the change in energy price with the revised resources after the capacity addition is made;

4. Determine profitability after step three—if the resource is profitable, then the resource is added; and

5. Evaluate the transmission transfers to determine if it is more profitable to build and sell capacity into another zone after the resource has been added.

To ensure that regions do not overbuild based on economics, the decision criteria may also include a maximum reserve margin as shown in Figure 2.4.

Figure 2.4 Capacity Decision Reserve Constraints



Source: ABB.

Retirement Decisions. For economic retirements, the Investment Component retires all generating units with negative gross margins (i.e., energy and capacity revenues minus expenses for fuel, emissions allowances, variable O&M, and fixed O&M) for four consecutive years.

The Investment Component may also retire a generating resource based on the age of the resource. For age-based retirements, the following service lives are assumed:

- Coal: 60 to 75 years;
- Nuclear: 60 years;
- Combined Cycle: 60 years;
- Gas Turbines: 60 to 75 years; and
- Oil Turbines: 60 to 75 years.

For renewable resources, it is assumed that the plants will be replaced with a new similarly sized plant when plant retirement occurs. If there is no capacity addition made, the capacity price is based on the minimum of the revenue deficit for the most economic resource to add or the most economic resource to retire.

Retrofit Decisions. For retrofits, the Investment Component identifies, from a list of generating units that can be retrofitted, the units that would be more profitable in the current year with the retrofit than in the existing configuration, taking into account the capital costs of the retrofit amortized over the likely remaining life of the unit. Once the Investment Component decides to retrofit a unit, it passes the updated operational characteristics of the unit to the Operations Component.

Capacity Price. The annual capacity price in each zone is calculated as the amount that the marginal unit in the zone would require to satisfy the reserve margin it would need over and above energy market revenues to break even financially, including the amortized capital cost of the unit. In the final iteration, a decision is made as to whether it would be more profitable to sell the capacity to another zone given the transmission constraints, which would then set the capacity price in both zones.

The algorithm used by the model to calculate capacity prices does not mirror the PJM Reliability Pricing Model (RPM), which establishes capacity prices through an auction process. The ABB methodology, however, incorporates the same fundamental principles employed by the RPM such that:

- The capacity price is established by zone;
- When capacity is sufficient to satisfy the overall reliability requirement, the capacity price is adequate to make the marginal resource whole; and
- Lower energy prices translate into higher capacity prices, other factors held constant.

Fuels Module

The Fuels Module consists of three sub-modules, one each for natural gas, coal, and oil.

Natural Gas Sub-Module. The natural gas sub-module produces forecasts of monthly natural gas prices at individual pricing hubs. The Operations Component consists of a model of the aggregate U.S. and Canadian natural gas sector. For each month and iteration, it executes in the following manner:

- For each iteration of the Operations Component, natural gas demand by the power sector is taken from the prior iteration of the Power Module.
- Canadian and the lower 48 (L48) U.S. states' residential, commercial, and industrial (RCI) demand forecasts are treated as exogenous inputs to the natural gas sub-module. RCI demand is forecast based on an analysis of RCI demand in the EIA AEO 2016 and the National Energy Board of Canada (NEBC) 25-year outlook. ABB also conducts its own research and analysis of industrial demand based on publicly available analysis of forecast industrial demand. Historical data from the ABB Velocity Suite product are

used as a starting point: for demand growth applied based on growth rates taken from EIA and NEBC forecasts; and to add monthly seasonal shape to annual forecasts.

- Imports and exports of liquefied natural gas (LNG) as well as pipeline exports to Mexico (outside California-connected Baja California) are also treated as exogenous demand sources drawing on the combined Canadian and L48 natural gas system. These forecasts are created based on analysis of: historical data for individual pipelines and import terminals; individual pipeline and LNG export projects; projected supply and demand for global LNG; and projected demand for natural gas in Mexico. North American production is represented in the Operations Component by a series of L48 and Canadian supply curves. These relate production at a wellhead to the wellhead price of natural gas for each basin and geology in each year. Then, an annual production algorithm identifies the relative prices at each of the supply basins to the basin production necessary to meet annual natural gas demand. Regional storage is based upon a schedule of injections and withdrawals required to balance monthly demand and production. Finally, monthly natural gas production, transportation and demand after storage are simulated within a natural gas network optimization model to provide both natural gas flows and prices at each point within the natural gas network. Prices at each point in the topology are determined based upon wellhead prices plus transportation costs.

From this solution, the monthly Henry Hub price is identified directly from its geographic point within the natural gas network.[11]

Coal Sub-Module. The coal sub-module utilizes a network linear programming algorithm that satisfies, at least possible cost, the annual demand for coal at individual power plants with supply from existing mines using the available modes of transportation.

Oil Sub-Module. U.S. crude oil prices are based on conditions in the global oil market. Based on extensive prior analysis, ABB Advisors believes that the feedback to the global oil market from the markets represented in the North American forecast (i.e., power, natural gas, coal, and emissions) is extremely weak. Consequently, U.S. crude oil prices are treated as an exogenous input.

ABB's oil forecast is based on a survey of other long term oil price forecasts (EIA, International Energy Agency (IEA), etc.). ABB uses the same methodology for blending the New York Mercantile Exchange (NYMEX) as for natural gas: for months 1-24, ABB is 100 percent dependent on NYMEX; for months 24-48, ABB uses a blend of NYMEX and the long-term forecast; and for months 49 and forward, ABB uses the long-term forecast. ABB generates forecasts of region-specific prices for refined oil

[11] The Henry Hub, located in Louisiana, is the most liquid natural gas market in the U.S. and is generally viewed as the primary pricing location for natural gas in the North American market. Henry Hub is the delivery point for NYMEX natural gas futures contracts. Virtually every natural gas forecast produced in the industry, including the ABB forecast and the EIA's AEO 2016, is based in part on Henry Hub prices.

products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the West Texas Intermediate (WTI) price.

Emissions Module

The emissions module considers existing and potential regulations restricting the emissions of SO_2, NOx, CO_2, and mercury. ABB uses a proprietary emissions forecast model to simulate emission control decisions and emission results simultaneously in the three cap-and-trade markets (SO_2, NOx annual, and NOx ozone season). This economic model acts as a central system planner to minimize system-wide total costs of environmental compliance across the entire forecast period. Unit characteristics, simulated operations, emission control costs, control efficiencies, announced installations, and state-level EPA Cross-State Air Pollution Rule (CSAPR) emission caps provide the input data. Based on these inputs, the model forecasts emission prices, installation dates, and resulting system-wide emissions. In addition to the input data, the model relies on the following assumptions:

- State-level caps with limited trading;
- Current traded prices;
- Economical determination of equipment installation timing after known announcements;
- Consistent plant dispatch (or merit) order regardless of the installation of additional control equipment;
- Use of Selective Catalytic Reduction (SCR) and wet Flue Gas Desulfurization (FGD) for NOx and SO_2 control, respectively;
- Prices reflecting investments in environmental control;
- Limits on the number of forecast installations per year; and
- Cost and efficiency values based on EPA analysis.

The sub-module is capable of modeling a cap-and-trade program for CO_2, considering emissions not only from the power sector but also from other sectors of the economy.

Renewables Module

For purposes of developing the LTER projections, renewable resources are exogenously supplied to the model (to meet the various states' RPS's) with specifications that include location by ABB transmission zone, state within the zone (optional), size in megawatts (MW), technology type, cost assumptions (variable and fixed O&M, per-kilowatt (kW) capital costs, debt equity ratio, financing costs, taxes and other incentives), capacity factor, and annual output degradation factor. Absent specific inputs for specific renewable energy resources, default values are contained in the model. Renewable resources are exogenously added to meet the state RPS requirements or may be added in excess of the RPS requirements. In developing the assumed levels and locations of renewable resource additions required to meet RPS requirements, PPRP considered the RPS in-state requirements (e.g., the solar renewable energy requirements in Maryland and New Jersey) and practical limitation on renewable energy development in particular regions (e.g., limitations on wind power development in Maryland due to capability constraints).

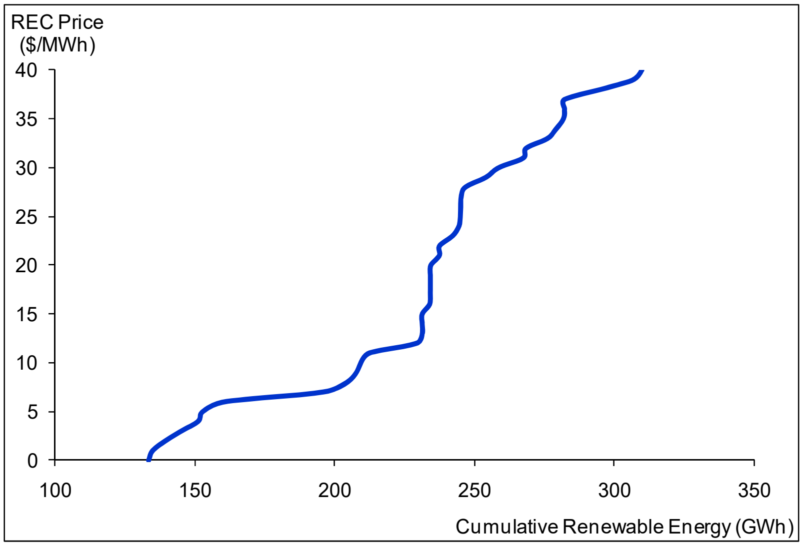
The renewables module also calculates REC prices for identified REC markets. REC prices represent the revenue required by the marginal renewable capacity addition to break even financially, taking into account the energy market revenues, variable and fixed O&M expenses, and amortized capital costs.

The forecast of REC values is based on the premise that renewable energy generators rely on RECs to complement energy and capacity revenues to meet their production costs and levelized capital requirements, i.e., a "gap analysis" approach is utilized. The federal Investment Tax Credit (ITC) and Production Tax Credit (PTC) are additional sources of revenue included in the gap analysis.

For each year of the analysis, a supply curve is developed for all the renewable assets in the appropriate renewable market area. Figure 2.5 presents a sample supply curve. The X-axis shows the cumulative renewable capacity in cumulative gigawatt-hours (GWh). The Y-axis presents the revenue deficit as calculated in Step 3, above, for each eligible renewable unit. Depending upon where the demand for RECs falls, the price will adjust accordingly.

Calculation of the RECs prices also recognizes the availability of alternative compliance payments (ACPs) in particular markets that allow an APC to be used in lieu of the retirement of a REC. ACPs, therefore, act as a cap on the price of RECs in those markets and, where ACPs are available, the renewables module precludes RECs prices from exceeding ACPs.

Figure 2.5 Renewable Energy Credit Supply Curve Example



Source: ABB.

3. REFERENCE CASE MODELING ASSUMPTIONS

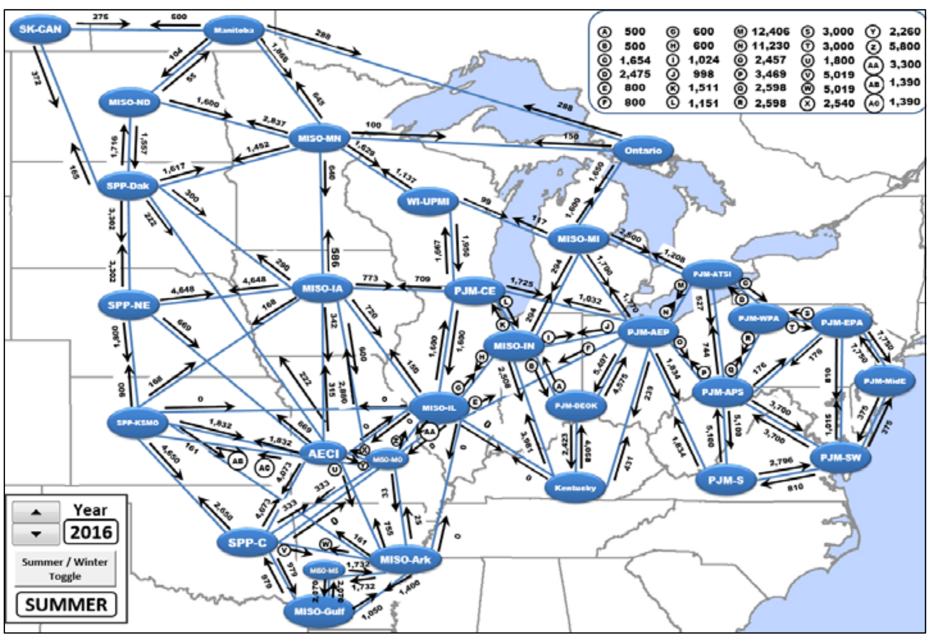
3.1 Introduction

This chapter presents the key assumptions relied upon for the Reference Case, the reasoning underlying these assumptions, and the sources of the data relied upon. The succeeding chapters presenting the alternative scenarios focus on the differences between the relevant alternative set of assumptions and those of the Reference Case.[12]

3.2 Transmission Topology

The ABB Model separates the relevant geographic areas contained within PJM into market centers or "bubbles," as shown in Figure 3.1. Transmission capability between bubbles is particularly important because transmission constraints are the main cause of price differentials across PJM. Most of Maryland's energy users (those within the Potomac Electric Power Company (Pepco), the Southern Maryland Electric Cooperative (SMECO), and the Baltimore Gas and Electric (BGE) service territories) fall within the PJM Southwest bubble (PJM-SW); Allegheny Power customers fall within the PJM-APS bubble; and Delmarva Power & Light Company (DPL) customers fall within the PJM-Mid-East (PJM-MidE) bubble. It is important to note that the prices in all of the PJM bubbles are relevant when determining the price of electricity in Maryland because PJM operates as an integrated market.

Figure 3.1 Modeled Transmission Zones in PJM and Surrounding Areas



Note: The numbers between bubbles represent the directional MW transmission transfer capacity between the zones.

Source: ABB.

[12] A table summarizing the input assumptions is contained in Appendix D.

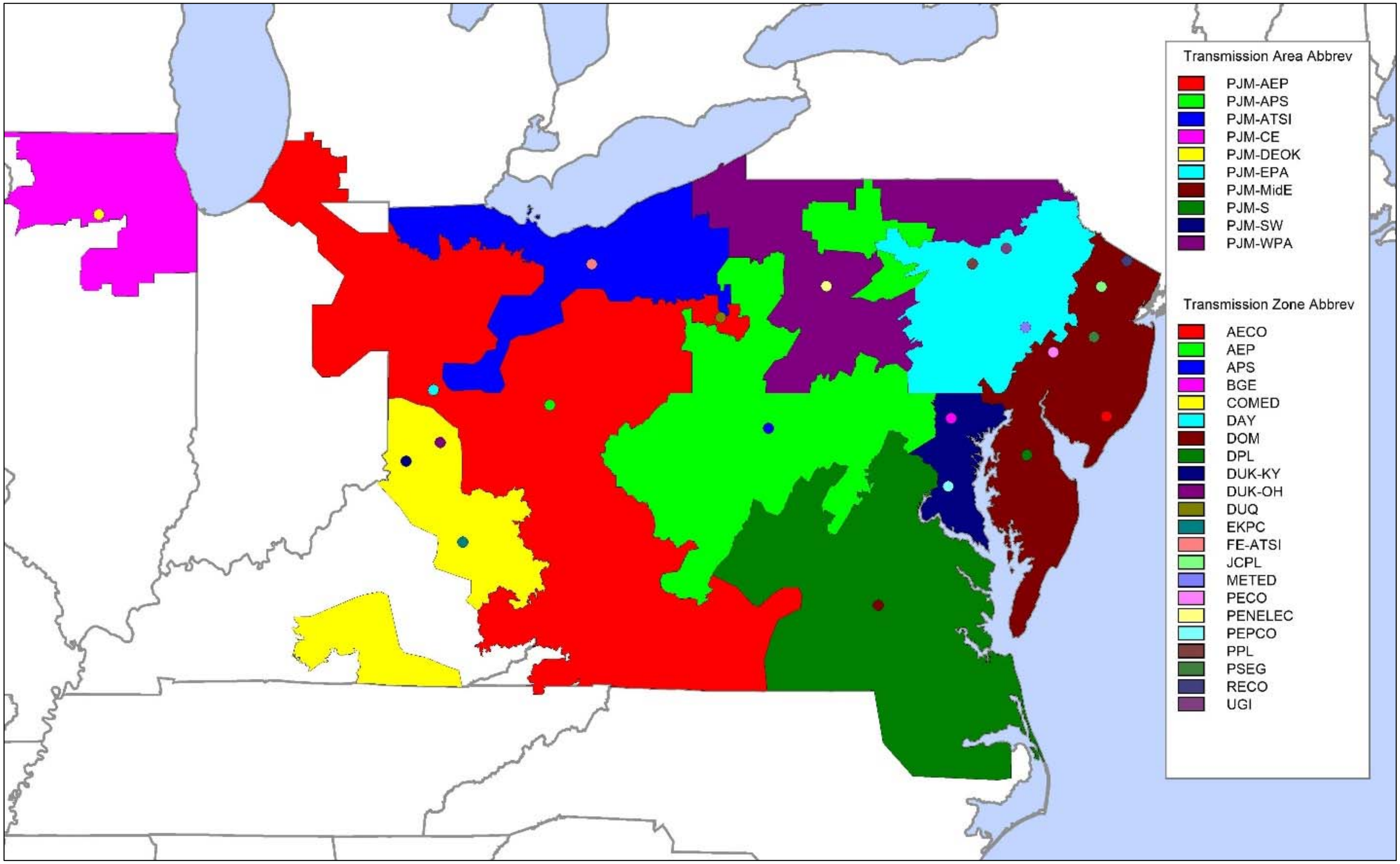
Table 3.1 describes the geographic areas associated with the market bubbles shown in Figure 3.1; the markets containing portions of Maryland are shown in bold type. Figure 3.2 shows the PJM transmission zones and utilities within each zone.

Table 3.1 PJM Market Area Names and Locations

Market Area Name	Abbreviation	Market Area Description
Manitoba	Manitoba	Manitoba (Canada)
MISO – Arkansas	MISO-Ark	Arkansas
MISO – Gulf	MISO-Gulf	Louisiana, Texas, Mississippi
MISO – Illinois	MISO-IL	Southern Illinois
MISO – Indiana	MISO-IN	Cinergy + Other Indiana Utilities (Ohio, Indiana)
MISO – Iowa	MISO-IA	Iowa
MISO – Michigan	MISO-MI	Michigan Electric Coordinated Systems
MISO – Minnesota	MISO-MN	Minnesota, Wisconsin, North Dakota
MISO – Mississippi	MISO-MS	Entergy Mississippi, South Mississippi Electric Power Association
MISO – Missouri	MISO-MO	Eastern Missouri
MISO – North Dakota	MISO-ND	MISO North Dakota
MISO – WI-UPMI	WI-UPMI	Wisconsin, Upper Michigan
PJM – AEP	PJM-AEP	American Electric Power (Virginia, Ohio, Indiana, Kentucky)
PJM – APS	**PJM-APS**	**Allegheny Power System (West Virginia, Maryland, Pennsylvania)**
PJM – ATSI	PJM-ATSI	FirstEnergy – American Transmission Systems Inc. (Ohio, Pennsylvania)
PJM – ComEd	PJM-CE	Commonwealth Edison/Northern Illinois
PJM – DEOK	PJM-DEOK	Duke Energy Ohio, and Kentucky
PJM – South	PJM-S	Dominion Virginia Power Company
PJM Mid-Atlantic – E	**PJM-MidE**	**PJM Mid-Atlantic – East of East Interface (Maryland, New Jersey, Pennsylvania, Delaware)**
PJM Mid-Atlantic – East PA	PJM-EPA	PJM Mid-Atlantic – East Pennsylvania
PJM Mid-Atlantic – SW	**PJM-SW**	**PJM Mid-Atlantic – Southwest (Maryland, District of Columbia)**
PJM Mid-Atlantic – West PA	PJM-WPA	PJM Mid-Atlantic – West Pennsylvania
Saskatchewan	SK-CAN	Saskatchewan Power (Canada)
SPP – Central	SPP-C	Southwest Power Pool – Central Region (Louisiana, Missouri, Oklahoma, non-ERCOT Texas)
SPP – Dakotas	SPP-Dak	North Dakota, South Dakota, Iowa
SPP – KSMO	SPP-KSMO	Southwest Power Pool – North (Kansas, Missouri)
SPP – Nebraska	SPP-NE	Nebraska

Note: MISO = Midcontinent Independent System Operator

Figure 3.2 PJM Transmission Areas and Associated Utilities



Note: The Reference Case transmission topology reflects transmission lines in place as of January 2016.

Source: ABB.

3.3 Loads

Load forecasts are a required input for the simulation models relied upon to conduct the LTER analysis. For the Reference Case, PPRP used PJM's most recent load forecast (released in December 2015).[13] As noted earlier, PJM adjusted its forecast downward to reflect the impacts of both distributed solar generation and demand-side management (DSM) programs in Maryland and other PJM states. See Section 10.5 for a discussion of EmPOWER Maryland, the State's primary DSM program.

Table 3.2 summarizes the LTER load forecast. Note that demand response is treated as a callable resource in the ABB Model and, therefore, MW reductions due to demand response are not reflected in the values in Table 3.2. Also, peak demand values represent the sum of regional peaks, and thus are greater than the values provided in PJM's load forecast for RTO-wide peaks due to peak load diversity considerations.

[13] PJM, *PJM Load Forecast Report*, December 2015, https://www.pjm.com/~/media/documents/reports/2016-load-report.ashx, 52-61; 86-89.

Table 3.2 Reference Case Load Forecasts

Year	Peak Demand (MW)	Energy (GWh)
2015	161,639*	811,877*
2016	158,345	811,335
2017	160,374	821,812
2018	162,129	833,095
2019	163,323	839,492
2020	163,441	841,989
2021	163,814	843,262
2022	164,593	848,709
2023	165,280	854,214
2024	166,472	862,838
2025	167,585	866,736
2026	168,687	872,863
2027	169,756	879,605
2028	170,730	889,029
2029	171,941	894,596
2030	173,297	899,599
2031	174,550*	906,168**
2032	175,576*	911,601**
2033	176,612*	917,072**
2034	177,658*	922,582**
2035	178,702*	928,132**
Average Annual Growth Rates		
2015 through 2025	0.36%	0.66%
2020 through 2030	0.59%	0.66%
2025 through 2035	0.64%	0.69%

* PJM's December 2015 load forecast extends from the years 2016 through 2030. For the year 2015, values from the prior year's forecast were used, which did *not* reflect load reductions due to distributed solar generation.

** For the years 2031 through 2035, PPRP extrapolated the forecast values based on average annual growth in the last three years of PJM's forecast.

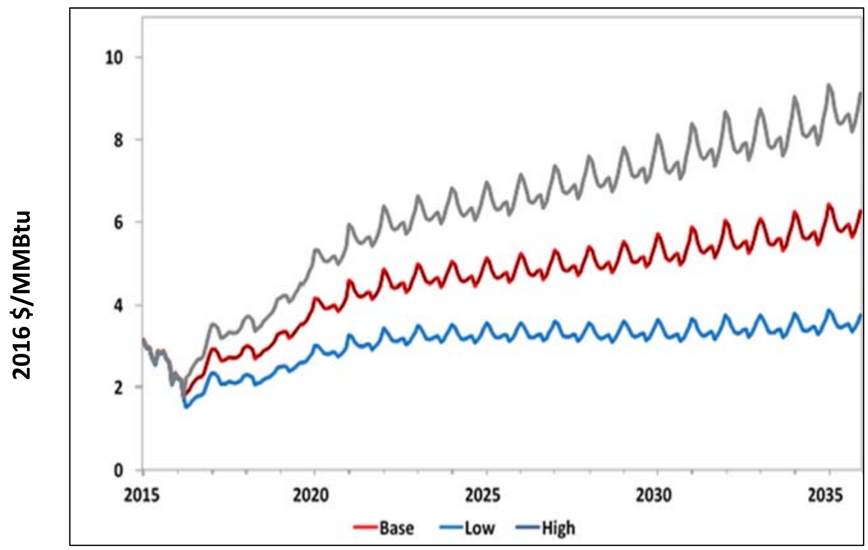
3.4 Operational and Cost Characteristics for Generation Units

Generation unit operational and cost characteristics are critical assumptions because they determine the cost of electricity generation. The operational characteristic assumptions include fuel costs and fixed and variable O&M expenses. Fuel prices are among the most important assumptions in the LTER because they determine which power plants operate, the price of electricity in each market bubble (this price depends on the marginal unit in each bubble), and the types of new power plants (e.g., natural gas, nuclear) that are constructed to meet growing demand as well as to replace generation from retiring plants.

Figure 3.3 plots ABB's base, high, and low natural gas price projections for the Henry Hub, which is the primary natural gas hub in the U.S. The Henry Hub natural gas price is adjusted upward in the model simulations to reflect the costs necessary to transport natural gas from the Henry Hub to the geographic region where each generator is located. This methodology, which relies on Henry Hub basis point differentials, is standard in the industry.

The Reference Case relies on the base natural gas forecast shown as the middle line in red in Figure 3.3. The high and low cases are used in alternative scenarios and included in Figure 3.3 to provide perspective regarding the degree of uncertainty surrounding future natural gas prices. Alternative scenarios based on high and low natural gas prices relative to those prices under the Reference Case are discussed in Chapter 5, "Natural Gas Price Alternative Scenarios."

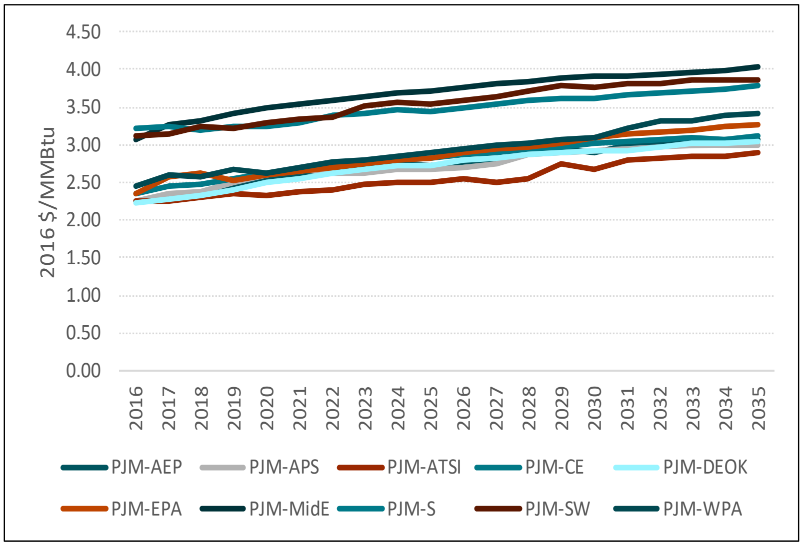
Figure 3.3 Natural Gas Price Forecast for the Henry Hub



Source: ABB Spring 2016 Reference Case.

Figure 3.4 plots coal prices by PJM area for various regions in PJM. These projections are based on detailed information about individual generating units, and these data are used to produce burner-tip prices at each coal-fired power plant based on the specific type of coal (e.g., Central Appalachia, Illinois Basin) that each generator purchases.

Figure 3.4 Coal Price Forecast by PJM Area

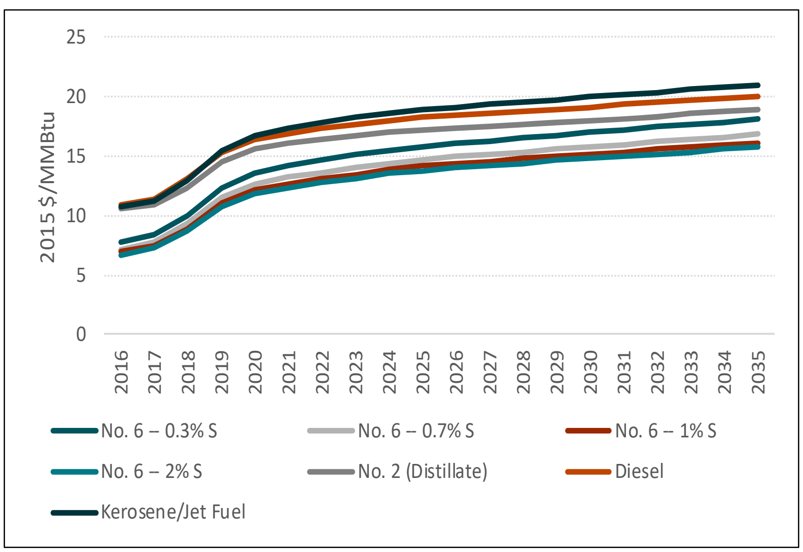


Note: The zonal designations correspond to the zones shown in Table 3.1 and Figure 3.2.

Source: ABB Spring 2016 Reference Case.

Fuel oil projections are presented in Figure 3.5. Prices vary by fuel type (No. 2 distillate or No. 6) and sulfur content. Nuclear fuel price projections, obtained from EIA, range from approximately \$0.85/MMBtu (2015\$) in 2015 to approximately \$1.05/MMBtu (2015\$) in 2035.

Figure 3.5 Fuel Oil Price Forecast by Type



Note: S = Sulfur

Source: ABB Fall 2015 Reference Case.

The ABB model adds new generation when it is economic to do so based on market conditions and the cost of constructing new facilities. Table 3.3 contains detailed information on the capital, variable O&M, fixed O&M, and fuel costs associated with new generation technologies; Table 3.4 contains the corresponding operational assumptions. The financial parameters needed to guide investment decisions are presented in Table 3.5. Assumptions needed for the calculation of RECs prices in the Renewables Module are shown in Table 3.6. Note that, in Table 3.4, capacity factors are shown only for solar PV and wind power projects. This is because the model dispatches other technologies based on least-cost and reliability criteria. The intermittent resources (solar and wind) are run when available, with the assumed annual capacity factors shown in Table 3.4.

Table 3.3 Cost Assumptions of New Generation over the Forecast Period

Unit Type	Fixed O&M (2015$/kW-yr)	Variable O&M (2015$/MWh)	Fuel Cost (2015$/MWh)	Overnight Construction Cost (2015$/kW)
Combustion Gas Turbine	$11.67	$3.51	$38.83 – $61.03	$680
Combined Cycle Natural Gas F-Class	12.96	2.21	25.15 – 39.52	1,000
Combined Cycle Natural Gas G-Class	13.07	2.15	24.50 – 38.51	1,025
Combined Cycle Natural Gas H-Class	13.17	2.01	27.29 – 32.31	1,035
Nuclear	99.77	0.55	9.17 – 10.95	5,800
Geothermal Steam Turbine	110.00	0.00	0.00	3,000
Landfill Gas	40.00	5.00	0.00	3,250
Biomass	103.01	1.54	22.83 – 27.13	4,500
Photovoltaic Solar	25.00	0.00	0.00	2,250[1]
Wind Turbine – On-shore	35.00	0.00	0.00	1,800[2,3]
Wind Turbine – Off-shore	73.88	0.00	0.00	4,260[4]

[1] Assumes a technology cost improvement of 4 percent per year through 2020, and 3 percent per year through 2030; thereafter, no technology cost improvement. Assumptions regarding capital costs for solar PV are based on research of publicly available information.

[2] Assumes a technology cost improvement of 1 percent per year through 2020, and 3 percent per year through 2030; thereafter, no technology cost improvement.

[3] Ryan Wiser and Mark Bolinger, *2014 Wind Technologies Market Report*, U.S. Department of Energy, August 2015, https://emp.lbl.gov/sites/all/files/lbnl-188167.pdf.

[4] Walter Musial and Bonnie Ram, *Large-Scale Off-shore Wind Power in the United States*, National Renewable Energy Laboratory, September 2010, http://www.nrel.gov/docs/fy10osti/49229.pdf.

Source: Unless otherwise noted, information regarding the characteristics of prototype units is derived from research conducted by ABB and PPRP.

Table 3.4 Operational Assumptions of New Generation over the Forecast Period

Unit Type	Summer Capacity (MW)	Capacity Factor	Full-Load Heat Rate HHV (Btu/kWh)	Forced Outage Rate	Maintenance Outage Rate (MOR)
Combustion Gas Turbine	160	--	10,500	3.6%	4.1%
Combined Cycle Natural Gas F-Class	450	--	6,800	5.5	9.7
Combined Cycle Natural Gas G-Class	350	--	6,625	5.2	9.6
Combined Cycle Natural Gas H-Class	400	--	6,400	5.0	9.5
Nuclear	1,000	--	10,400	3.8	6.1
Geothermal Steam Turbine	10	--	10,000	20.0	0.0
Landfill Gas	10	--	8,910	30.0	0.0
Biomass	10	--	13,648	30.0	0.0
Photovoltaic Solar	10	15%	0	0.0	0.0
Wind Turbine – On-shore	10	30%	0	0.0	0.0
Wind Turbine – Off-shore	10	40%	10,000	30.0	0.0

Note: HHV = higher heating value

Source: ABB, PPRP.

Table 3.5 Financial Assumptions

	Debt	Equity
Debt/Equity Ratio	50%	50%
Cost Rate	7%	12%
Effective Tax Rate	39.55%	--
Inflation Rate	2.5%	--

Source: ABB, PPRP.

Table 3.6 Renewable Energy Credit-related Model Inputs

Technical Inputs	
Useful Life of Project (years)	20
Weighted Average Cost of Capital	9.5%
Cost Reduction Associated with Incentives and Rebates	3.5%
Sources of Revenues (for Developer)	
Energy Market Revenue	Average of energy prices PJM-wide[1]
Capacity Market Revenue	Average of capacity prices PJM-wide[1]
PJM Capacity Derate for Wind Resources	13.0%
Wind Capacity Eligible for PJM Capacity Market	1.3 MW

[1] Values vary based on the location of a facility.

Source: ABB, PPRP.

3.5 Environmental Policies

3.5.1 EPA Regulations

In general, the Reference Case includes emissions regulations for which the EPA has issued a final rule. The input assumptions for EPA regulations included in the Reference Case are provided below.

1. Cross-State Air Pollution Rule

   As described in Chapter 2, ABB uses a proprietary emission forecast model to simulate emission control decisions and results simultaneously in the three cap-and-trade markets (SO_2, NOx annual, and NOx ozone season) that comprise the CSAPR. The capital and operating costs of SCR and FGD equipment is unit-specific, based on ABB Velocity Suite engineering research. As an example, average FGDs add approximately \$3.80/MWh to variable O&M and about \$45/kW-year to fixed O&M and capital costs based on a study by Sargent & Lundy conducted for EPA.[14] CSAPR is included in the Reference Case.

2. Mercury and Air Toxics Standards

   The Reference Case includes implementation of the Mercury and Air Toxics Standards (MATS) Rule by inclusion of announced retirements. To reflect any additional retirements, ABB models the economic retirement of coal plants to capture the impacts associated with at-risk units.

3. Carbon Pollution Standards for New Power Plants

   Section 111(b) of the Clean Air Act (CAA) has been interpreted as providing EPA with the authority to address emissions from new, modified, reconstructed, and existing power plants. In the EPA's final New Source Performance Standards (NSPS) rule, a new source is defined as any fossil fuel-fired power plant that commenced construction on or after January 8, 2014. The rule establishes separate standards for two types of fossil fuel-fired sources that exceed 25 MW:

   - Stationary combustion turbines, generally firing natural gas; and
   - Electric utility steam generating units, generally firing coal.

   The standards reflect the degree of emission limitations achievable through the application of the best system of emission reduction (BSER) that EPA determined was adequately demonstrated for each type of unit.

[14] Sargent & Lundy, LLC, *IPM Model – Updates to Cost and Performance for APC Technologies – SDA FGD Cost Development Methodology*, March 2013, https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-2_sda_fgd_cost_methodology_3.pdf.

The final standard for base load combustion and combined cycle turbines is an emission limit of 1,000 pounds of CO_2 per megawatt-hour (lbs/MWh). The final standard for steam generating fossil fuel-fired units is an emission limit of 1,400 lbs/MWh. The 1,400 lbs/MWh limit is consistent with the emission rate for a highly efficient supercritical pulverized coal (SCPC) unit with partial CCS and represents an approximately 20 percent capture rate. For non-base load combustion turbines, the emission limit was set at a clean fuels input-based rate of 120 lbs/MMBtu.

4. Clean Power Plan

The EPA's CPP, though finalized, is *not* part of the Reference Case. The U.S. Supreme Court has stayed implementation of the CPP, pending the resolution of state and industry challenges to the rule. The LTER, however, includes an alternative scenario based on the CPP, as described in Chapter 8, "CPP Alternative Scenario."

3.5.2 Renewable Energy Portfolio Standard

Maryland's RPS has undergone modification several times since its enactment in 2004. These modifications have included, but are not limited to: (1) reducing the scope of the geographical area for eligible renewables; (2) establishing a separate requirement for solar PV energy; (3) establishing a process for inclusion of off-shore wind resources; and (4) changing the annual solar requirements and solar alternative compliance payments. Current RPS law is reflected in the Reference Case. Table 3.7 summarizes current RPS law; a full discussion of the Maryland RPS is contained in Section 10.1.

Table 3.7 Maryland's Renewable Energy Portfolio Standard

	Percentages of Renewable Energy Required[1]			Alternative Compliance Payments ($/MWh)		
Year	Tier 1 Solar	Tier 1 Other	Tier 2	Tier 1 Solar	Tier 1 Other	Tier 2
2015	0.50%	10.0%	2.5%	$350	$40	$15
2016	0.70	12.0	2.50	350	40	15
2017	0.95	12.2	2.50	200	40	15
2018	1.40	14.4	2.50	200	40	15
2019	1.75	15.7	0.00	150	40	--
2020	2.00	16.0	0.00	150	40	--
2021	2.00	16.7	0.00	100	40	--
2022	2.00	18.0	0.00	100	40	--
2023	2.00	18.0	0.00	50	40	--
2024+	2.00	18.0	0.00	50	40	--

[1] Tier 1 renewables include solar, wind, biomass, anaerobic decomposition, geothermal, ocean, fuel cells powered through renewables, small hydro, poultry-litter incineration facilities, and waste-to-energy facilities. Tier 2 renewables include hydroelectric power other than pump-storage generation. Solar, geothermal, poultry litter-to-energy, waste-to-energy, or refuse-derived fuel are eligible and must come from within the State. All other renewable energy generation must be located in the PJM region or in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region.

In the past, the supply of RECs from Tier 1 non-solar and Tier 2 resources in PJM, or in states that can deliver power to PJM, has been adequate to fulfill Maryland's RPS requirements. The LTER assumes that this will continue to be the case throughout the study period.

According to ABB's Velocity Suite, large scale solar capacity in Maryland nearly doubled from 64 MW to 122 MW between 2012 and 2016, and another 604 MW of capacity have been proposed to come online by 2018. In light of this growth, and the continuation of federal tax incentives for solar projects, the LTER assumes that there will be sufficient solar capacity to meet the solar portion of the Maryland RPS throughout the study period.

3.5.3 Regional Greenhouse Gas Initiative

Maryland is a member of the Regional Greenhouse Gas Initiative (RGGI), along with eight other mid-Atlantic and northeastern states. The purpose of RGGI is to limit the amount of CO_2 that can be emitted from fossil fuel power plants in the member states up to an aggregate cap. Power plants in Maryland adhere to the RGGI requirements through the purchase of emission allowances, which are auctioned by each participating state. Power plants within one state, however, may purchase allowances issued by another RGGI state as a means of compliance. Consequently, the CO_2 budget amount for any one state does not represent a hard cap for the respective state, although the aggregate allowances of all states within RGGI represent a hard cap.

Following a comprehensive program review in 2012, the nine RGGI states lowered the 2014 RGGI cap to 91 million tons, and agreed to continue lowering the cap by 2.5 percent each year from the years 2015 through 2020. Table 3.8 shows Maryland's current RGGI budget.

Table 3.8 Maryland's RGGI CO_2 Allowance Budget (tons)

Year	Allowances
2016	14,385,683
2017	14,179,851
2018	13,701,106
2019	13,234,330
2020+	12,779,223

Source: Original allowance data established by COMAR 26.09.02.03; adjusted for First and Second Control Period Interim Adjustments established by RGGI; see http://www.rggi.org/design/overview/allowance-allocation/2015-allowance-allocation.

RGGI sets a minimum price for emissions allowances; allowance prices may exceed, but cannot drop below, the minimum, set at $2.10 per ton of CO_2 emissions for 2016. The floor price increases each year at the rate of inflation. In the June 2016 auction, the clearing price was $4.63/ton. The Reference Case assumes that RGGI emissions allowance prices rise steadily throughout the study period, as shown in Table 3.9.

Table 3.9 Assumed RGGI Prices in the Reference Case

Years	RGGI Price (2016$/ton)
2016	$6
2017-2018	8
2019-2020	9
2021-2027	10
2028-2031	11
2032-2034	12
2035	16

Source: ABB Spring 2016 Reference Case.

The future of RGGI is uncertain. The EPA's CPP is designed to be compatible with RGGI; indeed, RGGI states could comply with the CPP simply by continuing to participate in RGGI. However, if the CPP is struck down by the Supreme Court, it is unclear whether RGGI states will opt to continue the program past 2020. The Reference Case assumes the program will continue with a 2.5 percent annual reduction in the CO_2 cap through 2030.

3.5.4 Greenhouse Gas Reduction Act

During the 2016 legislative session, the Maryland Legislature strengthened the State's Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The updated law requires the State to reduce greenhouse gas (GHG) emissions 40 percent below 2006 levels by 2030. The updated GGRA continues to direct the State to implement specific programs to reduce GHG emissions in all sectors. The GGRA specifies that emissions reduction measures related to energy supply do not "decrease the likelihood of reliable and affordable electrical service," and also take into consideration whether the measures will result in increased electricity costs to consumers.

The original GGRA required the Maryland Department of the Environment (MDE) to prepare and publish an inventory of Statewide GHG emissions for calendar year 2006 and develop a projected "business-as-usual" inventory for calendar year 2020. These were completed in June 2011. The inventory includes GHG emissions estimates for all sectors, including power generation and power consumption-based emissions of GHGs (CO_2, methane (CH_4), and nitrous oxide (N_2O)). According to the MDE inventory of 2006, Maryland's electricity consumption-based GHG emissions were about 42.2 million tons of carbon dioxide equivalent ($MMtCO_{2e}$), making up about 39 percent of total gross State GHG emissions.[15] The inventory includes all power plants in Maryland (both RGGI and non-RGGI generators) as well as small-scale and behind-the-meter generators, and utilizes the average PJM generation mix to estimate emissions associated with electricity imports.

[15] The other sectors addressed in the GGRA emissions inventory are: residential, commercial, and industrial fuel use; transportation; fossil fuel industry; industrial processes; agriculture; and waste management.

The GGRA implementation plan depends on a menu of mechanisms to reduce GHG emissions. These mechanisms include, among other things, the Maryland RPS, RGGI, and EmPOWER Maryland. All three of these existing programs are incorporated into the Reference Case and the alternative scenarios. However, since the GGRA does not include penalties for failure to meet its requirements, the LTER does not treat these requirements as binding constraints. Instead, the Reference Case and alternative scenarios indicate whether the GGRA's goals are likely to be achieved under each set of scenario-specific conditions.

3.5.5 Healthy Air Act

Maryland's Healthy Air Act (HAA) limits the emissions of NOx, SO_2, and mercury from Maryland coal plants. Under the HAA, emission limits are set for each plant, but owners of multiple plants can meet the requirement aggregated over all of their affected plants in the State. The NOx and SO_2 emissions rates for HAA plants were set at the unit level, based on research. The mercury emissions rates were averaged at the unit level, based on the actual emissions reported to the MDE for 2014. Table 3.10 lists the emissions rates applied to the Maryland HAA plants.

Table 3.10 Maryland HAA Plant Emissions Rates (lbs/MMBtu)

Facility	SO_2[1]	NOx	Mercury
Brandon Shores Unit 1	0.060	0.0797	0.000000883
Brandon Shores Unit 2	0.061	0.1072	0.000000883
Chalk Point Unit 1	0.075	0.1458	0.000001691
Chalk Point Unit 2	0.075	0.3165	0.000001691
C.P. Crane Unit 1	1.092	0.4126	0.000001646
C.P. Crane Unit 2	0.845	0.3834	0.000001646
Dickerson Unit 1	0.057	0.0370	0.000000285
Dickerson Unit 2	0.057	0.2536	0.000000285
Dickerson Unit 3	0.057	0.2576	0.000000285
Herbert A Wagner Unit 2	1.415	0.3490	0.000004391
Herbert A Wagner Unit 3	1.590	0.0759	0.000004391
Morgantown Unit 1	0.063	0.0370	0.000000093
Morgantown Unit 2	0.063	0.0385	0.000000093

[1] SO_2 rates represent averages over the study period. ABB changes these rates annually based on type of coal burned, and they are pre-scrubbed rates.

The ABB Model reports total emissions at the plant level and, therefore, captures all in-State emissions, which are reported in the results as being from Maryland. Carbon dioxide emissions are also calculated at the plant level and, therefore, can be reported at the state level. The same emissions rates were applied for each alternative scenario.

4. Reference Case Results

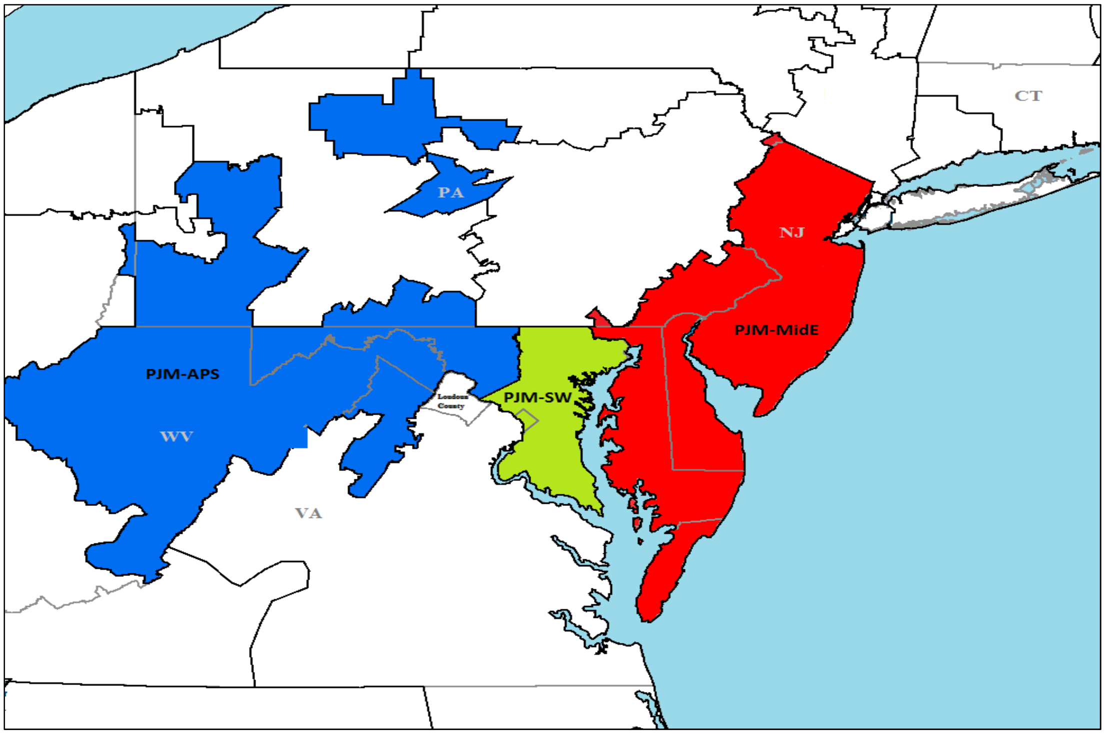
4.1 Introduction

As noted in Chapter 3, the Reference Case is based on a set of assumptions that incorporates existing legislation and regulations, the existing PJM backbone transmission system, existing power plants (including those currently under construction), and a forecast of energy and peak demand consistent with PJM's December 2015 forecast. Comparative results between this 2016 LTER Reference Case (2016 RC) and the 2013 LTER Reference Case Update (2013 RCU) will be presented at selected points throughout the chapter.[16,17] For these comparisons, the current 2016 RC results were truncated at 2030 to match the time period used for the 2013 RCU. Unless otherwise indicated, cost data is reported in 2015 dollars.

Throughout this section, results are presented for Maryland as a whole, as well as for the three ABB transmission zones that include portions of Maryland: PJM-APS, PJM-SW, and PJM-MidE, as shown in Figure 4.1. It is helpful to keep in mind that PJM-SW is comprised of the service territories of BGE, Pepco, and SMECO, and therefore also includes the District of Columbia. All plants added in the PJM-SW zone, however, are assumed to be constructed in Maryland. PJM-MidE includes all of the Delmarva Peninsula including Delaware, all of New Jersey, and the Philadelphia area. As such, Maryland's Delmarva territory is only a small portion of the PJM-MidE zone. Similarly, PJM-APS includes all of Allegheny Power, of which Maryland is only a small portion. Consequently, power plants "constructed" by the model that are located in either PJM-MidE or PJM-APS are not assigned to Maryland for purposes of reporting forecasted values such as Maryland emissions, Maryland power plant fuel use, or Maryland electric generating capacity.

[16] For the purpose of this specific comparative analysis in Chapter 4, the 2016 LTER Reference Case results will be referred to as the "2016 RC;" elsewhere in this report, they are addressed simply as the "Reference Case."
[17] Maryland Department of Natural Resources, Power Plant Research Program, *Long-Term Electricity Report for Maryland – Reference Case Update*, May 2013, http://pprp.info/pprac/Docs/LTER_RCU_FINAL.pdf.

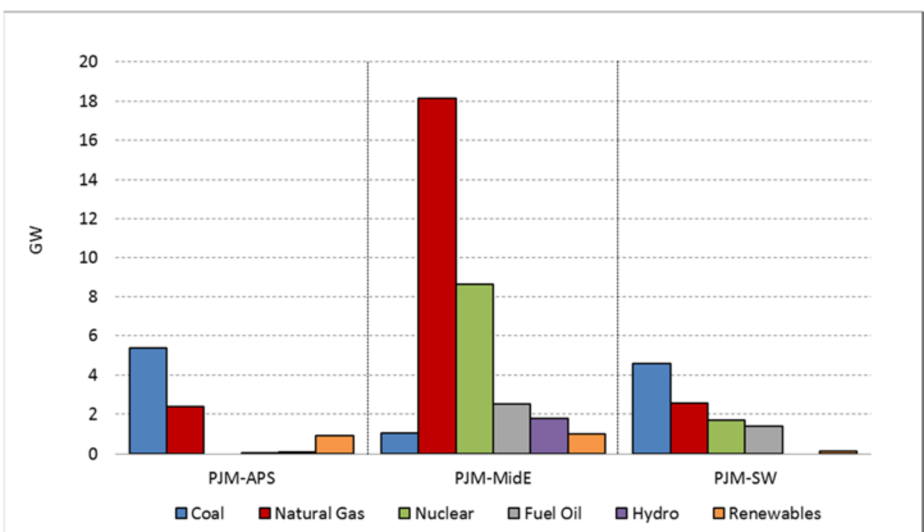
Figure 4.1 Transmission Zones in ABB Model That Include Maryland



Source: ABB.

It is also helpful to have a sense of each region's portfolio of generation resources at the beginning of the LTER study period, shown in Figure 4.2, since many results in this section are driven by the addition and/or retirement of plants in the three zones.

Figure 4.2 Current Generating Capacity by Fuel Type and PJM Transmission Zones



4.2 Capacity Additions and Retirements

Table 4.1 is based on the plants classified as "planned construction." To be considered "planned construction," a plant must have, at a minimum, obtained all necessary air permits. The plants summarized in Table 4.1 are included not only in the 2016 RC, but in all of the alternative scenarios considered.

Table 4.1 Planned Capacity Additions in PJM by Year (MW)

Primary Fuel Type	2015	2016	2017	2018	Total
Renewables	255	189	2	4	**451**
Fossil Fuels	2,495	4,840	4,764	260	**12,358**
Total	**2,749**	**5,029**	**4,766**	**264**	**12,809**

Note: In the "Fossil Fuel" category, combined cycle and combustion turbines represent approximately 80 percent of total planned capacity. Renewables represent approximately 3.5 percent of the total.

Source: ABB Midwest Fall 2015 Reference Case.

To satisfy the remaining demand in a transmission zone, the model either builds generic power plants or imports energy from other transmission zones, based on least-cost principles and reliability requirements. Total new generic natural gas capacity builds in PJM as a whole reach 42,170 MW by 2035 under the 2016 RC assumptions.

Figure 4.3 shows the cumulative additions to generating capacity added automatically by the model for the three PJM zones that include portions of Maryland: PJM-SW, PJM-MidE, and PJM-APS. All the plants are natural gas, combined cycle (CC) plants or natural gas, combustion turbines (CT).[18] This is not a modeling restriction; it is a result based on least-cost system additions. The zone with the largest increase in capacity additions is PJM-APS, where just over 7 GW are added. This is largely attributable to PJM-APS having lower power plant construction costs than either PJM-MidE or PJM-SW.

[18] The ABB Model adds discrete natural gas power plants. The effective capacity of combined cycle natural gas plants varies between 350-450 MW in summer, depending on the class of plant. See Table 3.4 for further detail.

Figure 4.3 Generic Natural Gas Capacity Additions – 2016 RC

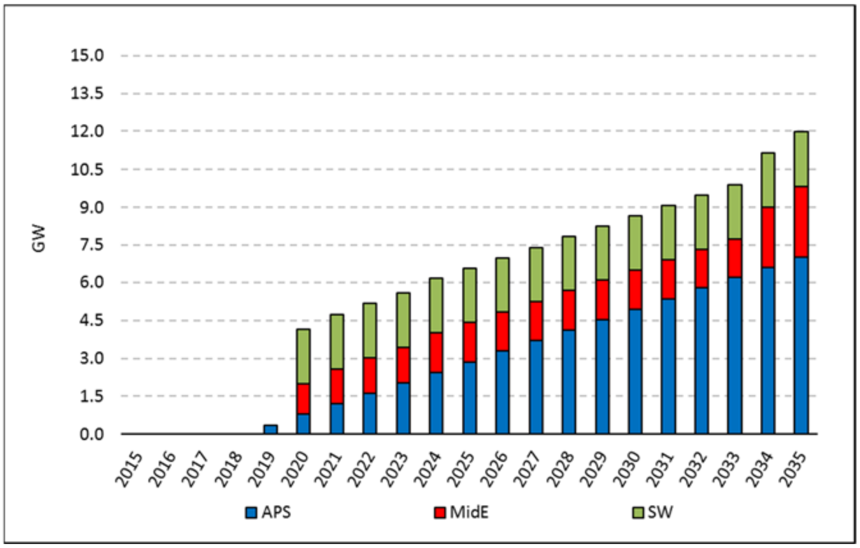
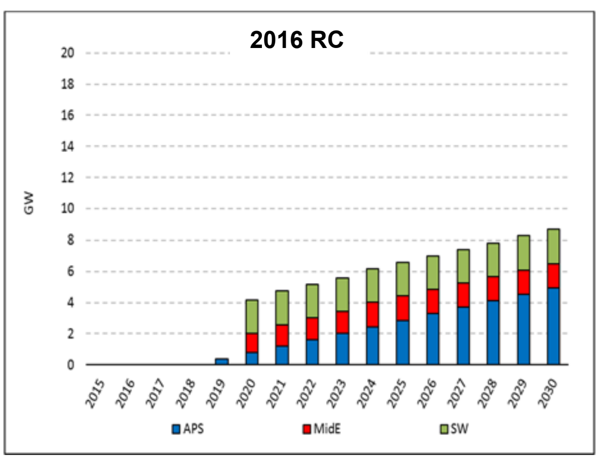
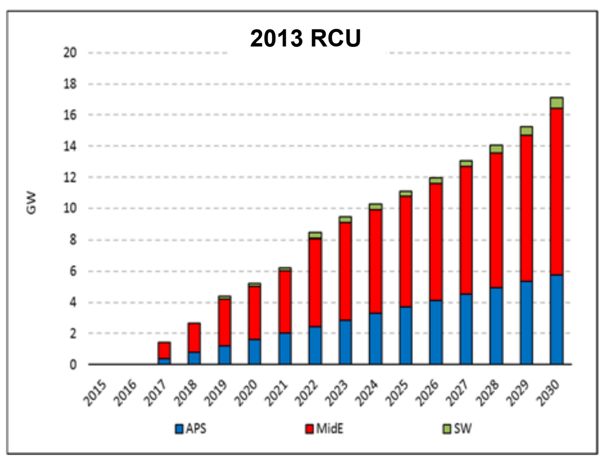


Figure 4.4 shows the cumulative generic capacity additions added by the ABB model for the 2016 RC (left side) and the 2013 RCU (right side) for PJM-SW, PJM-MidE, and PJM-APS. The amount of generic capacity added for the 2016 RC is about half that of the 2013 RCU, reflecting lower projected load growth. Note that the first plant added for the 2016 RC is in 2019 compared to 2017 for the 2013 RCU. Also, the amount of generic capacity added for PJM-MidE is much lower in the 2016 RC compared to the 2013 RCU, due principally to lower load growth in the 2016 RC. In addition, three large natural gas power plants are scheduled to come on-line in Maryland in the early years of the forecast period, thereby reducing the need for generic CC and CT builds in the 2016 RC.

Figure 4.4 Comparison of Cumulative Generic Natural Gas Capacity Additions – 2016 RC/2013 RCU Results





The ABB Model does not construct intermittent renewable energy generation to meet load requirements. To satisfy RPS requirements in the states with RPS legislation, renewable energy generation is added exogenously (i.e., as an input) to the model. When an RPS calls for a specific technology, such as solar technology related to Maryland's RPS solar carve-out, that specific technology is added by the model user. The remaining RPS compliance is met through additions of the least-cost qualifying technology. Maryland and other PJM states are assumed to fully meet the non-solar portion of the RPS through REC purchases rather than ACPs.

Table 4.2 shows the cumulative renewable energy capacity additions built in Maryland and PJM as a whole.[19] Through 2035, a total of 1,110 MW of renewable capacity is added in Maryland in the 2016 RC: 910 MW of solar capacity and 200 MW of off-shore wind capacity. In PJM as a whole, a total of 8,742 MW of renewable capacity (4,831 MW of solar capacity and 3,911 MW of non-solar renewable capacity) is added to meet the RPS requirements for the aggregate of PJM states.

Table 4.2 Cumulative Renewable Energy Capacity Additions (MW)

Year	Maryland	PJM Total
2015	13	896
2020	807	5,438
2025	949	7,276
2030	1,020	8,387
2035	1,110	8,742

Plant retirements occur for economic reasons or because of the age of the plant. In the 2016 RC, economic retirements are minimal; one 103-MW plant in PJM-SW retires in 2026.

Age-based retirements are significant because of the amount of older generating capacity operating in the PJM footprint. A little over 22.5 GW of generation capacity retires in PJM due to age during the study period, as shown in Table 4.3. This generation capacity retirement remains constant through all the LTER alternative scenarios with the exception of the CPP scenario which entails meeting the CPP emissions limitations by, in part, retiring certain coal generating facilities several years prior to when the model would have otherwise projected those plants retiring. The total MW of age-based retirements in PJM in the 2016 RC consists of 47 percent nuclear facilities, 20 percent coal facilities, 19 percent petroleum, 13 percent natural gas, and 1 percent biomass. Table 4.4 provides a summary of the generation capacity by technology and PJM transmission zones that are slated to close in Maryland, either due to announcements or for age-based reasons.

[19] The RPS discussion does not include the Maryland Tier 2 requirement, which sunsets in 2019.

Table 4.3 Age-based Retirements in PJM (MW)

Years	Fossil Fuels	Nuclear	Renewables	Total
2015-2020	3,975	--	131	**4,106**
2021-2025	2,315	--	--	**2,315**
2026-2030	2,850	2,018	--	**4,868**
2031-2035	2,693	8,522	--	**11,215**
Total	**11,833**	**10,540**	**131**	**22,504**

Note: Coal-fired power plant retirements represent approximately 40 percent of fossil fuel sources retired, natural gas retirements account for approximately 25 percent, and petroleum accounts for approximately 35 percent of total fossil fuel retirements

Source: ABB Midwest Fall 2015 Reference Case.

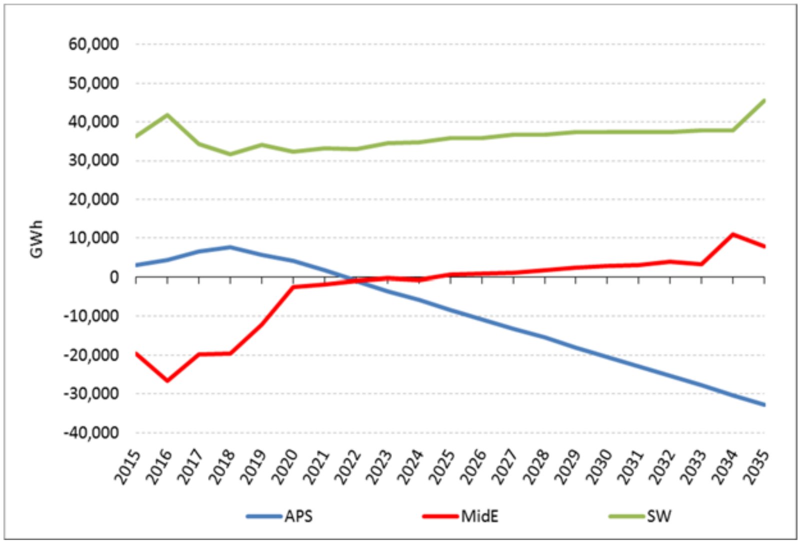
Table 4.4 Summary of Maryland Plant Retirements by PJM Transmission Zones

Area	Fuel Type	Last Retirement Year	Name Plate (MW)
PJM-MidE	Oil	2027	80
PJM-SW	Coal	2035	718
PJM-SW	Natural Gas	2030	530
PJM-SW	Oil	2023	741
PJM-SW	Uranium	2034	1,050

4.3 Net Imports

Maryland imports a significant portion of its total energy requirement—over 40 percent in recent years—due to the comparatively lower cost of power generation elsewhere in PJM. For example, Maryland and Delaware are the only states in PJM that belong to RGGI, which raises operational costs for power plants in the two states. The ABB Model primarily builds and utilizes power plants outside Maryland in general, and outside PJM-SW in particular due to operating as well as construction cost disparities. This can be observed in Figure 4.5, which shows that net imports into PJM-SW tend to be higher than PJM-MidE or PJM-APS. In PJM-APS, net imports drop to zero in 2022 with PJM-APS becoming a net exporter for the remainder of the modeling periods. This occurs as PJM MidE changes from a net-exporting to a net-importing transmission zone.

Figure 4.5 Net Imports by PJM Transmission Zone – Reference Case



Note: Negative values represent net exports.

4.4 Fuel Use

Generation mix indicates how much electricity the various types of power plants (e.g., coal, natural gas, nuclear, wind, etc.) generate within a given time period. Figure 4.6 shows the projected generation mix in Maryland under the 2016 RC set of assumptions.[20] The increase in natural gas generation beginning in 2017 is due, in large part, to the expectation that two combined cycle plants in Maryland—the 800-MW Keys Energy Center and the 746-MW St. Charles facility—will come online. Over the remainder of the study period, a gradual decline in natural gas output occurs alongside a gradual increase in coal output due to changes in the relative expected costs of each fuel. As shown in Figure 4.8 later in this chapter, natural gas prices are expected to rise more rapidly than coal prices. On a per-MMBtu basis, natural gas becomes more expensive than coal in 2017, and that relationship persists through the end of the analysis period (2035). It is noted that no new coal plants are added in Maryland or in PJM during the study period. The increase in the generation mix attributable to coal stems from the more intensive use of the existing fleet of coal-fired generation in response to the lower relative price of coal. The drop in nuclear generation at the end of the study period is due to the retirement of Calvert Cliffs 1, a 1,050-MW nuclear facility located in PJM-SW.

[20] As discussed earlier, new plants in PJM-MidE and PJM-APS are not attributed to Maryland.

Figure 4.6 Maryland Generation Mix – 2016 RC

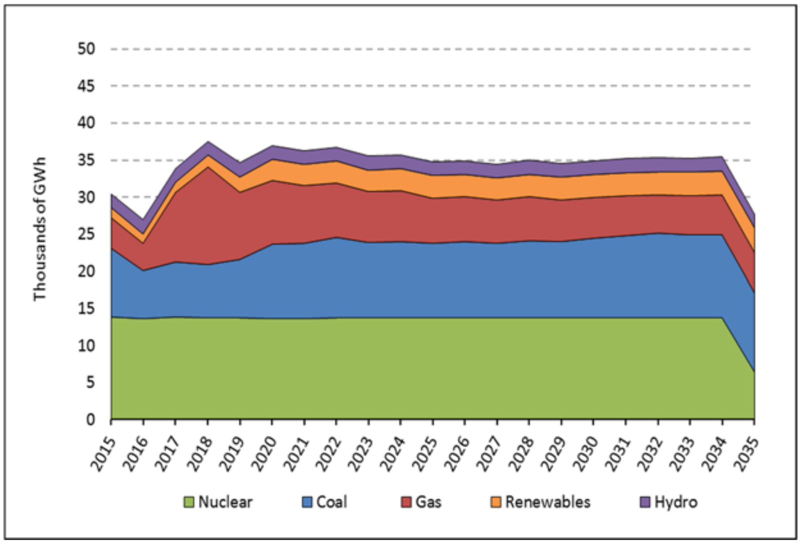


Figure 4.7 shows the projected generation mix in Maryland under the 2016 RC (left side) and the 2013 RCU (right side). Generation in Maryland for the 2016 RC is approximately 40 percent lower than in the 2013 RCU, with the difference almost entirely due to lower amounts of coal-fired generation. Lower projected load growth and the economics of natural gas as compared to coal, are the primary reasons behind this drop in coal generation in Maryland. Additionally, a small coal plant in Maryland retired.

Figure 4.7 Maryland Generation Mix – Comparison of 2016 RC/2013 RCU Results

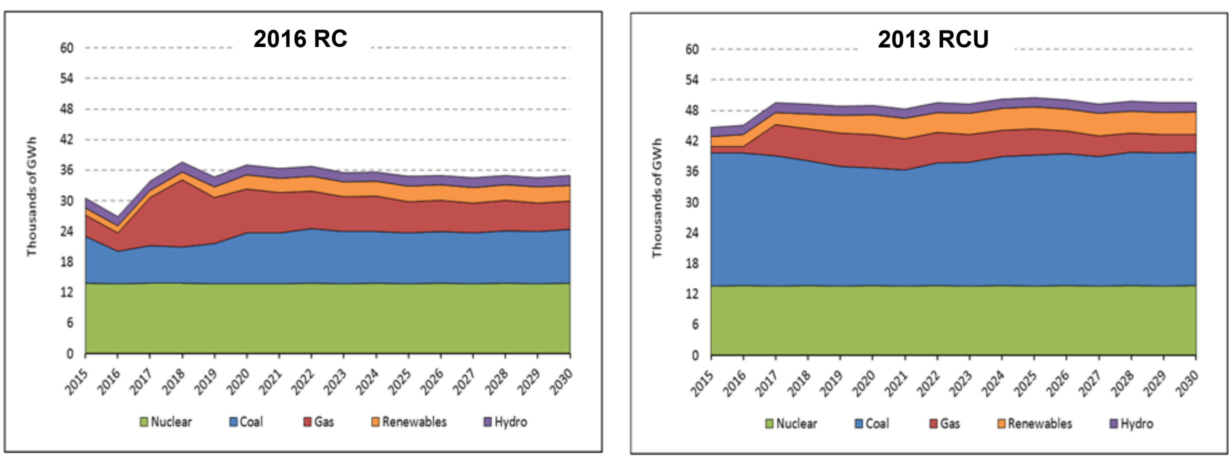


Figure 4.8 compares the natural gas and coal price projections, on a per-MMBtu basis, relied upon in the 2016 RC. As shown in the figure, natural gas price increases during the early years of the analysis cause natural gas to be more expensive than coal, and that relationship persists over the remainder of the analysis period.

Figure 4.8 Coal and Natural Gas Price Projections – 2016 RC

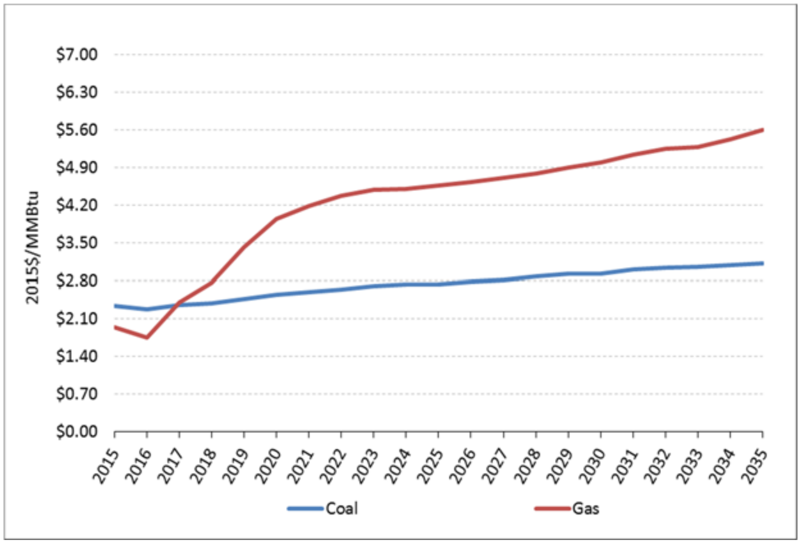


Figure 4.9 shows coal use and natural gas use for electricity generation in Maryland. The use of natural gas and coal reflects the changes in the relative prices of the two fuels (shown in Figure 4.8) and mirrors the generation profile shown in Figure 4.6. For comparison purposes, Figure 4.10 shows coal and natural gas use in PJM as a whole. Note that in Figure 4.9, the decline in natural gas use largely extends from 2019 through the end of the projection period. Coal use in the State, however, remains relatively flat after 2020. This relationship suggests that the declines in natural gas usage in Maryland are not fully offset by the increase in coal use. Looking at the analogous figure representing coal and natural gas use in PJM, Figure 4.10, natural gas use begins to increase in 2023, suggesting that some of the decline in natural gas generation in Maryland is being replaced by natural gas generation elsewhere in PJM.

Figure 4.9 Coal and Natural Gas Use for Electricity Generation in Maryland – 2016 RC

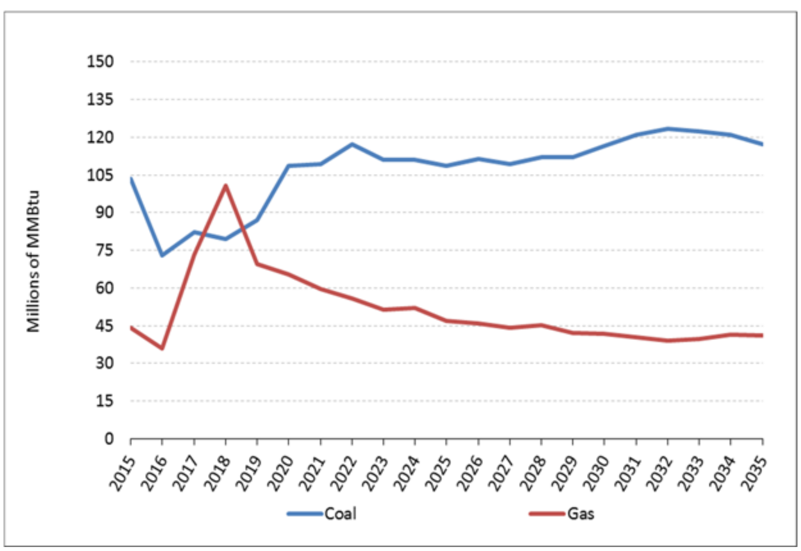


Figure 4.10 Coal and Natural Gas Use for Electricity Generation in PJM – 2016 RC

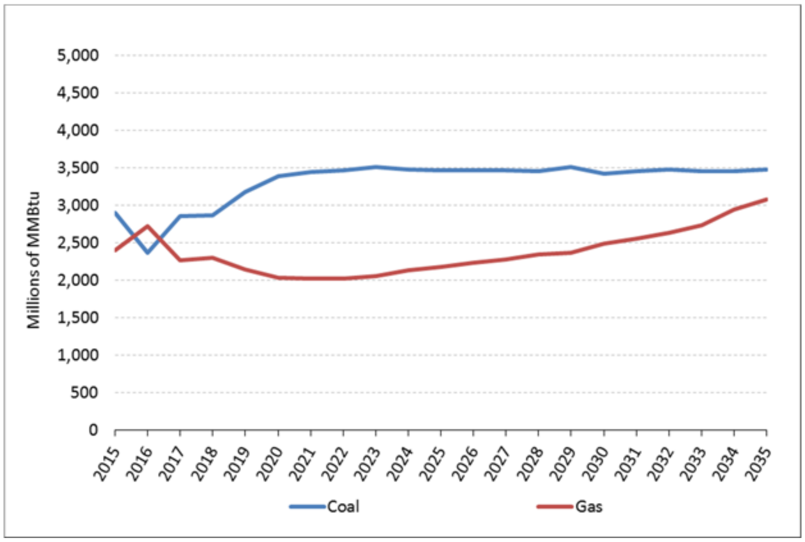
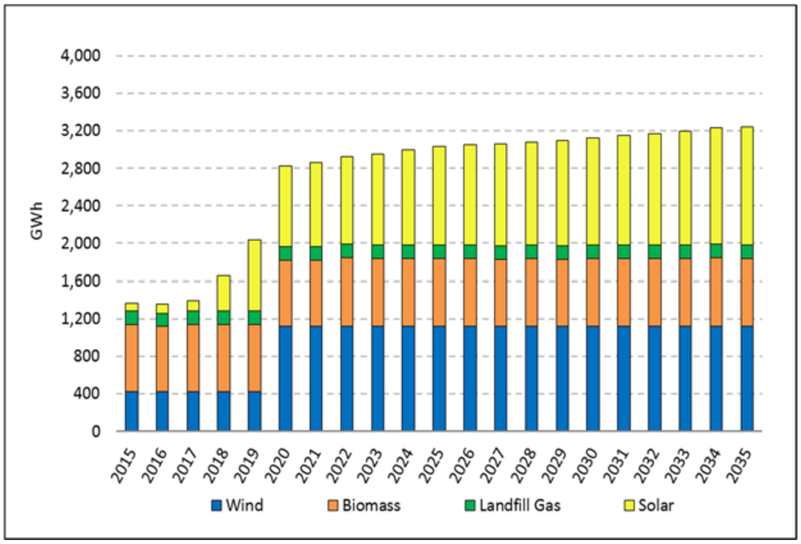


Figure 4.11 shows the total renewable energy generation in Maryland under the 2016 RC assumptions. The most significant jump in renewable energy generation in Maryland occurs in 2020, when 200 MW of off-shore wind are assumed to come online as a result of the Maryland Off-Shore Wind Act of 2013.[21] Meanwhile, utility-scale solar capacity and production are assumed to rise throughout the study period, due to a combination of solar-specific RPS requirements, federal incentives, and falling installation costs.[22] Through 2019, increases in solar capacity are based on actual proposed facilities. Solar capacity is then assumed to increase 4.0 percent annually from 2020-2024 to reflect the high level of solar construction activity expected to occur as solar developers take advantage of the ITC;[23] 1.5 percent annually from 2025 through 2028, as development lags after the preceding boom; and 2 percent annually for the rest of the study period.

[21] The 2016 RC assumes that a 500-MW off-shore wind project will be built. Two hundred MW of this project are assumed to be located in waters that fall under Maryland's jurisdiction, with the remainder elsewhere in the PJM-MidE transmission zone.
[22] PJM diminishes its load forecast to reflect the contribution of distributed solar generation. Distributed solar generation, therefore, is not reflected in Figure 4.11.
[23] A 30 percent solar ITC is available for both residential and commercial projects through 2019. The solar ITC then drops to 26 percent in 2020 and to 22 percent in 2021. In 2022, the solar ITC expires for residential applications and drops permanently to 10 percent for commercial projects.

Figure 4.11 Maryland Renewable Energy Generation – 2016 RC



Note: Distributed solar generation not reflected.

4.5 Energy Prices

Energy prices in all zones dip slightly during 2015, based on historical values and then increase steadily, in real terms, throughout the study period, as natural gas prices increase. Table 4.5 shows the all-hours energy prices for PJM-SW, PJM-MidE, PJM-APS, and the PJM average.[24]

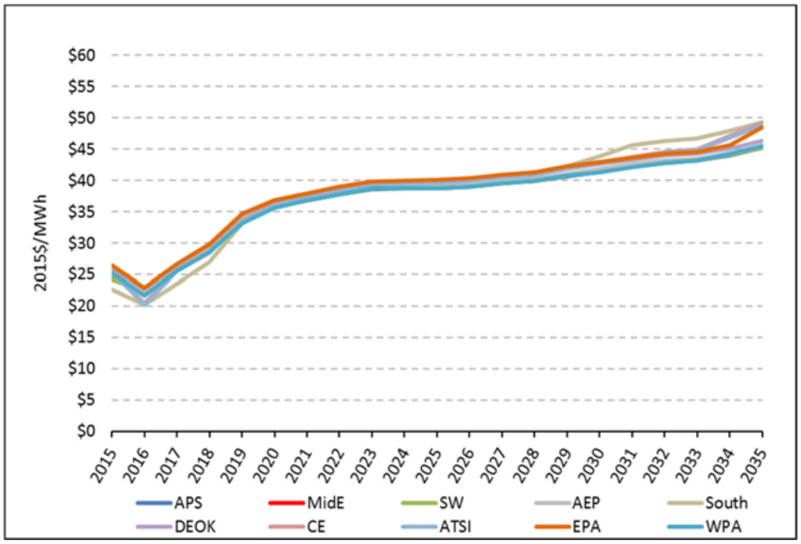
[24] Energy prices are hours-weighted rather than load-weighted. Load-weighted prices would be slightly higher since prices tend to be higher when loads are higher.

Table 4.5 PJM All-hours Energy Prices (2015$/MWh)

Year	PJM-SW	PJM-MidE	PJM-APS	PJM Average
2015	$26.38	$25.58	$25.61	$24.98
2016	22.89	20.46	22.43	21.79
2017	26.65	25.72	26.26	25.72
2018	29.78	28.60	29.36	28.83
2019	34.70	33.58	34.40	33.87
2020	36.79	36.31	36.47	36.12
2021	37.90	37.64	37.47	37.29
2022	38.99	38.61	38.43	38.30
2023	39.86	39.57	39.17	39.18
2024	39.93	39.62	39.20	39.26
2025	40.05	39.72	39.22	39.32
2026	40.36	40.06	39.49	39.62
2027	40.94	40.64	40.00	40.16
2028	41.34	41.09	40.34	40.57
2029	42.23	42.14	41.08	41.44
2030	42.93	42.90	41.85	42.30

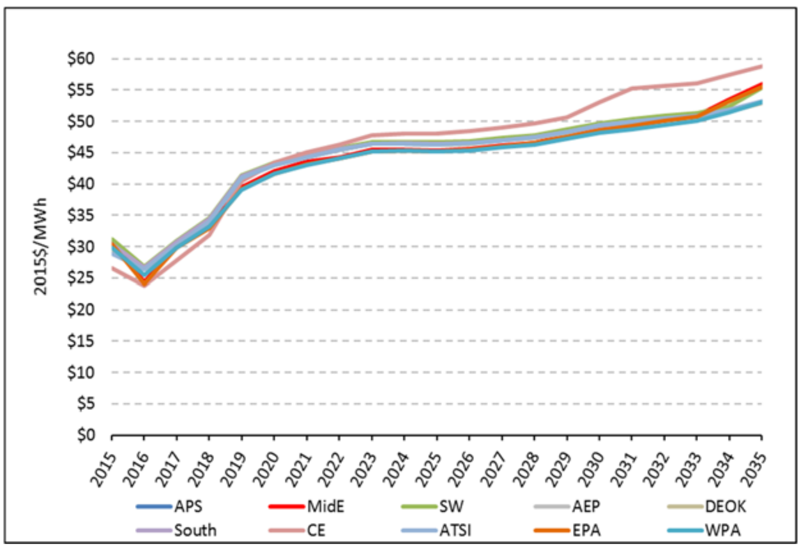
Figure 4.12 through Figure 4.14 show wholesale energy prices for all PJM transmission zones. There is little difference among energy prices throughout PJM, indicating relatively modest transmission congestion due to generation projected to be built in both the eastern and western PJM zones to address demand growth, and to replace retiring generation. One exception to the general price uniformity among the PJM zones is the Commonwealth Edison zone (PJM-CE) in Illinois. During the on-peak period, PJM-CE zone prices are about $5/MWh higher than the prices elsewhere in PJM starting in 2031 and continuing at higher levels throughout the analysis period, though with diminishing differentials during the last two years of the analysis period. This pattern of PJM-CE prices suggests that added congestion costs during the on-peak period diminish over time. Price differentials during the off-peak period, shown in Figure 4.14, appear to begin diverging slightly towards the end of the analysis period, through never in excess of $5/MWh.

Figure 4.12 PJM All-hours Energy Prices – 2016 RC



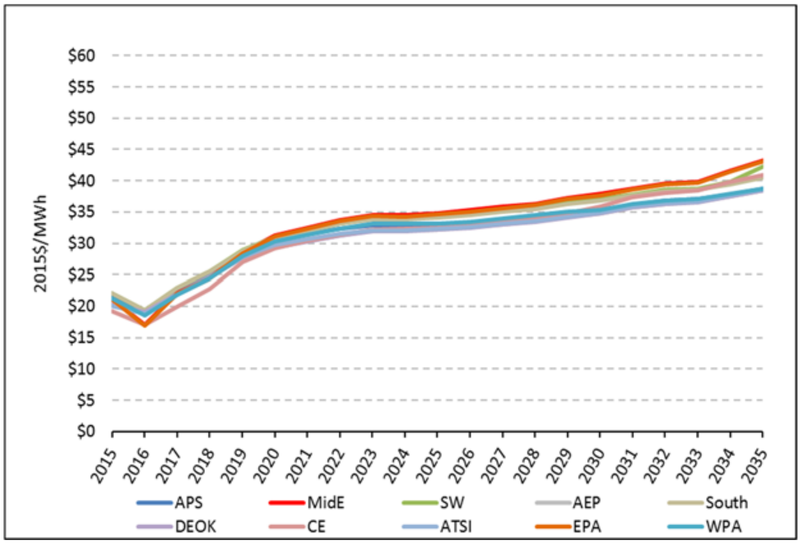
Note: See Table 3.1 for definitions of the transmission zones.

Figure 4.13 PJM On-peak Energy Prices – 2016 RC



Note: See Table 3.1 for definitions of the transmission zones.

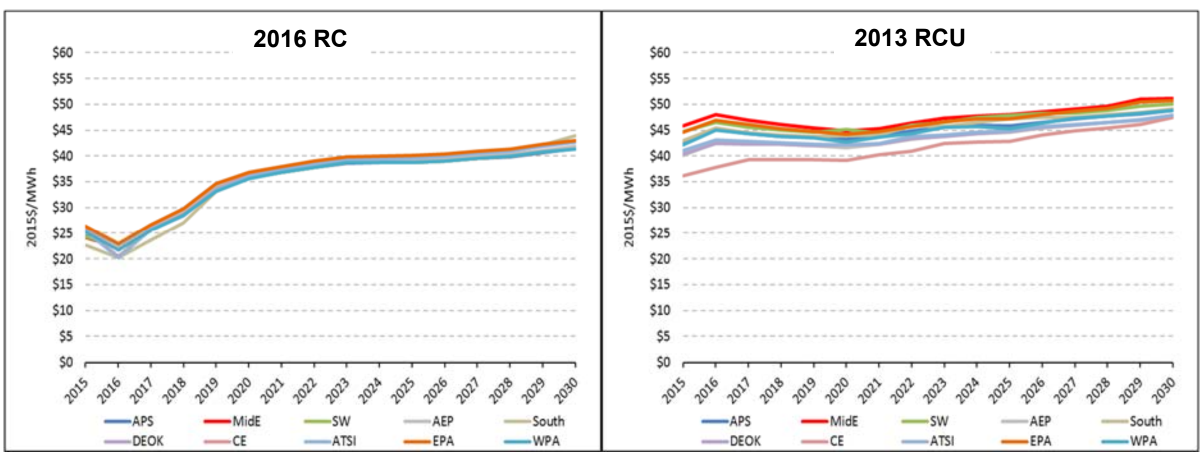
Figure 4.14 PJM Off-peak Energy Prices – 2016 RC



Note: See Table 3.1 for definitions of the transmission zones.

Figure 4.15 compares wholesale energy prices for all PJM transmission zones for the 2016 RC (left side) and the 2013 RCU (right side). As noted, there is little difference among energy prices throughout PJM for the 2016 RC. In contrast, the 2013 RCU has more price separation between the western and eastern zones of PJM, although the difference narrows toward the end of the forecast period as the wholesale prices converge. The narrowing of the differences is due to reduced west-to-east transmission congestion as additional power plants are constructed in the eastern portions of PJM to meet reliability requirements.

Figure 4.15 PJM All-hours Price Comparison – 2016 RC/2013 RCU Results



Note: See Table 3.1 for definitions of the transmission zones.

4.6 Capacity Prices

The ABB Model uses actual PJM Reliability Pricing Model (RPM) capacity prices through 2019 (the years available at the time the modeling was conducted). From 2015 to 2019, PJM overall is in a capacity supply surplus situation.[25] Therefore, the capacity values are calculated as "make-whole" payments for the marginal unit (see Chapter 2) until load growth requires new generation additions. As new generation is built, capacity prices can be calculated by the model using a cost-of-entry variable and thus capacity costs increase to levels more in line with the cost of new entry during the last ten years of the study period. Figure 4.16 shows projected capacity prices for the three transmission zones that include portions of Maryland. The average real price (2015$) for capacity in the PJM-SW zone from 2026 to 2035 is $152 per MW-day; for PJM-MidE, $203 per MW-day; and for the other PJM zones including PJM-APS, $210 per MW-day. Capacity prices rise sharply in PJM-SW and PJM-MidE in 2019 and 2020 for two reasons. First, the capacity prices through 2018 for all three transmission zones (PJM-SW, PJM-MidE, and PJM-APS) reflect actuals.[26] The 2019 capacity price is the first year that modeled prices are presented, and a degree of actuals-to-project discontinuity is evident. The increase in capacity prices also reflects the need for new generating capacity in both PJM-MidE and PJM-SW; new natural gas generation is added to both zones in 2020. Capacity prices decrease in both zones after 2020 as pressure to meet reliability requirements is eased through new generation (including renewables) and imports of power from the PJM-APS zone.

Figure 4.16 PJM Capacity Prices – 2016 RC

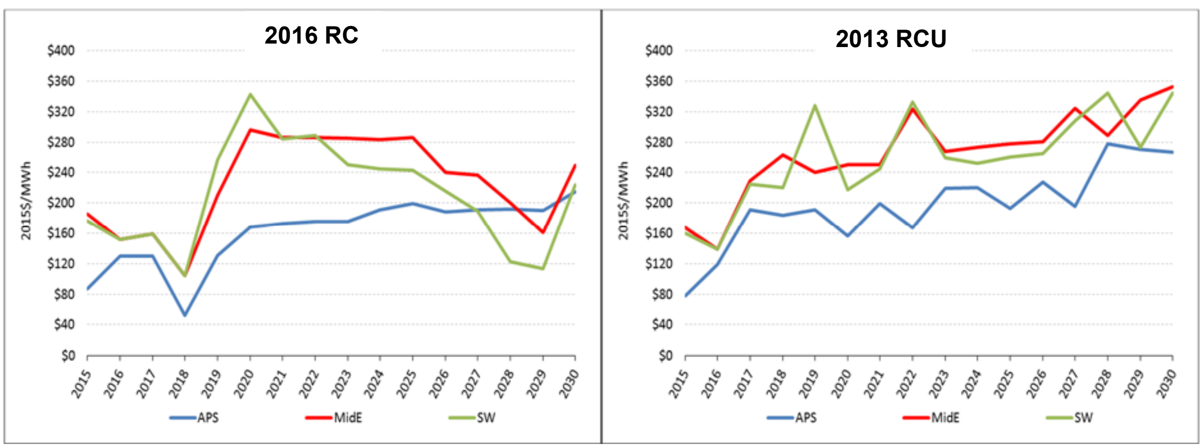
The capacity prices generated by the model can vary significantly from year to year and are highly sensitive to new generation, transmission system expansion, and load levels. Further, when PJM

[25] "Supply surplus" means available generating capacity exceeds peak demand requirements plus the PJM reserve margin of approximately 15 percent of peak demand.
[26] Capacity prices determined through the PJM RPM auction process are established three years in advance.

(or a zone within PJM) is characterized by excess generating capacity, capacity prices projected by the model tend to be relatively low ($150/MW-day). These results are consistent with actual capacity prices emerging from the PJM RPM auctions. It should be recognized that the capacity prices simulated by the model for any particular year may not accurately reflect actual future capacity prices for that year. In the 2011 LTER, as well as the 2013 RCU, a three-year rolling average of capacity prices was used to smooth capacity price projections that often changed substantially from one year to the next, and sometimes increased and decreased significantly over short periods of time. The current capacity projections resulting from the 2016 RC set of modeling assumptions are more stable than capacity prices that have characterized the results obtained in past LTER analyses, and as a consequence, no multi-year averaging is relied upon herein.

Figure 4.17 depicts capacity prices for the 2016 RC (left side) and the 2013 RCU (right side) through 2030. Capacity prices in the 2016 RC for the PJM-MidE and PJM-APS zones rise sharply between 2018 and 2020, then generally decrease through the end of the analysis period. Capacity prices gradually increase in the PJM-APS zone throughout the forecast period. Capacity prices for all three zones nearly converge in 2030. By comparison, capacity prices for the 2013 RCU for all three zones, with some year-to-year volatility, gradually rise throughout the forecast period. In both analyses, the PJM-APS capacity prices tend to be below the PJM-MidE and PJM-SW capacity prices, which tend to exhibit similar values.

Figure 4.17 Comparison of Capacity Prices – 2016 RC/2013 RCU Results



4.7 Emissions

4.7.1 Emissions in Maryland

Coal-fired power plants in Maryland are subject to the Maryland HAA. Coal plants that expect to continue operation in Maryland have already installed the SO_2 and NOx pollution abatement technologies necessary to comply with the HAA. Figure 4.18 through Figure 4.20 show HAA plant emissions for SO_2, NOx, and mercury. As shown in these three figures, the Maryland coal plants are able to stay well below the HAA emission caps, even with increases in coal generation projected to result from coal becoming less costly, on a per-Btu basis, than natural gas in the early years of the projection period.[27]

Figure 4.18 Maryland SO_2 Emissions (HAA Plants) – 2016 RC

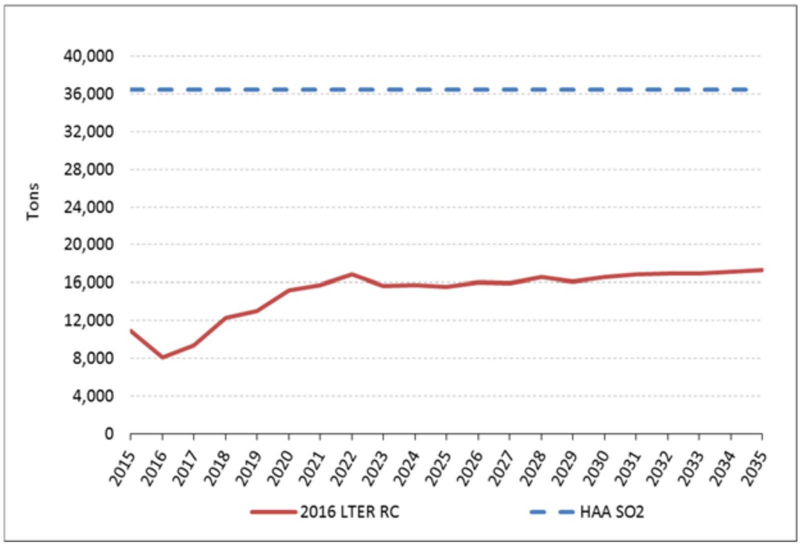
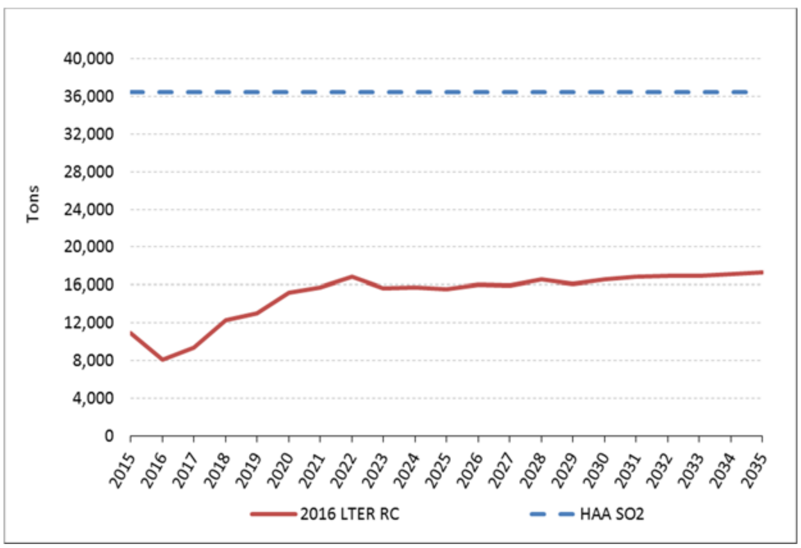


Figure 4.19 Maryland NOx Emissions (HAA Plants) – 2016 RC



[27] For the results of the 2016 RC, as well as for the results of the alternative scenarios, estimated emissions are based on generation by power plants located in Maryland. Another approach for estimating emissions attributable to Maryland is to focus on projected electricity *consumption* specific to Maryland. Appendix G provides the emissions projections over the analysis timeframe using electricity consumption in Maryland data as the main parameter for each of the scenarios.

Figure 4.20 Maryland Mercury Emissions (HAA Plants) – 2016 RC

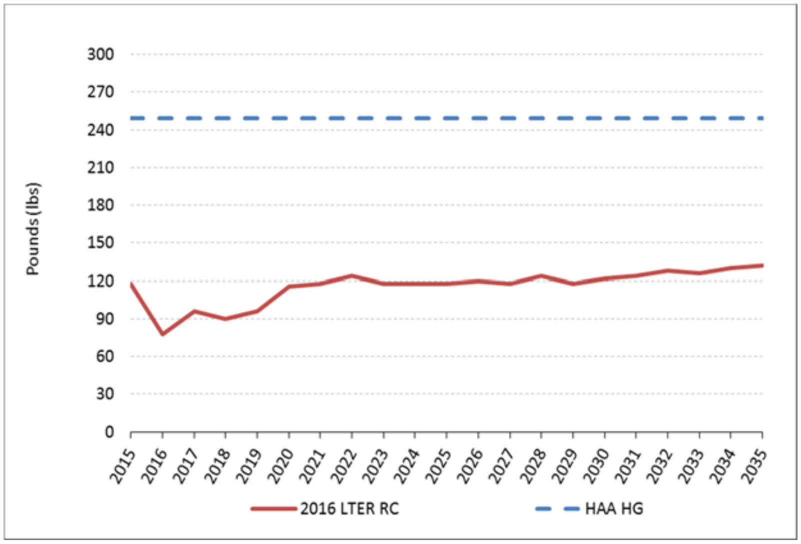


Figure 4.21 and Figure 4.22 illustrate HAA plant emissions for SO_2 and NOx for the 2016 RC and the 2013 RCU. SO_2 and NOx emissions are much lower for the 2016 RC compared to the 2013 RCU because of lower projected electric energy demand, therefore requiring less generation, and the lower levels of coal generation compared to natural gas generation. Though not shown, mercury emissions are also projected to be lower in the 2016 RC than in the 2013 RCU.

Figure 4.21 Comparison of HAA Plant SO_2 Emissions – 2016 RC/2013 RCU Results

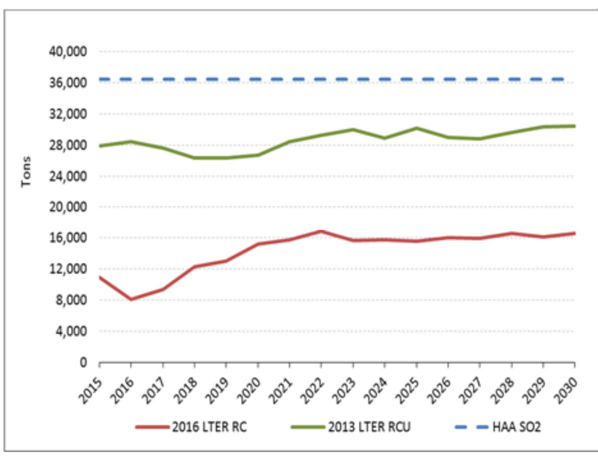
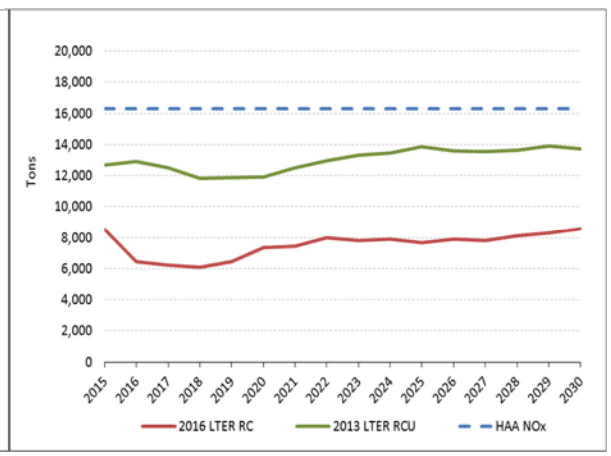


Figure 4.22 Comparison of HAA Plant NOx Emissions – 2016 RC/2013 RCU Results



Unlike the HAA's fixed limits on SO_2, NOx, and mercury emissions by Maryland coal plants, RGGI sets a region-wide limit on CO_2 emissions and individual plants purchase emissions allowances as needed. The number of CO_2 emission allowances are agreed to by the RGGI states to limit the ability of RGGI power plants, in the aggregate, to emit CO_2. In the 2016 RC, Maryland plants exceed the State's RGGI budget for CO_2 emissions (see Figure 4.23), but by purchasing emissions allowances allocated to other RGGI states Maryland would not be out of compliance with RGGI. An alternative scenario involving the earlier retirement of several Maryland-based coal plants is discussed in Chapter 9, and reflects a reduction in CO_2 emissions which brings the State within the RGGI budget without allowances.[28]

Figure 4.24 shows the RGGI budget and CO_2 emissions for the 2016 RC (left side) compared to the 2013 RCU (right side). The RGGI budget cap was lowered since the RCU, which is why the RGGI budget cap is different for both sides of Figure 4.24. Carbon dioxide emissions were lower than the RGGI budget cap for the 2013 RCU but exceed the revised lower cap for the LTER.

Figure 4.23 Maryland CO_2 Emissions (Power Plants) – 2016 RC

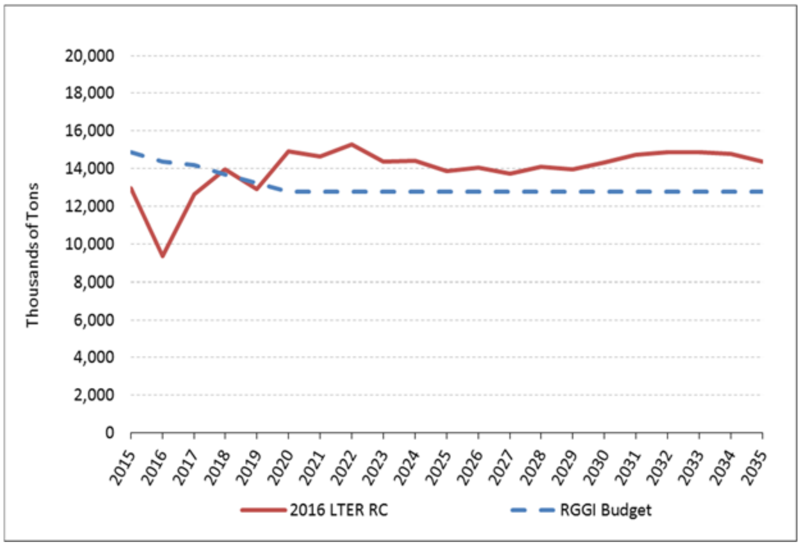
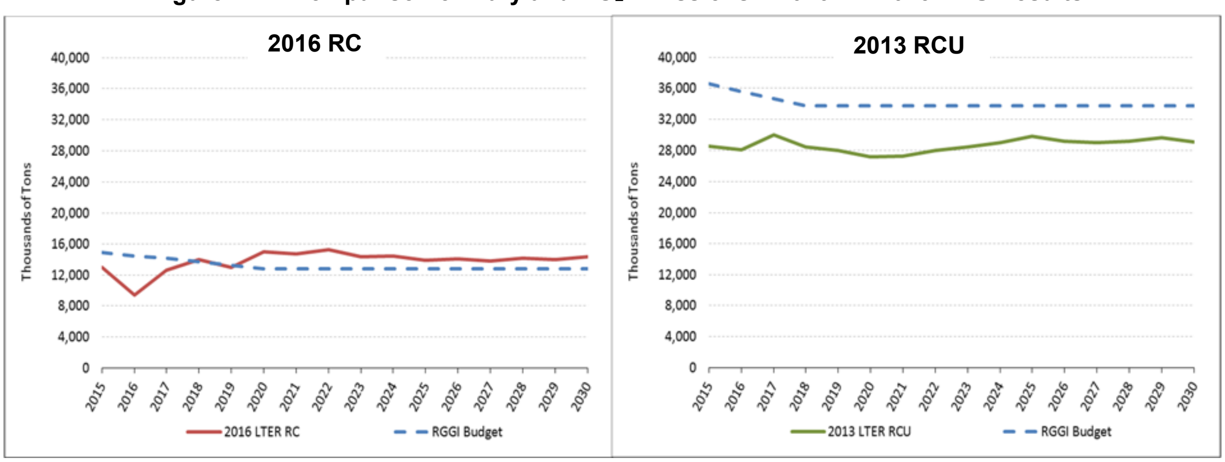


Figure 4.24 Comparison of Maryland CO_2 Emissions – 2016 RC/2013 RCU Results



[28] In Appendix H, a hypothetical approach related to RGGI is presented: the level of the increase in RGGI prices, above the Reference Case, which would influence Maryland plant owners to operate below the State's RGGI budget for economic reasons.

4.7.2 Emissions in PJM

Figure 4.25 through Figure 4.28 show PJM-wide emissions of SO_2, NOx, mercury, and CO_2 from power plants within the PJM footprint. Following some declines in emissions in the early years of the projection period resulting from enhancing emission control technology at certain plants in PJM (as determined based on public announcements), the general pattern of emissions is slight increases that are consistent with increases in the overall level of generation. The PJM emissions graphs presented in this chapter, which addresses the 2016 RC results, establish the baseline from which to evaluate the level of PJM emissions resulting from modified scenario assumptions. The 2015 values in each figure are historical, while those from 2016 onwards are projections.

Figure 4.25 PJM SO_2 Emissions (Power Plants) – 2016 RC

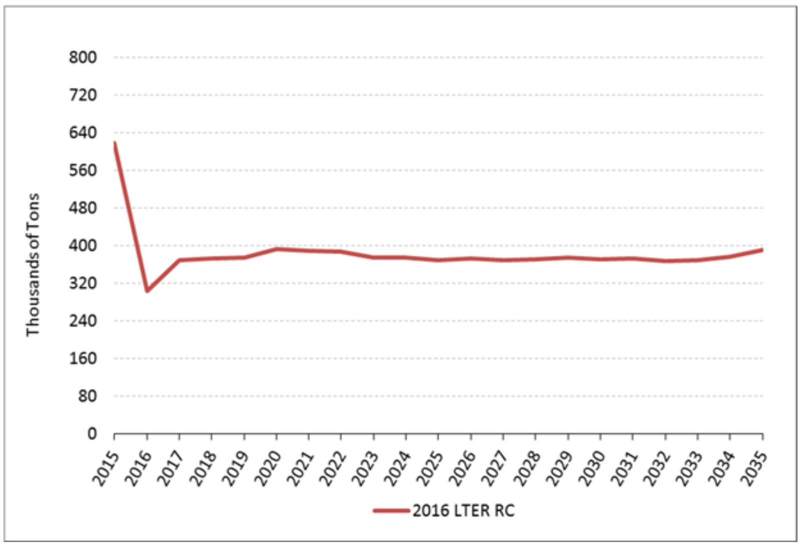


Figure 4.26 PJM NOx Emissions (Power Plants) – 2016 RC

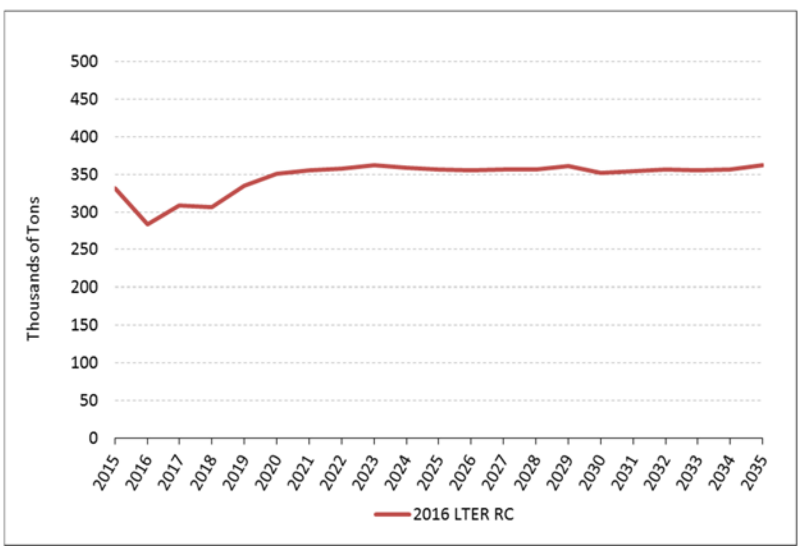


Figure 4.27 PJM Mercury Emissions (Power Plants) – 2016 RC

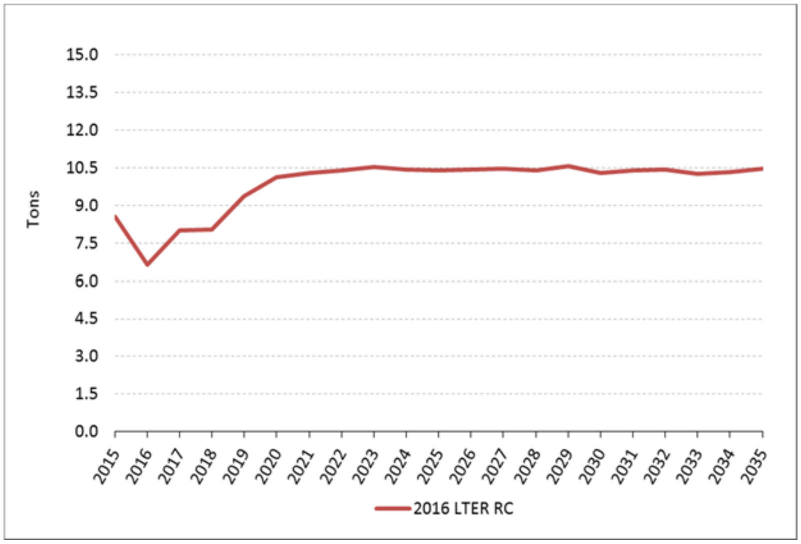
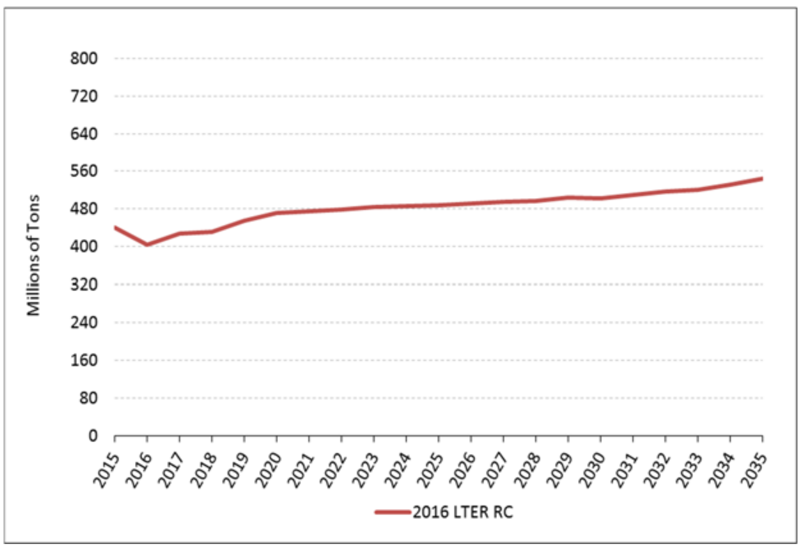


Figure 4.28 PJM CO_2 Emissions (Power Plants) – 2016 RC



4.8 Renewable Energy Credit Prices

For the years 2015 through 2017, REC prices are based on actual transactions for the following RECs: D.C. Tier 1; Delaware "New;" Illinois PJM-GATS "Other;" Illinois PJM-GATS Wind; Maryland Tier 1; New Jersey Class 1; and Pennsylvania Tier 1. The method used to develop the REC prices for the remainder of the study period are described in Section 2.2.3. REC prices are projected to fall as energy prices increase and as the growth of renewable energy generation capacity in PJM and neighboring Independent System Operators (ISOs) outpaces the need for RECs for RPS compliance, thus allowing renewable project developers to recover a larger portion of project costs through energy charges (see Figure 4.29).

Figure 4.29 Renewable Energy Credit Prices – 2016 RC

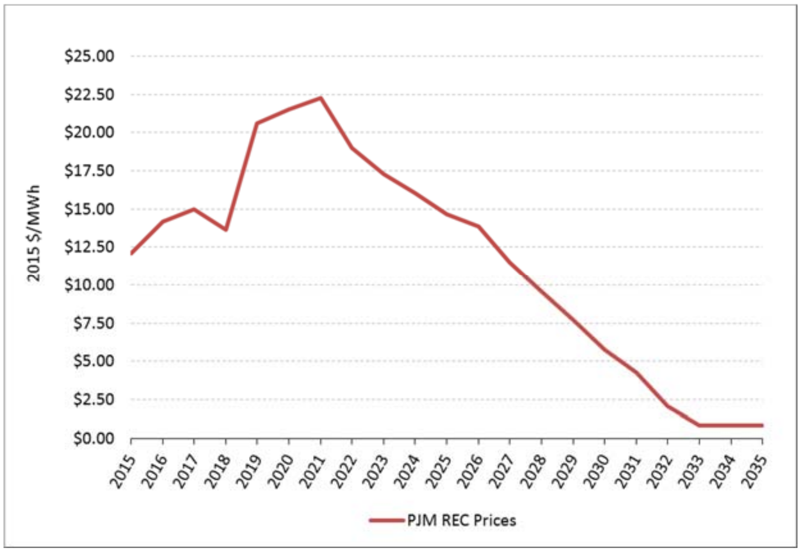
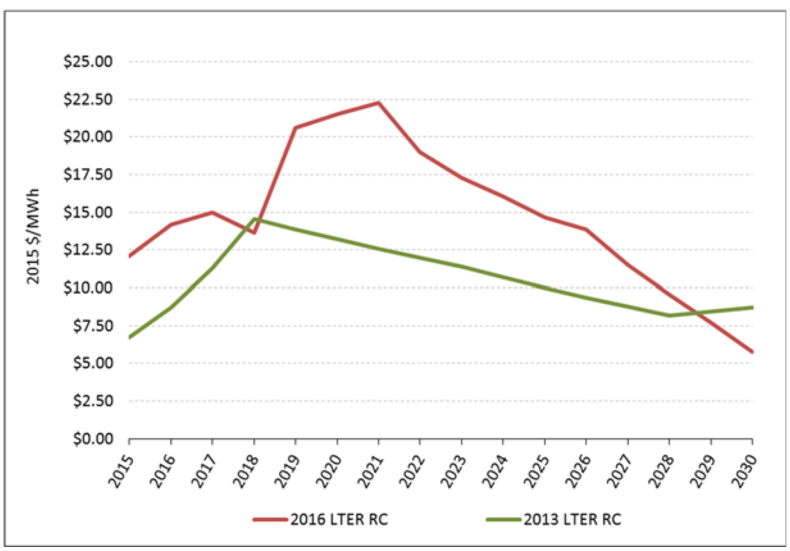


Figure 4.30 illustrates REC prices for the 2016 RC and the 2013 RCU. REC prices for the 2016 RC rise sharply to $21 by 2021 before falling for the rest of the forecast period. By comparison, REC prices for the 2013 RCU do not rise as sharply as the 2016 RC, but do not fall as sharply, either, ending at just under $8 in 2030 compared to about $6 for the 2016 RC. The differences in the REC price projections are largely attributable to differences in the projected wholesale energy prices. That is, because the 2013 RCU energy prices were projected to be higher than the 2016 RC results, the RECs prices, calculated principally as "make whole" payments, would be lower.

Figure 4.30 Renewable Energy Credit Prices – 2016 RC/2013 RCU Results



4.9 Summary of Key Results

The principal results to emerge from the 2016 RC analysis, which will be used to gauge the impacts of alternatives to the 2016 RC, are:

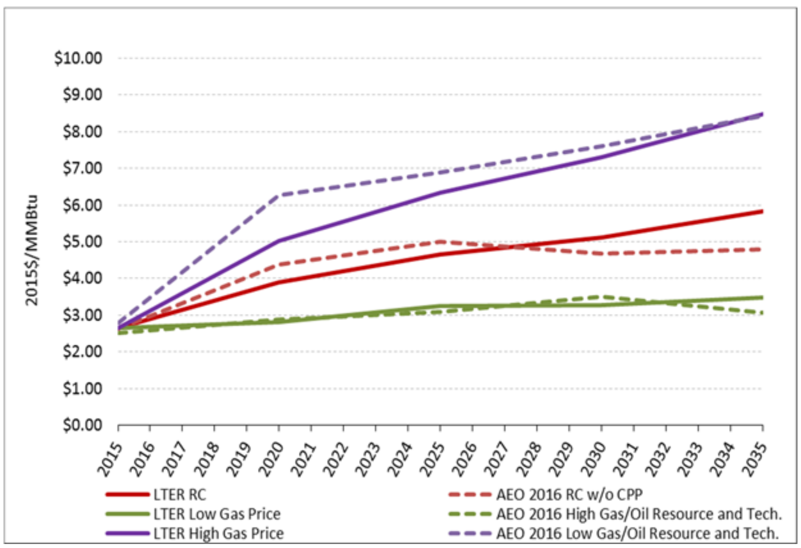
- New generation resources are expected to be either natural gas combined cycle units or combustion turbines based on least-cost evaluation criteria.
- Emissions of NOx, SO_2, and mercury from Maryland power plants subject to Maryland's HAA remain below the HAA caps for those pollutants throughout the study period.
- Emissions of CO_2 are shown to exceed Maryland's RGGI budget during the later years of the study period, which will require Maryland generation facilities to purchase RGGI emissions allowances from other RGGI states and/or purchase offsets in order for the State to comply with its RGGI obligations.
- Real energy prices are expected to rise gradually during the study period, due principally to increases in the real price (2015$) of natural gas from $2.65/MMBtu in 2015 to $5.83/MMBtu in 2035.
- Capacity prices are projected to fluctuate over the study period, ending at a slightly higher value in each transmission region of relevance to Maryland. Capacity price differentials among transmission zones are also anticipated to fluctuate, though capacity prices in PJM-APS are projected to generally be below the capacity prices in PJM-MidE and PJM-SW.
- REC prices are projected to increase through 2021 to approximately $21 per REC, then decline throughout the remainder of the analysis period to less than $1 per REC.

5. Natural Gas Price Alternative Scenarios

5.1 Introduction

One of the most important drivers of wholesale electricity prices is the price of natural gas. To explore the effects of alternative natural gas price assumptions, two competing scenarios were developed: a High Price Natural Gas (HPNG) scenario and a Low Price Natural Gas (LPNG) scenario. Average natural gas prices in the Reference Case and both natural gas price scenarios start at $2.65 per MMBtu in 2015.[29] Prices rise to $3.48/MMBtu by 2035 in the LPNG scenario, $5.83/MMBtu in the Reference Case, and $8.47/MMBtu in the HPNG scenario. Figure 5.1 and Table 5.1 show average annual natural gas prices for the Reference Case and the two natural gas scenarios. For comparison purposes, natural gas price trajectories for three analogous scenarios from the U.S. Energy Information Agency's (EIA's) *Annual Energy Outlook* report for 2016 (AEO 2016) are also shown.[30] While minor differences can be seen between each pair of scenarios, the overall spread in natural gas prices is similar.

Figure 5.1 Forecast of the Average Annual Natural Gas Price at Henry Hub – Natural Gas Scenarios



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[29] The natural gas prices presented in this chapter are for Henry Hub, the most liquid natural gas hub in the U.S. The ABB Model employs Henry Hub natural gas prices adjusted for transportation from Henry Hub.

[30] The AEO 2016 High Gas/Oil Resource and Technology scenario corresponds to the LTER Low Price Natural Gas scenario.

Table 5.1 Comparison of Natural Gas Price Projections (2015$/MMBtu)

Year	Reference Case	LTER Low Price Natural Gas	LTER High Price Natural Gas	AEO 2016 Reference Case w/o CPP	AEO 2016 High Oil/Natural Gas Resource and Technology	AEO 2016 Low Oil/Natural Gas Resource and Technology
2015	$2.65	$2.65	$2.65	$2.62	$2.51	$2.78
2020	3.89	2.82	5.02	4.37	2.89	6.27
2025	4.65	3.24	6.34	5.00	3.08	6.88
2030	5.12	3.27	7.30	4.68	3.50	7.61
2035	5.83	3.48	8.47	4.80	3.06	8.43

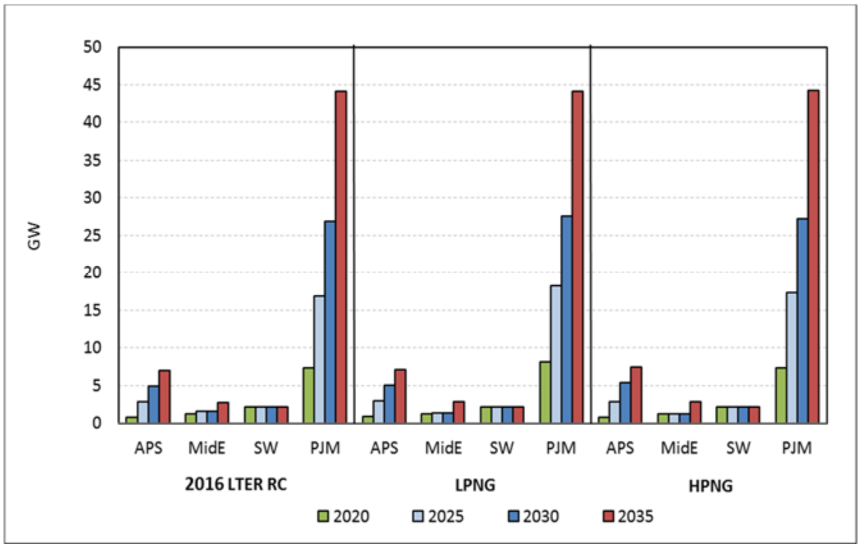
5.2 Capacity Additions and Retirements

Plant retirements in PJM are, at most, modestly affected by natural gas price projections. In both the Reference Case and the HPNG scenario, only one 103-MW plant retires due to economic factors. Under the LPNG scenario, the same plant and two others retire, representing a total of 475 MW. All three of these plants are coal-fired generators that came on-line before 1961.

Natural gas price variations also have little impact on overall capacity additions in PJM. As shown in Figure 5.2 and Table 5.2, 44.1 GW of new natural gas capacity are added in the Reference Case and LPNG scenario, while 44.3 GW are added in the HPNG scenario.[31] While there are modest differences in the location of new generating capacity among the three transmission zones considered, owing to slightly different economics due to the coal price/natural gas price differential, the differences are small.

[31] This result may be due in part to the ABB Model's design. The ABB Model is not structured such that loads change in response to changes in energy prices. Increases in natural gas prices result in increased electricity prices and, in turn, would result in reduced electricity consumption. In the ABB Model, electricity consumption levels are not sensitive to changes in price and hence the amount of retired coal-fired generation that would result from an increase in natural gas prices may be understated.

Figure 5.2 Cumulative Generic Natural Gas Capacity Additions (2020-2035) – Natural Gas Scenarios



Note: Average of summer and winter capacity ratings.

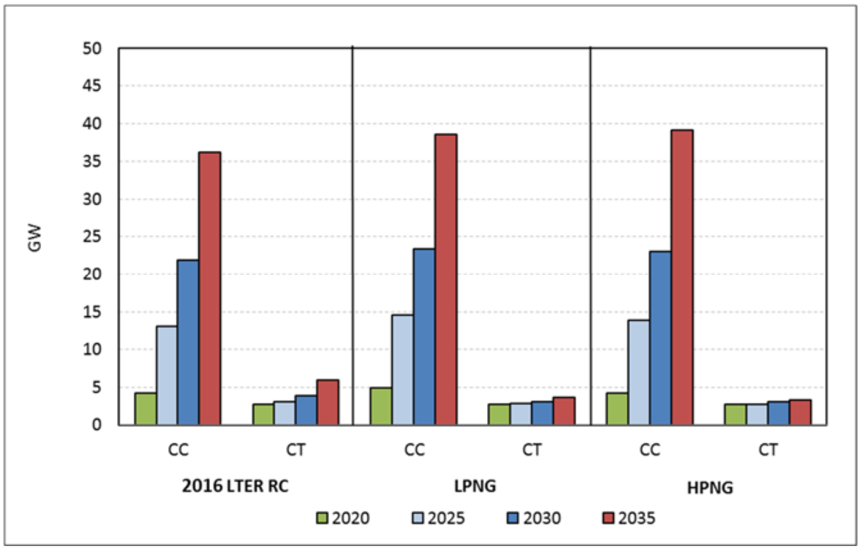
Table 5.2 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – Natural Gas Scenarios (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	1.57	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (LPNG minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.11	--	--	0.75
2025	0.11	(0.17)	--	1.41
2030	0.11	(0.17)	--	0.71
2035	0.11	0.11	--	(0.02)
Difference (HPNG minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	--	--	--
2025	--	(0.35)	--	0.48
2030	0.42	(0.35)	--	0.38
2035	0.42	0.07	--	0.13

Note: Average of summer and winter capacity ratings.

Variations in natural gas price projections do not significantly affect the type of natural gas plants that are built to meet reliability requirements. The two lowest-cost technologies for new generation are natural gas-fired combined cycle (CC) units and combustion turbine (CT) units. CTs have a lower per-MW installed capacity cost than CCs but are less efficient and therefore more expensive to run. As shown in Figure 5.3 and Table 5.3, regardless of the price of natural gas over the range of prices considered, CCs are more economic than CTs and represent the preferred technology under all three natural gas price assumptions (Reference Case, HPNG, and LPNG).

Figure 5.3 PJM Cumulative Natural Gas Additions – Natural Gas Scenarios



Note: Summer capacity rating.

Table 5.3 Comparison of Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – Natural Gas Scenarios (GW)

Reference Case (RC)		
Year	**CC**	**CT**
2020	4.25	2.72
2025	13.05	3.04
2030	21.85	3.84
2035	36.25	5.92
Difference (LPNG minus RC)		
Year	**CC**	**CT**
2020	0.70	--
2025	1.50	(0.16)
2030	1.50	(0.80)
2035	2.30	(2.24)
Difference (HPNG minus RC)		
Year	**CC**	**CT**
2020	--	--
2025	0.80	(0.32)
2030	1.20	(0.80)
2035	2.80	(2.56)

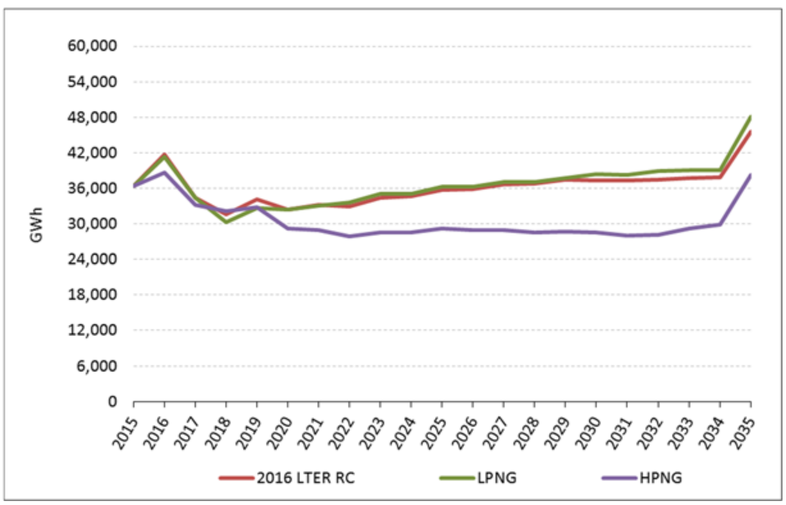
Note: Summer capacity rating.

5.3 Net Imports

Net imports in PJM-SW, PJM-Mid-E, and PJM-APS are shown in Figure 5.4 through Figure 5.6. In PJM-SW and PJM-APS, higher natural gas prices in the HPNG scenario cause coal plants—the primary form of generating capacity in both regions—to be used more intensively, which drives imports down relative to the Reference Case. In PJM-MidE—where natural gas is the predominant fuel used for electricity generation—higher gas prices cause plants in the region to be used less intensively, driving up imports.

There is very little change in electric energy imports in the PJM-SW transmission zone in the LPNG case (natural gas prices are low) relative to the Reference Case (shown in Figure 5.4). The reason for this is that under the HPNG assumptions, coal plants are run more intensively and hence coal-fired exports from the PJM-SW zone increase. Under the LPNG scenario assumptions, coal plants are less intensively used as is also true in the Reference Case; since the PJM-SW transmission zone does not contain very much natural gas capacity, the lower natural gas prices do not significantly affect generation relative to the Reference Case.

Figure 5.4 PJM-SW Net Imports – Natural Gas Scenarios



Net imports in the PJM-MidE zone (shown in Figure 5.5) decrease with low natural gas prices and increase with high natural gas prices. This result is based on relatively high levels of natural gas generation in the zone which includes not only the Maryland Eastern Shore, but also all of New Jersey and the Philadelphia area.

In the PJM-APS zone, changes in natural gas prices have little effect on net energy imports for most of the projection period (shown in Figure 5.6). Towards the end of the projection period, low natural gas prices cause an increase in imports (relative to the Reference Case) and high natural gas prices reduce net imports. The higher natural gas prices cause increases in coal-fired generation, thereby increasing the amount of coal-fired power being exported. Similarly, with low natural gas prices, coal-fired power is less economically attractive and less coal-fired energy is exported from PJM-APS, thereby increasing net imports relative to the Reference Case.

Figure 5.5 PJM-MidE Net Imports – Natural Gas Scenarios

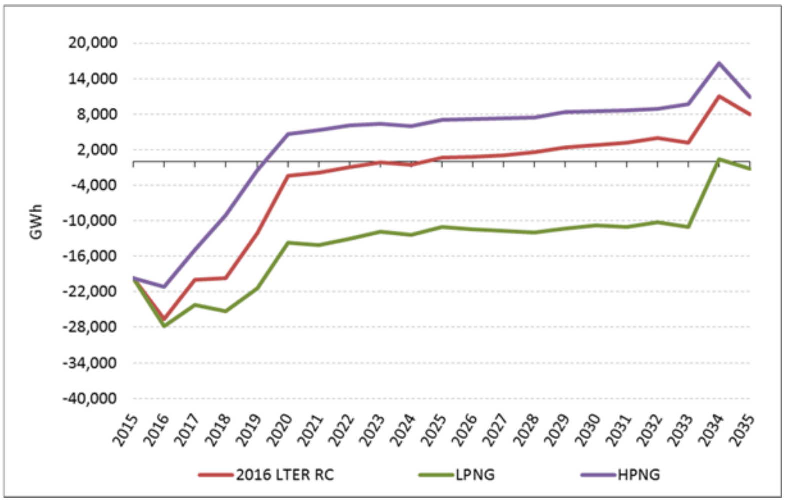
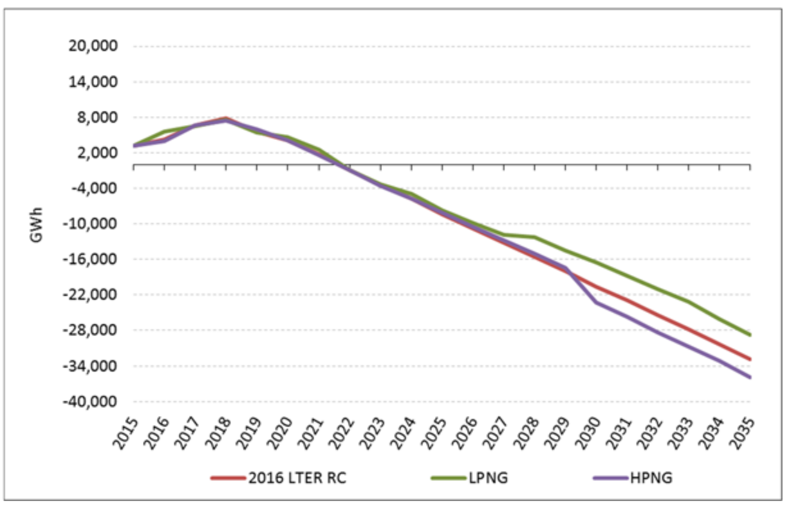


Figure 5.6 PJM-APS Net Imports – Natural Gas Scenarios



5.4 Fuel Use

Natural gas prices affect coal and natural gas use for electric generation in Maryland significantly, as shown in Figure 5.7 and Figure 5.8. High natural gas prices increase the use of existing coal plants in Maryland while decreasing the use of natural gas plants. The reverse is true for low natural gas prices. However, in the HPNG scenario, the increase in coal use in Maryland is far more significant than the corresponding drop in natural gas use. This is due to the coal-heavy nature of Maryland's generation fleet. Across PJM as a whole, the trade-offs between coal and natural gas use are more balanced, as shown in Figure 5.9 and Figure 5.10.

Figure 5.7 Coal Use for Electricity Generation in Maryland – Natural Gas Scenarios

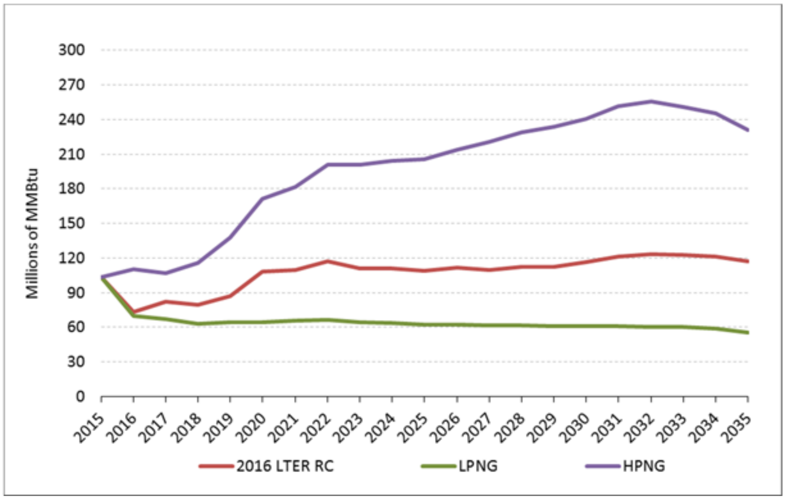


Figure 5.8 Natural Gas Use for Electricity Generation in Maryland – Natural Gas Scenarios

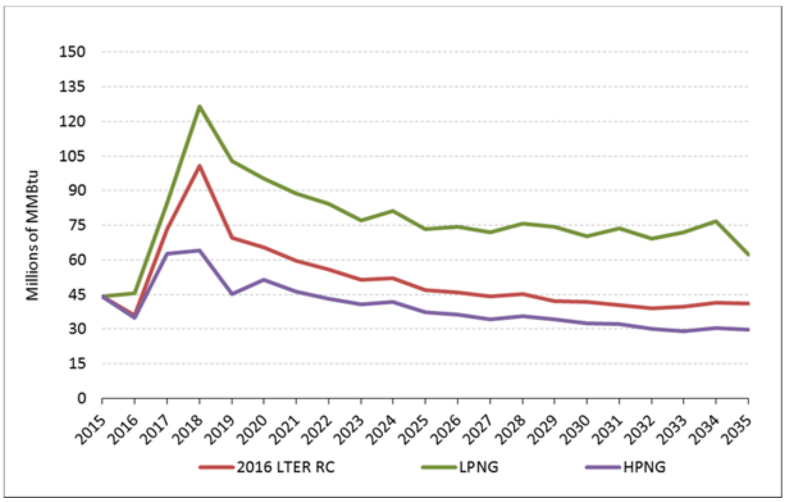


Figure 5.9 Coal Use for Electricity Generation in PJM – Natural Gas Scenarios

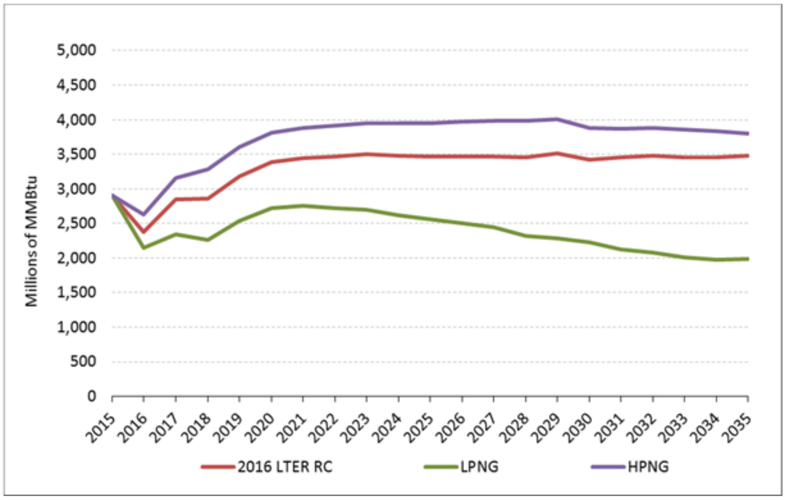
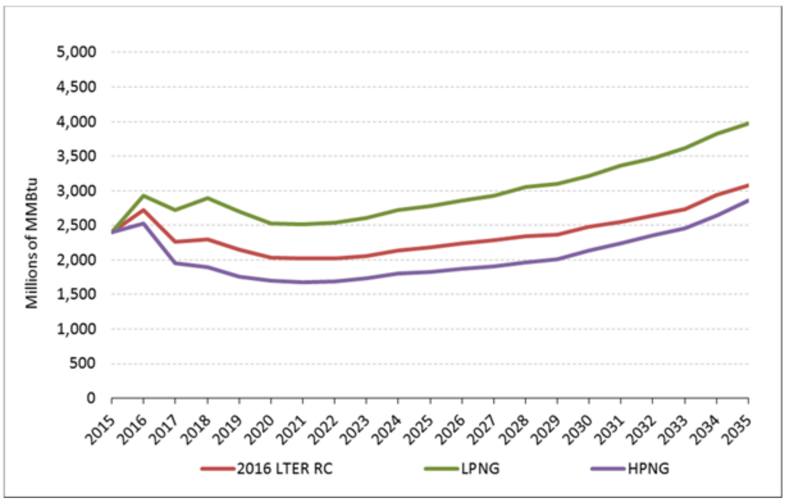


Figure 5.10 Natural Gas Use for Electricity Generation in PJM – Natural Gas Scenarios



As natural gas prices affect coal and natural gas use within Maryland, the overall generation mix in the State changes dramatically, as shown in Table 5.4. In the LPNG scenario, the share of natural gas generation in 2035 is 34 percent (compared to 20 percent in the Reference Case); coal is 19 percent (compared to 39 percent in the Reference Case); and nuclear is 26 percent (compared to 23 percent in the Reference Case). The capacity factors for coal-fired plants are higher in the HPNG scenario, while the capacity factor of combined cycle natural gas plants is lower. The reverse is true in the LPNG scenario.

Table 5.4 Maryland Generation Mix – Natural Gas Scenarios

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	5%
2025	Reference Case	34,757	40	29	18	5	9
	HPNG	42,370	32	45	11	4	8
	LPNG	33,856	41	16	29	5	9
2035	Reference Case	27,641	23	39	20	7	11
	HPNG	36,412	18	58	11	5	9
	LPNG	24,677	26	19	34	8	13

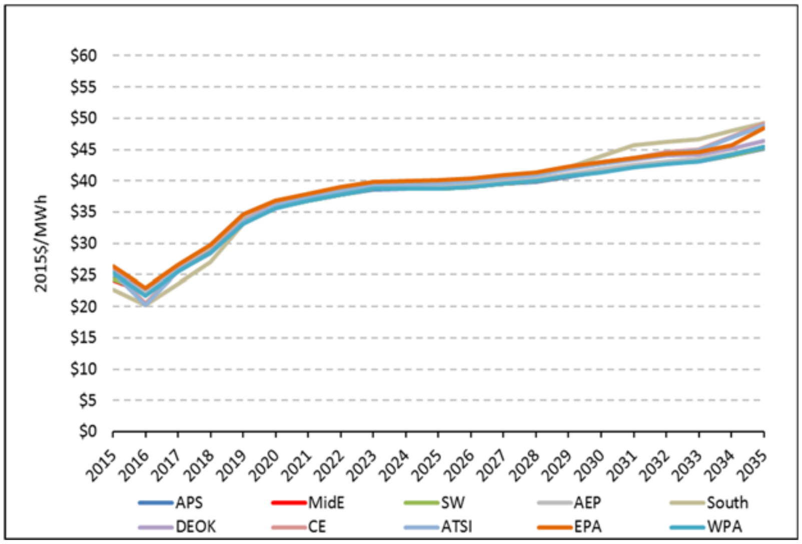
5.5 Energy Prices

Natural gas prices have a significant and direct impact on PJM electricity prices. In the Reference Case, electricity prices increase nearly uniformly across PJM, throughout the study period, as shown in Figure 5.11. The gradual rise in real electricity prices shown in Figure 5.11 corresponds to the gradual rise in real natural gas prices over the analysis period.[32] In the HPNG scenario, electricity prices ultimately rise about 30 percent higher than in the Reference Case. Conversely, in the LPNG scenario, electricity prices ultimately fall about 30 percent lower than in the Reference Case. Figure 5.12 through Figure 5.14 show all-hours, on-peak, and off-peak electricity price projections for PJM-SW.[33]

[32] See Figure 5.1.

[33] PJM-SW is representative of the trends in price across all three zones; that trend is more clearly demonstrated with a single (one zone) set of data.

Figure 5.11 PJM All-hours Energy Prices – Reference Case



Note: See Table 3.1 for definitions of the transmission zones.

Figure 5.12 PJM-SW All-hours Energy Prices – Natural Gas Scenarios

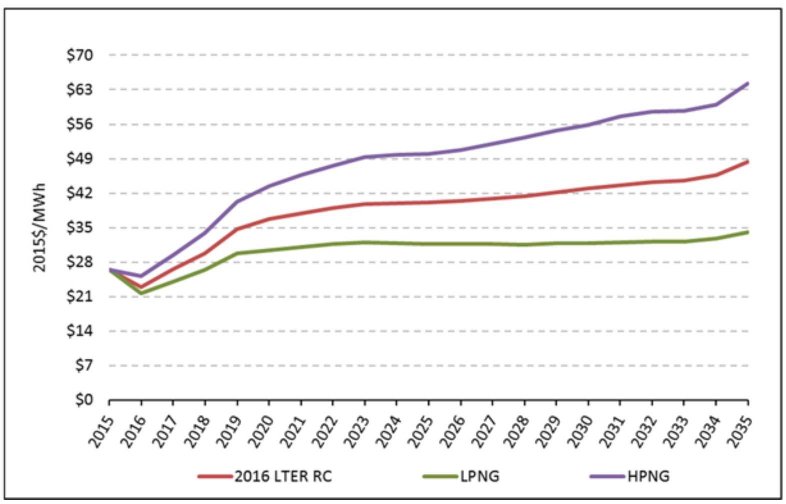


Figure 5.13 PJM-SW On-peak Energy Prices – Natural Gas Scenarios

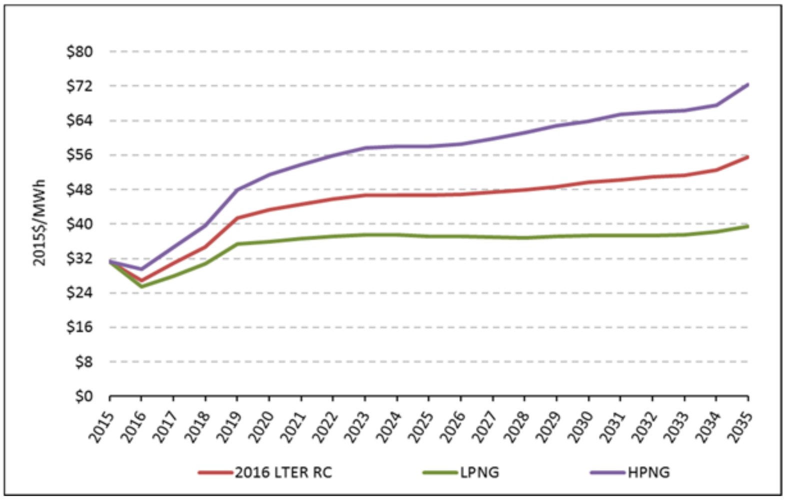
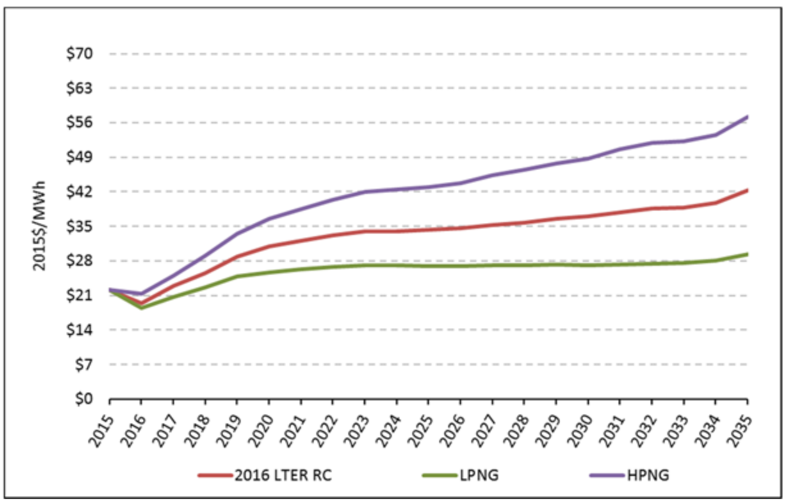


Figure 5.14 PJM-SW Off-peak Energy Prices – Natural Gas Scenarios



The impact of either higher or lower natural gas prices on electricity is significant in both the peak and off-peak periods, which reflects that PJM's marginal generation source is predominantly natural gas. Maryland's ability to influence the price of natural gas through measures to encourage additional natural gas supply or to limit demand for natural gas is extremely limited. As noted earlier, natural gas is a national market, with price differentials among various regions in the U.S. largely attributable to transportation costs. In addition, Maryland's demand for natural gas is a relatively small part of the overall natural gas demand, and available natural gas supplies in Maryland, to date, have been very small. Therefore, Maryland cannot on its own influence natural gas market prices in any meaningful way.

5.6 Capacity Prices

Projected capacity prices for the Reference Case, the HPNG, and the LPNG scenarios for PJM-SW, PJM-MidE, and PJM-APS are shown in Figure 5.15 through Figure 5.17. Projected capacity prices under all scenarios for each particular zone are similar under both natural gas price scenarios and the Reference Case prices. The reason underlying the similarity in capacity prices under the three scenarios for each of the three zones that include a part of Maryland is that capacity prices are sensitive to timing and type of new power plant construction. Under the three scenarios, there is not very much variation in either the timing of builds or the type of capacity being built to meet reliability requirements.

Figure 5.15 PJM-SW Capacity Prices – Natural Gas Scenarios

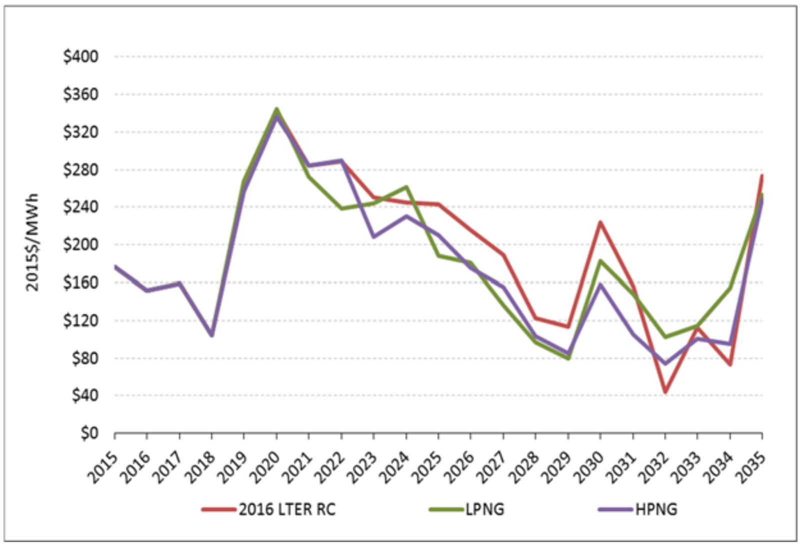


Figure 5.16 PJM-MidE Capacity Prices – Natural Gas Scenarios

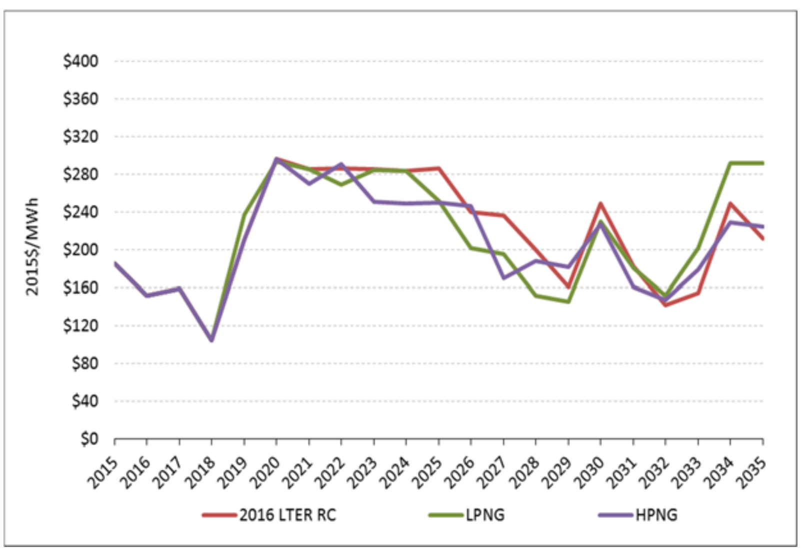
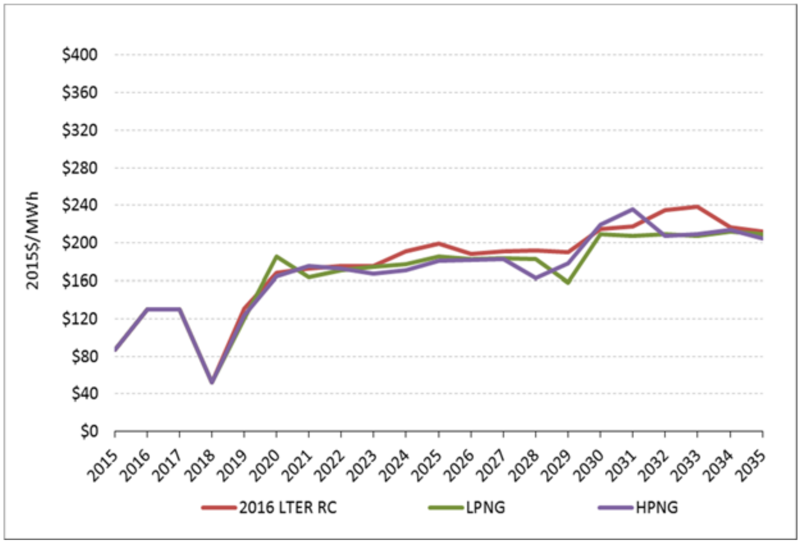


Figure 5.17 PJM-APS Capacity Prices – Natural Gas Scenarios



5.7 Emissions

Emissions in Maryland under the two alternative natural gas price scenarios reflect the shifts in reliance on coal vis-à-vis natural gas for electricity production as discussed in Section 5.4. Specifically, more intensive use of Maryland's coal plants in the HPNG scenario leads to higher SO_2, NOx, and mercury emissions from plants subject to the Maryland HAA, as shown in Figure 5.18 through Figure 5.20.[34] Under the LPNG assumptions, Maryland's coal plants are less intensively used and emissions of SO_2, NOx, and mercury correspondingly decline.

[34] It should be noted that the ABB Model does not treat the HAA's emissions limits as constraints; instead, it shows what emissions from HAA plants would be if dispatch decisions were made without regard to the HAA. Thus, HAA plants exceed the HAA's NOx and mercury emissions limits in the HPNG scenario.

Figure 5.18 Maryland SO_2 Emissions (HAA Plants) – Natural Gas Scenarios

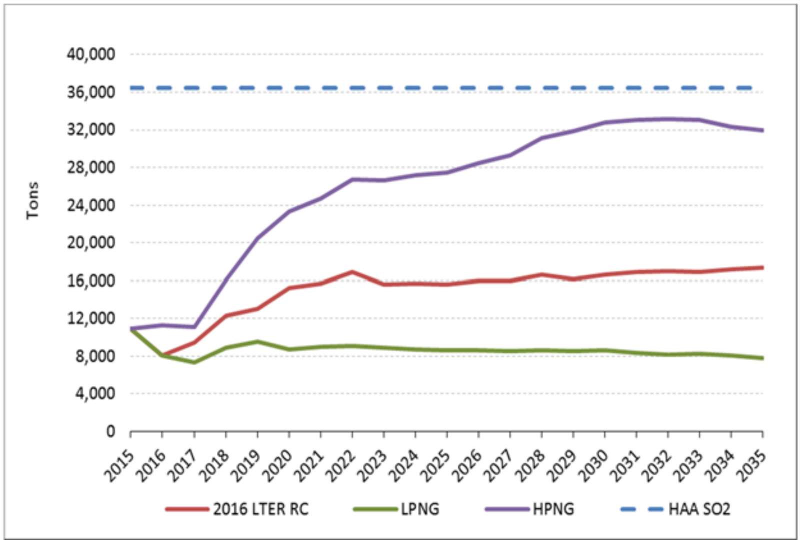


Figure 5.19 Maryland NOx Emissions (HAA Plants) – Natural Gas Scenarios

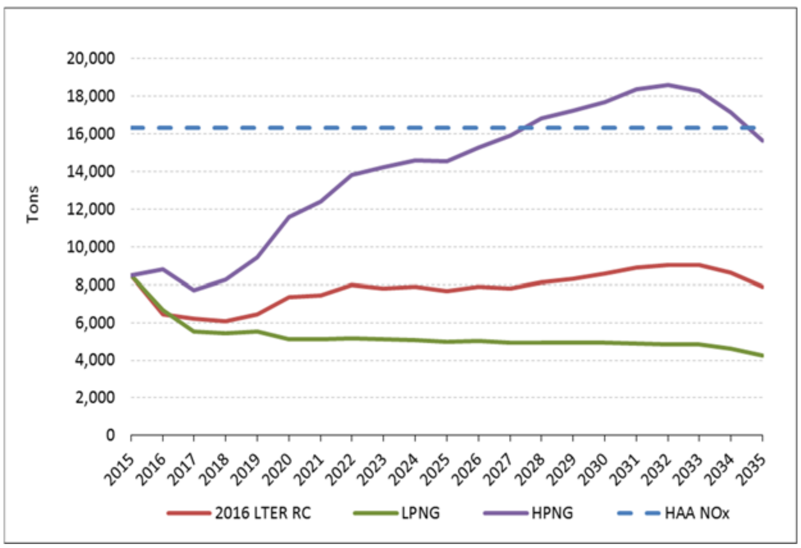
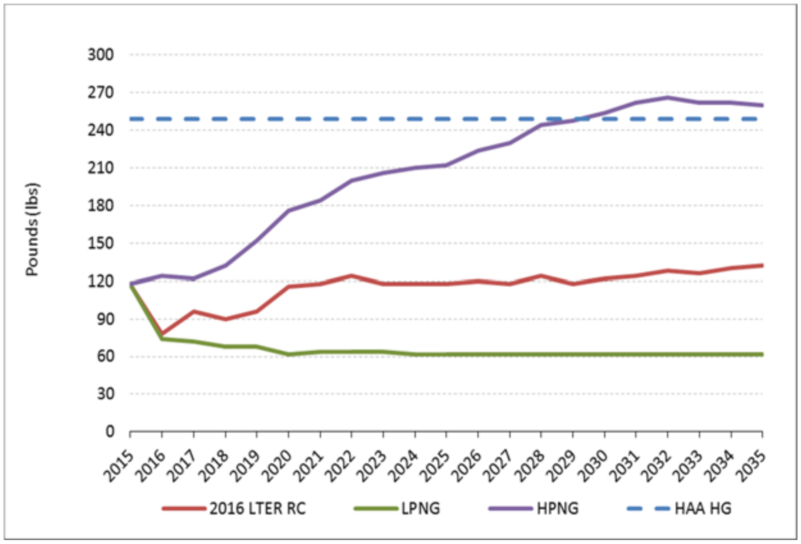
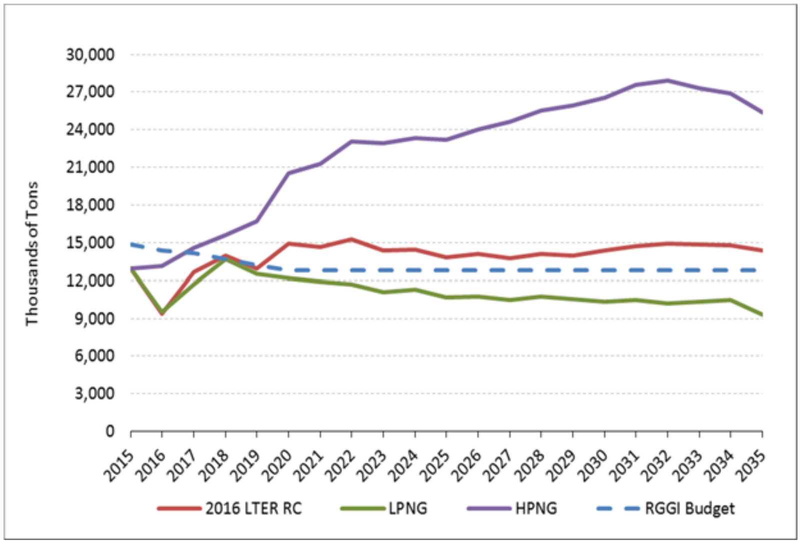


Figure 5.20 Maryland Mercury Emissions (HAA Plants) – Natural Gas Scenarios



Total CO_2 emissions in Maryland for power plant operations are also dramatically higher in the HPNG scenario than in the Reference Case, and lower in the LPNG scenario than in the Reference Case, as shown in Figure 5.21. In the HPNG scenario, CO_2 emissions greatly exceed Maryland's RGGI budget. Given that similar economic forces would likely drive up CO_2 emissions in other RGGI states, demand for emissions allowances would increase significantly, in turn driving up the cost of generation for coal plants (and to a lesser extent, in natural gas plants) in RGGI states. This, in turn, could cause a feedback loop that would shift the dispatch economics away from coal plants in RGGI states to natural gas plants in RGGI states, and also to coal plants in PJM states that do not belong to RGGI. Since RGGI prices are treated as an exogenous input in the ABB Model (see Section 3.5.3), there is no feedback loop to capture these dynamic price, generation, and emission impacts.

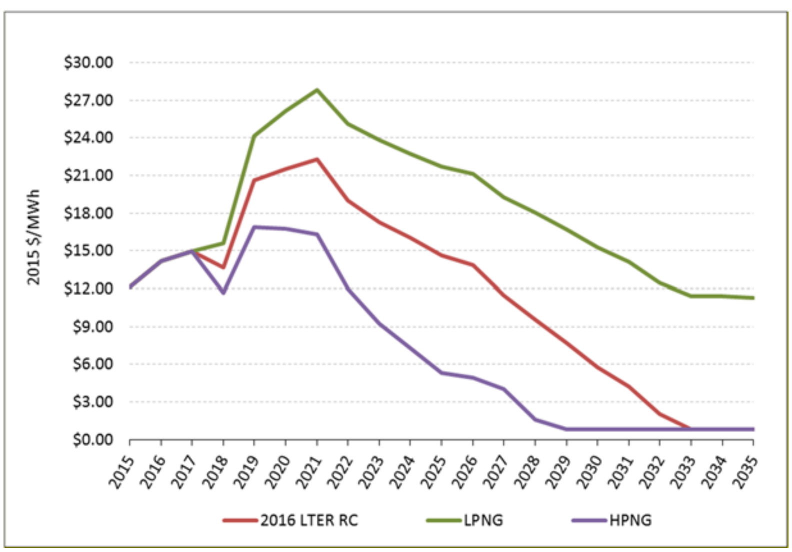
Figure 5.21 Maryland Electric Generation CO_2 Emissions – Natural Gas Scenarios



5.8 Renewable Energy Credit Prices

Figure 5.22 compares REC prices for the Reference Case, the HPNG, and the LPNG scenarios. Under the HPNG scenario, market prices for energy are higher than those for the Reference Case. Since renewable energy projects can recover more of their costs through energy sales, less of these costs need to be recovered through REC prices, based on the gap analysis methodology described in Section 2.2.3. Therefore, under the HPNG scenario, REC prices only rise to about $17 per REC in 2019 and fall to a $1 floor in 2029, well before they decrease to their minimum value in the Reference Case in 2033. The LPNG scenario results in higher REC prices than the Reference Case for analogous reasons—i.e., lower energy prices require renewable energy developers to recoup more of their costs through REC sales.

Figure 5.22 Renewable Energy Credit Prices – Natural Gas Scenarios



5.9 Summary of Key Results

The modeling analysis presented in this chapter provides the following findings:

- Natural gas prices influence the intensity of use of coal-fired and natural gas-fired plants in PJM-SW, PJM-MidE, and PJM-APS. In the two regions with coal-heavy generation portfolios, PJM-SW and PJM-APS, high natural gas prices ultimately drive down net imports, while low natural gas prices ultimately drive net imports up. The reverse is true for PJM-MidE where natural gas capacity predominates.

- Neither higher nor lower natural gas prices significantly affect the construction of new gas-fired power plants in Maryland relative to the Reference Case.

- Natural gas prices have a substantial impact on energy prices. By the year 2030, energy prices under the HPNG scenario—in all three zones that include a portion of Maryland—are about $20 per MWh above the Reference Case prices. Under the LPNG scenario, prices in all three zones are roughly $10/MWh below the Reference Case prices.

- Natural gas prices have minimal impact on capacity prices given the small impact that natural gas prices have on power plant construction (for either the timing of new capacity additions or the type of new capacity additions).

- Emissions of SO_2, NO_x, mercury, and CO_2 in Maryland are significantly higher under the HPNG scenario assumptions than under the Reference Case assumptions. They are lower under the LPNG assumptions than under the Reference Case assumptions, but less significantly.

6. Load Growth and Climate Change Alternative Scenarios

6.1 Introduction

The High and Low Load alternative scenarios address the estimated impacts of varied load growth rates. In the High Load (HL) scenario, the rate of annual percentage growth in peak demand and energy consumption in each PJM transmission zone is increased by 0.5 percentage points relative to the Reference Case. In the Low Load (LL) scenario, the rate of annual percentage growth in peak demand and energy consumption in each PJM transmission zone is decreased by 0.5 percentage points relative to the Reference Case. In Section 6.9 of this chapter, a Climate Change scenario is discussed which is based on projected temperature rises relative to a 30-year historical benchmark period; rising temperatures increase peak demand and energy consumption, though less significantly than in the HL scenario.

Figure 6.1 compares energy consumption projections and the compound annual growth rates (CAGRs) for the Reference Case and the HL and LL scenarios, while Figure 6.2 does the same for peak demand. In both cases, loads in all PJM zones are approximately 10 percent lower than the Reference Case by 2035 in the LL scenario and approximately 10 percent higher than the Reference Case by 2035 in the HL scenario.

Figure 6.1 PJM Energy Consumption – Load Growth Scenarios

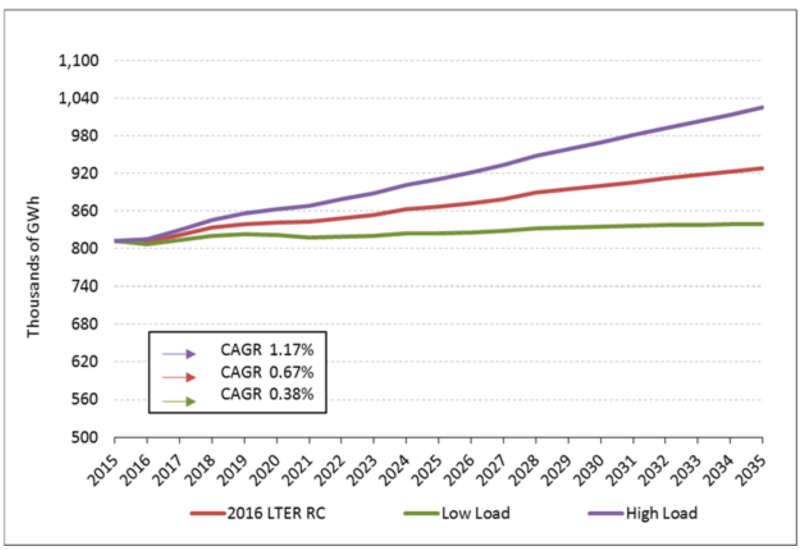
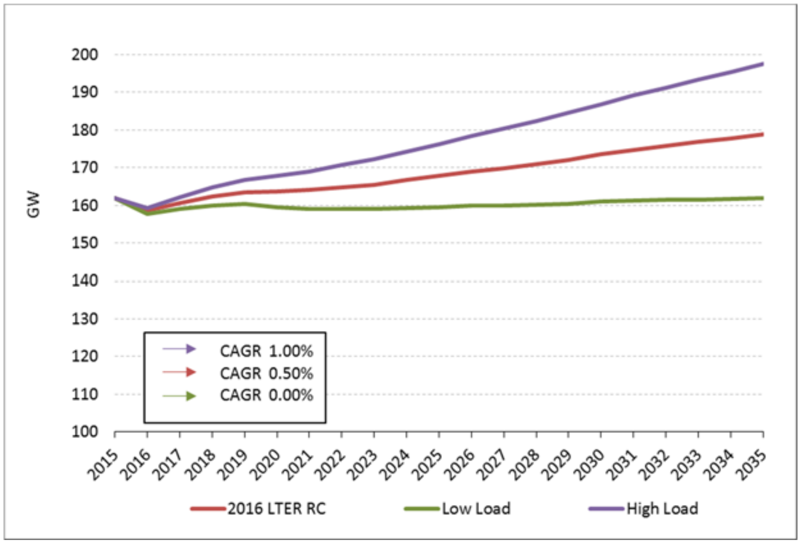


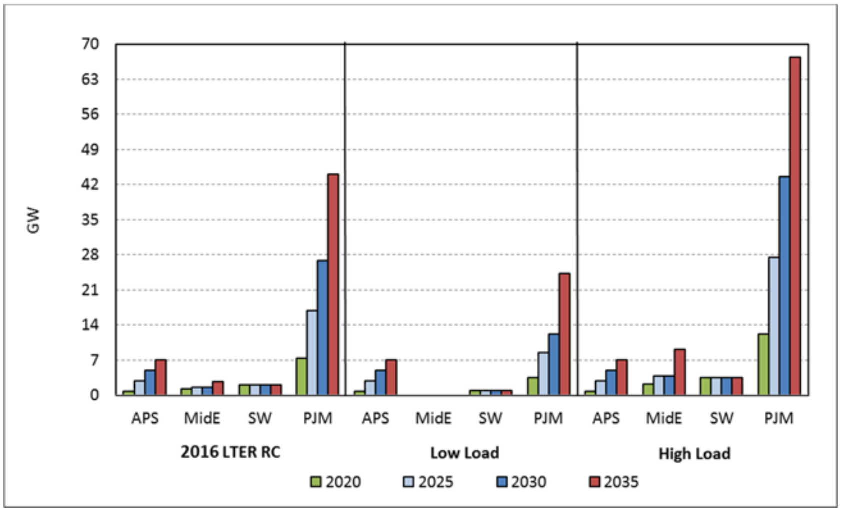
Figure 6.2 PJM Peak Demand – Load Growth Scenarios



6.2 Capacity Additions and Retirements

For all load scenarios, planned capacity additions, age-based plant retirements, and renewable energy builds in Maryland are identical to those for the Reference Case, since these are incorporated by assumption into the model. In addition, neither economic retirements nor renewable energy builds in PJM are affected by changes in load. By contrast, changes in load strongly affect the amount of natural gas-fired capacity added in Maryland and throughout PJM, as shown in Figure 6.3 and quantified in Table 6.1. Across PJM, natural gas capacity additions are more than 50 percent greater in the HL scenario than in the Reference Case, and more than 50 percent lower in the LL case. Within the PJM transmission zones of relevance to Maryland, the results are more varied. PJM-MidE is most sensitive to changes in load; natural gas capacity additions in the PJM-MidE zone increase by more than 100 percent in the HL scenario relative to the Reference Case—surpassing builds in PJM-APS, despite the higher cost of construction in PJM-MidE. In PJM-SW, the impacts of load changes mirror those seen PJM-wide. In PJM-APS, changes in load have almost no impact. The reason for this is that east-to-west transmission limitations result in generating capacity being constructed in the eastern zones to meet the load requirements in those zones.

Figure 6.3 Cumulative PJM Natural Gas Capacity Additions – Load Growth Scenarios



Note: Average of summer and winter capacity ratings.

Table 6.1 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – Load Growth Scenarios (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	5.27	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (LL minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	(1.22)	(1.11)	(3.89)
2025	--	(1.57)	(1.11)	(8.40)
2030	--	(5.27)	(1.11)	(14.68)
2035	--	(2.81)	(1.11)	(19.85)
Difference (HL minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	1.11	1.39	4.80
2025	--	2.33	1.39	10.67
2030	--	(1.38)	1.39	16.71
2035	--	6.32	1.39	23.20

Note: Average of summer and winter capacity ratings.

6.3 Net Imports

Changes in load have minimal impact on net imports in the PJM-SW, PJM-MidE, or PJM-APS transmission zones. The HL scenario results in slightly greater net imports than the Reference Case, while the LL scenario results in slightly lower net imports, as shown in Figure 6.4 through Figure 6.6. The spread between each alternative load scenario and the Reference Case grows over the course of the study period, as the cumulative impact of capacity builds—which occur more often outside these three regions than within them—grows. The one exception to this generalization occurs in the years 2033 through 2035 in PJM-MidE. Here, net imports in the HL scenario dip below those in the Reference Case. This is likely due to the burst of natural gas capacity construction that occurs in PJM-MidE between 2030 and 2035, as discussed in the prior section and as seen in Figure 6.3 and Table 6.1, above. Under all of the load growth scenarios: PJM-SW relies on substantial net imports of energy throughout the entire analysis period; PJM-MidE moves from being a net exporter of energy to a net importer as load continues to grow throughout the forecast horizon; and PJM-APS is a net exporter for most of the analysis period under both the HL and LL scenarios, which is consistent with the Reference Case results.

Figure 6.4 PJM-SW Net Imports – Load Growth Scenarios

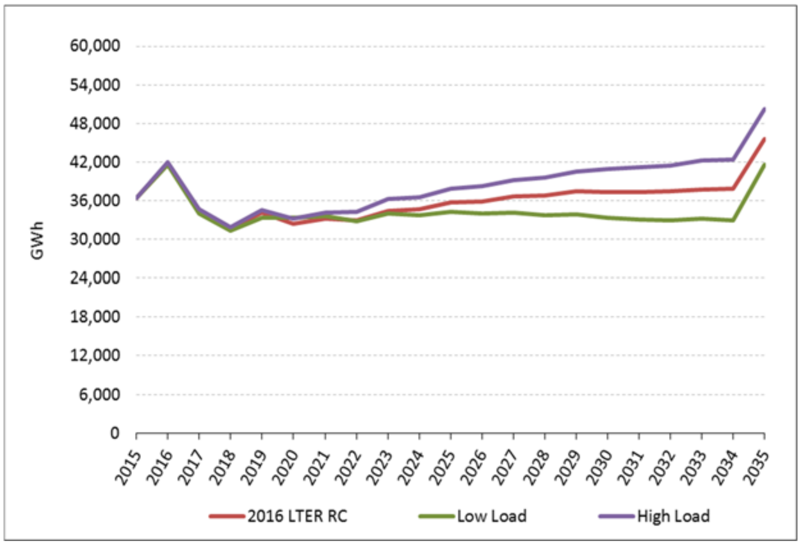


Figure 6.5 PJM-MidE Net Imports – Load Growth Scenarios

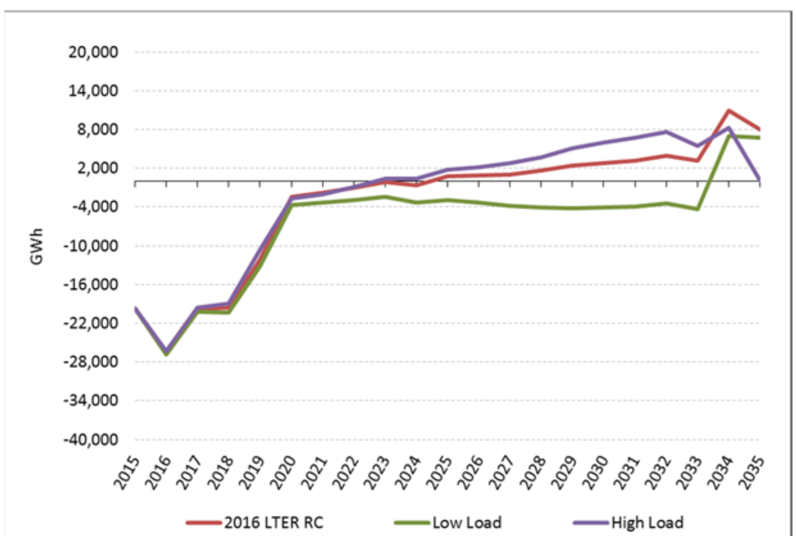
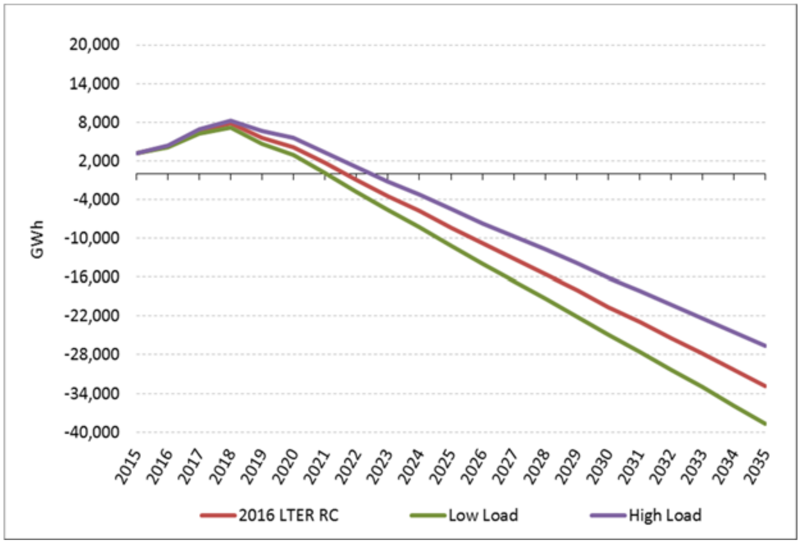


Figure 6.6 PJM-APS Net Imports – Load Growth Scenarios



6.4 Fuel Use

Changes in load affect the use of natural gas and coal for electricity generation in Maryland, though the impacts on natural gas use are more pronounced (see Figure 6.7 and Figure 6.8). With regard to natural gas, load changes affect both the intensity with which natural gas plants are utilized and the rate at which new natural gas plants are constructed. With regard to coal, load changes only affect the intensity with which the coal-fired plants are utilized.

Figure 6.7 Coal Use for Electricity Generation in Maryland – Load Growth Scenarios

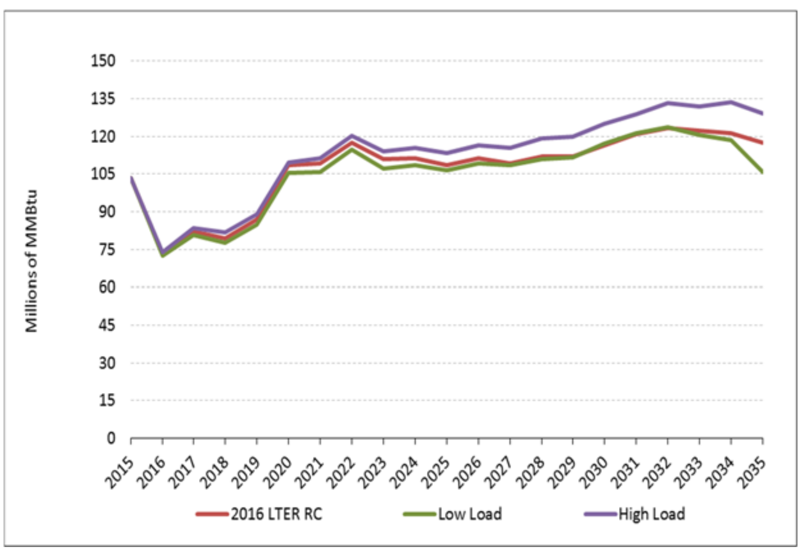
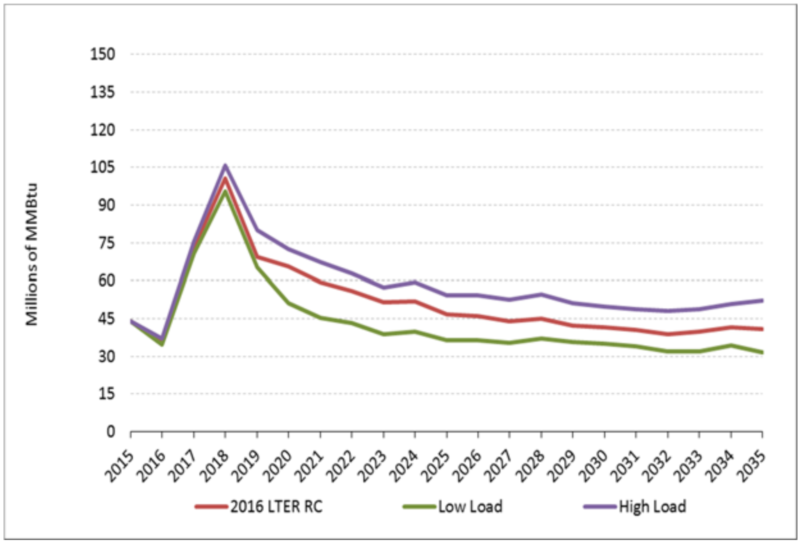


Figure 6.8 Natural Gas Use for Electricity Generation in Maryland – Load Growth Scenarios



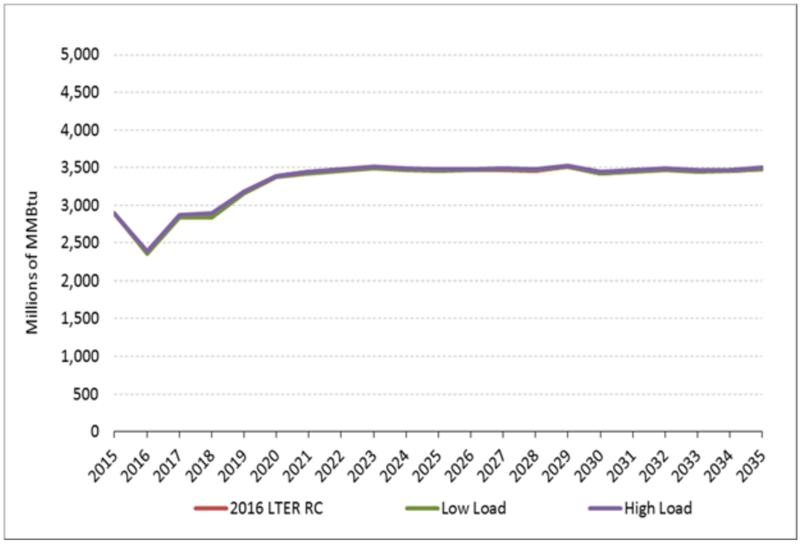
The changes in natural gas and coal generation are reflected in Maryland's overall generation mix. As seen in Table 6.2, the assumed changes in load growth for the HL and LL alternative scenarios affect the percentage of generation attributed to natural gas generation more significantly than any other fuel source.

Table 6.2 Maryland Generation Mix – Load Growth Scenarios

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	5%
2025	Reference Case	34,757	40	29	18	5	9
	High Load	36,051	38	29	19	5	9
	Low Load	33,071	42	30	14	6	9
2035	Reference Case	27,641	23	39	20	7	9
	High Load	30,107	21	39	23	6	11
	Low Load	25,270	25	38	16	7	13

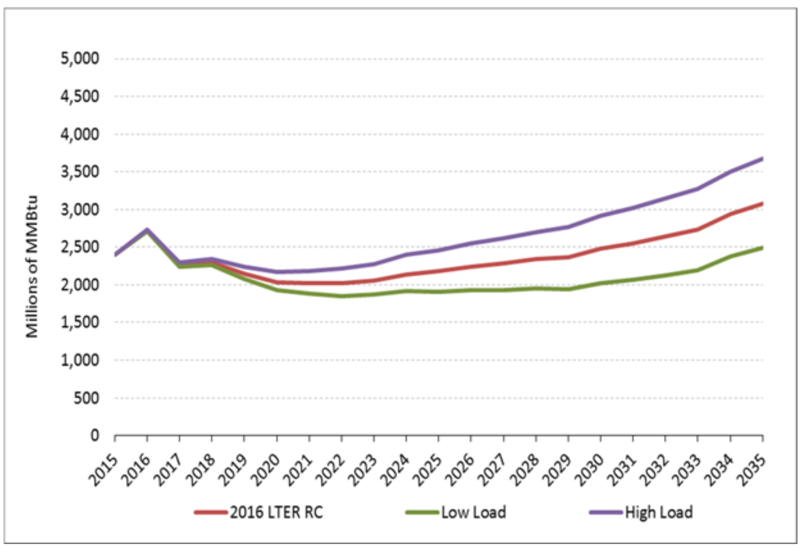
The disproportionate impact that load changes have on natural gas use versus coal use for electricity generation is more pronounced on a PJM-wide basis. As shown in Figure 6.9, coal use is basically unchanged PJM-wide, whereas natural gas use changes in both the HL and LL scenarios (see Figure 6.10). Throughout the majority of the study period, natural gas is the more expensive of the two fuels and is the marginal fuel in about half of the hours. As a consequence, natural gas use will be more sensitive to changes in load than coal (or nuclear) generation, both of which tend to be intra-marginal.

Figure 6.9 Coal Use for Electricity Generation in PJM – Load Growth Scenarios



Note: The Reference Case and Low Load lines are directly under the High Load line and hence cannot be separately observed.

Figure 6.10 Natural Gas Use for Electricity Generation in PJM – Load Growth Scenarios



6.5 Energy Prices

Load growth has small impacts on energy prices. For example, Figure 6.11 through Figure 6.13 compare energy prices in the three PJM transmission zones of relevance to Maryland during all hours, on-peak hours, and off-peak hours, respectively. In all three cases, energy prices in the HL scenario are slightly above, and LL scenario assumptions are slightly below, the energy prices estimated for the Reference Case. The higher loads in the HL scenario cause slightly costlier generating capacity to be dispatched to meet the higher load levels, resulting in slightly higher prices than in the Reference Case. The reverse relationships exist for the LL scenario. Over time, the difference between the HL scenario loads and the Reference Case loads increase and the energy price differences also increase, regardless of zone. The differences, however, continue to be small over the analysis period. An analogous relationship between load levels for the LL scenario and the Reference Case is also evident.

Figure 6.11 PJM-SW, PJM-MidE, PJM-APS All-hours Energy Prices – Load Growth Scenarios

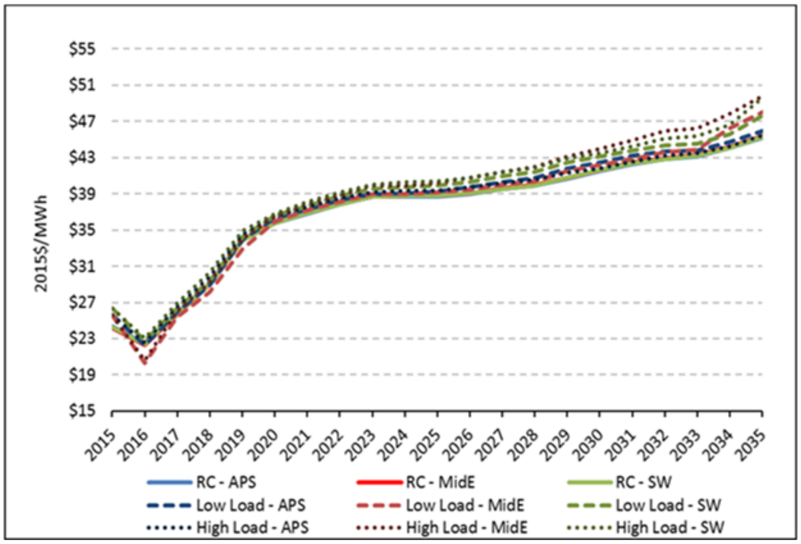


Figure 6.12 PJM-SW, PJM-MidE, PJM-APS On-peak Energy Prices – Load Growth Scenarios

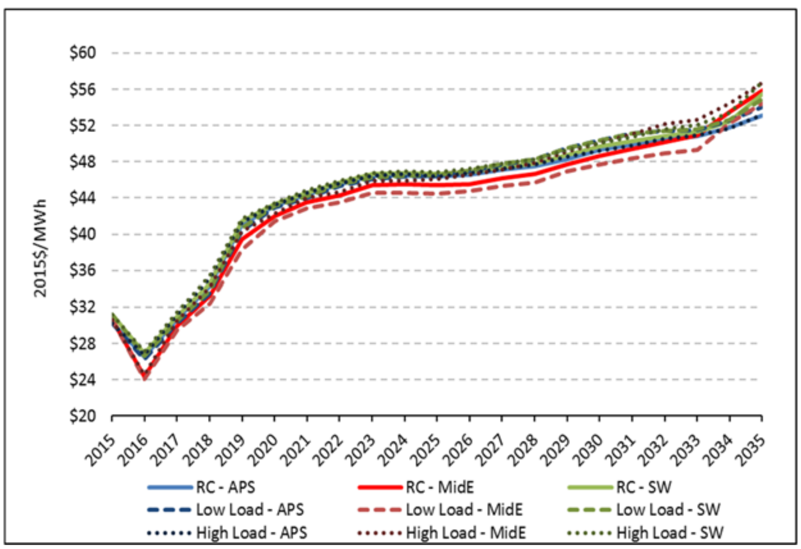
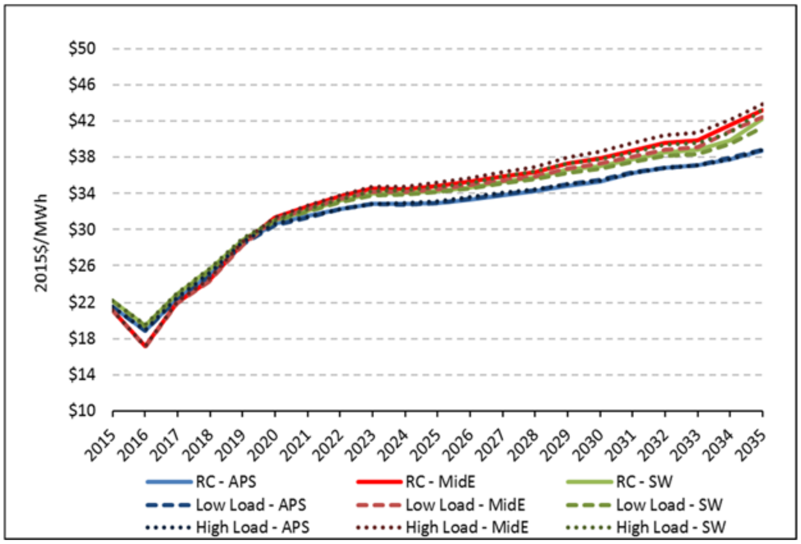


Figure 6.13 PJM-SW, PJM-MidE, PJM-APS Off-peak Energy Prices – Load Growth Scenarios



6.6 Capacity Prices

Under the LL scenario, capacity prices in the PJM-MidE and PJM-APS transmission zones are below the projected capacity prices in the Reference Case (see Figure 6.14 through Figure 6.16). The pattern of capacity prices in the two alternative load growth scenarios for PJM-MidE and PJM-APS relative to the capacity prices for those zones under the Reference Case assumption is influenced by a combination of new capacity builds, growth in zonal loads, and imports/exports of energy to other zones. The lower pressure on capacity resulting from slower load growth in all three zones results in the observed reduced capacity prices, though that relationship is less pronounced in the PJM-SW zone.

The opposite is the case for the HL growth scenario, where capacity prices in PJM-MidE and PJM-APS tend to be higher than the capacity prices resulting from the Reference Case assumptions. The reasons for upward pressure on capacity prices relative to the Reference Case under the HL scenario are analogous to the reasons underlying the lower capacity price pressure in the LL scenario.

Figure 6.14 PJM-SW Capacity Prices – Load Growth Scenarios

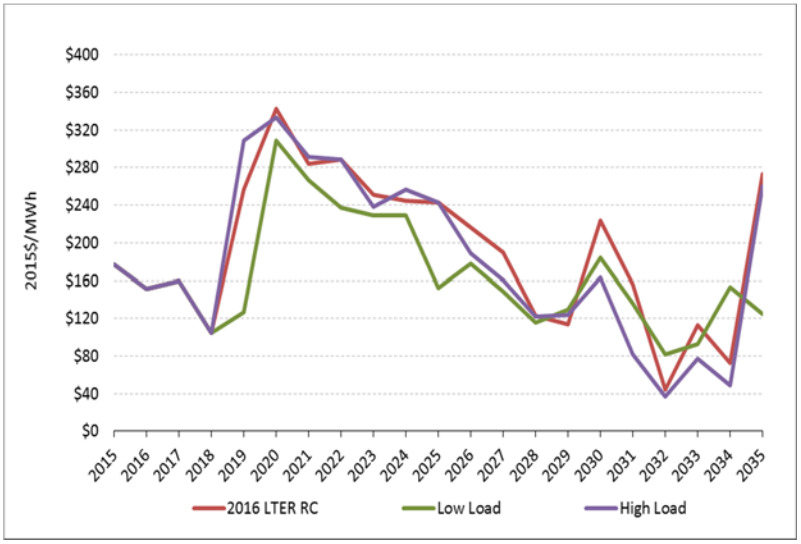


Figure 6.15 PJM-MidE Capacity Prices – Load Growth Scenarios

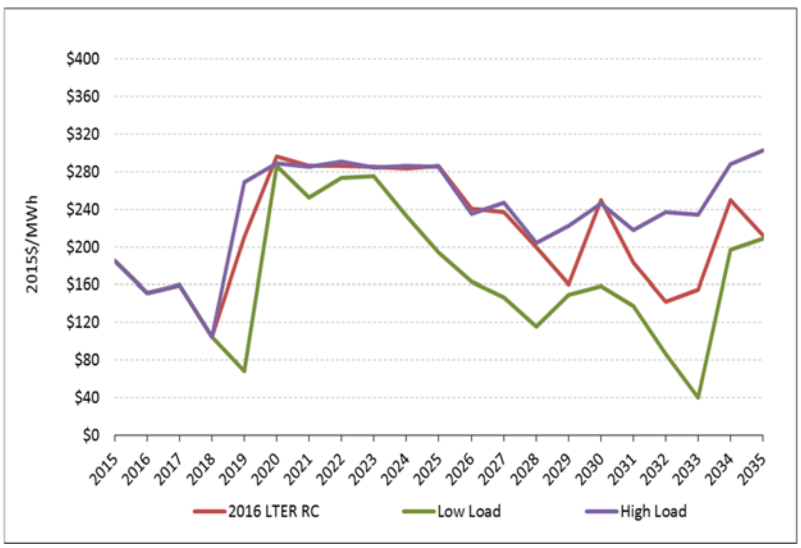
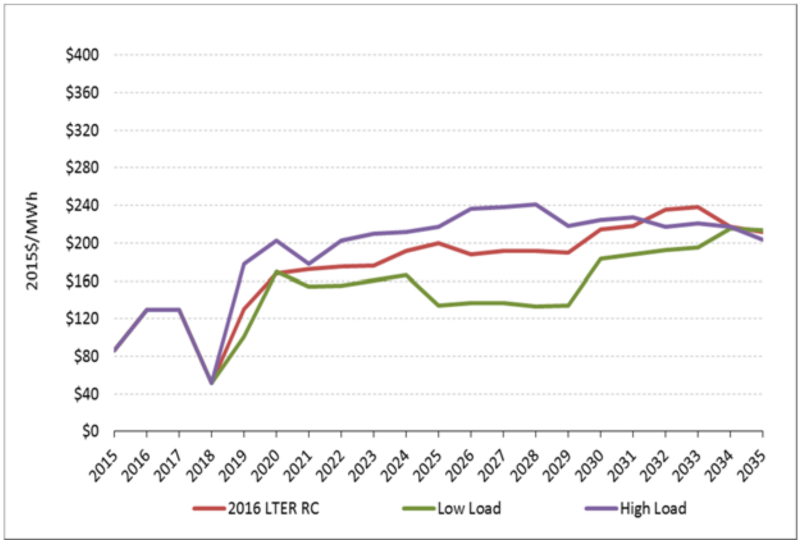


Figure 6.16 PJM-APS Capacity Prices – Load Growth Scenarios



6.7 Emissions

Maryland plants subject to HAA SO_2, NOx, and mercury emissions restrictions exhibit little difference in the load growth scenarios when compared to emissions under the Reference Case. Because HAA plants have emissions controls in place, the small changes in generation levels among the LL scenario, the HL scenario, and the Reference Case result in minimal changes in emissions. Comparisons of emissions of SO_2, NOx, and mercury for Maryland's HAA plants are shown in Figure 6.17 through Figure 6.19 for the Reference Case and the two alternative load growth scenarios.

Figure 6.17 Maryland SO_2 Emissions (HAA Plants) – Load Growth Scenarios

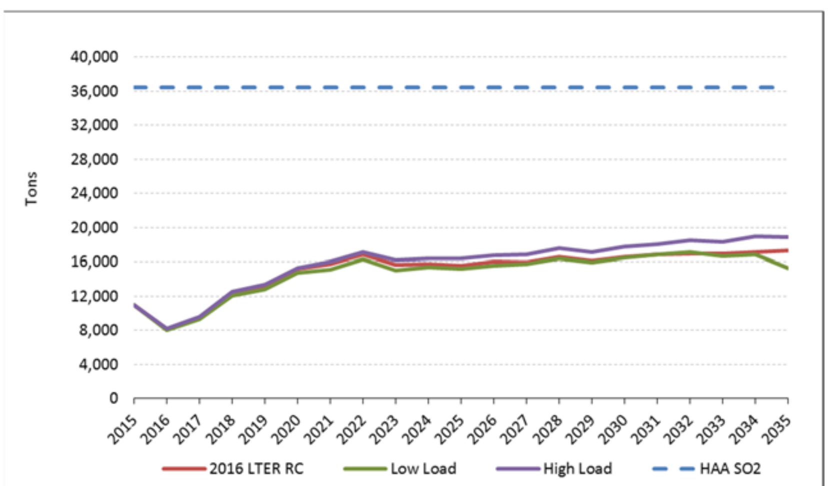


Figure 6.18 Maryland NOx Emissions (HAA Plants) – Load Growth Scenarios

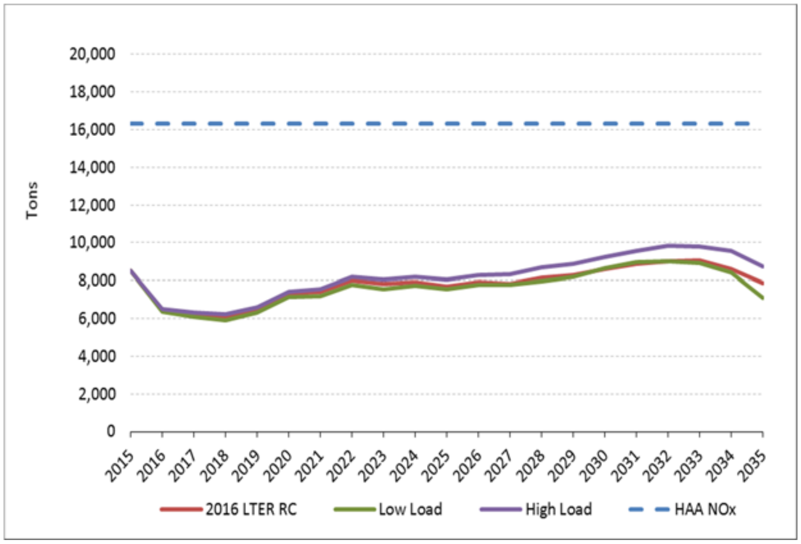
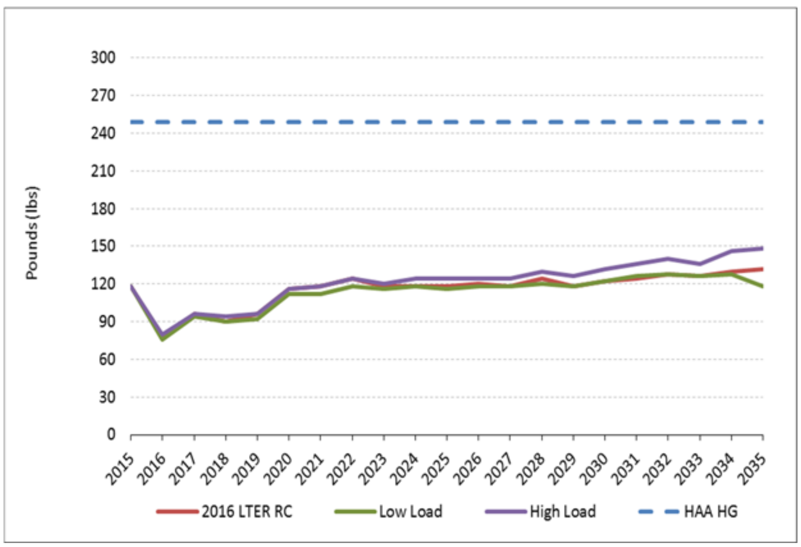
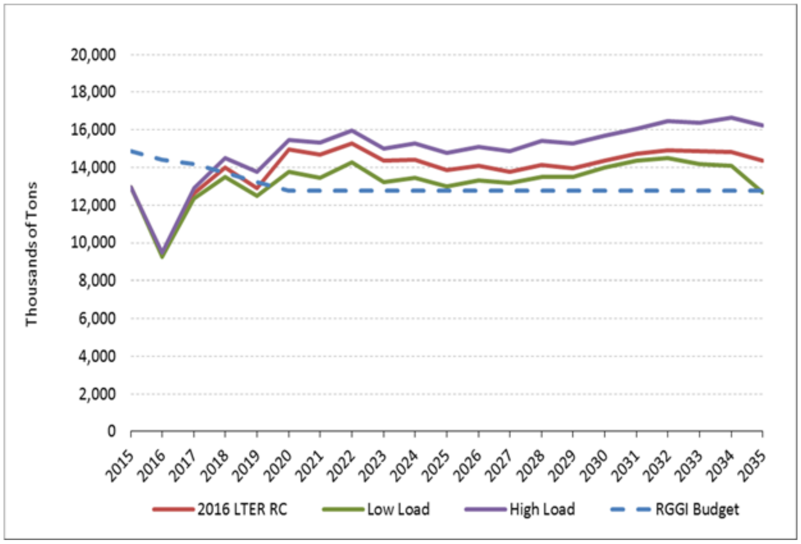


Figure 6.19 Maryland Mercury Emissions (HAA Plants) – Load Growth Scenarios



Carbon dioxide emissions for all Maryland power plants vary as a result of differences in load growth, as shown in Figure 6.20. Just as coal usage drops off less in the LL scenario than it rises in the HL scenario, so too do CO_2 emissions drop off slightly less in the LL scenario than they rise in the HL scenario. In all three scenarios, including the low load growth scenario, CO_2 emissions exceed the Maryland RGGI budget in all but the earliest years of the analysis period. This would necessitate Maryland power plants purchasing non-Maryland RGGI emissions allowances to compensate for the excess emission levels.

Figure 6.20 Maryland CO_2 Emissions (All Plants) – Load Growth Scenarios



Note: PPRP recognizes that the current RGGI program ends in 2018, but for the purposes of this LTER analysis, RGGI was extended through the study period at the 2018 level to provide a metric against which greenhouse gas emissions from in-State generation may be measured. For a description of Maryland's GGRA, see Section 3.5.4.

6.8 Renewable Energy Credit Prices

The REC prices under the alternative load growth scenarios are virtually identical to the REC prices under the Reference Case assumptions due to the very small changes in electricity prices.

6.9 Climate Change Scenario

In addition to the HL and LL scenarios, PPRP created a Climate Change alternative scenario, which is based on assumptions about temperature change that, in turn, impact assumptions about load growth. This section summarizes the process PPRP followed to develop the Climate Change scenario and discusses how the results differ from the HL scenario.

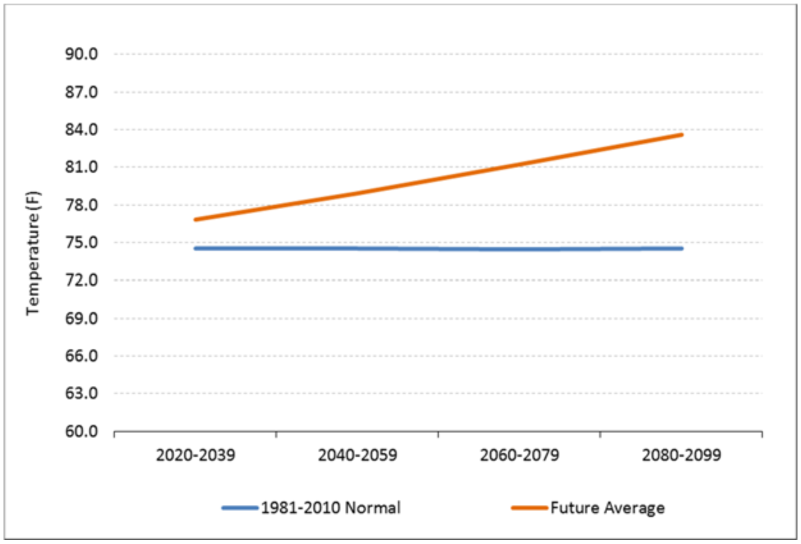
PPRP looked to Maryland's 2015 Greenhouse Gas Reduction Act (GGRA) Update for guidance on how significantly temperatures are likely to rise due to climate change over the course of the LTER's 20-year study period.[35] The GGRA Update, in turn, refers readers to a national study called the *American Climate Prospectus* (Climate Prospectus), which provides temperature change projections by state.[36] For three 20-year time spans in the century ending 2099—the years 2020 through 2039, 2040 through 2059, and 2080 through 2099—the Climate Prospectus projects how much warmer average summer and winter temperatures are likely to be than average summer and winter temperatures were

[35] Maryland Department of the Environment, *Greenhouse Gas Emissions Reduction Act Plan Update 2015*, 2015, www.mde.state.md.us/programs/Air/ClimateChange/Documents/ClimateUpdate2015.pdf.

[36] Appendix D to the 2015 GGRA Plan Update is titled *Summary of American Climate Prospectus Data Describing Impacts for Maryland.* This document refers readers to temperature change projections provided on the American Climate Prospectus study's website, http://climateprospectus.org/data/, accessed by PPRP in May 2016.

during the benchmark years of 1981-2010. Figure 6.21 shows the Climate Prospectus' projections for the summer months in Maryland.

Figure 6.21 Projected Average Summer Temperature Rise in Maryland Relative to 30-Year Average



Source: American Climate Prospectus.

PPRP translated the Climate Prospectus' summer and winter projections for Maryland into linear equations by assuming that the average level of temperature rise for a given era and season would be reached in the middle year of the era. The resulting temperature rise projections for the years 2020 through 2031 in Maryland are shown in Table 6.3. For the fall and spring months, PPRP assumed that temperature would rise at a rate equivalent to the average of the Climate Prospectus' projections for summer and winter.

Table 6.3 Average Temperature Rise in Maryland Due to Climate Change Relative to 30-Year (1981-2010) Average Temperatures

Year	Summer (June, July, August)	Winter (December, January, February)	All Other Months
2020	0.23˚F	0.22˚F	0.23˚F
2021	0.47	0.44	0.46
2022	0.70	0.66	0.68
2023	0.94	0.88	0.91
2024	1.18	1.11	1.14
2025	1.41	1.33	1.37
2026	1.65	1.55	1.60
2027	1.88	1.77	1.82
2028	2.11	1.99	2.05
2029	2.35	2.21	2.28
2030	2.58	2.43	2.51
2031	2.82	2.65	2.74

Note: PPRP focused on the years 2020 through 2031 because these are the years that overlap between the LTER study period, the Climate Prospectus study period, and PJM's 2016 Load Forecast.

At PPRP's request, the staff of PJM's Resource Adequacy Planning department applied PPRP's temperature-rise projections to PJM, for each PJM zone, to generate an alternative simulation of PJM's 2016 Load Forecast. This "climate-change adjusted" PJM load forecast includes annual projections for peak load and energy use, by PJM transmission zone, for the years 2016 through 2031. Figure 6.22 and Figure 6.23 show these changes in a PJM-wide context, relative to the HL scenario and the Reference Case.[37] It is important to note that, in the Climate Change scenario, peak demand changes more dramatically than annual energy because peak demand is determined solely by the need for generation during the Climate Change scenario's hotter summer months, while increased energy use in the Climate Change scenario's summer months is offset by *decreased* energy use in winter. While the offset is not one-for-one, it is very close.

[37] PPRP extrapolated loads for the years 2032 through 2035.

Figure 6.22 PJM Peak Demand – Climate Change and High Load Scenarios

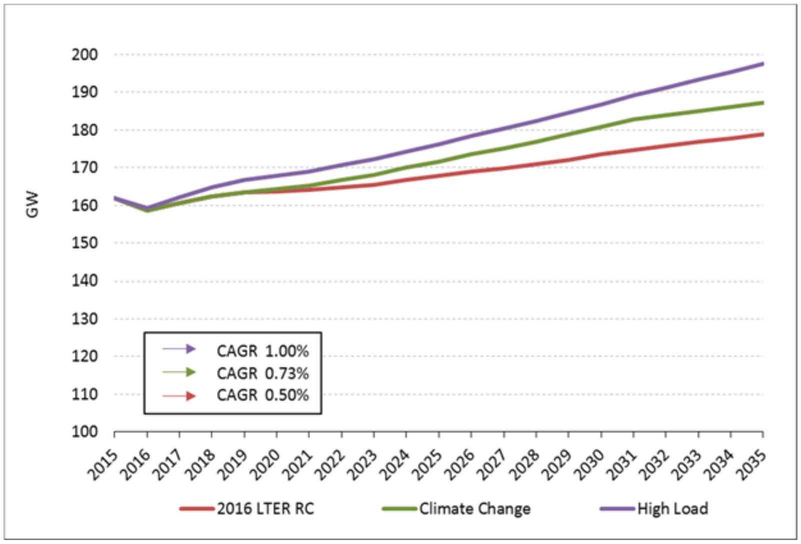
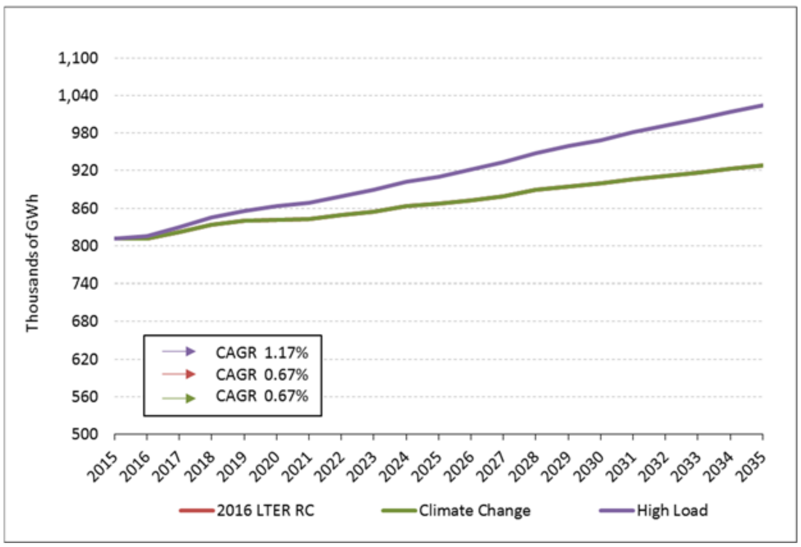


Figure 6.23 PJM Energy Consumption – Climate Change and High Load Scenarios



Note: The Reference Case line is directly under the Climate Change line and hence cannot be separately observed.

The Climate Change scenario's results tend to be similar to the HL scenario's results but more modest in magnitude—often to the point that they are virtually indistinguishable from the Reference Case. The most significant differences between the Climate Change scenario, the HL scenario, and the Reference Case are those related to capacity additions and prices. Just as in the HL scenario, increases in peak demand under the Climate Change scenario result in increases in natural gas capacity in PJM-MidE, PJM-SW, and PJM-wide, but at a more modest rate (see Figure 6.24). These developments reflect and/or cause modest deviations in capacity market prices among the three scenarios, as shown in Table 6.4.

Figure 6.24 Cumulative Capacity Additions – Climate Change and High Load Scenarios

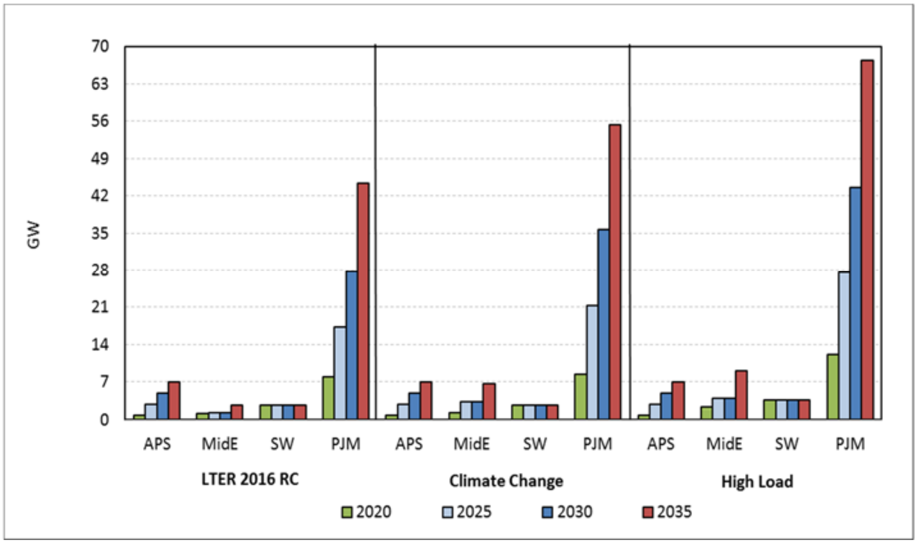


Table 6.4 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – Climate Change and High Load Scenarios (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	1.57	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (Climate Change minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	0.17	0.42	1.01
2025	--	1.74	0.42	4.51
2030	--	1.74	0.42	8.76
2035	--	3.89	0.42	11.23
Difference (High Load minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	1.11	1.39	4.80
2025	--	2.33	1.39	10.67
2030	--	2.33	1.39	16.71
2035	--	6.32	1.39	23.20

Figure 6.25 through Figure 6.27 compare projected energy prices for the Reference Case, the HL scenario, and the Climate Change scenario in the PJM-SW, PJM-MidE, and PJM-APS transmission zones. Figure 6.25 presents all-hours energy prices, Figure 6.26 presents on-peak energy prices, and Figure 6.27 presents off-peak prices.

The comparison of the HL and Reference Case prices presented earlier in this chapter showed that the HL scenario prices for both the on-peak and off-peak periods, and hence the all-hours prices, were all above the Reference Case prices for the analogous pricing period. This consistency also holds for the energy prices estimated for the Climate Change scenario though, unlike the HL scenario prices, the Climate Change scenario prices tend to be slightly below the Reference Case prices for each of the three transmission zones that include portions of Maryland. The deviations of the Climate Change scenario prices from the Reference Case prices, however, are very slight regardless of the pricing period or the transmission zone. The reason for this is that the lower energy consumption levels under the Climate Change scenario relative to the Reference Case during the winter season and during portions of the shoulder seasons places downward pressure on energy prices that offsets the increase in energy prices resulting from higher loads during the summer season. The differentials, however, are small throughout the full analysis period and for all three of the transmission zones.

Figure 6.25 PJM-SW, PJM-MidE, PJM-APS All-hours Energy Prices – Climate Change Scenario

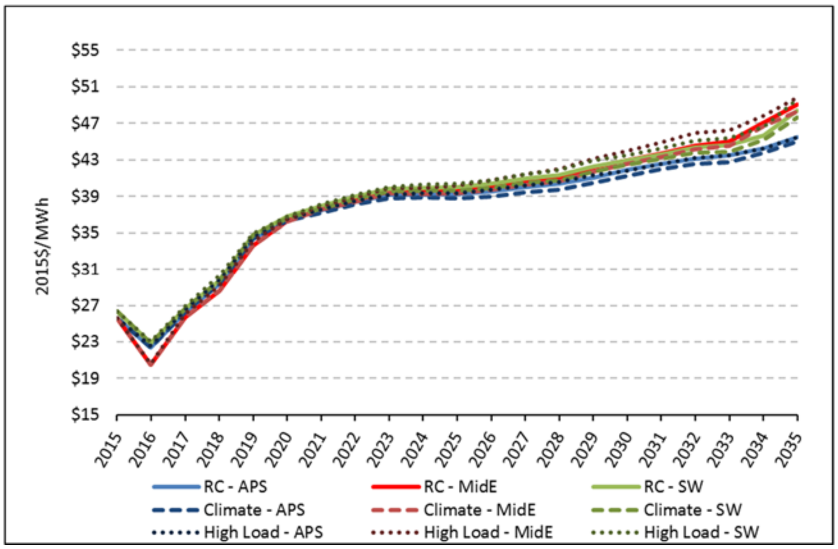


Figure 6.26 PJM-SW, PJM-MidE, PJM-APS On-peak Energy Prices – Climate Change Scenario

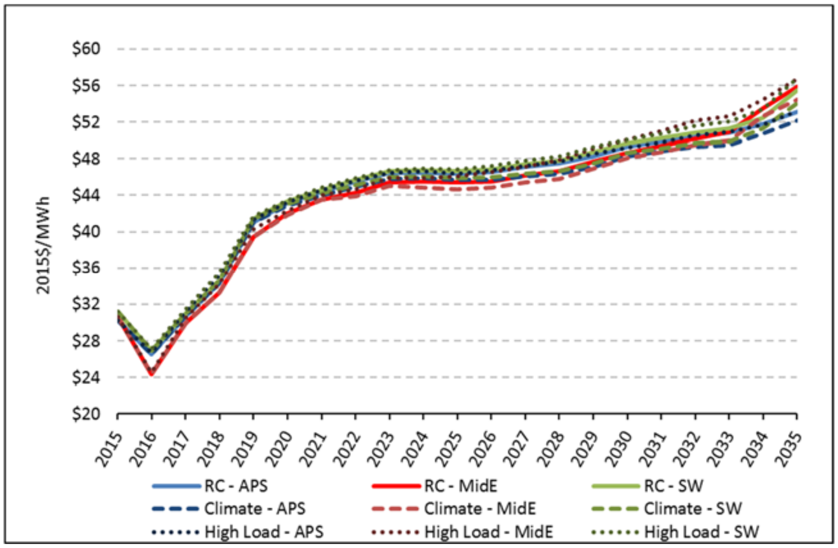


Figure 6.27 PJM-SW, PJM-MidE, PJM-APS Off-peak Energy Prices – Climate Change Scenario

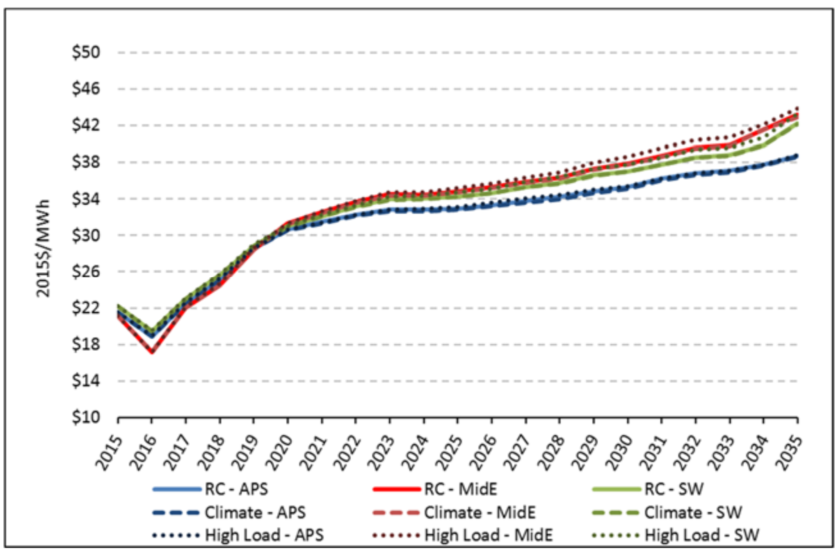


Figure 6.28 through Figure 6.30 compare the projected capacity prices (Reference Case, HL scenario, and Climate Change scenario) in the PJM-SW, PJM-MidE, and PJM-APS transmission zones. The differences in load growth over the range of assumed load increases have very little effect on capacity prices in any of the three transmission zones. The exception to this is the capacity prices in PJM-MidE between 2031 and 2034, which under the HL scenario are significantly above both the Reference Case and the Climate Change scenario capacity prices. This is a result of significant generic natural gas plant builds in PJM-MidE during those years relative to builds under either the Reference Case or the Climate Change scenario (see Table 6.4, above).

Figure 6.28 PJM-SW Capacity Prices – Climate Change Scenario

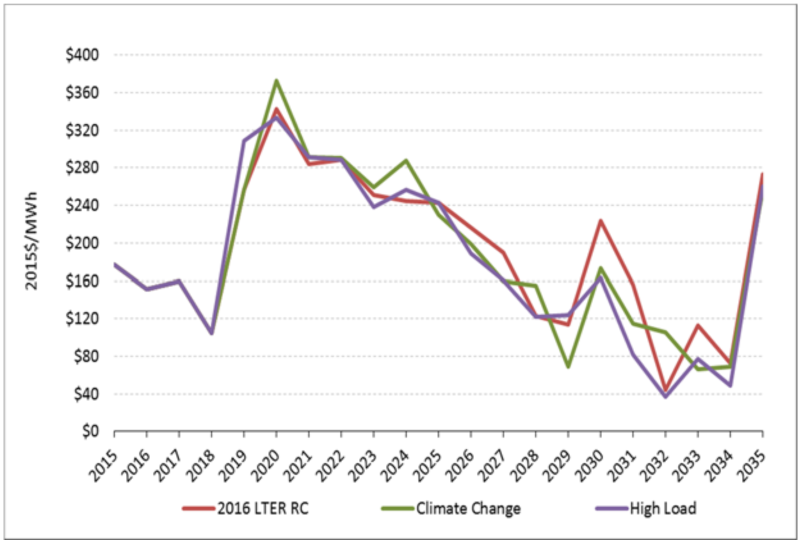


Figure 6.29 PJM-MidE Capacity Prices – Climate Change Scenario

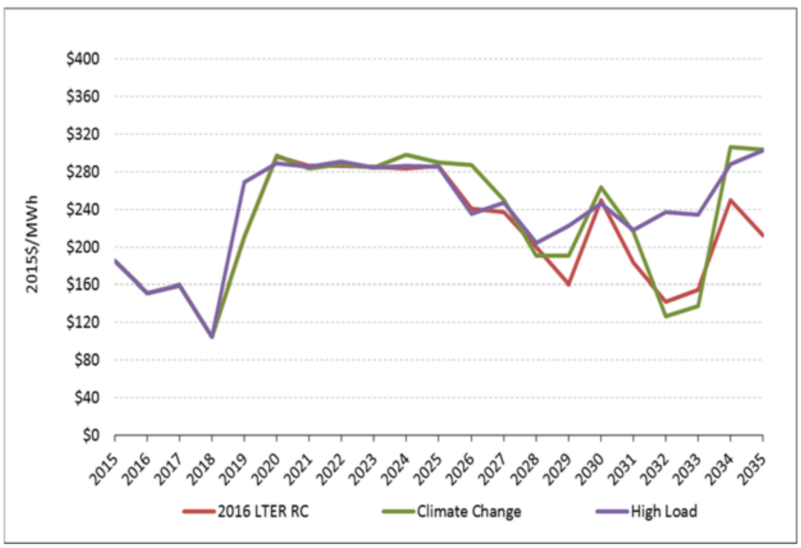


Figure 6.30 PJM-APS Capacity Prices – Climate Change Scenario

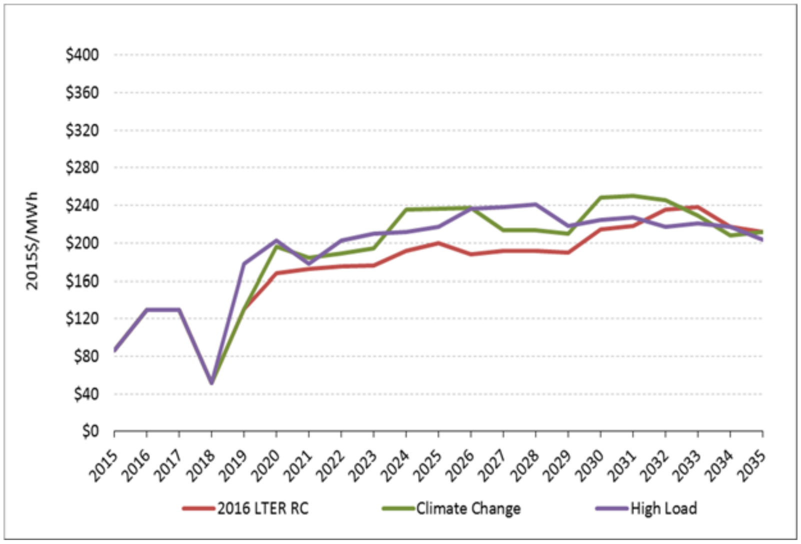


Figure 6.31 through Figure 6.33 show the similarities between the Climate Change scenario and Reference Case results with regard to net imports. The HL results are included in these graphs for reference. Imports are principally related to energy and there is little difference in energy generation under the Climate Change scenario relative to the Reference Case. Additionally, there is also little difference in energy consumption due to the summer/winter offset. Consequently, we see only very small changes in energy imports in the three zones relative to the Reference Case.

Figure 6.31 PJM-SW Net Imports – Climate Change Scenario

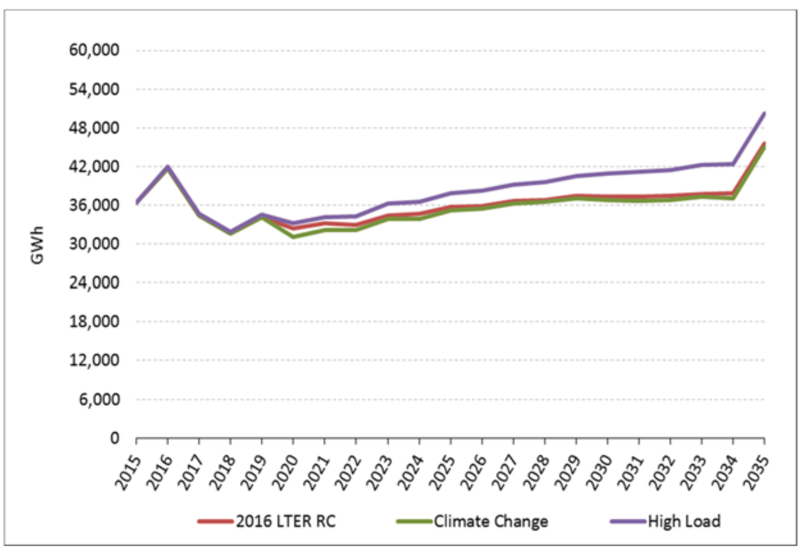


Figure 6.32 PJM-MidE Net Imports – Climate Change Scenario

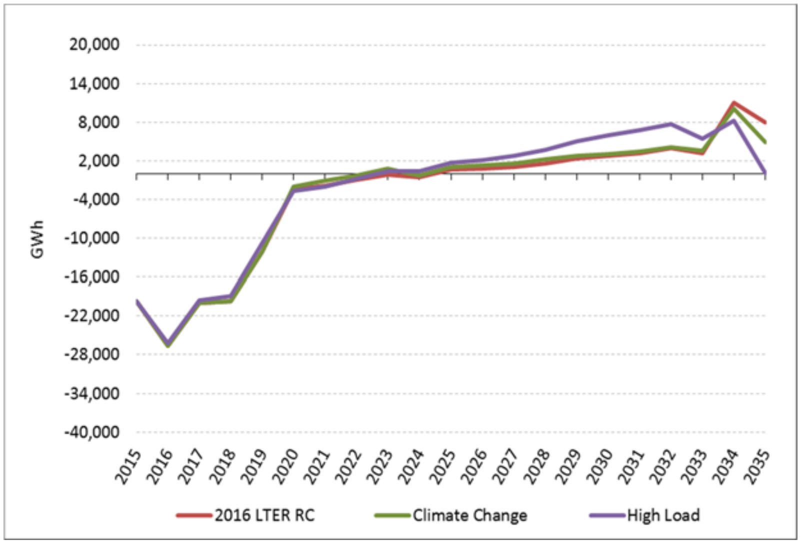
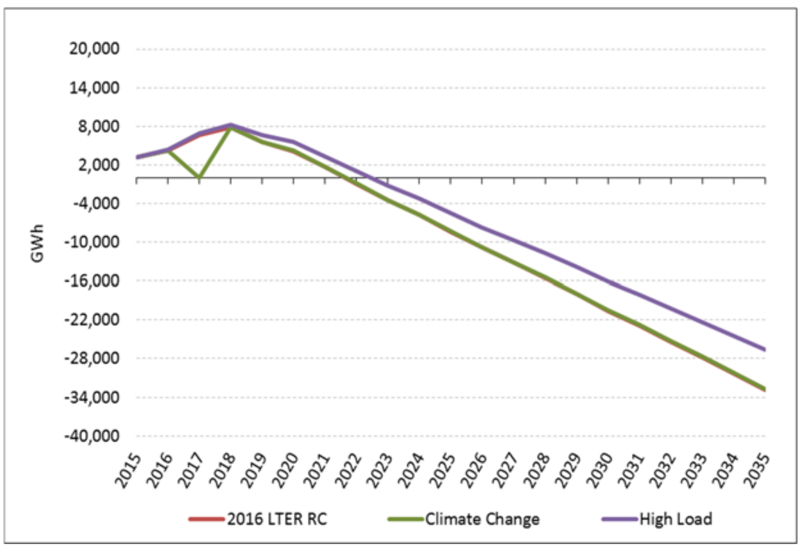


Figure 6.33 PJM-APS Net Imports – Climate Change Scenario



Note: The Reference Case line is directly under the Climate Change line and hence cannot be separately observed.

Table 6.5 shows the generation mix in terms of percent by type of generator. As seen on this table, there is very little change in the fuel mix in any of these scenarios relative to each other.

Table 6.5 Maryland Generation Mix – Climate Change Scenario

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	5%
2025	Reference Case	34,757	40	29	18	5	9
	High Load	36,051	38	29	19	5	8
	Climate Change	35,393	39	28	20	5	9
2035	Reference Case	27,641	23	39	20	7	12
	High Load	30,107	21	39	23	6	11
	Climate Change	28,205	23	37	22	7	11

Figure 6.34 through Figure 6.36 show Maryland emissions of SO_2, NOx, and mercury for Maryland's HAA plants under the Reference Case and the HL and Climate Change scenarios. As seen from these figures, there is very little difference in emissions under the Reference Case and the Climate Change scenario. Because difference in fuel use and generation between the two scenarios is small, so are the emissions impacts. For all three pollutants, Maryland stays well below the HAA caps.

Figure 6.34 Maryland SO_2 Emissions (HAA Plants) – Climate Change Scenario

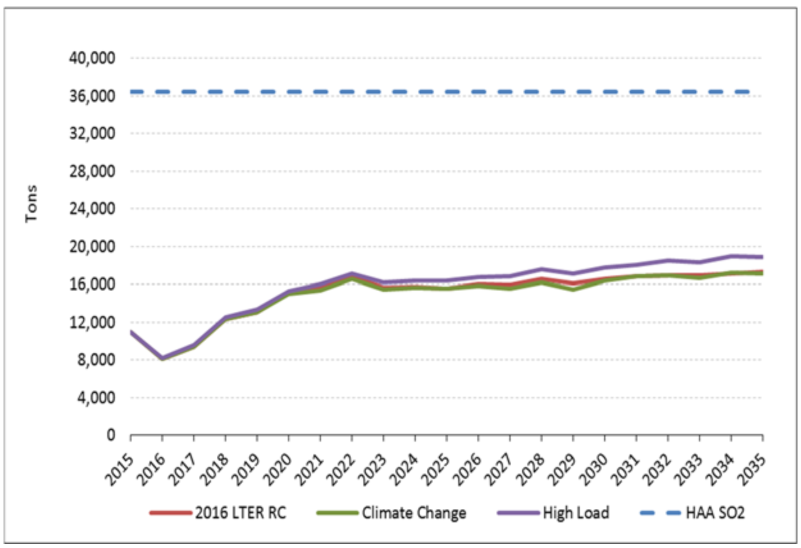


Figure 6.35 Maryland NOx Emissions (HAA Plants) – Climate Change Scenario

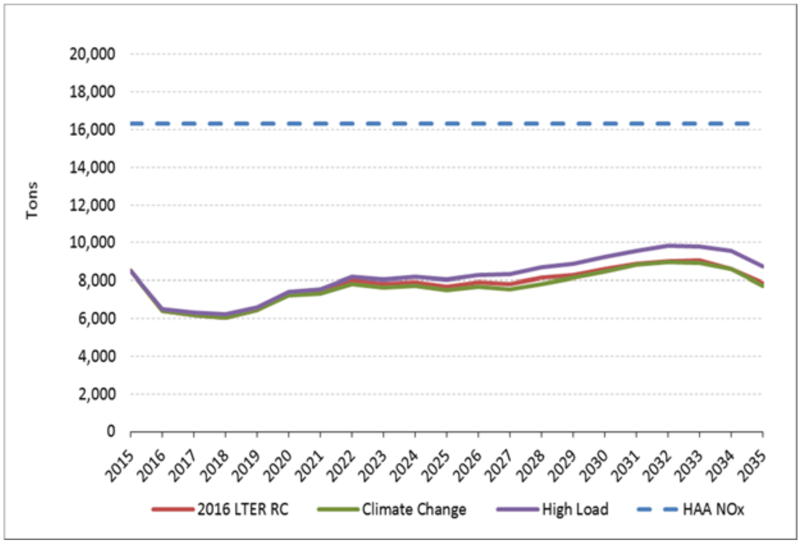


Figure 6.36 Maryland Mercury Emissions (HAA Plants) – Climate Change Scenario

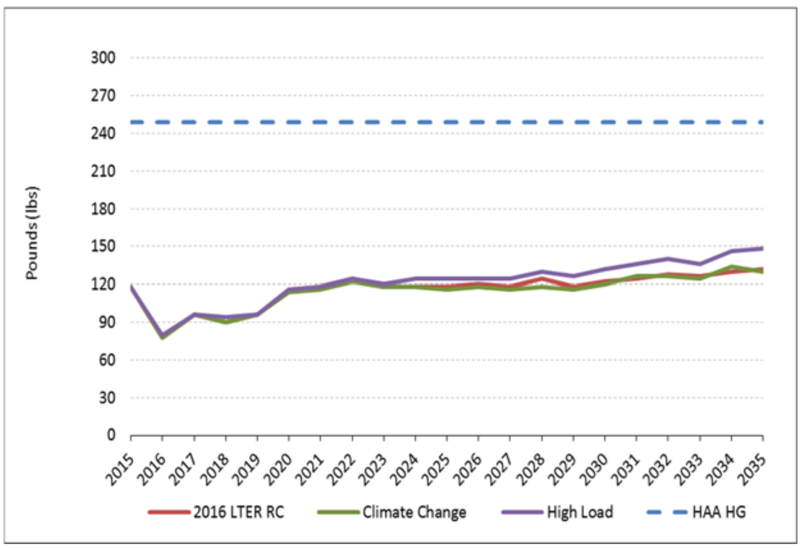
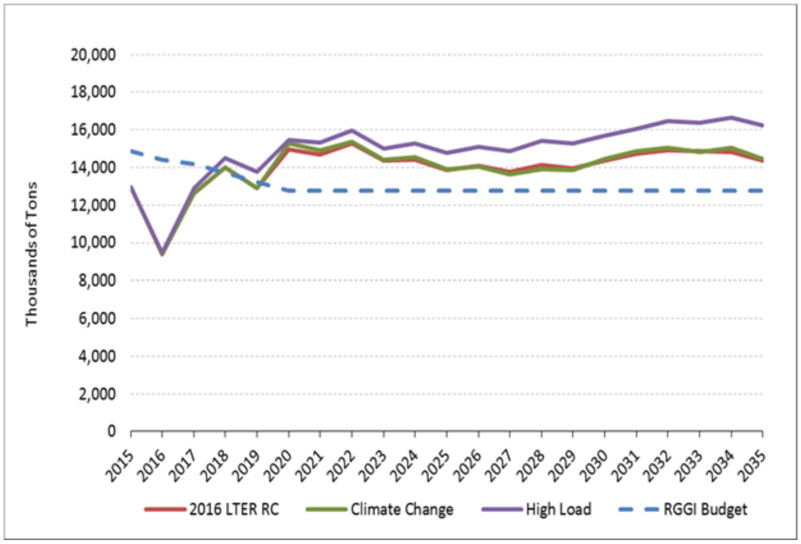


Figure 6.37 shows emissions of CO_2 for Maryland power plants for the Reference Case, the Climate Change scenario, and the HL scenario. The levels of CO_2 emissions in the Reference Case, the Climate Change scenario, and the HL scenario are essentially the same. As noted previously in this chapter, the HL scenario results in slightly higher levels of CO_2 emissions for Maryland plants than does the Reference Case. In all three scenarios, the Maryland plants exceed the RGGI budget (more so for the HL scenario) and, consequently, Maryland fossil fuel generators will need to purchase RGGI emissions allowances in excess of those allocated to Maryland.

Figure 6.37 Maryland CO_2 Emissions (All Plants) – Climate Change Scenario



The Climate Change scenario does not have a significant effect on REC prices compared to those in the Reference Case. In Section 6.8, the HL and LL scenarios' REC prices were compared to those estimated for the Reference Case, and described as having virtually no change. Similarly, comparing the Climate Change scenario to the HL scenario and the Reference Case indicates only a barely perceptible difference; the projections follow the same trajectory but with a final (2035) difference of approximately \$0.54 per REC. In 2035, the high HL scenario REC price is forecast to be \$0.86 per REC, and the Climate Change scenario value is \$1.40 per REC.

6.10 Summary of Key Results

The following key results are based on the modeling and analysis presented in this chapter:

- Across PJM, natural gas capacity additions are more than 50 percent greater in the HL scenario than in the Reference Case, and more than 50 percent lower in the LL scenario.

- PJM-MidE is most sensitive to changes in load; natural gas builds more than double in the HL scenario—surpassing builds in PJM-APS, despite the higher cost of construction in PJM-MidE.

- Under the HL scenario, net imports in PJM-SW, PJM-MidE, and PJM-APS are modestly higher than in the Reference Case; under the LL scenario, net imports are modestly lower.

- Changes in load have a more pronounced impact on the use of natural gas for electricity generation than on the use of coal.

- Load changes have only a slight impact on energy prices in PJM-SW, PJM-MidE, or PJM-APS.

- Capacity prices in all three Maryland zones remain low in the LL scenario until the later years of the study period, and then increase with the need for new plant construction. Capacity prices under the HL scenario increase in the mid- to late 2010s and remain at relatively high levels throughout the remainder of the study period. The differences in capacity prices reflect differences in the tightness of the capacity markets.

- Under all Load Growth scenarios, Maryland emissions of SO_2, NOx, and mercury remain below the HAA caps in all years.

- Under all load growth scenarios, Maryland CO_2 emissions exceed the RGGI budget.

- RECs prices projected under both of the Load Growth scenarios, and the Climate Change scenario, are essentially the same as under the Reference Case prices; there is a slight increase in price (approximately $0.54 per REC) at the end of the study period under the Climate Change scenario compared to the Reference Case and the HL scenario.

7. Renewable Portfolio Standard Alternative Scenarios

7.1 Introduction

The Renewable Portfolio Standard (RPS) scenarios explore multiple possibilities involving increased RPS goals in Maryland and throughout PJM. Currently, RPS policies exist in 29 states and the District of Columbia, and apply to 55 percent of total U.S. retail electricity sales. Roughly half the states with RPS policies have raised their commitments since the initial adoption of their RPS policies.[38] (See Section 10.1.4 for a more detailed discussion of Maryland's RPS.) Section 7.2 of this chapter looks at the impacts of changes to the Maryland RPS if they were to occur in isolation. Section 7.3 explores the opposite extreme—i.e., the impact of changes to the Maryland RPS if those changes were to occur in conjunction with similar changes being made in other PJM states.[39] PPRP chose to include the PJM-wide scenario because PJM's market is shaped less by any given member's actions—especially smaller members such as Maryland—and more by the collective impact of multiple states choosing to set similar priorities in response to similar political and economic developments. Thus, questions about the impact of Maryland's RPS policy choices can best be understood by looking at the spectrum of impacts that could occur, depending on the actions taken in other states in PJM. Table 7.1 summarizes the RPS goals that characterize each RPS Alternative Scenario.

Table 7.1 Overarching RPS Goals – MD and PJM RPS Scenarios

Scenario	RPS Goal
Moderate Maryland RPS Scenario	MD RPS rises to 25% by 2020, including 2.5% solar by 2020
High Maryland RPS Scenario	MD RPS rises to 35% by 2030, including 3.0% solar by 2025
Very High Maryland RPS Scenario	MD RPS rises to 50% by 2030, including 5.0% solar by 2030
Moderate PJM RPS Scenario	PJM-wide RPS of 25% by 2020, including 2.5% solar by 2020

Because decisions about renewable energy capacity additions are provided as inputs to the model, PPRP made several assumptions about how more aggressive RPS obligations would be met. For example, PPRP assumed that higher RPS requirements would be fulfilled entirely with actual generation, as opposed to alternative compliance payments (ACPs). Furthermore, PPRP assumed that new wind capacity would be used to fulfill any new RPS requirements, with the exception of solar carve-outs. For the Maryland RPS scenarios, PPRP further assumed that all necessary additional renewable energy capacity would either be built in Maryland or within a zone in which a portion of Maryland lies (i.e., PJM-SW, PJM-Mid-E, or PJM-APS).[40]

With respect to renewables placement within PJM for the PJM-wide scenario, the requirements for renewables were calculated on a state-by-state basis as the differential between the state's current RPS and the more aggressive RPS's (e.g., 25 percent renewables, including 2.5 percent solar). The

[38] Galen Barbose, *U.S. Renewables Portfolio Standards 2016 Annual Status Report*, Lawrence Berkeley National Laboratory, April 2016, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf.
[39] Eight of PJM's 13 member states plus the District of Columbia have mandatory RPS standards.
[40] It should be noted that Maryland's RPS only requires solar Renewable Energy Credits (RECs) to be generated in-State.

placement of the renewables was based on the zonal locations of the state and prorated if the state occupied more than one ABB transmission zone.

Since RPS requirements are tied to retail electricity sales in a given state, PPRP also made assumptions about load growth in Maryland and other PJM states. PPRP based Maryland's load growth from 2015-2023 on the Maryland Public Service Commission's (PSC's) most recent Ten-year Plan, which includes annual load projections (net of demand-side management) through 2023.[41] For the remaining years, PPRP assumed that load would continue to grow at a 0.70 percent compound annual growth rate (CAGR).[42] For the remaining PJM states, PPRP relied on a Lawrence Berkeley National Laboratory (LBNL) report on RPS demand, which projects retail electricity sales by "applying regional growth rates from the most-recent edition of the Energy Information Administration's Annual Energy Outlook (Reference Case forecast) to the most-recent available state-level retail sales data."[43]

Based on these assumptions, PPRP calculated the additions in renewable energy capacity, above those already assumed for the Reference Case, as shown in Table 7.2.

Table 7.2 New Renewables Capacity Additions, beyond Those Assumed for the Reference Case, by 2035 – RPS Scenarios (MW)

Scenario	Solar[1]	Wind[2]
Moderate Maryland RPS Scenario	270	1,585
High Maryland RPS Scenario	538	3,767
Very High Maryland RPS Scenario	1,146	6,681
Moderate PJM RPS Scenario[3]	10,706	32.743

[1] For all of the alternative Maryland RPS scenarios, 100 percent of the Maryland solar energy requirement is located in Maryland, divided between PJM-SW (25 percent) and PJM-MidE (75 percent).

[2] For all of the alternative Maryland RPS scenarios, all new wind generation is assumed to be located outside Maryland, divided evenly between PJM-MidE and PJM-APS.

[3] These figures are renewable capacity additions to PJM excluding additions to Maryland, which are identical to those shown in the Moderate Maryland RPS scenario row. PJM additions are spread throughout the PJM footprint.

41 Public Service Commission of Maryland, *Ten Year Plan (2014-2023) of Electric Companies in Maryland*, August 2014, www.psc.state.md.us/wp-content/uploads/2014_2023_TYP_Final1.pdf.

42 Based on the PJM growth in energy for the PJM-SW transmission zone.

43 Galen Barbose, *RPS Demand Projections* (last updated July 2016), Lawrence Berkeley National Laboratory, https://emp.lbl.gov/sites/all/files/RPS%20Demand%20Projections_Sept%202016.xlsx.

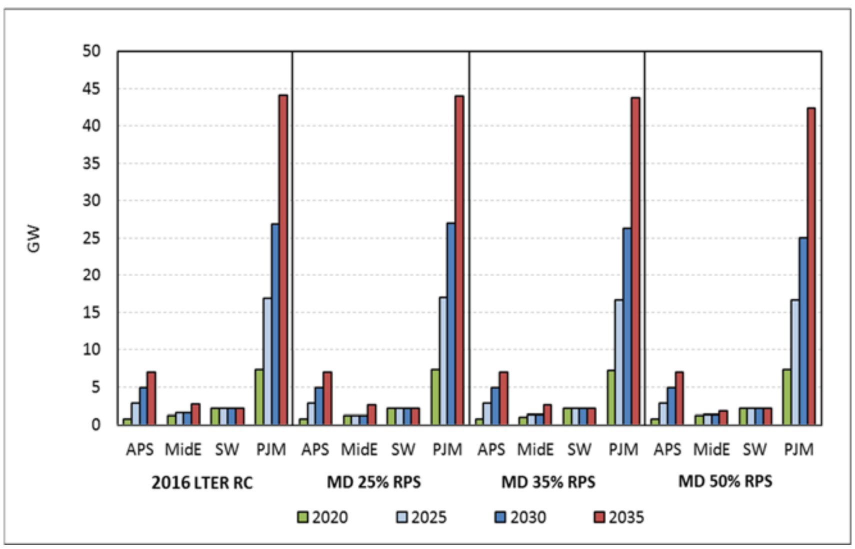
7.2 Maryland 25 Percent, 35 Percent, and 50 Percent RPS Scenario Results

7.2.1 Capacity Additions and Retirements

Because Maryland is such a small member of PJM, raising the State's RPS to 25 percent, 35 percent, or 50 percent has little impact on non-renewable demand in Maryland or in PJM as a whole.[44] As in the Reference Case, the only plant to retire for economic reasons is a 103-MW coal plant in PJM-SW. By definition, age-based plant retirements are unchanged in the Maryland RPS scenarios.

Changes to Maryland's RPS also have almost no impact on capacity builds PJM-wide; natural gas capacity additions in the Maryland RPS scenarios are less than 1 percent lower than in the Reference Case by 2035. However, the influx of renewable energy construction in PJM-MidE does make it a slightly less attractive zone for new natural gas capacity additions. By the end of the study period, new capacity builds under the 25 percent and 35 percent scenarios in PJM-MidE are 170 MW, or 6 percent, lower than in the Reference Case. Under the 50 percent scenario in PJM-MidE, new capacity builds are 1 GW, or 36 percent, lower than the Reference Case. Capacity builds in PJM-SW and PJM-APS are unchanged. These comparisons are shown in Figure 7.1 and Table 7.3.

Figure 7.1 Comparison of Cumulative Generic Natural Gas Plant Additions – MD RPS Scenarios



Note: Average of summer and winter capacity ratings.

[44] In this section, all changes to the Maryland RPS are assumed to occur in isolation. Qualifying statements such as "while other states' RPS's remain static" are omitted for the sake of brevity.

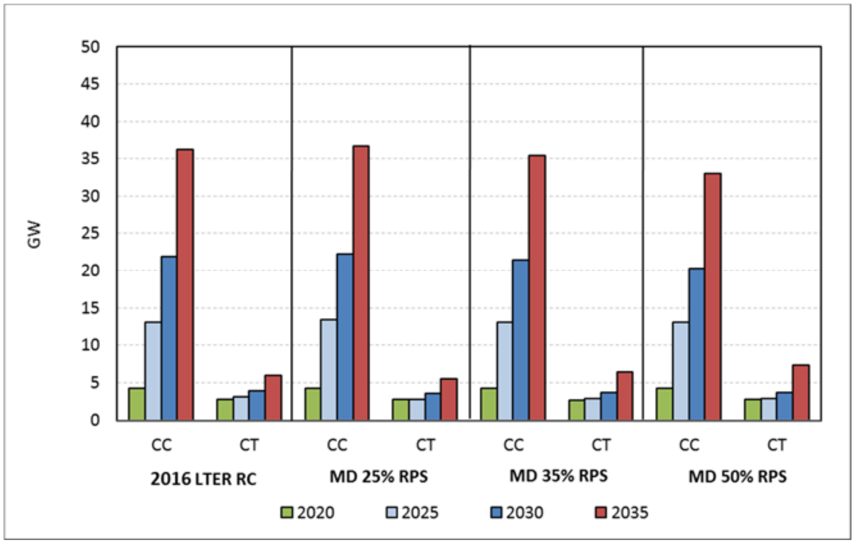
Table 7.3 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – MD RPS Scenarios (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	1.57	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (MD 25% RPS minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	--	--	--
2025	--	(0.35)	--	0.07
2030	--	(0.35)	--	0.07
2035	--	(0.17)	--	(0.11)
Difference (MD 35% RPS minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	(0.17)	--	(0.17)
2025	--	(0.17)	--	(0.17)
2030	--	(0.17)	--	(0.59)
2035	--	(0.17)	--	(0.31)
Difference (MD 50% RPS minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	--	--	--
2025	--	(0.17)	--	(0.17)
2030	--	(0.17)	--	(1.84)
2035	--	(1.01)	--	(1.76)

Note: Average of summer and winter capacity ratings.

Raising Maryland's RPS has a modest impact on the type of natural gas capacity that is added in PJM by 2035, as shown in Figure 7.2 and Table 7.4. Combustion turbine (CT) plant builds are 480 MW, or 8 percent, greater in the Maryland 35 percent RPS scenario than in the Reference Case. Meanwhile, combined cycle (CC) builds drop to 800 MW, or 2 percent, below the Reference Case. The most significant shift is under the 50 percent scenario, where CT increases by 1.4 GW and CC decreases by 3.2 GW in 2035 compared to the Reference Case. These results suggest that, in the Maryland RPS scenarios, the mix of natural gas plants slightly changes from intermediate or baseload CC to CT that responds when needed to meet fluctuations in demand or generation.

Figure 7.2 PJM Generic Plant Additions by Type – MD RPS Scenarios



Note: Summer capacity rating.

Table 7.4 Generic Plant Additions by Type – MD RPS Scenarios (GW)

Reference Case Generic Generation Added by Model		
Year	CC	CT
2020	4.25	2.72
2025	13.05	3.04
2030	21.85	3.84
2035	36.25	5.92
Difference (MD 25% RPS minus RC) Generic Generation Added by Model		
Year	CC	CT
2020	--	--
2025	0.40	(0.32)
2030	0.40	(0.32)
2035	0.40	(0.48)
Difference (MD 35% RPS minus RC) Generic Generation Added by Model		
Year	CC	CT
2020	--	(0.16)
2025	--	(0.16)
2030	(0.40)	(0.16)
2035	(0.80)	0.48
Difference (MD 50% RPS minus RC) Generic Generation Added by Model		
Year	CC	CT
2020	--	--
2025	--	(0.16)
2030	(1.60)	(0.16)
2035	(3.20)	1.44

Note: Summer capacity rating.

7.2.2 Net Imports

In the Maryland RPS scenarios, net imports drop below Reference Case levels in both PJM-MidE and PJM-APS—the two regions where new wind is built to fulfill higher RPS requirements—as seen in Figure 7.4 and Figure 7.5. By 2035, in the Maryland 35 percent RPS Scenario, net imports in PJM-APS drop by nearly 5,000 GWh, or 15 percent, below Reference Case levels, while net imports in PJM-MidE drop by a little over 3,500 GWh, or approximately 25 percent. The most significant difference is under the Maryland 50 percent scenario, with net imports in PJM-APS estimated to increase by 16,000 GWh, or 49 percent, above the Reference Case, while net imports in PJM-MidE decrease by 9,600 GWh, or 86 percent, lower than the Reference Case. However, net imports remain steady across all three scenarios in PJM-SW, as seen in Figure 7.3. This suggests that the generation provided by new solar capacity in PJM-SW replaces non-solar generation built in PJM-SW in the Reference Case.

Figure 7.3 PJM-SW Net Energy Imports – MD RPS Scenarios

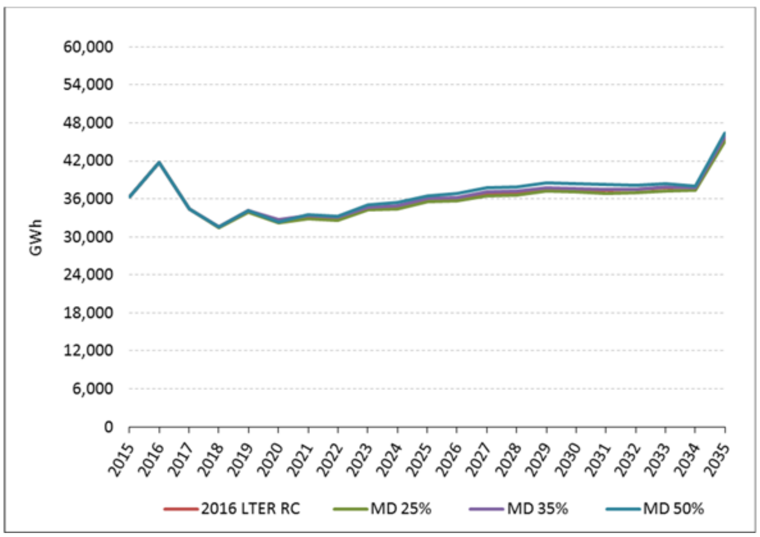


Figure 7.4 PJM-MidE Net Energy Imports – MD RPS Scenarios

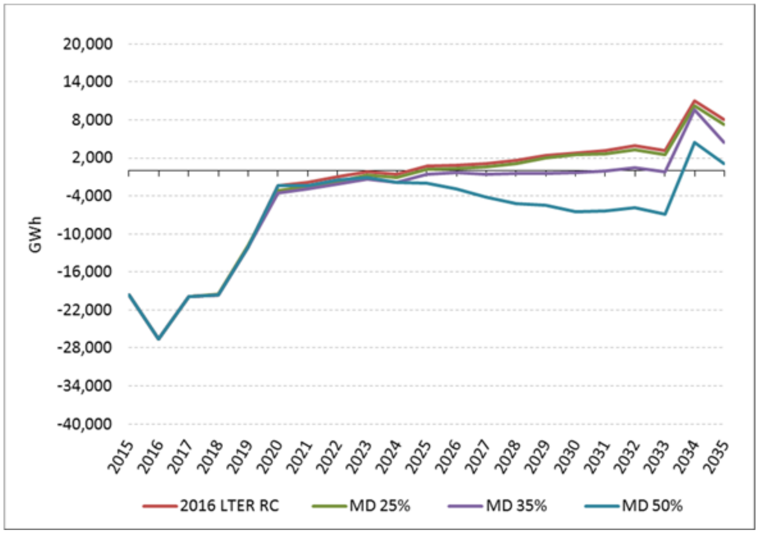
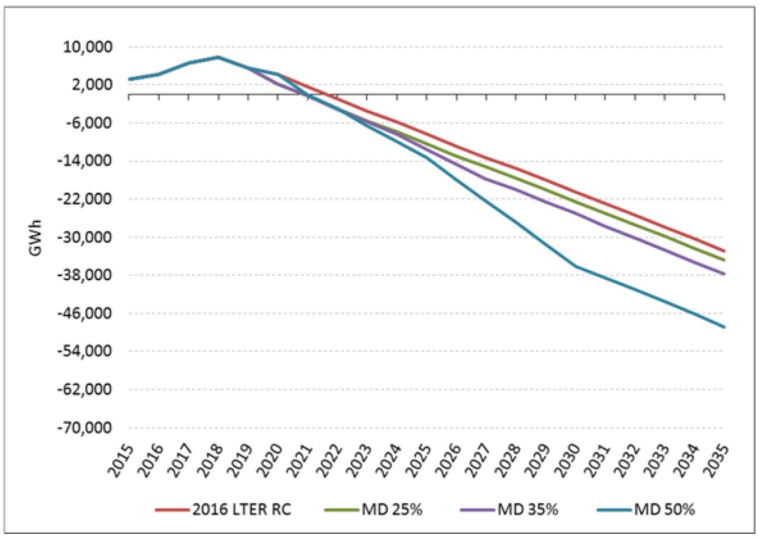


Figure 7.5 PJM-APS Net Energy Imports – MD RPS Scenarios



7.2.3 Fuel Use

Raising Maryland's RPS causes almost no change in Maryland's coal and natural gas use, as shown in Figure 7.6 and Figure 7.7. Maryland's fossil fuel plants continue to generate electricity to meet loads located throughout PJM.

Figure 7.6 Coal Use for Electricity Generation in Maryland – MD RPS Scenarios

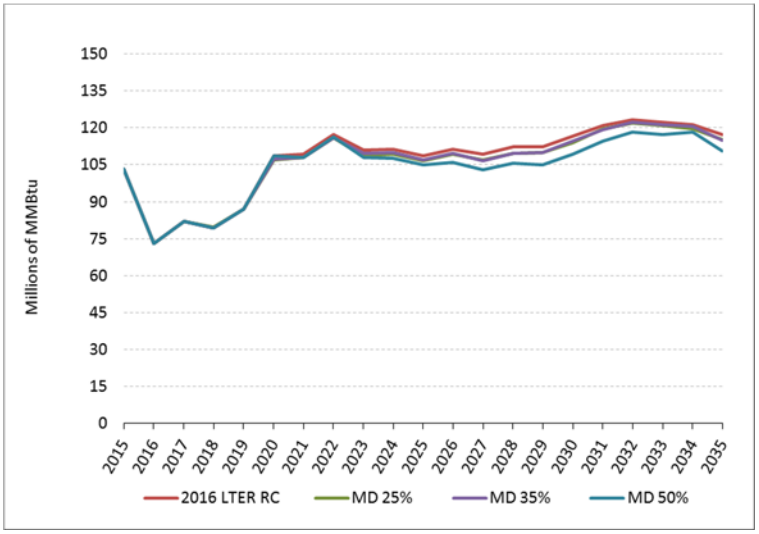
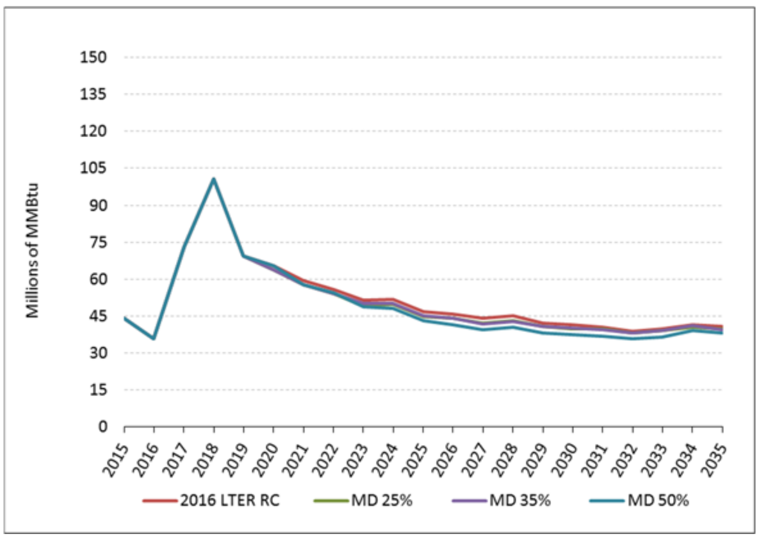


Figure 7.7 Natural Gas Use for Electricity Generation in Maryland – MD RPS Scenarios



With respect to coal and natural gas use PJM-wide, increasing the Maryland RPS to either 25 percent, 35 percent, or 50 percent has no meaningful impact.

While coal and natural gas generation remain steady in the Maryland RPS scenarios, nuclear declines significantly in 2035 in both the Reference Case and the three RPS scenarios. Due to the decline in nuclear in 2035, the percentage of coal generation in Maryland increases by approximately 10 percentage points in the Reference Case and the three RPS scenarios, as seen in Table 7.5. Under the 50 percent scenario, however, the percentage of renewable generation increases by 1,896 GWh, or 58 percent, higher than the Reference Case.

Table 7.5 Maryland Generation Mix – MD RPS Scenarios

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	4%
2025	Reference Case	34,757	40	29	18	5	9
	MD 25% RPS	34,639	40	28	17	5	10
	MD 35% RPS	35,028	39	28	17	5	11
	MD 50% RPS	34,737	40	28	16	5	11
2035	Reference Case	27,641	23	39	20	7	12
	MD 25% RPS	27,667	23	38	19	7	13
	MD 35% RPS	27,914	23	37	19	7	14
	MD 50% RPS	28,540	22	35	18	7	18

7.2.4 Energy Prices

Figure 7.8 through Figure 7.10 show energy prices in the three Maryland RPS scenarios. Prices align with the trends seen for each transmission zone in the Reference Case. Because these regions are well-integrated with the rest of PJM, wholesale energy prices reflect PJM-wide electricity supply trends, without being greatly perturbed by small, local increases in renewable energy generation.

Figure 7.8 PJM All-hours Energy Prices – MD RPS Scenarios

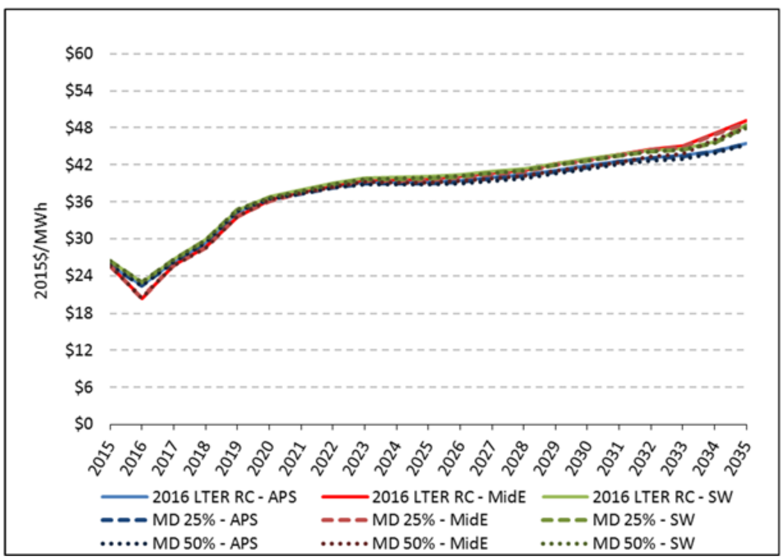


Figure 7.9 PJM On-peak Energy Prices – MD RPS Scenarios

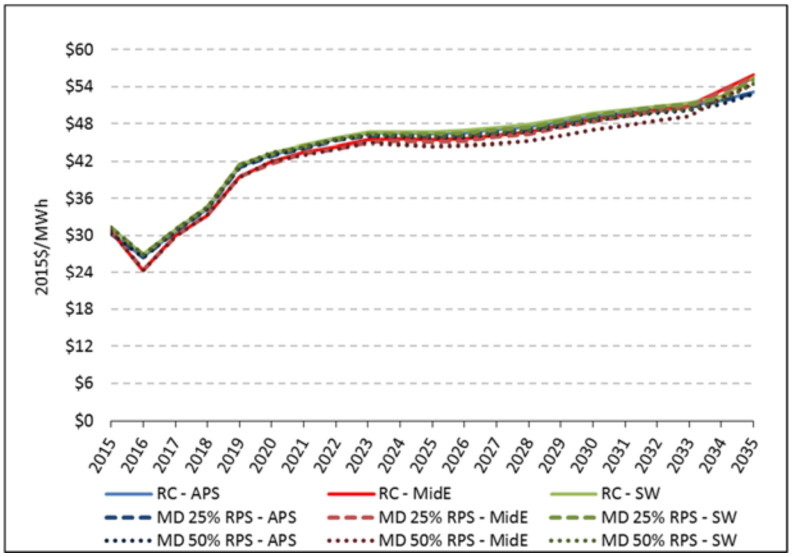
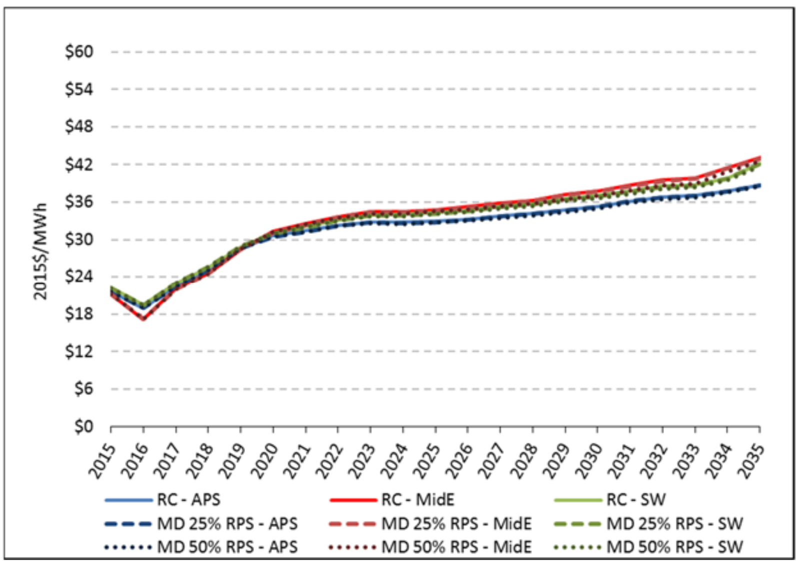


Figure 7.10 PJM Off-peak Energy Prices – MD RPS Scenarios



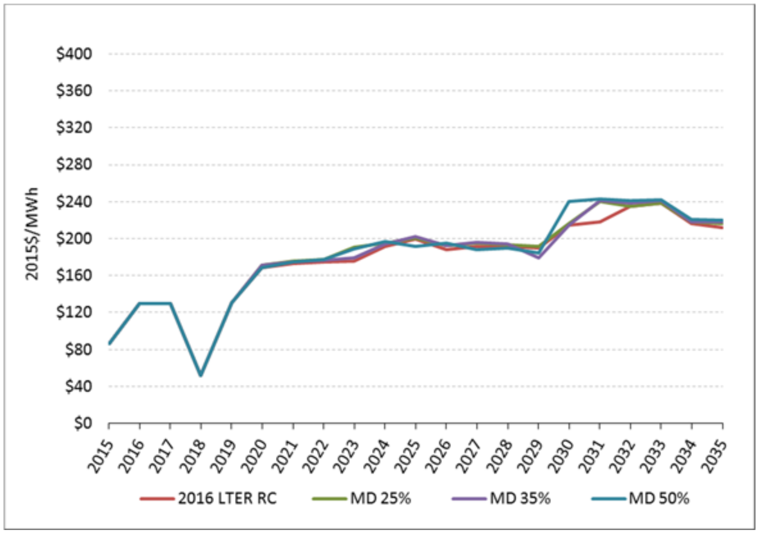
7.2.5 Capacity Prices

Raising the RPS in Maryland causes only minor fluctuations in capacity prices in the three zones of relevance to Maryland, as seen in Figure 7.11 through Figure 7.13. These results are consistent with the minimal changes to capacity builds discussed in Section 7.2.1. In the PJM-SW and PJM-MidE zones, there is a noticeable divergence between the capacity price trend for the 50 percent RPS scenario in comparison to the Reference Case and other RPS scenarios. In PJM-SW, the capacity prices do not follow the other scenarios from 2028 through 2033 due to tightened available capacity as a result of no new additions. In PJM-MidE, capacity prices are lower from 2029 through 2031 when compared to the other RPS scenarios due to a significant amount of new generation causing PJM-MidE to become a net exporter.

Figure 7.11 PJM-SW Capacity Prices – MD RPS Scenarios

Figure 7.12 PJM-MidE Capacity Prices – MD RPS Scenarios

Figure 7.13 PJM-APS Capacity Prices – MD RPS Scenarios



7.2.6 Emissions

Emissions in Maryland are only very slightly changed by higher Maryland RPS requirements, as seen in Figure 7.14 through Figure 7.17, primarily because in-State coal and natural gas plants continue to generate at Reference Case-levels,

Figure 7.14 Maryland SO_2 Emissions (HAA Plants) – MD RPS Scenarios

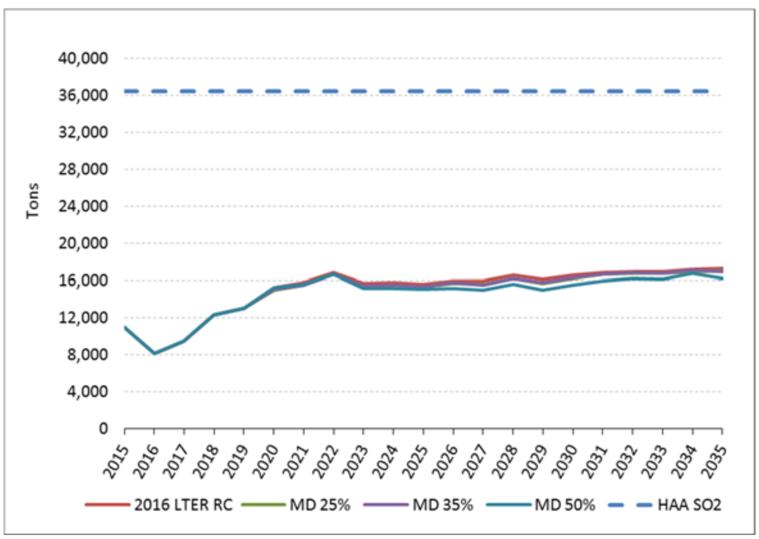


Figure 7.15 Maryland NOx Emissions (HAA Plants) – MD RPS Scenarios

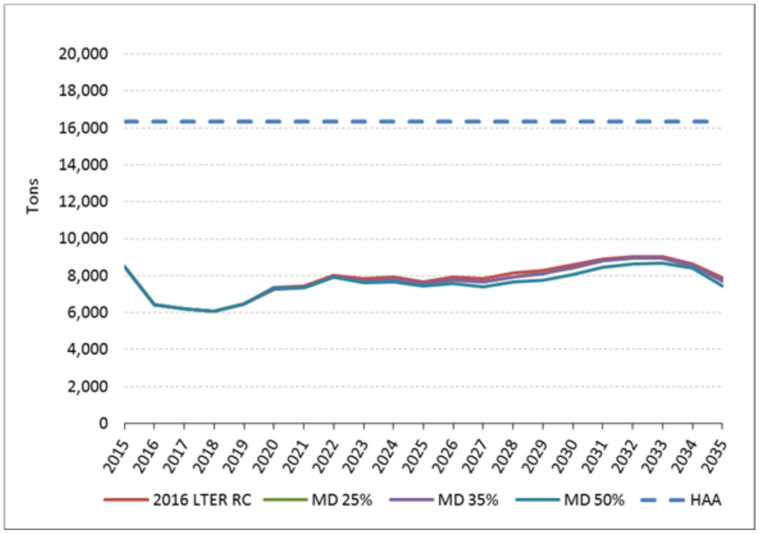


Figure 7.16 Maryland Mercury Emissions (HAA Plants) – MD RPS Scenarios

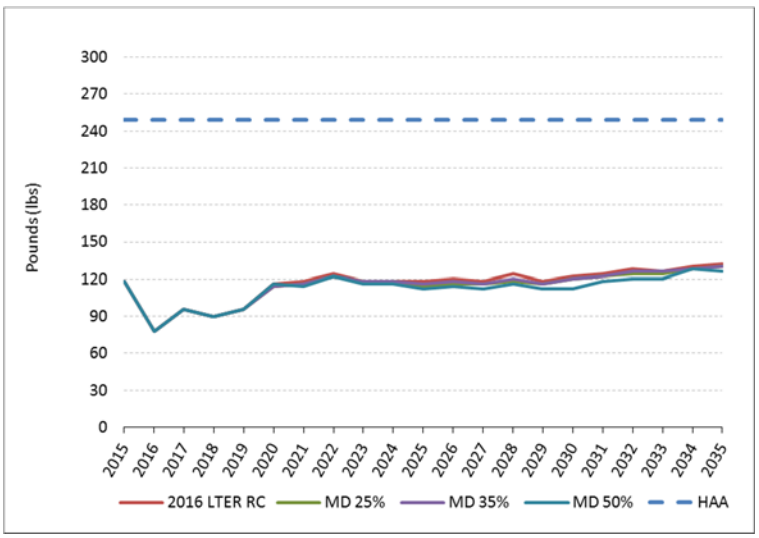
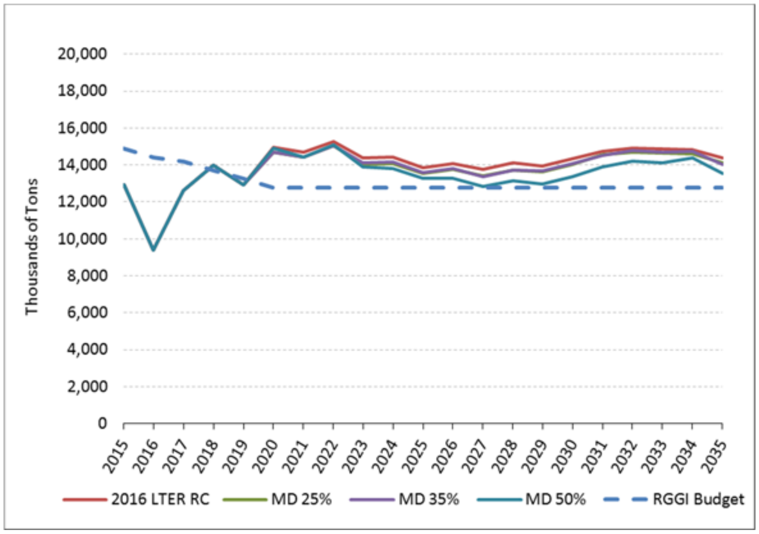
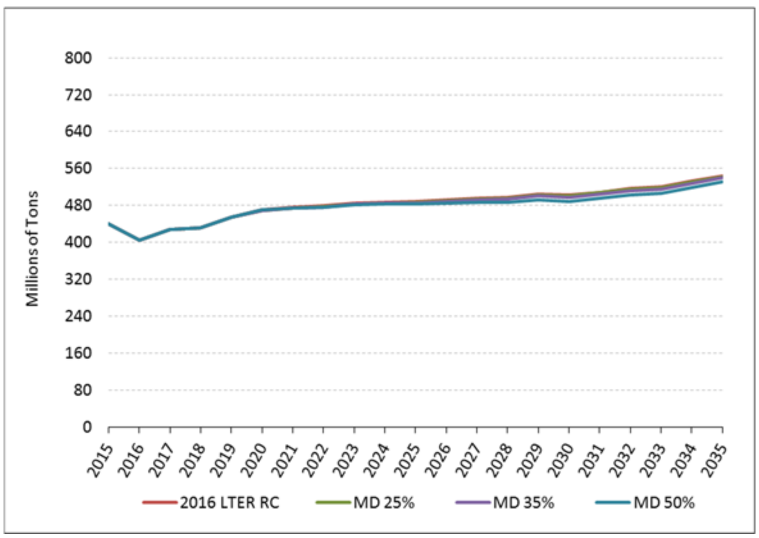


Figure 7.17 Maryland CO_2 Emissions (All Plants) – MD RPS Scenarios



Likewise, increasing Maryland's RPS does not produce significant changes in emissions in PJM. For example, Figure 7.18 shows PJM-wide CO_2 emissions; they align even more closely with the Reference Case than the Maryland-specific emissions shown directly above.

Figure 7.18 PJM CO_2 Emissions – MD RPS Scenarios



7.2.7 Renewable Energy Credit Prices

None of the three Maryland RPS scenarios results in other-than-trivial changes to the REC prices calculated for the Reference Case. The reason for this is that none of the scenarios result in meaningful changes to energy prices or capacity prices.

7.2.8 Cost/Benefit Considerations

Even though there are no significant changes in electric energy prices, capacity prices, or REC prices, the higher RPS requirements associated with the three Maryland-only aggressive renewables cases result in increased costs to end-users. These additional costs result from additional REC purchases required to meet Maryland's RPS, which would increase RPS-related compliance costs proportionally to the increase in the RPS requirement. To the extent that off-shore wind is relied upon to meet the higher requirement and that the off-shore wind receives cost recovery treatment different from other Tier 1 renewables, there could be additional costs related to off-shore wind. To the extent that additional transmission may be required to accommodate the higher levels of renewables, those costs would be, in part, incurred by Maryland consumers. In addition to the cost considerations noted above, there may be additional non-quantifiable costs and benefits related to marginal reductions in emissions and other quality-of-life and aesthetics issues.

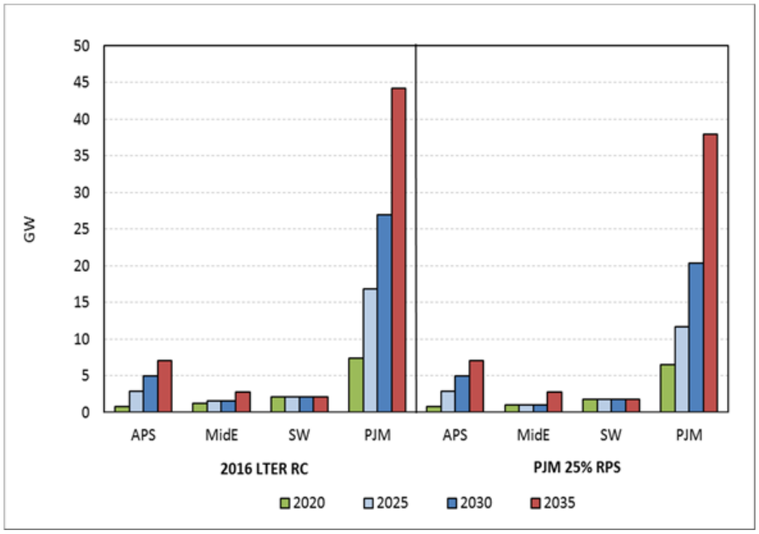
7.3 PJM 25 Percent RPS Scenario Results

The remainder of this chapter looks at Maryland-specific outcomes of raising Maryland's RPS in conjunction with a PJM-wide move to raise RPS standards.

7.3.1 Capacity Additions and Retirements

Plant retirements are unchanged by PJM-wide RPS requirements. However, creating (and meeting) an across-the-board RPS in PJM has major impacts on the need for new non-renewable capacity, as shown in Figure 7.19 and Table 7.6. A 25 percent PJM-wide RPS would lower natural gas builds by over 6 GW, or 14 percent, relative to the Reference Case. Within the three PJM zones of relevance to Maryland, creating PJM-wide RPS standards has unusually diverse results. At the 25 percent RPS level, the need for new natural gas capacity rises 35 percent and 150 percent in PJM-APS and PJM-MidE, respectively, while it falls slightly in PJM-SW.

Figure 7.19 Generic Plant Additions – PJM RPS Scenario (GW)



Note: Average of summer and winter capacity ratings.

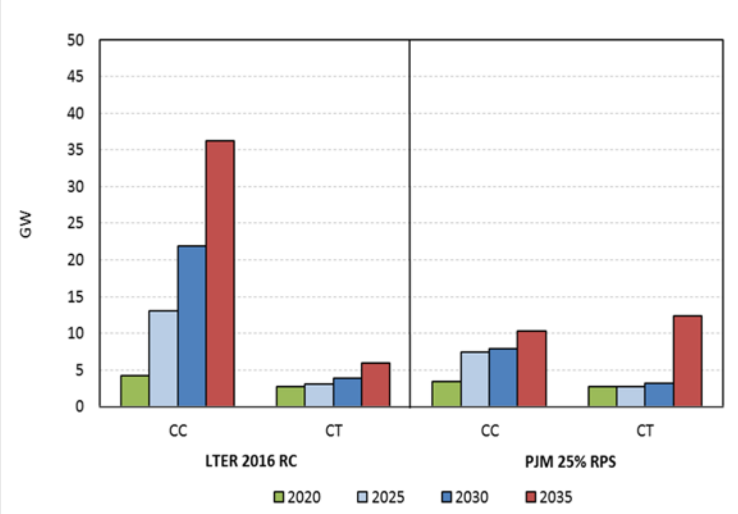
Table 7.6 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – PJM RPS Scenario (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	1.57	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (PJM 25% RPS minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	(0.17)	(0.42)	(0.83)
2025	--	(0.52)	(0.42)	(5.23)
2030	--	(0.52)	(0.42)	(6.58)
2035	--	--	(0.42)	(6.19)

Note: Average of summer and winter capacity ratings.

Creating a PJM-wide RPS also dramatically impacts both CC and CT builds, as shown in Figure 7.20 and Table 7.7. The mix of natural gas plants changes from intermediate or baseload CC to CT that can quickly respond to variations in demand or generation.

Figure 7.20 Generic Plant Additions by Type – PJM RPS Scenario



Note: Summer capacity rating.

Table 7.7 Generic Plant Additions by Type – PJM RPS Scenario (GW)

Reference Case (RC) Generic Generation Added by Model		
Year	**CC**	**CT**
2020	4.25	2.72
2025	13.05	3.04
2030	21.85	3.84
2035	36.25	5.92
Difference (PJM 25% RPS minus RC) Generic Generation Added by Model		
Year	**CC**	**CT**
2020	(0.80)	--
2025	(5.20)	0.16
2030	(8.00)	1.60
2035	(10.80)	4.64

Note: Summer capacity rating.

7.3.2 Net Imports

The creation of a PJM-wide RPS marginally increases net imports for the majority of the study period in PJM-SW and PJM-MidE relative to the Reference Case, as seen in Figure 7.21 and Figure 7.22, while net imports fall dramatically in PJM-APS, as seen in Figure 7.23. While the states that comprise PJM-SW and PJM-MidE already have established RPS standards, roughly half of PJM-APS is in West Virginia, which currently has no RPS. Therefore, a disproportionately large amount of new renewable energy capacity is placed in PJM-APS for the PJM RPS scenario. This is likely an important factor in dramatically decreasing the need for imports in PJM-APS.

Figure 7.21 PJM-SW Net Energy Imports – PJM RPS Scenario

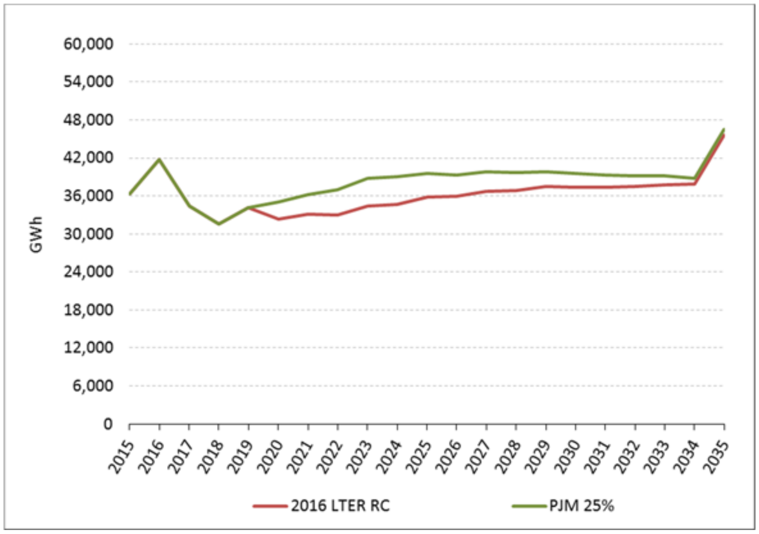


Figure 7.22 PJM-MidE Net Energy Imports – PJM RPS Scenario

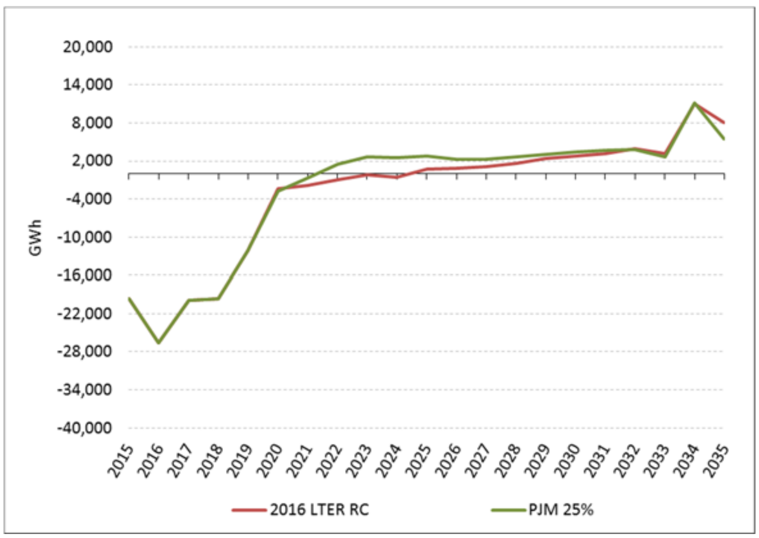
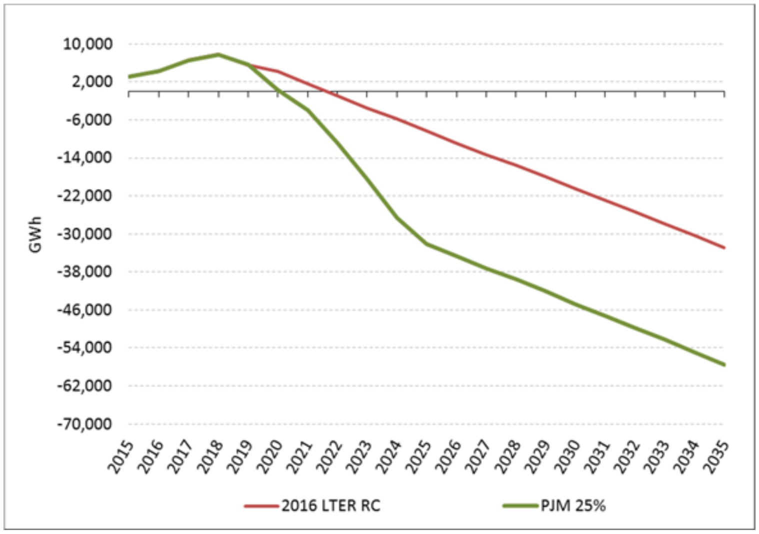


Figure 7.23 PJM-APS Net Energy Imports – PJM RPS Scenario



7.3.3 Fuel Use

The creation of a PJM-wide RPS causes immediate and sustained drops in coal and natural gas use in Maryland relative to the Reference Case, as shown in Figure 7.24 and Figure 7.25. The same is true throughout PJM, as shown in Figure 7.26 and Figure 7.27. Both within Maryland and PJM-wide, natural gas use is more significantly affected than coal use, which reflects the fact that renewable energy builds not only cause existing fossil fuel plants to be used less intensively, but also diminish the need for new natural gas plant builds, as discussed in Section 7.2.1. Natural gas use is also disproportionately affected since it is generally the marginal fuel and hence is the first displaced by new renewable energy generation.

Figure 7.24 Coal Use for Electricity Generation in Maryland – PJM RPS Scenario

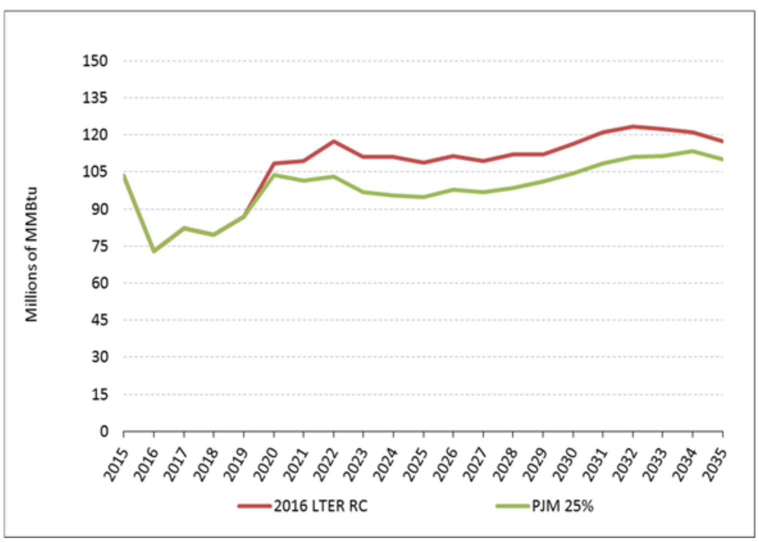


Figure 7.25 Natural Gas Use for Electricity Generation in Maryland – PJM RPS Scenario

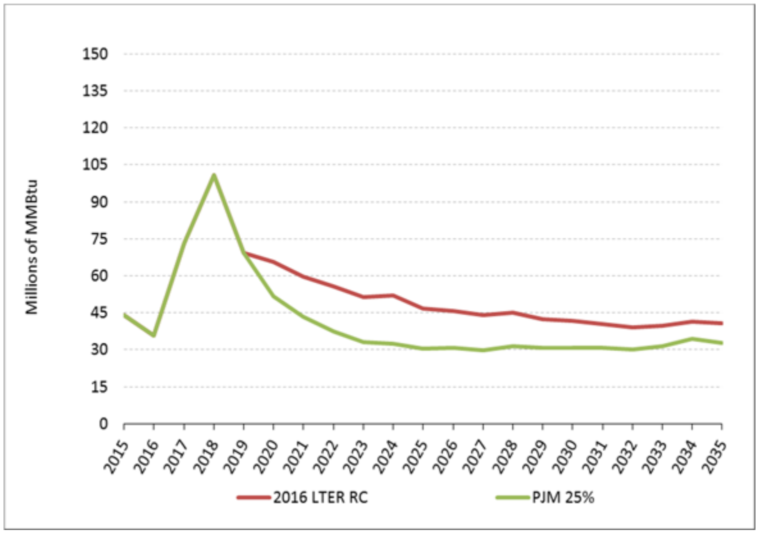


Figure 7.26 Coal Use for Electricity Generation in PJM – PJM RPS Scenario

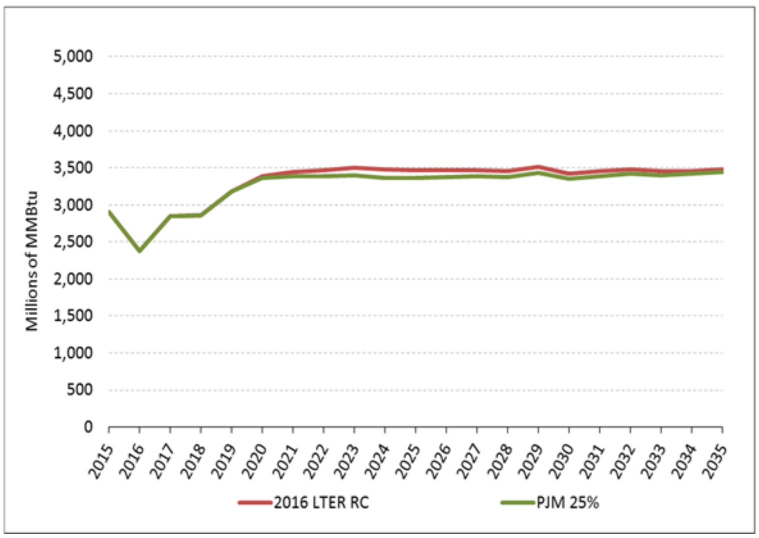


Figure 7.27 Natural Gas Use for Electricity Generation in PJM – PJM RPS Scenario

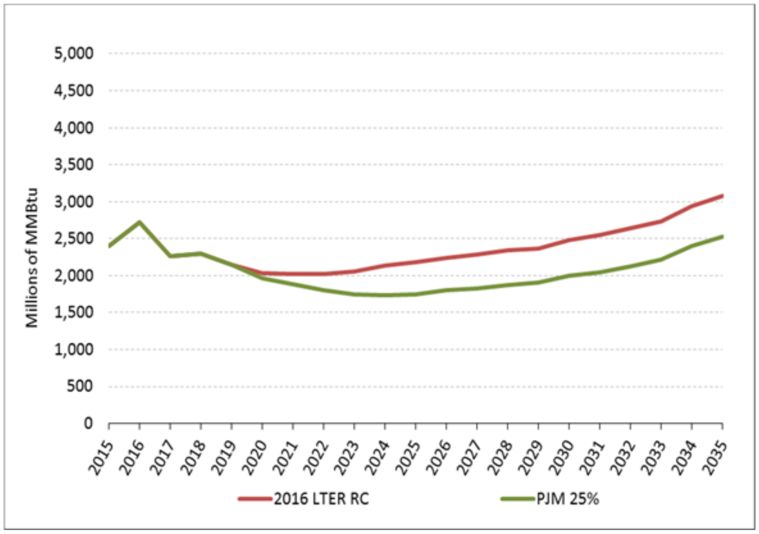


Table 7.8 shows changes in both natural gas and coal use in the broader context of Maryland's generation mix. In the PJM 25 percent RPS scenario, both coal and natural gas generation represent roughly 6 percent less of the State's total generation as compared to the Reference Case, while renewable energy generation represents roughly 12 percent more.

Table 7.8 Maryland Generation Mix – PJM RPS Scenario

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	4%
2025	Reference Case	34,757	40	29	18	5	9
	PJM 25% RPS	31,436	44	28	12	6	11
2035	Reference Case	27,641	23	39	20	7	12
	PJM 25% RPS	26,109	25	38	16	7	14

7.3.4 Energy Prices

Figure 7.28 through Figure 7.30 show energy prices in the PJM RPS Scenario during all-hours, on-peak hours, and off-peak hours. In all three PJM transmission zones of relevance to Maryland, prices are substantially lower than in the Reference Case. Higher renewable energy generation allows less costly conventional generation units to meet load on the margin, thus putting downward pressure on prices.[45]

[45] This result is also seen in the following chapter, "Clean Power Plan Alternative Scenario."

Figure 7.28 PJM All-hours Energy Prices – PJM RPS Scenario

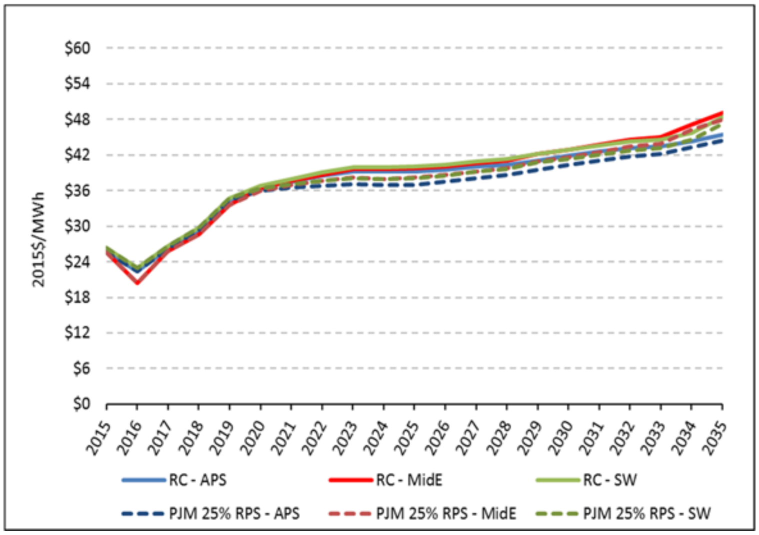


Figure 7.29 PJM On-peak Energy Prices – PJM RPS Scenario

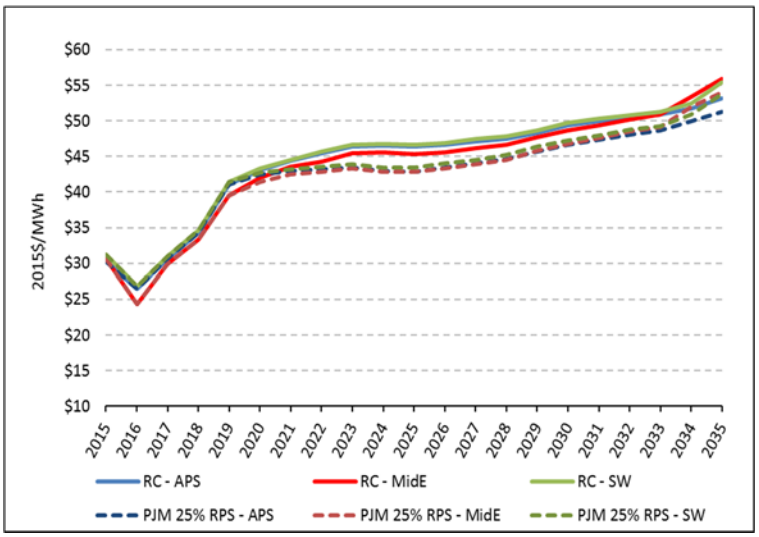
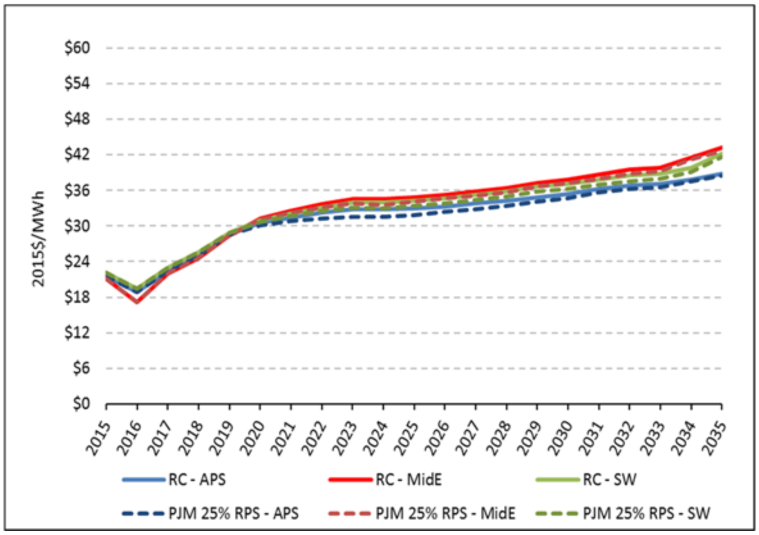


Figure 7.30 PJM Off-peak Energy Prices – PJM RPS Scenario



7.3.5 Capacity Prices

The major additions of new renewable energy capacity associated with the PJM RPS scenario places downward pressure on capacity prices in PJM-SW and PJM-MidE, relative to the Reference Case, as shown in Figure 7.31 and Figure 7.32. In PJM-APS, capacity prices are only marginally impacted by PJM-wide RPS requirements, as seen in Figure 7.33. It appears that the increase in renewable energy generation in PJM-APS results in increased exports (as evidenced by the reductions in net imports shown in Figure 7.23), which may be blunting what would otherwise be a more pronounced downward movement in capacity prices in the zone.

Figure 7.31 PJM-SW Capacity Prices – PJM RPS Scenario

Figure 7.32 PJM-MidE Capacity Prices – PJM RPS Scenario

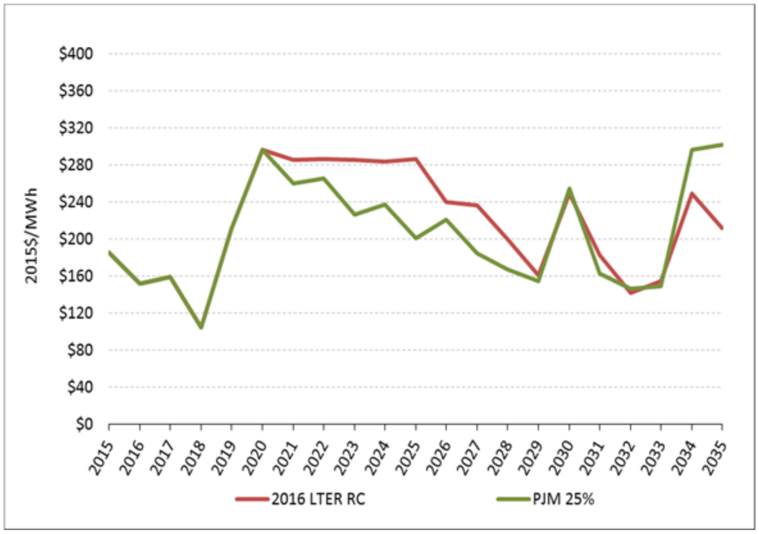
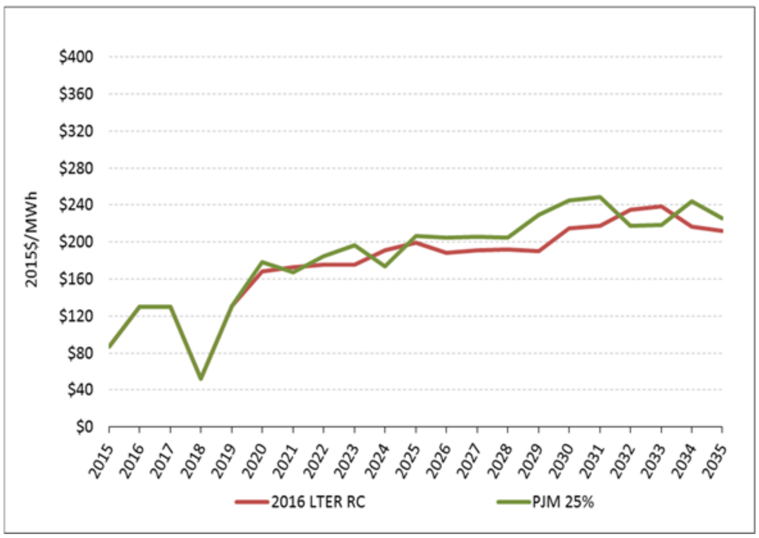


Figure 7.33 PJM-APS Capacity Prices – PJM RPS Scenario



7.3.6 Emissions

Emissions from Maryland's Healthy Air Act (HAA) plants are modestly lower in the PJM RPS scenarios, as shown in Figure 7.34 through Figure 7.36. This corresponds with the drop in coal use identified in Section 7.3.3.

Figure 7.34 Maryland SO_2 Emissions (HAA Plants) – PJM RPS Scenario

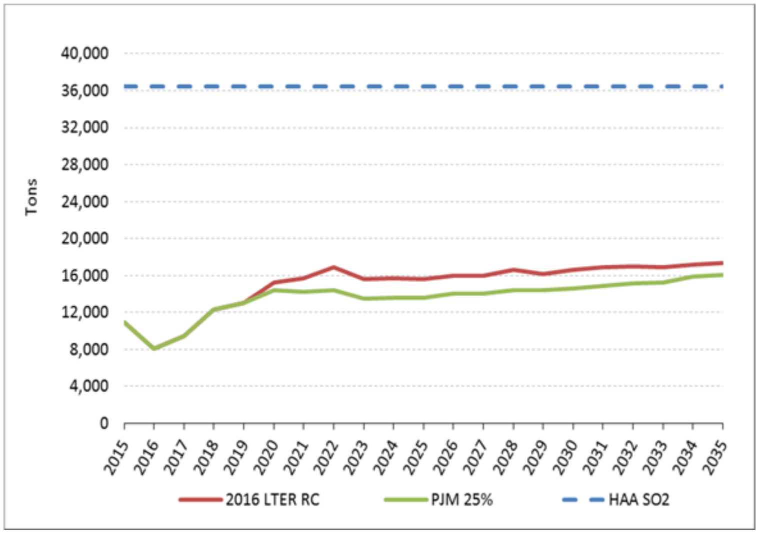


Figure 7.35 Maryland NOx Emissions (HAA Plants) – PJM RPS Scenario

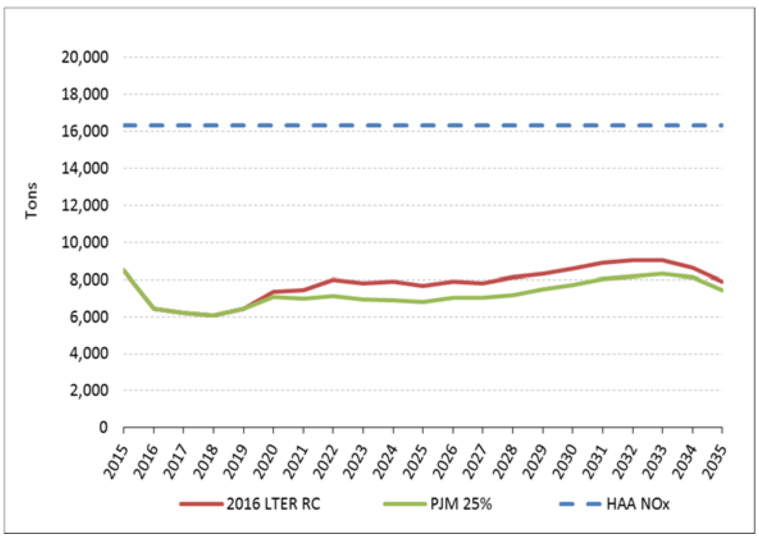


Figure 7.36 Maryland Mercury Emissions (HAA Plants) – PJM RPS Scenario

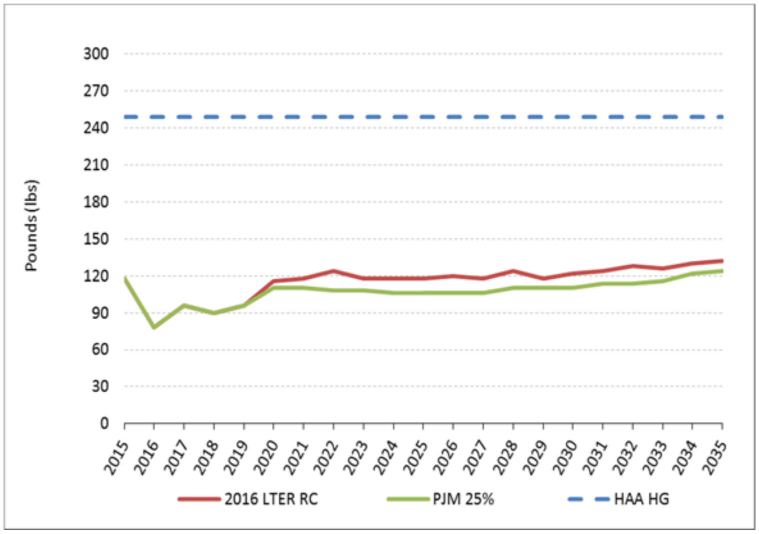


Figure 7.37 shows CO_2 emissions from all plants in Maryland for the PJM RPS scenario. Carbon dioxide emissions drop modestly, relative to Reference Case levels, for the majority of the study period. These changes are enough to bring Maryland within, or just above, its RGGI budget for the final dozen years of the study period.

Figure 7.37 Maryland CO_2 Emissions (All Plants) – PJM RPS Scenario

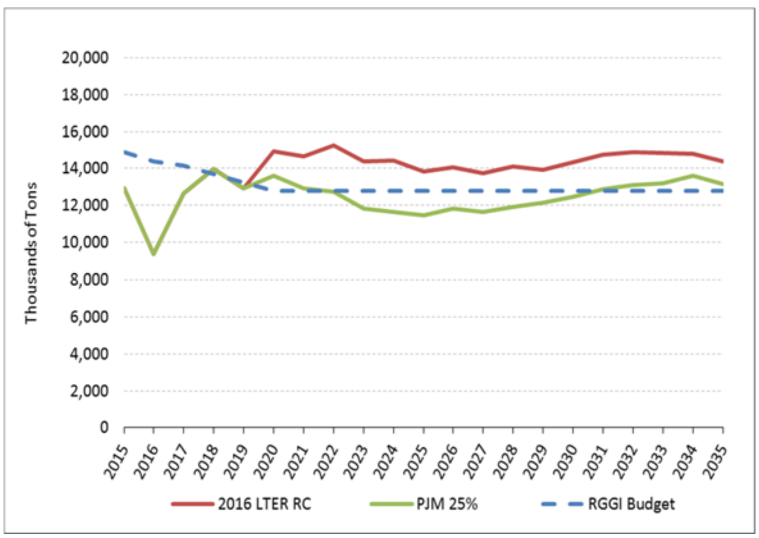
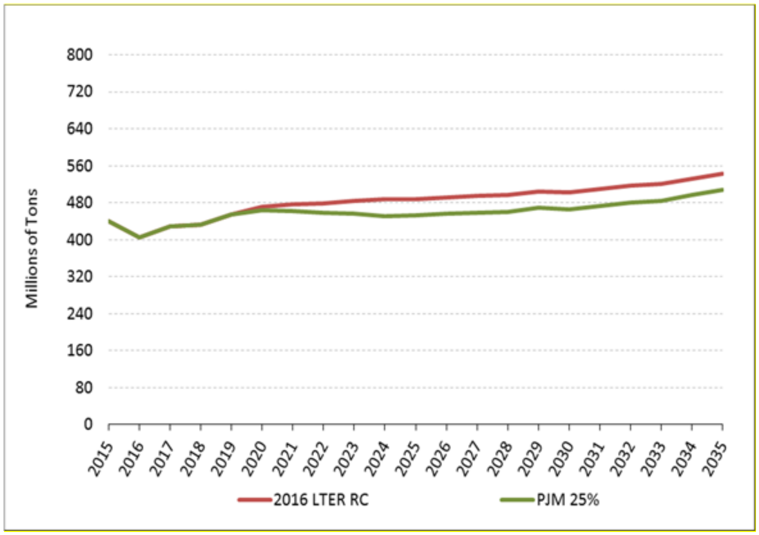


Figure 7.38 displays CO_2 emissions for all of PJM, indicating a decline in emissions across the RTO from the Reference Case if the 25 percent PJM RPS is implemented.

Figure 7.38 PJM CO_2 Emissions – PJM RPS Scenario



7.3.7 Cost/Benefit Considerations

The same considerations related to added costs to end-use consumers, as well as the range of benefits associated with reduced emissions, apply to the PJM-wide aggressive RPS scenario as to the Maryland-only aggressive RPS scenarios, as noted in Section 7.2.8.

7.4 Summary of Key Results

The following key results are based on the modeling and analysis presented in this chapter:

- Across PJM, natural gas capacity additions are marginally impacted by changes in Maryland's RPS, while a PJM-wide RPS dramatically diminishes the need for new natural gas capacity.

- Under the Maryland RPS scenarios, net imports for PJM-SW, PJM-MidE, and PJM-APS are modestly lower than in the Reference Case. In the PJM RPS scenario, disproportionately large additions of new renewable energy capacity in PJM-APS cause net imports in the region to fall dramatically below Reference Case levels.

- Raising Maryland's RPS has no impact on coal or natural gas use in the State; fossil plants continue to generate electricity for the PJM-wide market. In the PJM RPS scenario, both coal and, to a greater extent, natural gas use drop relative to the Reference Case, as new renewable energy capacity meets significant portions of PJM's load.

- Because energy prices reflect PJM-wide trends in supply and demand, raising Maryland's RPS has no impact. Creating a PJM-wide RPS, however, shifts the marginal unit to a lower-cost resource, decreasing average energy prices in all hours.

- Raising Maryland's RPS causes insignificant fluctuations in capacity prices, while establishing a PJM-wide RPS tends to depress capacity prices in PJM-SW and PJM-MidE.

- Under the Maryland RPS scenarios, Maryland emissions of SO_2, NOx, mercury, and CO_2 are unchanged from the Reference Case. Under the PJM RPS scenario, Maryland plant emissions fall modestly, relative to the Reference Case, as renewable energy generation displaces a portion of fossil fuel generation in the State (and PJM-wide).

8. Clean Power Plan Alternative Scenario

8.1 Introduction

In August 2015, the EPA issued the Clean Power Plan (CPP) under the authority of Section 111(d) of the Clean Air Act (CAA). The CPP is designed to reduce power sector emissions by 32 percent compared to 2005 levels by 2030. It establishes emissions “performance standards” for existing steam electric and natural gas-fired power plants. Based on these standards, the EPA set state-specific goals for CO_2 emissions from power plants. The goals are expressed both as rate-based (lbs/MWh) and mass-based (tons) targets, as part of the EPA’s effort to give states latitude in devising implementation strategies. Table 8.1 shows the targets developed by the EPA for Maryland.

Table 8.1 Clean Power Plan Goals for Maryland

	CO_2 Rate (lbs/net MWh)	CO_2 Emissions (tons)	
2012 Historic[1]	2,031	20,171,027	
2020 Projections (without CPP)	1,411	16,342,909	
	Rate-based Goal (lbs/net MWh)	**Mass-based Goal (annual average CO_2 emissions in tons)**	**Mass Goal (Existing) & New Source Complement (annual average CO_2 emissions in tons)**
Interim Period 2022-2029	1,510	16,209,396	16,380,325
Interim Step 1 Period 2022-2024[2]	1,644	17,447,354	17,517,496
Interim Step 2 Period 2025-2027[3]	1,476	15,842,485	16,079,110
Interim Step 3 Period 2028-2029[4]	1,359	14,902,826	15,126,393
Final Goal 2030 and Beyond	1,287	14,347,628	14,498,436

[1] The EPA made some targeted baseline adjustments at the state level to address commenter concerns about the representativeness of baseline-year data. These are highlighted in the CO_2 Emission Performance Rate and Goal Computation Technical Specification Document.

[2], [3], [4] Note that states may elect to set their own milestones for Interim Step Periods 1, 2, and 3 as long as they meet the interim and final goals articulated in the emission guidelines. In its state plan, the state must define its interim step milestones and demonstrate how it will achieve these milestones, as well as the interim goal and final goal. See section VIII.B of the final rule preamble for more information.

Source: www.epa.gov/sites/production/files/2016-09/documents/maryland.pdf.

In February 2016, the U.S. Supreme Court issued a stay on the CPP’s implementation pending resolution of legal challenges to the Plan in the United States Court of Appeals for the District of Columbia (D.C. Circuit). The CPP scenario is intended to explore the impact of CPP implementation, should it be upheld in court.

The CPP scenario assumes that five strategies (CPP Strategies), each of which is commonly regarded as a cost-effective way to lower carbon emissions, are adopted throughout the country in order for states to meet their emission reduction goals. These strategies are:

1. Redispatch – Cost multipliers are used to move natural gas combined cycle units up in the dispatch order and move coal plants down in the dispatch order. This is

accomplished by multiplying coal plant running costs (for dispatch purposes only) by a factor slightly greater than one and multiplying natural gas combined cycle plant running costs (for dispatch purposes only) by a factor slightly less than one.

2. Energy Efficiency – U.S. energy consumption is lowered 4.7 percent by 2030 through the implementation of energy efficiency programs in states that either do not have energy efficiency programs or only modest energy efficiency programs.

3. Renewable Energy – Renewable capacity is added throughout the United States to reach 26 percent of the overall energy mix. Of the more than 330 GW of renewable capacity added, more than 180 MW are solar capacity and over 140 MW are wind capacity.

4. Targeted Retirements – Steam-fired units that are inefficient, unprofitable, or high carbon emitters are targeted for retirement. This includes 9 GW of coal, natural gas, and petroleum capacity in PJM and approximately 27 GW of coal capacity throughout the U.S.

5. Transmission – Transmission lines are upgraded to alleviate congestion caused by renewable energy capacity additions and steam plant retirements, including 7 GW of interexchange capacity in the Eastern Interconnection.

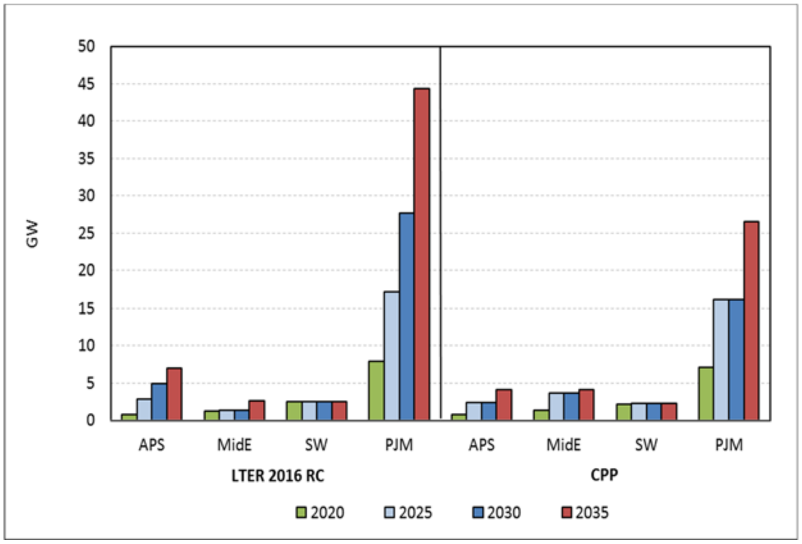
As discussed in Section 3.5.3, Maryland has already employed several of these strategies to lower CO_2 emissions from power plants in order to meet its RGGI goals.

8.2 Capacity Additions and Retirements

Under the CPP scenario, plant retirements in PJM are treated as inputs, as described above. Over nine of the 27 GW of steam generation selected for “targeted retirement” are located in PJM, including more than 1,000 MW in PJM-MidE and more than 500 MW in PJM-SW.

The decreased load assumed for the CPP scenario (as the result of energy efficiency programs) diminishes the need for new capacity in PJM, as shown in Figure 8.1 and Table 8.2. In the Reference Case, 44.1 GW of new natural gas capacity are added, while only 26.5 GW are added in the CPP scenario. However, trends in the three PJM transmission zones of relevance to Maryland are mixed; PJM-APS follows the PJM-wide pattern of fewer builds, while in PJM-MidE and in PJM-SW, more natural gas capacity is built in the CPP scenario than in the Reference Case. This new natural gas capacity helps to replace steam-fired units targeted for retirement.

Figure 8.1 Cumulative Generic Natural Gas Capacity Additions – Clean Power Plan Scenario



Note: Average of summer and winter capacity ratings.

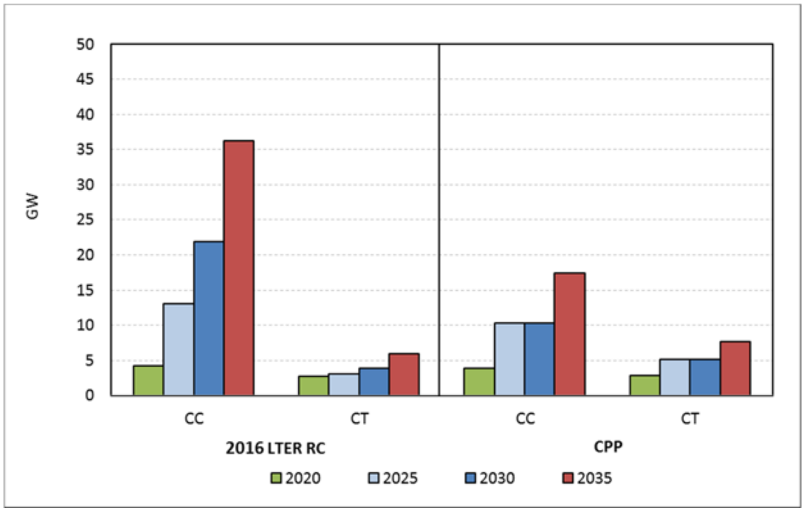
Table 8.2 PJM Cumulative Generic Natural Gas Combined Cycle and Combustion Turbine Capacity Additions – Clean Power Plan Scenario (GW)

Reference Case (RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	5.27	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (CPP minus RC)				
Year	**APS**	**MidE**	**SW**	**PJM-wide**
2020	--	0.17	--	(0.24)
2025	(0.42)	2.09	0.17	(0.65)
2030	(2.50)	(1.62)	0.17	(10.67)
2035	(2.91)	1.36	0.17	(17.64)

Note: Average of summer and winter capacity ratings.

The CPP Strategies also have mixed impacts on the types of natural gas plants that are built to meet reliability requirements, as shown in Figure 8.2 and Table 8.3. While CC plants represent the preferred technology under both scenarios, roughly 50 percent fewer gigawatts of combined cycle capacity are added in PJM, even as roughly 30 percent more CT capacity is built. This shift indicates that new natural gas peaking plants in the CPP scenario are used to provide generation for relatively few hours per year.

Figure 8.2 PJM Cumulative Natural Gas Capacity Additions – Clean Power Plan Scenario



Note: Summer capacity rating.

Table 8.3 Comparison of Cumulative Generic Combined Cycle and Combustion Turbine Capacity Additions – Clean Power Plan Scenario (GW)

Reference Case (RC) Generic CC and CT Capacity Additions		
Year	**CC**	**CT**
2020	4.25	2.72
2025	13.05	3.04
2030	21.85	3.84
2035	36.25	5.92
Difference (Clean Power Plan minus RC) Generic Capacity Added by ABB Model		
Year	**CC**	**CT**
2020	(0.40)	0.16
2025	(2.80)	2.08
2030	(11.60)	1.28
2035	(18.80)	1.76

Note: Summer capacity rating.

8.3 Net Imports

Net imports in PJM-SW, PJM-Mid-E, and PJM-APS are shown in Figure 8.3 through Figure 8.5. In each zone, the relative influence of factors that tend to drive up imports (e.g., targeted retirements) and those that tend to drive down imports (e.g., energy efficiency, renewable capacity additions) varies, leading to unique results. In PJM-SW, roughly 500 MW of targeted retirements are balanced by new renewable capacity and reduced loads (due to energy efficiency increases), leaving net imports unchanged throughout the study period. In PJM-MidE, roughly 1,000 MW of targeted retirements are outweighed by the combined impact of reduced loads, increased renewable energy capacity, increased natural gas capacity, and increased intensity of natural gas plant use; from 2020 onwards, net imports in the CPP scenario dip below those in the Reference Case. Finally, in PJM-APS, net imports are greater in the CPP scenario than in the Reference Case from 2025 and forward because: (1) decreases in load and the addition of new renewable energy capacity do not fully offset the less intensive use of the region's coal fleet (though no plants are targeted for retirement in that transmission zone); and (2) there are fewer generic natural gas builds in the PJM-APS zone under the CPP scenario assumptions than under the Reference Case assumptions.

Figure 8.3 PJM-SW Net Imports – Clean Power Plan Scenario

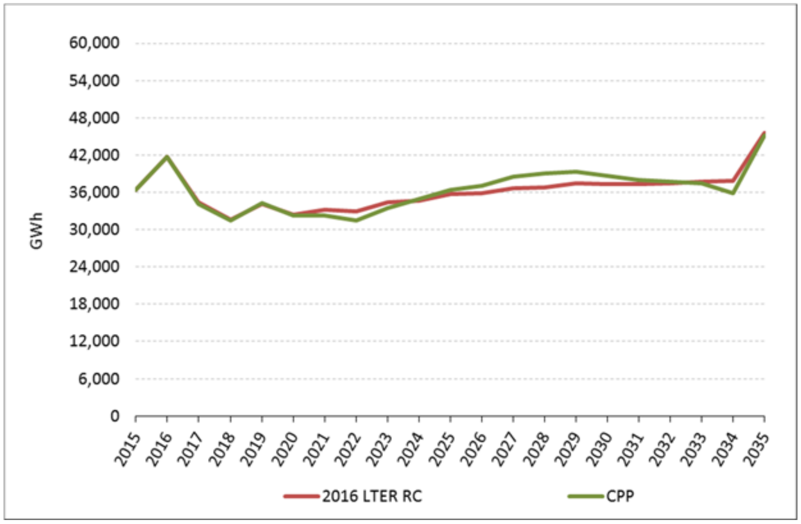


Figure 8.4 PJM-MidE Net Imports – Clean Power Plan Scenario

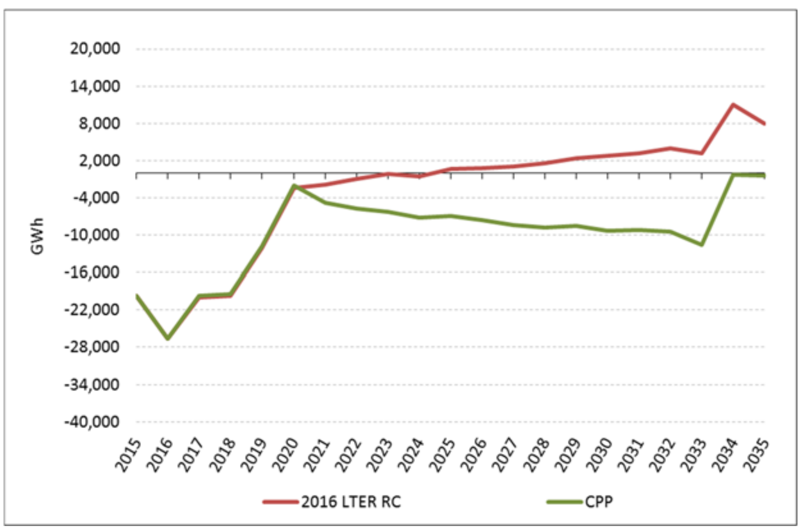
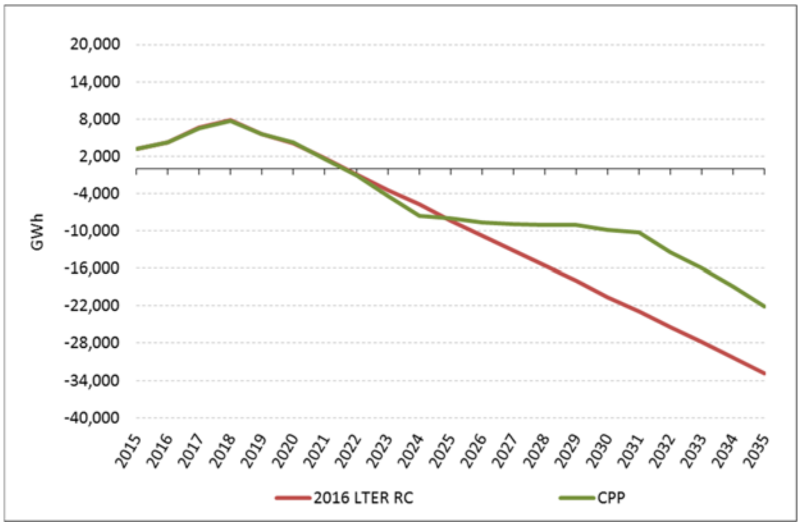


Figure 8.5 PJM-APS Net Imports – Clean Power Plan Scenario



8.4 Fuel Use

The five compliance strategies modeled in the CPP scenario drive down both coal and natural gas use PJM-wide relative to the Reference Case, as shown in Figure 8.6 and Figure 8.7. Within Maryland, the CPP strategies have less uniform results, as shown in Figure 8.8 and Figure 8.9. In the years 2020 through 2024, coal use in Maryland increases relative to the Reference Case. During these years, Maryland's coal fleet, which has already installed pollution control equipment to comply with Maryland's HAA, replaces generation lost by coal plants outside Maryland that are targeted for retirement or that fall lower in the dispatch order due to their relative inefficiency. From 2024 onwards, coal use in Maryland falls below Reference Case levels; after 2028, natural gas use rises above Reference Case levels. This latter result is likely due to the fact that Maryland has already invested heavily in energy efficiency measures. Thus, in the CPP scenario, demand does not fall as sharply in the State as it does nationwide. Also, the CPP scenario places new renewable generation capacity in other portions of the country that are especially well-suited to wind and solar generation. Consequently, the CPP scenario results indicate that Maryland's in-state loads are more likely to be met with natural gas generation than is the case nationwide.

Figure 8.6 Coal Use for Electricity Generation in PJM – Clean Power Plan Scenario

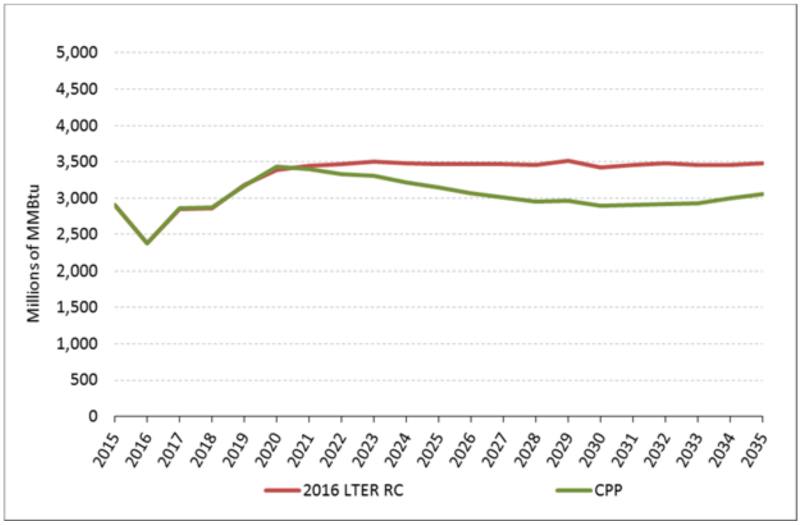


Figure 8.7 Natural Gas Use for Electricity Generation in PJM – Clean Power Plan Scenario

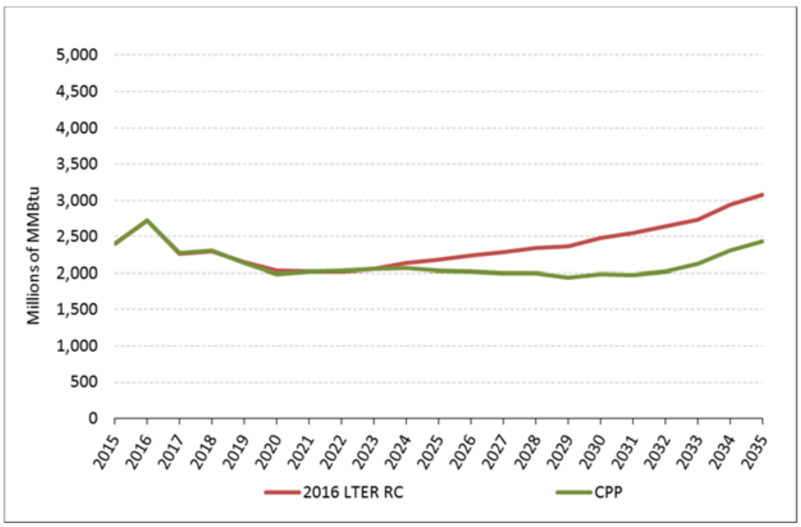


Figure 8.8 Coal Use for Electricity Generation in Maryland – Clean Power Plan Scenario

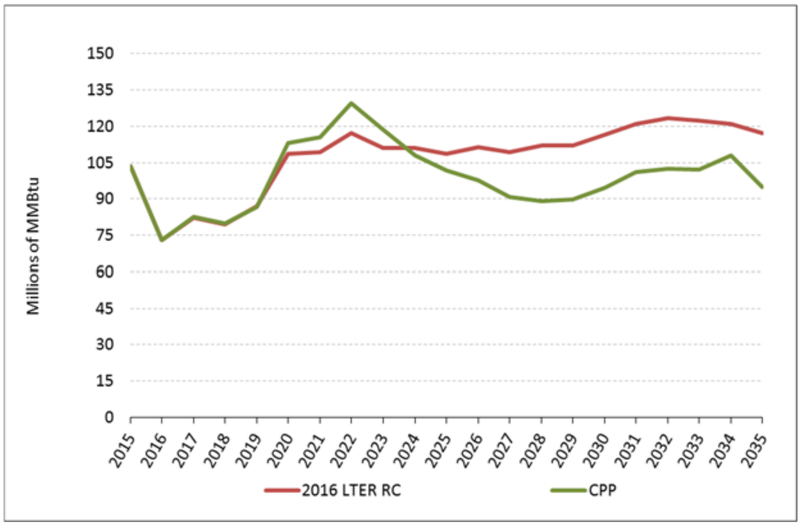


Figure 8.9 Natural Gas Use for Electricity Generation in Maryland – Clean Power Plan Scenario

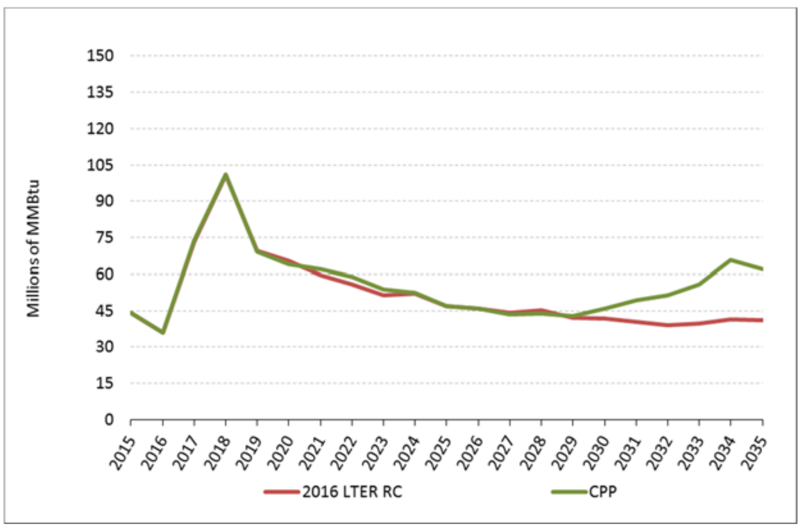


Table 8.4 shows the generation mix in Maryland over time. It reflects the additional factors in the CPP scenario that encourage a shift from coal use to natural gas use. By year 2035 in the CCP scenario, coal represents 7 percentage points less, while natural gas represents 10 percentage points more, of the generation mix than in the Reference Case.

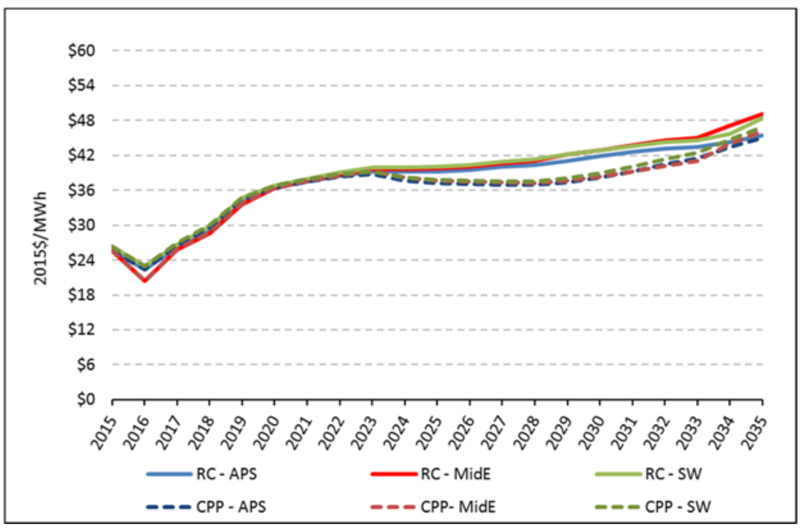
Table 8.4 Maryland Generation Mix – Clean Power Plan Scenario

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	5%
2025	Reference Case	34,757	40	29	18	5	9
	CPP	34,151	42	28	19	6	6
2035	Reference Case	27,641	23	39	20	7	12
	CPP	28,382	23	32	30	7	8

8.5 Energy Prices

In the CPP scenario, energy prices are slightly lower than the corresponding prices in the Reference Case beginning in 2023, as seen in Figure 8.10 through Figure 8.12. Decreased demand plus higher renewable energy generation allows less costly conventional generation units to meet load on the margin, thus putting downward pressure on price. In addition, the CPP scenario is characterized by minimally lower natural gas and slightly lower coal prices (see Figure 8.13 and Figure 8.14, respectively) that result from lower national demand for these fuels due to the CPP.[46]

Figure 8.10 PJM-SW, PJM-MidE, PJM-APS All-hours Energy Prices – Clean Power Plan Scenario



[46] In the CPP scenario, coal usage drops off more significantly than natural gas usage.

Figure 8.11 PJM-SW, PJM-MidE, PJM-APS On-peak Energy Prices – Clean Power Plan Scenario

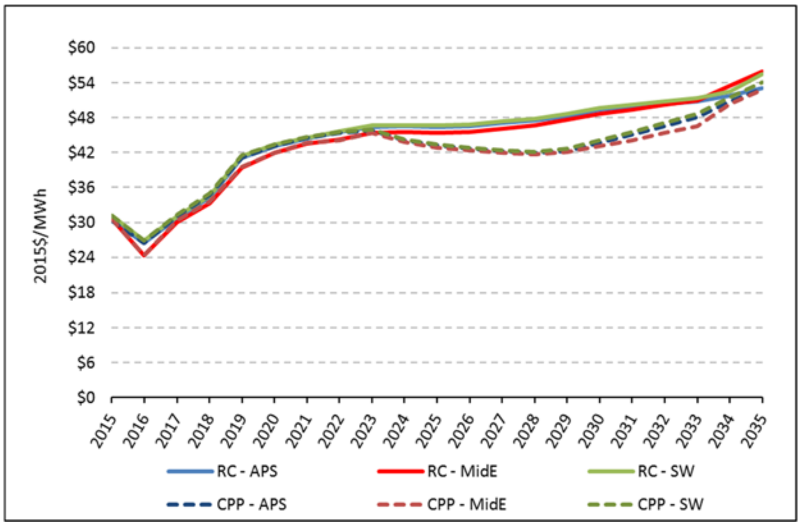


Figure 8.12 PJM-SW, PJM-MidE, PJM-APS Off-peak Energy Prices – Clean Power Plan Scenario

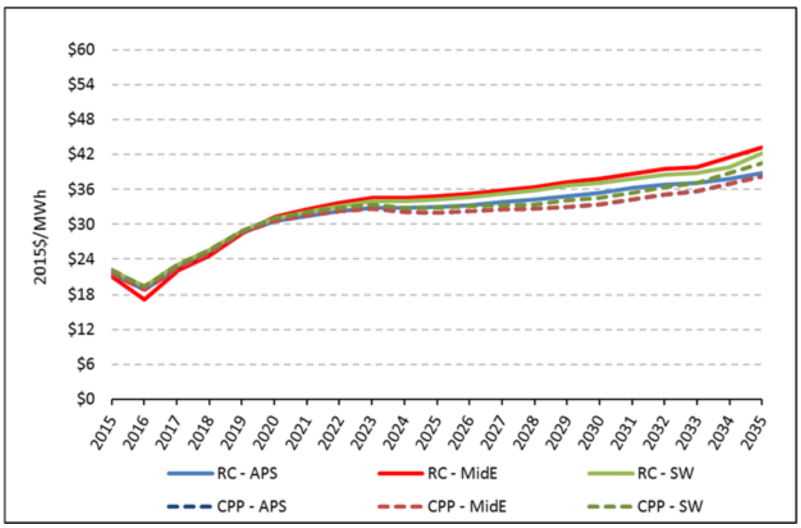


Figure 8.13 Coal Prices – Clean Power Plan Scenario

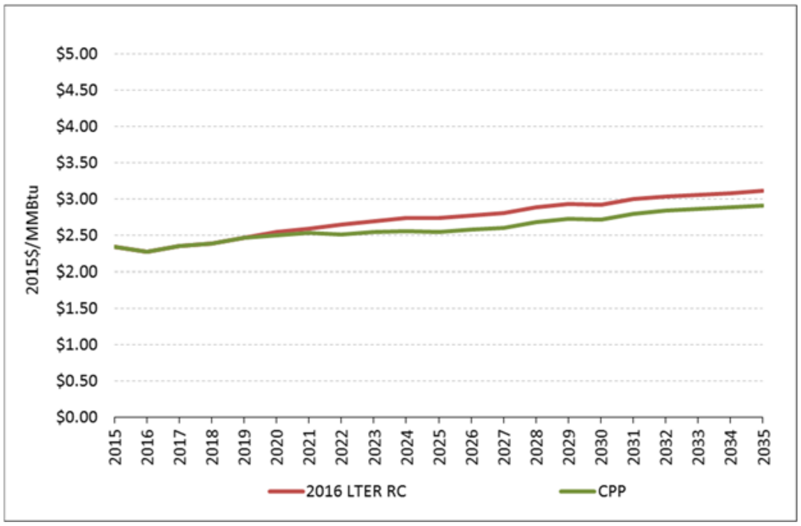
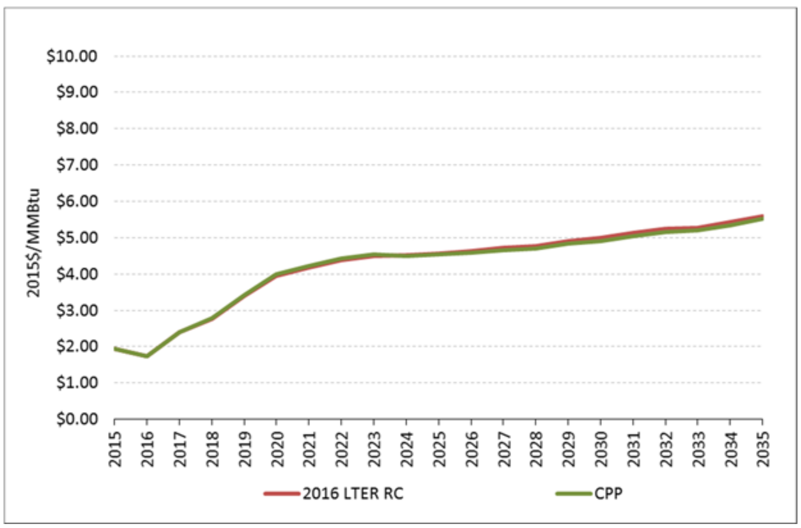


Figure 8.14 Natural Gas Prices – Clean Power Plan Scenario



8.6 Capacity Prices

Projected capacity prices for the Reference Case and the CPP scenario for PJM-SW, PJM-MidE, and PJM-APS are shown in Figure 8.15 through Figure 8.17. In each of these zones, increased renewable energy generation capacity and decreased demand in the CPP scenario generally put downward pressure on capacity prices. Variations in the timing of new plant builds cause variations in the movement of capacity prices in each of the three transmission zones, leading to years during which capacity prices under the CPP assumptions exceed capacity prices under the Reference Case assumptions.

Figure 8.15 PJM-SW Capacity Prices – Clean Power Plan Scenario

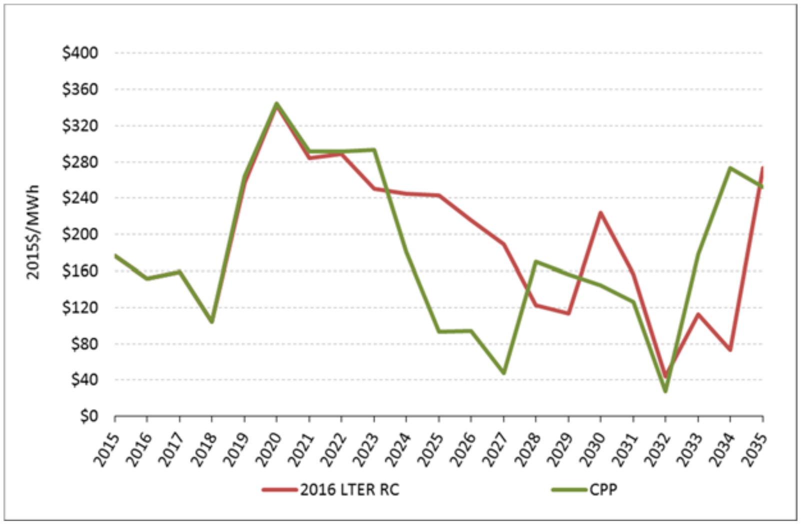


Figure 8.16 PJM-MidE Capacity Prices – Clean Power Plan Scenario

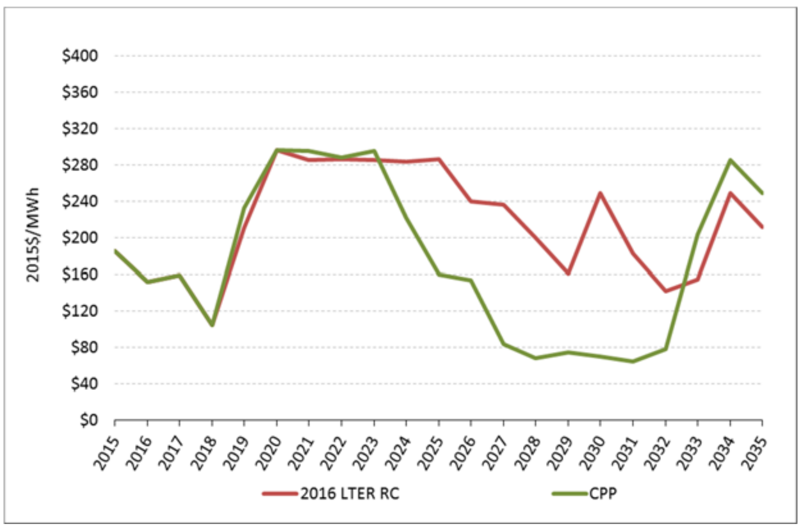
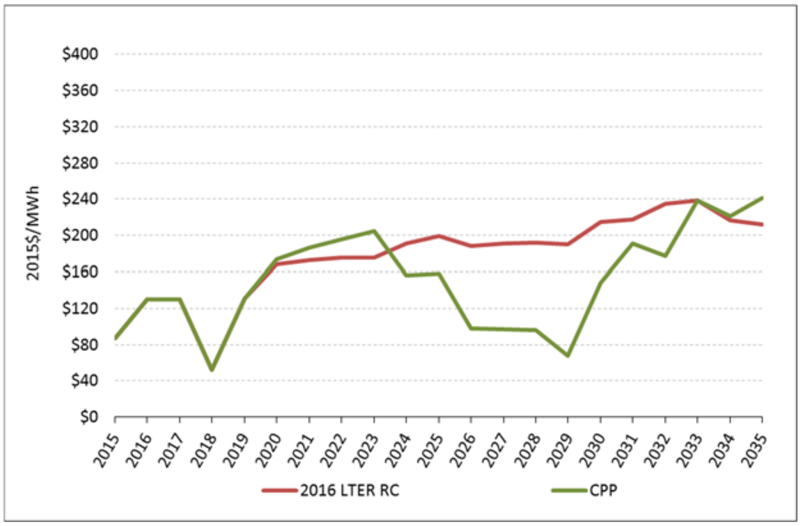


Figure 8.17 PJM-APS Capacity Prices – Clean Power Plan Scenario



8.7 Emissions

Emissions in Maryland under the CPP scenario reflect a gradual shift towards reliance on renewable and natural gas generation, and away from coal generation, as discussed in prior sections. However, during the years 2019 through 2024, the more intensive use of Maryland's coal plants noted in Section 8.4 leads to temporarily higher SO_2, NOx, mercury, and CO_2 emissions in Maryland, as shown in Figure 8.18 through Figure 8.21.

Figure 8.18 Maryland SO_2 Emissions (HAA Plants) – Clean Power Plan Scenario

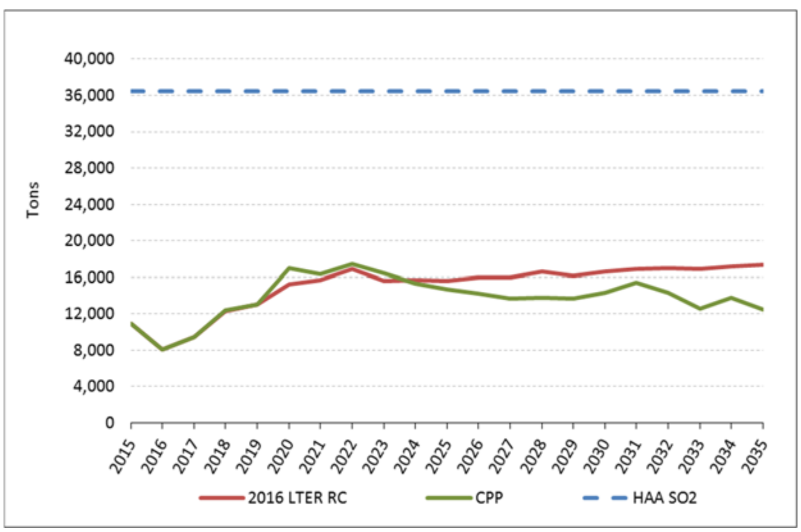


Figure 8.19 Maryland NOx Emissions (HAA Plants) – Clean Power Plan Scenario

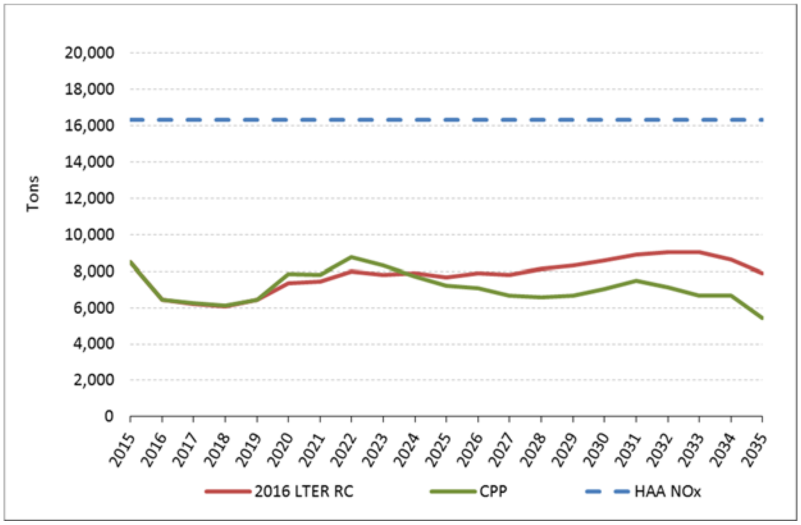


Figure 8.20 Maryland Mercury Emissions (HAA Plants) – Clean Power Plan Scenario

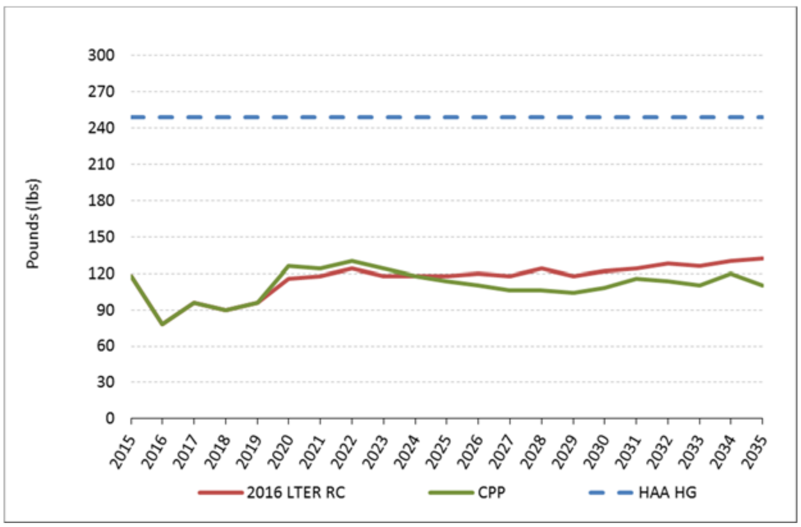
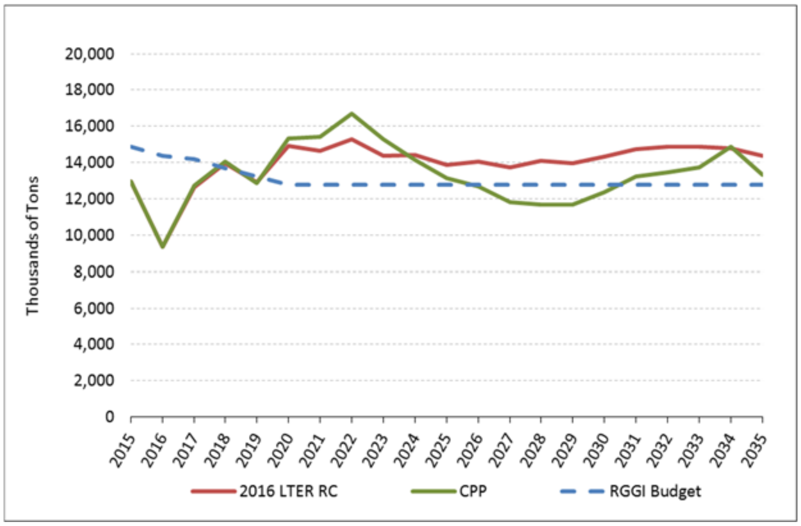


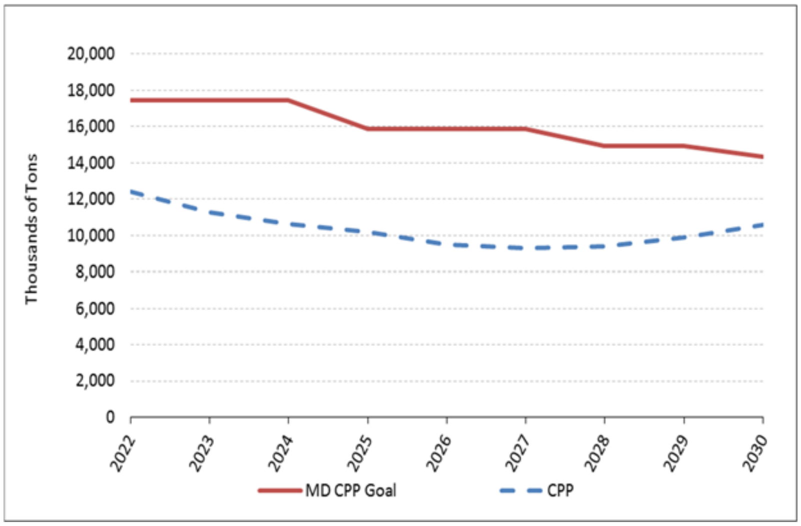
Figure 8.21 Maryland CO_2 Emissions (All Plants) – Clean Power Plan Scenario



Under the CPP scenario, Maryland is able to comply with the CPP's downward-stair-step targets throughout the study period, as shown in Figure 8.22. This is in large part due to measures already in place to help the State meet its RGGI targets and HAA limitations.[47] Note that power plant emissions in Figure 8.22 are far lower than those in Figure 8.21 because only existing power plant emissions are represented, not emissions from new plants. For example, in 2022, three new natural gas plants—St. Charles, Keys Energy Center, and Wildcat Point—account for over two million tons of CO_2 emissions that are *not* included in the figure below.

[47] There is speculation that Maryland's CPP compliance plan could rely on more stringent RGGI emissions budgets. The CPP scenario does not model this approach, in part because RGGI budgets are not treated as binding constraints in the LTER.

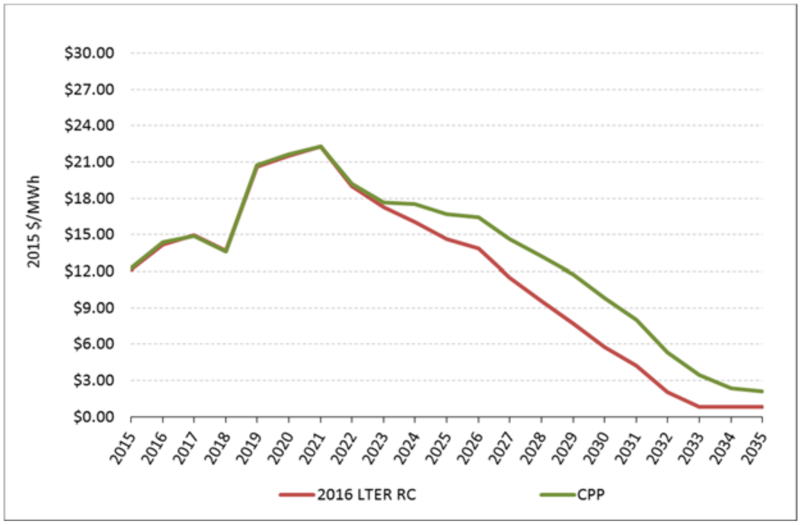
Figure 8.22 Maryland CO_2 Emissions (CPP Plants Only) – Clean Power Plan Scenario



8.8 Renewable Energy Credit Prices

Figure 8.23 compares REC prices for the Reference Case and the CPP scenario. REC prices in the two scenarios begin to diverge in 2023, with REC prices in the CPP scenario remaining approximately \$1 to \$4 above those in the Reference Case for the remainder of the study period. This trend mirrors the trend in energy prices shown in Figure 8.10, where all-hours energy prices in the CPP scenario begin to dip below Reference Case levels in 2023 and stay lower than the Reference Case for most of the remaining years of the study period. Just as with the Low Price Natural Gas alternative scenario, lower energy prices in the CPP scenario require renewable energy project developers to recoup a greater proportion of their costs through RECs, driving those prices up.

Figure 8.23 Renewable Energy Credit Prices – Clean Power Plan Scenario



8.9 Summary of Key Results

The modeling analysis presented in this chapter provides the following findings:

- CPP compliance strategies drive down generation in Maryland and shift generation from coal-fired plants to natural gas plants.

- CPP compliance strategies have mixed effects on the construction of new natural gas-fired power plants in Maryland relative to the Reference Case, driving new natural gas plant construction down in PJM-APS, and up in PJM-MidE and PJM-SW.

- CPP compliance strategies cause energy prices to be slightly lower than in the Reference Case. This is due to decreased energy consumption and peak demand nationwide, increased reliance on renewable energy, and slightly lower natural gas and coal prices than in the Reference Case.

- Decreased demand in the CPP scenario puts downward pressure on capacity prices in PJM-SW, PJM-MidE, and PJM-APS.

- Emissions of SO_2, NOx, mercury, and CO_2 in Maryland are ultimately lower under the CPP than in the Reference Case.

9. Early Coal Plant Retirement and NOx Emissions Compliance Alternative Scenarios

9.1 Introduction

The Early Coal Plant Retirement (ECPR) and NOx Emissions Compliance (NOx) scenarios address uncertainty surrounding Maryland coal plant retirement dates. The five Maryland coal-fired units listed in Table 9.1, all of which are located in PJM-SW, were recently slated to retire in May 2017. NRG Energy (NRG), the owner of the plants, pushed back this retirement date twice before canceling it completely. Two of the EPA's regulations concerning coal plant emissions—its Mercury and Air Toxics Standards (MATS) and its Clean Power Plan (CPP)—are facing legal challenges and may be overturned. (See Section 10.2 for a discussion of EPA regulations.) The ECPR scenario assumes that the five NRG units in question retire in 2018, as opposed to continuing to function throughout the forecast period. At the State level, MDE began implementing enhanced NOx regulations on coal-fired plants in 2015. These regulations are intended to allow Maryland to attain and maintain compliance with federal standards for ozone pollution. MDE anticipates that seven of the State's coal units will be retired at the end of 2019, and an eighth in 2020, in order to comply with these regulations. MDE asked PPRP to run the NOx alternative scenario to model the results of these retirements. Retirement assumptions for both alternative scenarios are summarized in Figure 9.1.

Table 9.1 Selected Coal Plant Retirement Dates – ECPR and NOx Scenarios

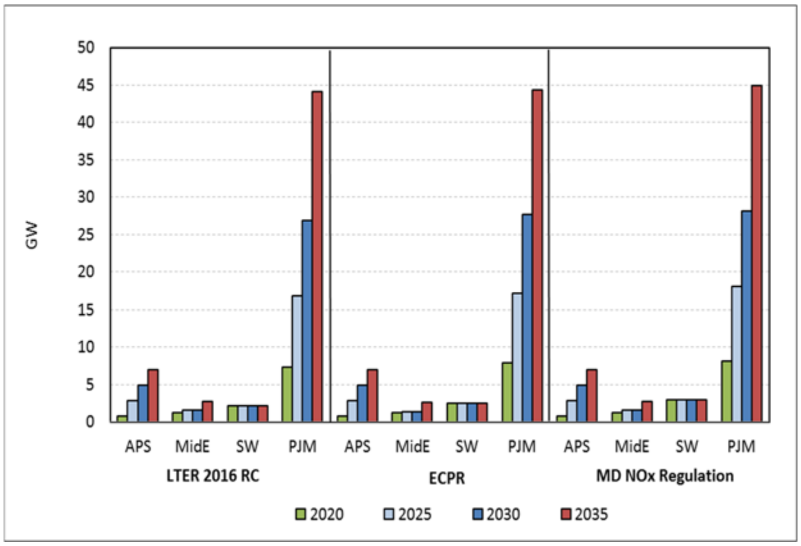
Unit Name	Unit Capacity (MW)	Retirement Year (Reference Case) (Age-based)	Retirement Year (ECPR Case)	Retirement Year (NOx Case)
Chalk Point: ST1	341	2038	2018	2019
Chalk Point: ST2	342	2039	2018	2019
NRG Dickerson: 2	182	2034	2018	2019
NRG Dickerson: 3	182	2036	2018	2019
NRG Dickerson: ST1	182	2033	2018	2019
CP Crane: 1	190	2035	No change	2019
CP Crane: 2	209	2037	No change	2019
HA Wagner: 2	136	2020	No change	No change

9.2 Capacity Additions and Retirements

The ECPR and NOx scenario retirements have no impact on the lifespans of other plants in PJM during the study period. As in the Reference Case, the lone plant to retire for economic reasons is a 103-MW coal plant in PJM-SW. By definition, age-based plant retirements are unchanged in the ECPR and NOx scenarios relative to the Reference Case.

The ECPR and NOx retirements have almost no impact on capacity builds PJM-wide; natural gas capacity additions in the two scenarios are less than 2 percent higher than in the Reference Case by 2035. However, the ECPR and NOx retirements do make PJM-SW a more attractive zone for new capacity additions. By the end of the study period, new capacity builds in PJM-SW are 420 MW, or 19 percent, higher than in the Reference Case in the ECPR scenario. In the NOx scenario, new capacity builds in PJM-SW are up 830 MW relative to the Reference Case. This new capacity replaces roughly one third of the coal capacity lost by the region in the ECPR scenario and two thirds of the coal capacity lost in the NOx scenario. Capacity builds in PJM-APS are unchanged, and in PJM-MidE only slightly diminished, as shown in Figure 9.1 and Table 9.2.

Figure 9.1 Cumulative Generic Plant Additions – ECPR and NOx Scenarios



Note: Average of summer and winter capacity ratings.

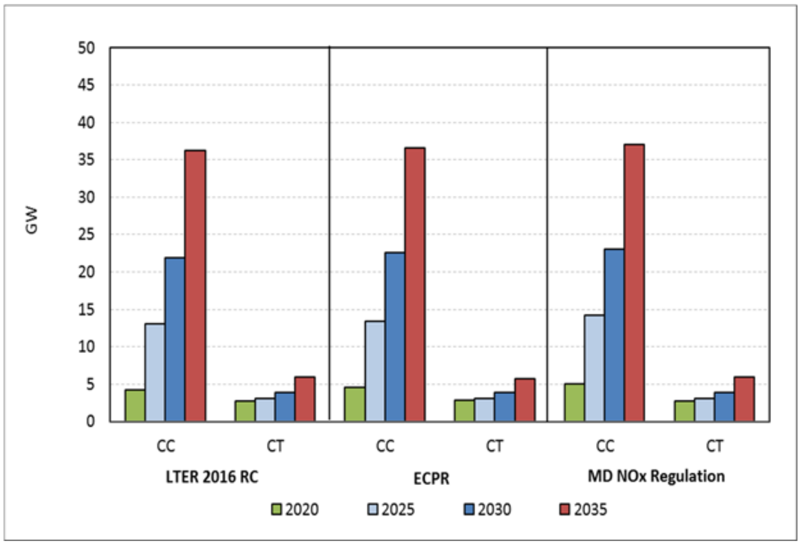
Table 9.2 Cumulative Generic CC and CT Unit Capacity Plant Additions – ECPR and NOx Scenarios (GW)

Reference Case (RC)				
Year	APS	MidE	SW	PJM-wide
2020	0.78	1.22	2.16	7.38
2025	2.86	1.57	2.16	16.88
2030	4.94	1.57	2.16	26.90
2035	7.02	2.81	2.16	44.14
Difference (ECPR minus RC)				
Year	APS	MidE	SW	PJM-wide
2020	--	--	0.42	0.54
2025	--	(0.17)	0.42	0.37
2030	--	(0.17)	0.42	0.78
2035	--	(0.17)	0.42	0.19
Difference (MD NOx Regulation minus RC)				
Year	APS	MidE	SW	PJM-wide
2020	--	--	0.83	0.83
2025	--	--	0.83	1.25
2030	--	--	0.83	1.25
2035	--	--	0.83	0.83

Note: Average of summer and winter capacity ratings.

The ECPR and NOx scenario retirements have negligible impacts on the type of natural gas capacity that is added in PJM, as shown in Figure 9.2 and Table 9.3.

Figure 9.2 Cumulative Generic Plant Additions by Type – ECPR and NOx Scenarios



Note: Summer capacity rating.

Table 9.3 Cumulative Generic Plant Additions by Type – ECPR and NOx Scenarios (GW)

Reference Case (RC)		
Year	**CC**	**CT**
2020	4.25	2.72
2025	13.05	3.04
2030	21.85	3.84
2035	36.25	5.92
Difference (ECPR minus RC)		
Year	**CC**	**CT**
2020	0.35	0.16
2025	0.35	--
2030	0.75	--
2035	0.35	(0.16)
Difference (Maryland NOx minus RC)		
Year	**CC**	**CT**
2020	0.80	--
2025	1.20	--
2030	1.20	--
2035	0.80	--

Note: Summer capacity rating.

9.3 Net Imports

As shown in Figure 9.3, the ECPR and NOx scenario retirements in PJM-SW cause the region's net imports to rise slightly relative to the Reference Case, which reflects the fact that PJM-SW's remaining plants and newly added capacity only replace a portion of the generation once provided by the retiring coal plants. In PJM-MidE and PJM-APS, however, net imports are essentially unchanged from the Reference Case, as seen in Figure 9.4 and Figure 9.5.

Figure 9.3 PJM-SW Net Energy Imports – ECPR and NOx Scenarios

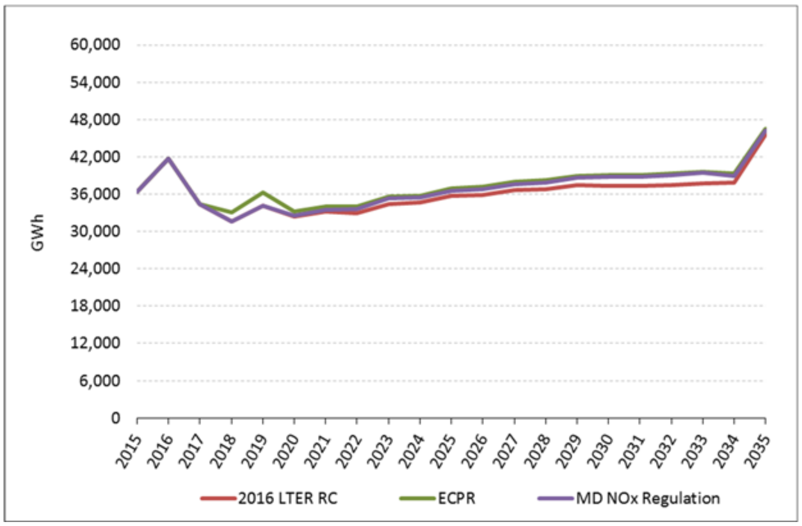


Figure 9.4 PJM-MidE Net Energy Imports – ECPR and NOx Scenarios

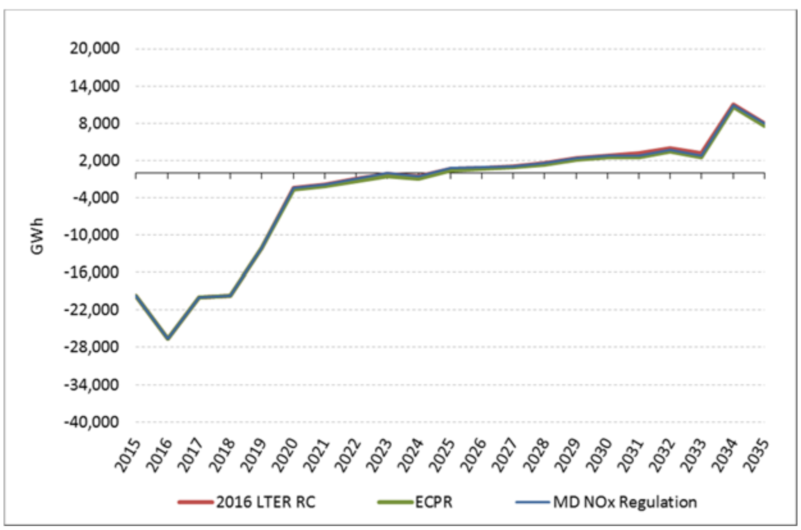
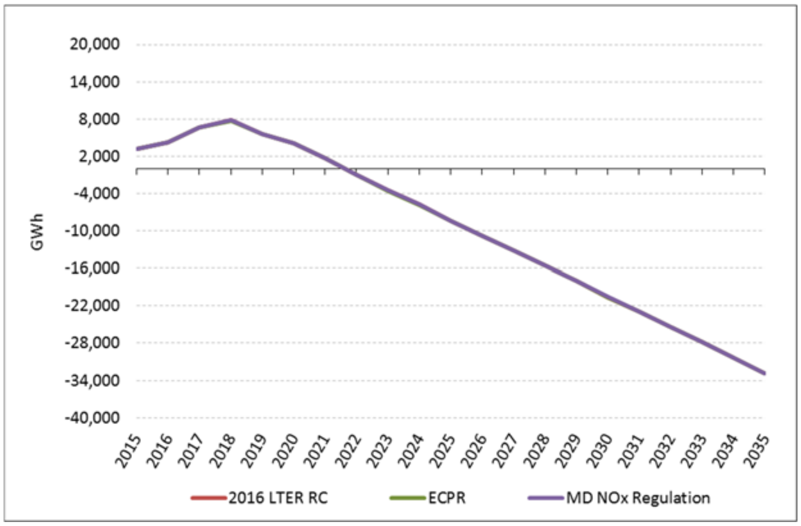


Figure 9.5 PJM-APS Net Imports – ECPR and NOx Scenarios



Note: The Reference Case and ECPR lines are directly under the NOx line and hence cannot be separately observed.

9.4 Fuel Use

Both the ECPR and NOx retirements cause immediate and sustained drops in coal use in Maryland, as shown in Figure 9.6. Simultaneously, natural gas use rises, as shown in Figure 9.7, as Maryland's natural gas plants generate much of the electricity that was once supplied by the coal plants that retire in 2018 through 2020. However, the changes in usage are not one-to-one in either scenario since coal and natural gas plants differ in their efficiency, and plants outside of Maryland also augment Maryland generation to compensate for the ECPR and NOx retirements.

Figure 9.6 Coal Use for Electricity Generation in Maryland – ECPR and NOx Scenarios

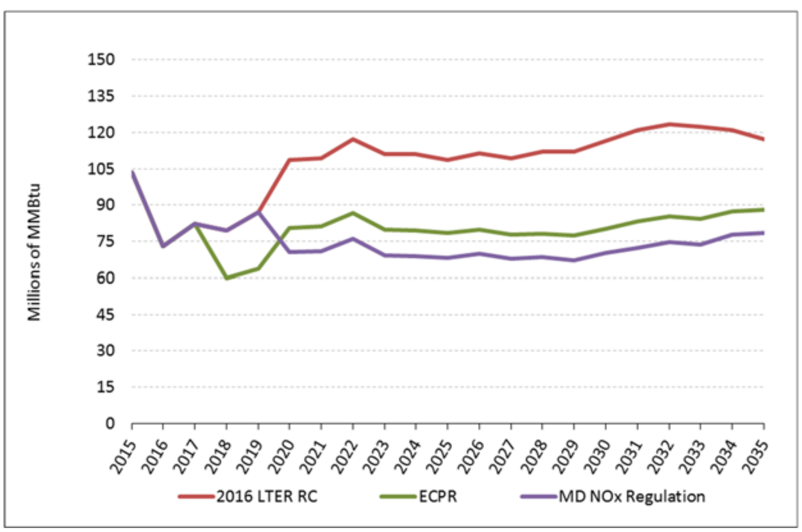
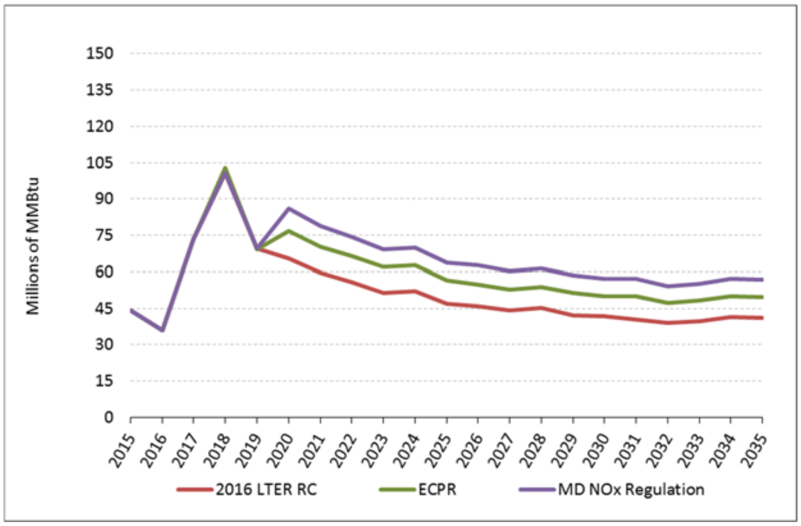
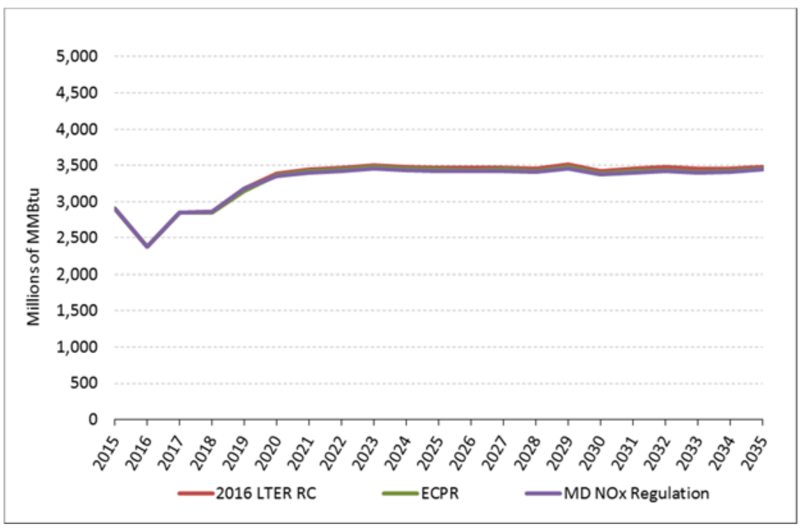


Figure 9.7 Natural Gas Use for Electricity Generation in Maryland – ECPR and NOx Scenarios



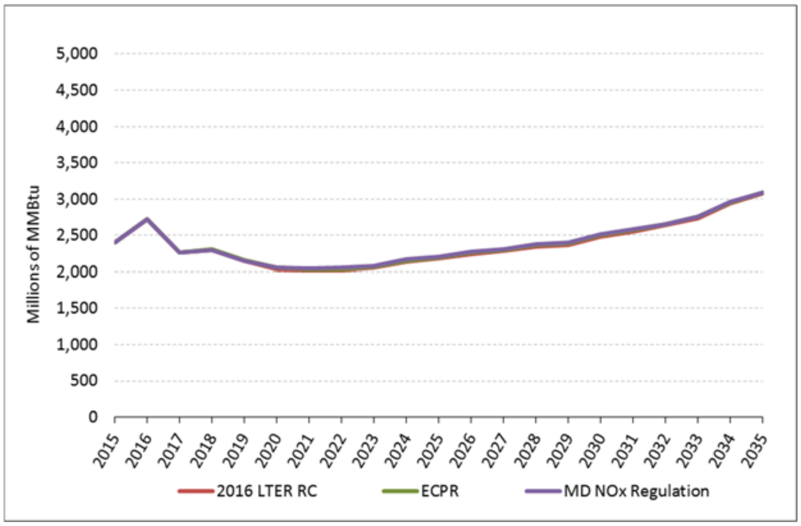
For comparison purposes, Figure 9.8 and Figure 9.9 show natural gas and coal use PJM-wide in the ECPR and NOx scenarios. At this scale, the impact of the early coal plant retirements is essentially unchanged from the Reference Case.

Figure 9.8 Coal Use for Electricity Generation in PJM – ECPR and NOx Scenarios



Note: The Reference Case line is directly under the ECPR and NOx lines and hence cannot be separately observed.

Figure 9.9 Natural Gas Use for Electricity Generation in PJM – ECPR and NOx Scenarios



Note: The Reference Case line is directly under the ECPR and NOx lines and hence cannot be separately observed.

Table 9.4 shows the generation mix in Maryland over time. It shows that natural gas is the primary fuel to replace coal in the ECPR and NOx scenarios. By year 2035 in the ECPR and NOx scenarios, coal represents 8 to 11 percentage points less of the generation mix than in the Reference Case, while natural gas represents 6 to 10 percentage points more of the generation mix.

Table 9.4 Maryland Generation Mix – ECPR and NOx Scenarios

Year	Scenario	Total Generation (GWh)	Nuclear	Coal	Natural Gas	Hydro	Renewables
2015	All Scenarios	30,443	45%	30%	14%	6%	4%
2025	Reference Case	34,757	40	29	18	5	9
	ECPR	33,545	41	22	23	6	9
	NOx Emissions Compliance	33,841	41	19	26	5	9
2035	Reference Case	27,641	23	39	20	7	12
	ECPR	26,534	24	31	26	7	12
	NOx Emissions Compliance	26,849	24	28	30	7	1

9.5 Energy Prices

Figure 9.10 through Figure 9.12 show energy prices in the ECPR and NOx scenarios. Prices are basically unchanged by the coal plant retirements in any of the three transmission zones that include portions of Maryland, and therefore align with the trends seen for each transmission zone in the Reference Case. Because these regions are well-integrated with the rest of PJM, wholesale energy prices reflect PJM-wide electricity supply trends, without being greatly influenced by local fluctuations in generation.

Figure 9.10 PJM-SW, PJM-MidE, PJM-APS All-hours Energy Prices – ECPR and NOx Scenarios

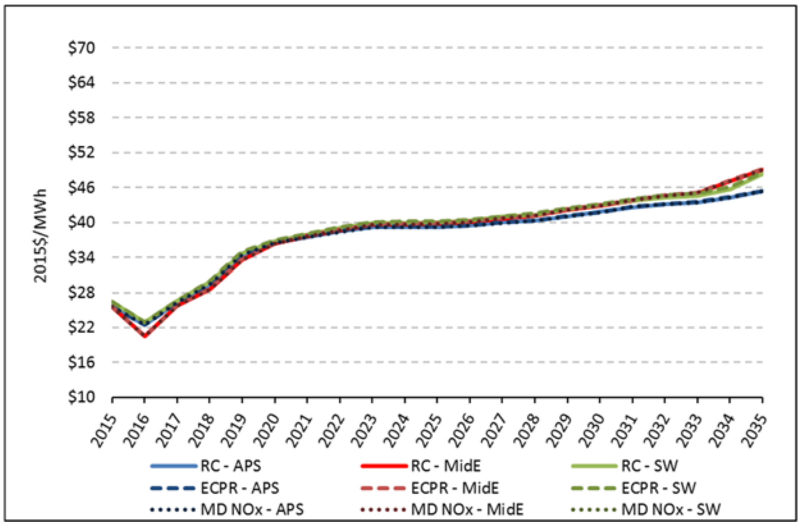


Figure 9.11 PJM-SW, PJM-MidE, PJM-APS On-peak Energy Prices – ECPR and NOx Scenarios

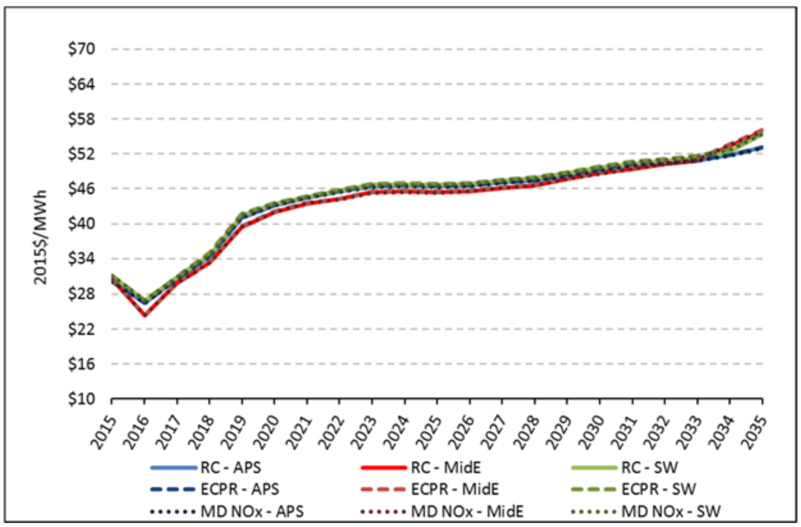
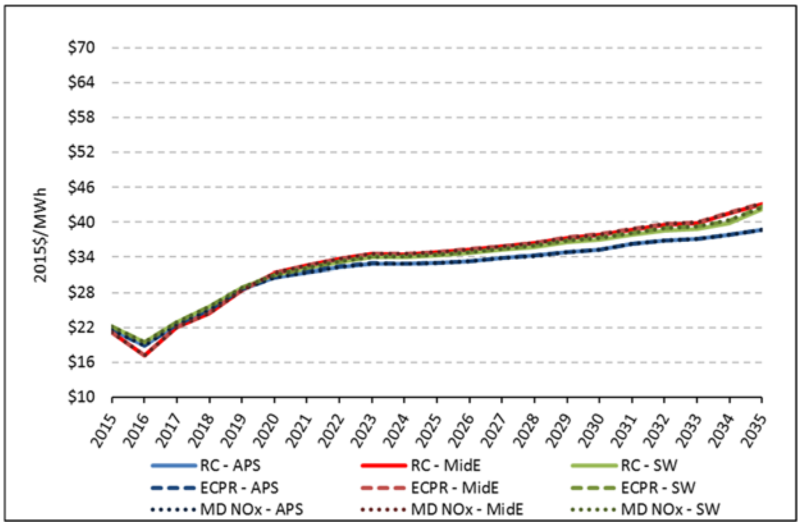


Figure 9.12 PJM-SW, PJM-MidE, PJM-APS Off-peak Energy Prices – ECPR and NOx Scenarios



9.6 Capacity Prices

The ECPR and NOx scenario retirements cause small fluctuations in capacity prices in PJM-SW relative to the Reference Case. Most notably, soon after coal plants retire in the years 2018 through 2020, capacity prices hit a maximum; in the ECPR and NOx scenarios, this peak is roughly $30/MW-day and $85/MW-day above the analogous peak in the Reference Case, respectively. At times in the remaining years of the study period, PJM-SW capacity prices dip below those in the Reference Case. This is due to builds that occur in response to the plant retirements, and which subsequently depress capacity prices. In PJM-APS and PJM-MidE, capacity prices are only marginally affected by the coal plant retirements. (See Figure 9.13 through Figure 9.15.)

Figure 9.13 PJM-SW Capacity Prices – ECPR and NOx Scenarios

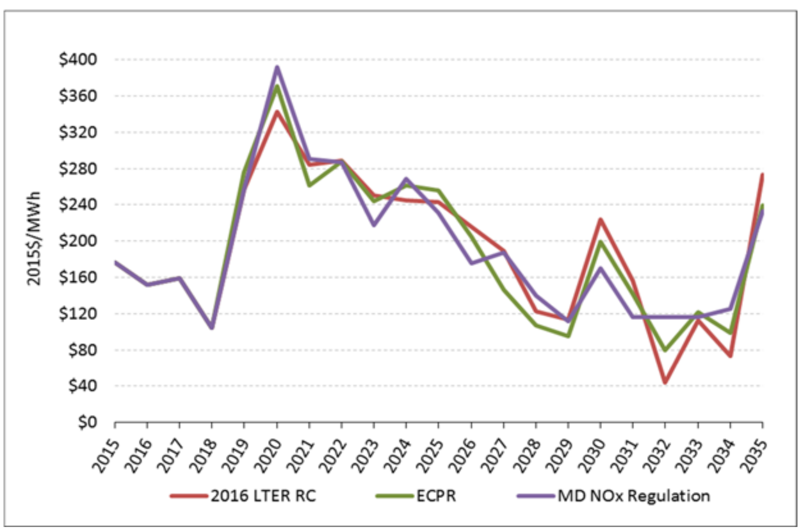


Figure 9.14 PJM-MidE Capacity Prices – ECPR and NOx Scenarios

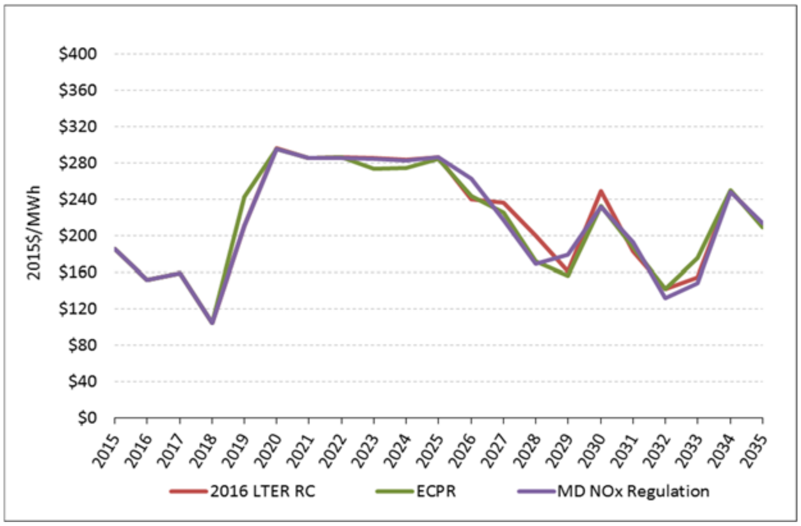
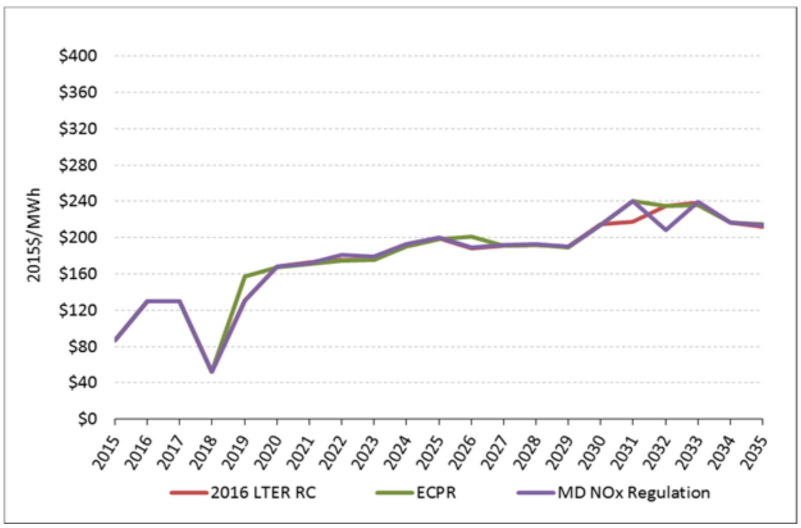


Figure 9.15 PJM-APS Capacity Prices – ECPR and NOx Scenarios



9.7 Emissions

The five units that retire early in the ECPR scenario are all subject to Maryland's Healthy Air Act (HAA). However, State-wide SO_2 emissions by HAA plants are virtually unchanged in the ECPR scenario relative to the Reference Case, as shown in Figure 9.16. This is because the retiring plants have already installed SO_2 pollution control equipment. For example, in the year before their retirement, the five plants represent less than 8 percent of HAA plant SO_2 emissions. In subsequent years, the remaining HAA coal plants increase generation to a level that offsets SO_2 savings associated with the ECPR plant retirements. The five retiring plants, however, do contribute significantly to NOx and mercury emissions by HAA plants. Thus, when the plants go offline, these emissions fall well below Reference Case levels, as shown in Figure 9.17 and Figure 9.18. The two additional units that retire early in the NOx alternative scenario, CP Crane 1 and 2, contribute significantly to SO_2, NOx, and mercury emissions in the State. Therefore, during 2019 and afterwards, emissions of all three pollutants (SO_2, NOx, and mercury) fall below both Reference Case and ECPR levels.

Figure 9.16 Maryland SO_2 Emissions (HAA Plants) – ECPR and NOx Scenarios

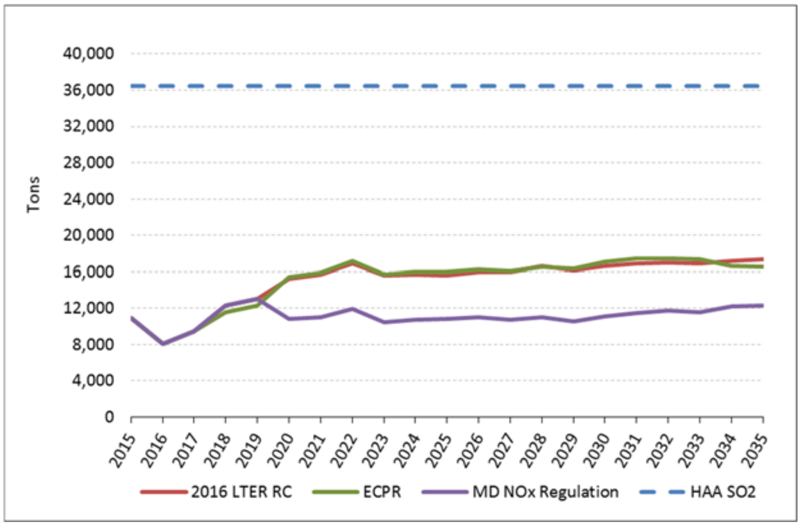


Figure 9.17 Maryland NOx Emissions (HAA Plants) – ECPR and NOx Scenarios

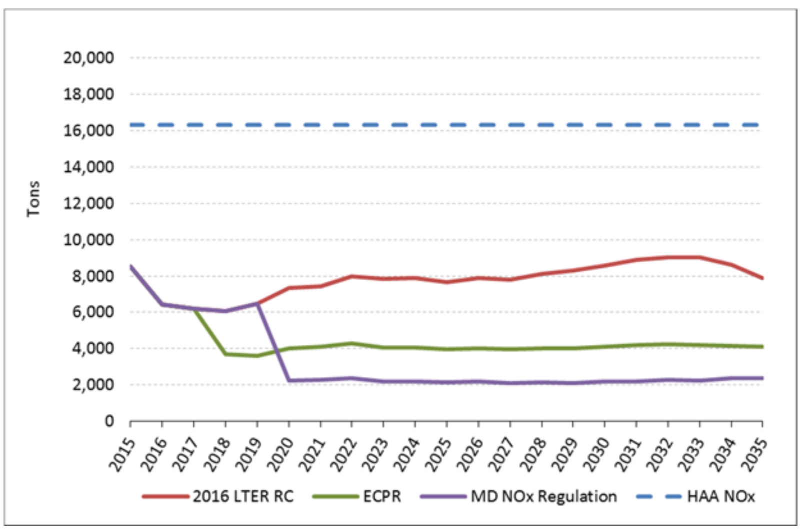


Figure 9.18 Maryland Mercury Emissions (HAA Plants) – ECPR and NOx Scenarios

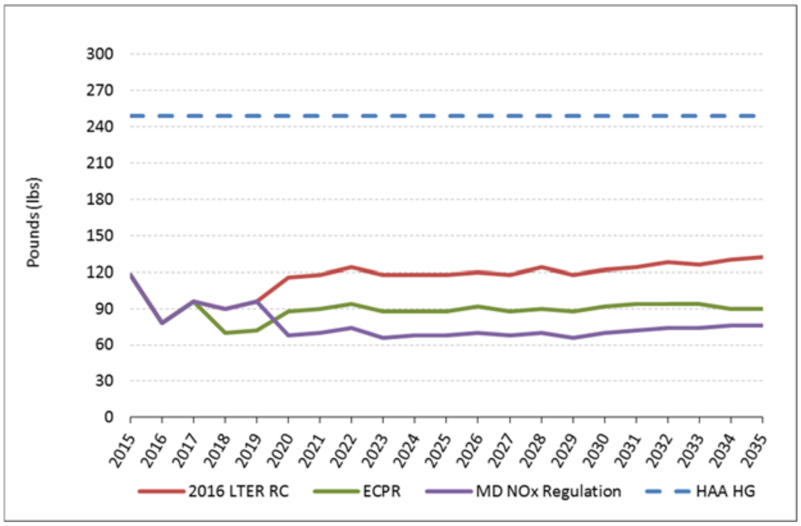
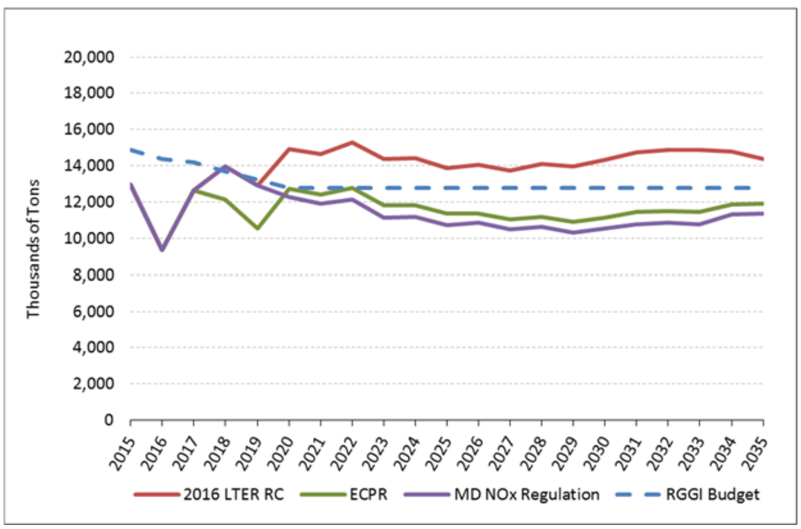


Figure 9.19 shows CO_2 emissions from all plants in Maryland for the ECPR and NOx scenarios. CO_2 emissions drop immediately after the five coal plants retire, and remain roughly 20 percent below Reference Case levels for the remainder of the study period. In the ECPR scenario, CO_2 never exceeds the State's RGGI budget. Similarly, in the NOx scenario, CO_2 emissions drop as plants retire and bottom out slightly below ECPR levels, due to the greater number of plant retirements.

Figure 9.19 Maryland CO_2 Emissions (All Plants) – ECPR and NOx Scenarios



9.8 Renewable Energy Credit Prices

There is virtually no change in the prices of RECs in the ECPR and NOx scenarios relative to the Reference Case due to the lack of impacts on energy and capacity prices in PJM, both of which heavily affect the RECs prices.

9.9 Summary of Key Results

The following key results are based on the modeling and analysis presented in this chapter:

- Across PJM, natural gas capacity additions are less than 2 percent greater in the ECPR and NOx scenarios than in the Reference Case. However, a greater proportion of these builds occur in the PJM-SW transmission zone.

- Under the ECPR and NOx scenarios, net imports in PJM-SW are modestly higher than in the Reference Case, as plants outside the region help to compensate for the early coal plant retirements.

- The ECPR and NOx scenario retirements cause a pronounced shift away from coal use and towards natural gas use in the State.

- The ECPR and NOx scenario retirements have almost no impact on energy prices in PJM-SW, PJM-MidE, or PJM-APS, nor any impact on REC prices.

- The early coal plant retirements initially place upward pressure on capacity prices in PJM-SW. In later years of the study period, capacity prices in PJM-SW fluctuate slightly above and slightly below Reference Case levels, in response to builds that occur only in the ECPR and NOx scenarios.

- Under the ECPR and NOx scenarios, Maryland emissions of SO_2 vary only slightly from the Reference Case, while NOx and mercury emissions fall relative to the Reference Case and are well below HAA caps.

- Under the ECPR and NOx scenario assumptions, Maryland CO_2 emissions fall below the RGGI budget in all years, as compared to the Reference Case in which CO_2 emissions rise above the RGGI budget for Maryland beginning in 2020.

10. Discussion Topics

In this chapter, further background is provided on topics that are relevant to electric power in Maryland. These sections will help readers better understand: federal, regional, and state regulations, initiatives, and programs that influence power plant operations; technological trends that have enhanced the competitiveness of natural gas, wind, and solar PV in particular; and the relationships among climate change, electricity demand, and electricity supply in Maryland. Highlighted and discussed throughout this chapter are sources of long-term uncertainty—which, in part, are the bases for the selection of alternative scenarios in the LTER. Note also key areas of uncertainty that cannot be captured by the modeling approach relied upon for the LTER.

10.1 Renewable Energy

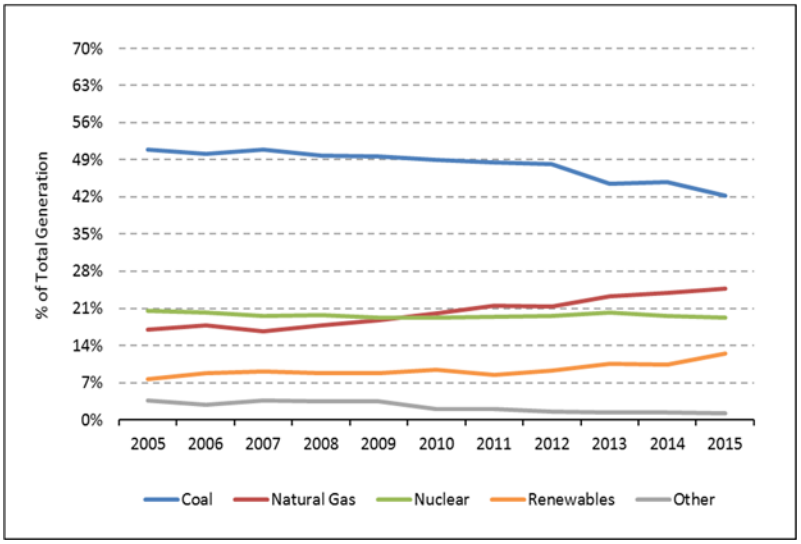
The renewable energy industry has experienced rapid growth over the past decade. In the following pages, these trends are reviewed at the national, regional, and state levels. Also discussed are two important drivers of this growth: technological advances; and supportive government policies, such as net metering, the federal production tax credit, the federal investment tax credit, and state renewable portfolio standards (RPS's). Because particular uncertainty surrounds the future of supportive government policies, four LTER alternative scenarios explore the potential impact of changes to these policies (see Chapter 7).

10.1.1 Renewable Energy Growth Trends in the United States

Renewable energy, including hydro, accounted for 13 percent of U.S. total generation in 2015 compared to just under 9 percent in 2005. The contribution from non-hydro renewable energy generation more than tripled over that time period, from 2 percent to just over 7 percent.[48] (See Figure 10.1 for overall electricity generation composition, followed by Figure 10.2 with a breakdown of the renewables percentages.)

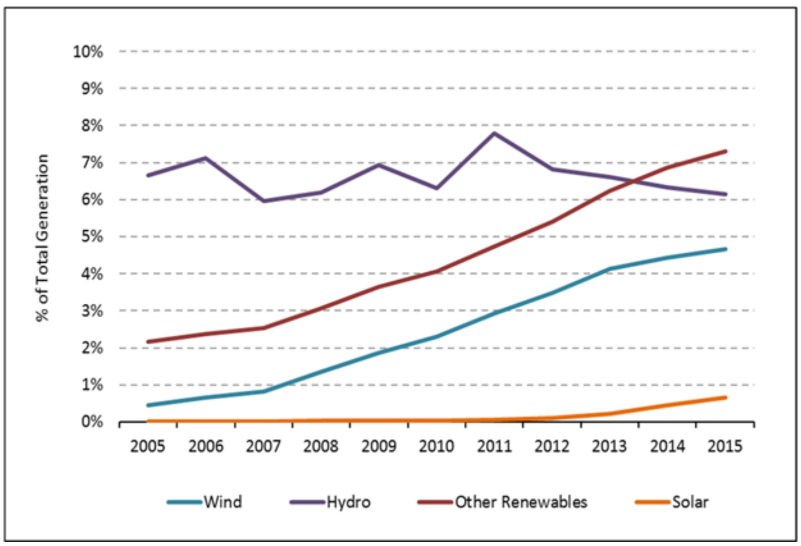
[48] U.S. Energy Information Administration, Summary and Disposition of Electricity, February 16, 2016, http://www.eia.gov/electricity/data.cfm#summary.

Figure 10.1 U.S. Electricity Generation Composition



Source: U.S. Energy Information Administration, Summary and Disposition of Electricity, February 16, 2016, http://www.eia.gov/electricity/data.cfm#summary.

Figure 10.2 U.S. Renewable Energy Generation Composition Breakdown (Based on Total Generation)

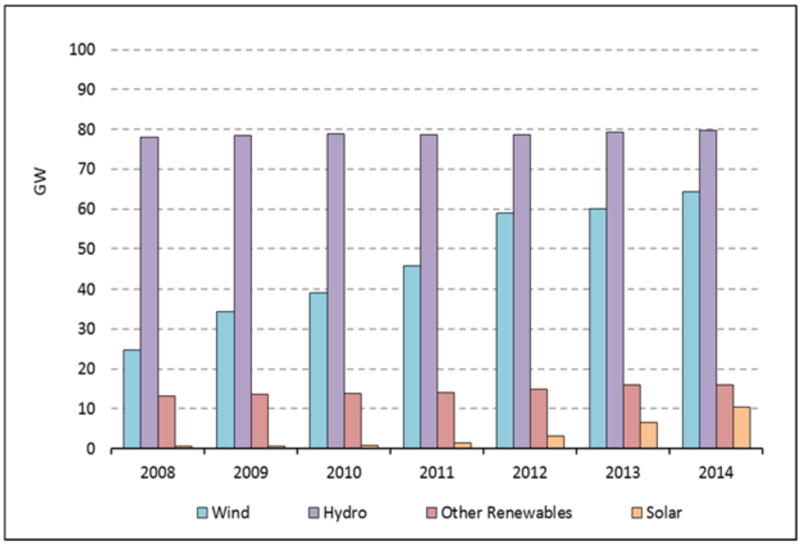


Note: The "Other Renewables" category includes EIA categories of other biomass, wood waste, and geothermal.

Source: U.S. Energy Information Administration, Summary and Disposition of Electricity, February 16, 2016, http://www.eia.gov/electricity/data.cfm#summary.

In terms of installed capacity, the most significant growth among renewable energy technologies has occurred in wind and solar PV, as shown in Figure 10.3. Wind, for example, has about doubled in installed capacity since 2009, from 34 GW to 64 GW as of 2014.[49] Including both utility-scale and distributed solar, 20 GW of solar is now on-line in the U.S. as of 2015, compared to only 70 MW in 2008.[50] In 2015, renewable energy accounted for over 70 percent of the new generation capacity in the U.S.[51]

Figure 10.3 U.S. Renewable Energy Net Summer Generating Capacity Breakdown (GW)



Source: U.S. Energy Information Administration, Summary and Disposition of Electricity, February 16, 2016, http://www.eia.gov/electricity/data.cfm#summary.

Although there is only one off-shore wind project under construction in the United States, off-shore wind is considered an area of major potential growth, especially in the Northeastern U.S. Another 21 off-shore wind projects are in various stages of development in 12 states, including Maryland, representing 15.6 GW.[52] By comparison, there were about 12 GW of off-shore wind projects worldwide as of the end of 2015, with the vast majority of this capacity located in Europe.[53]

[49] Ryan Wiser and Mark Bolinger, *2015 Wind Technologies Market Report,* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, August 2016, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.
[50] U.S. Energy Information Administration, *Electric Power Monthly,* "Net Summer Capacity for Utility Scale Solar Photovoltaic and Distributed Solar Photovoltaic Capacity (Megawatts)," August 2016, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_01_a.
[51] Ryan Wiser and Mark Bolinger, *2015 Wind Technologies Market Report,* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, August 2016, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.
[52] Aaron Smith, Tyler Stehly, and Walter Musial, *2014-2015 Offshore Wind Technologies Market Report*, National Renewable Energy Laboratory, September 2015, http://www.nrel.gov/docs/fy15osti/64283.pdf.
[53] Ryan Wiser and Mark Bolinger, *2015 Wind Technologies Market Report,* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, August 2016, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.

10.1.2 Renewable Energy Growth Trends in PJM and Maryland

Renewable energy generation accounted for about 3 percent of overall generation in PJM in 2015.[54] In Maryland, renewable energy, including hydro, accounted for just under 7 percent of in-State generation in 2014 (the most recent year of available data); non-hydro renewables accounted for 2.6 percent.[55] Renewable energy capacity in PJM and in Maryland is illustrated in Table 10.1.

Table 10.1 Utility-Scale Renewable Energy Capacity in Maryland and PJM (MW)

	Maryland	PJM
Biomass	128.2	1,130.9
Landfill Gas	25.1	669.6
Solar (utility-scale)[1]	48.8	383.0
Wind	160.0	6,448.2
Run-on-river Hydro	494.4	2,562.2
Total	**856.5**	**11,193.9**

[1] Distributed solar not included.

Source: September 2016 data from PJM, http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

There also is significant distributed solar energy capacity within PJM's service area and Maryland.[56] Within PJM, there were over 25,000 distributed generation solar projects totaling approximately 731 MW of capacity; Maryland accounted for 11,600 of those projects and 189 MW of capacity.[57] As of September 2015, Maryland had the eighth most distributed solar generation capacity statewide in the U.S.[58]

10.1.3 Factors in the Growth of Solar and Wind Technologies

The substantial growth in renewable energy chronicled above, specifically solar and on-shore wind, is in large part due to decreasing costs and improvements in technological efficiency, production, and reliability. Because of the sharp increase in on-shore wind and solar capacity in recent years, this section emphasizes those two technologies. Off-shore wind is also discussed because of off-shore wind's vast resource potential in Maryland and in the Northeastern U.S.

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[54] Monitoring Analytics, *2015 State of the Market Report for PJM*, Section 3 (Energy Market), March 2016, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2-sec3.pdf.

[55] U.S. Energy Information Administration, *Electricity: Detailed State Data*, January 13, 2016, https://www.eia.gov/electricity/data/state/.

[56] PJM is only cited as a geographic reference point. Most distributed solar systems will be behind the meter and, therefore, not visible to PJM.

[57] PJM Environmental Information Services, Renewable Generators Registered in GATS, https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS.

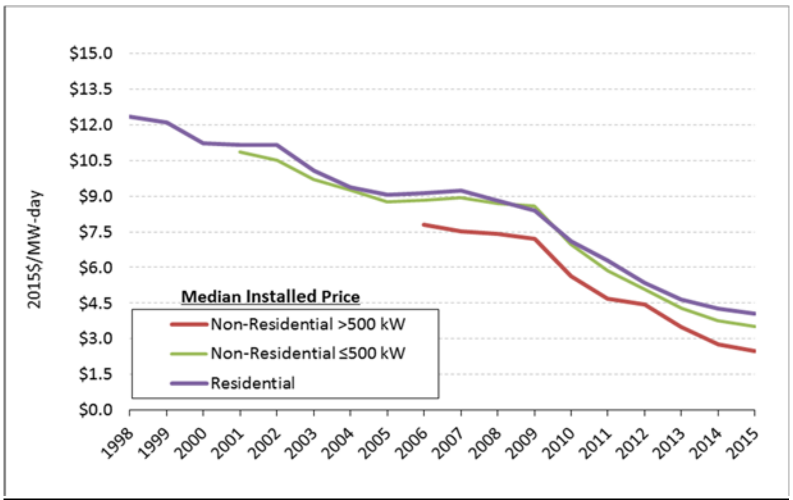
[58] U.S. Energy Information Administration, "EIA electricity data now include estimated small-scale solar PV capacity and generation," December 2, 2015, http://www.eia.gov/todayinenergy/detail.cfm?id=23972.

Solar

The installed capital costs for utility-scale solar have dropped 60 percent since 2008 to an average of $2.70 per watt (W) (equal to $2,700/kW), with the lowest cost reported at $1.70/W ($1,700/kW). Similarly, power purchase agreements (PPAs) for utility-scale solar that were signed in 2015 are at or below $50/MWh, with some as low as $30/MWh. Several factors have driven these cost declines, including: overproduction of PV modules; increasing efficiency of PV modules; and a trend among developers to oversize their PV projects relative to each project's inverter resulting in increased power production, although some generation may be curtailed at times of high solar production because the inverter cannot manage the output.[59]

Capital costs for distributed generation solar systems range from about $2/W ($2,000/kW) for non-residential systems over 500 kW in capacity to about $4/W ($4,000/kW) for residential solar systems (see Figure 10.4). Cost declines were again in part due to price declines in PV modules but also in part to the decrease in "soft costs," i.e., costs that are unrelated to the PV module, including: inverter and racking equipment for rooftop PV systems, marketing and customer acquisition, system design, labor, permitting, and inspection costs.[60]

Figure 10.4 Median Installed Solar Price Trends over Time



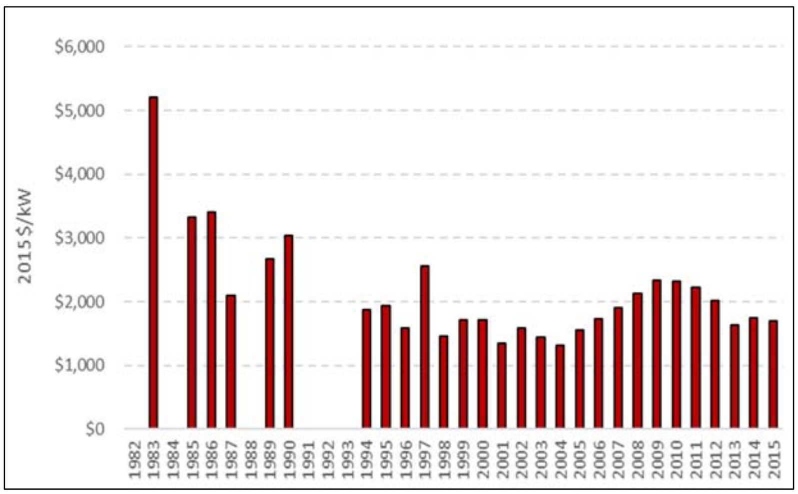
Source: Galen Barbose and Naïm Darghouth, *Tracking the Sun IX*, U.S. Department of Energy and Lawrence Berkeley National Laboratory, August 2016, https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf.

[59] Mark Bolinger and Joachim Seel, *Utility-Scale Solar 2015*, U.S. Department of Energy and Lawrence Berkeley National Laboratory, August 2016, https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf.
[60] Galen Barbose and Naïm Darghouth, *Tracking the Sun IX*, U.S. Department of Energy and Lawrence Berkeley National Laboratory, August 2016, https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report_0.pdf.

On-shore Wind Energy

As shown in Figure 10.5, from the beginning of the U.S. wind industry in California in the 1980s to $1,300/kW in 2001, the average installed costs of on-shore wind power projects declined then roughly doubled in cost to about $2,300/kW in 2010. Several reasons accounted for the increase in costs, including: increases in materials, energy, and labor costs; increased costs for turbine warranties; and manufacturers seeking higher profit due to high demand for wind turbines. Since 2010, capital costs for on-shore wind projects have dropped to $1,690/kW because of advances in wind turbine technology. That drop in costs has led to a sharp decrease in the costs of PPAs signed between wind companies and power purchasers, from about $70/MWh to about $20/MWh. It should be noted that the $20/MWh is skewed toward wind projects that are developed in the central part of the U.S., where development costs are lower than elsewhere in the country. PPA costs for wind in the Northeast will be higher because of higher development costs.

Figure 10.5 Wind Power Project Installed Cost Trend: Capacity-Weighted Average Cost



Note: Data not available for 1982, 1984, 1988, and 1991 through 1993.

Source: Ryan Wiser and Mark Bolinger, *2015 Wind Technologies Market Report,* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, August 2016, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.

Off-shore Wind Energy

Maryland has off-shore wind energy potential of over 53 GW, with 22 GW of that amount within the first three nautical miles from shore. Table 10.2 presents the significant potential for off-shore wind in the Mid-Atlantic region.

Table 10.2 Off-shore Wind Resources of Mid-Atlantic States by Area and Potential

	0-3 Nautical Miles		3-50 Nautical Miles		Total	
	Area (km^2)	Potential (GW)	Area (km^2)	Potential (GW)	Area (km^2)	Potential (GW)
Delaware	1,088	6	1,853	9	2,940	15
Maryland	**4,292**	**22**	**6,465**	**32**	**10,756**	**54**
New Jersey	2,271	11	17,664	88	19,935	100
New York	6,232	31	23,207	116	29,439	147
Virginia	5,648	28	13,242	66	18,890	94
Total	**19,530**	**98**	**62,430**	**312**	**81,960**	**410**

Note: Amounts may not be exact due to rounding.

Source: James McElfish, Adam Schempp, and Jordan Diamond, *A Guide to State Management of Off-shore Wind Energy in the Mid-Atlantic Region*, Environmental Law Institute, April 2013, http://midatlanticocean.org/wp-content/uploads/2014/03/A-Guide-to-State-Management-of-Off-shore-Wind-Energy-in-the-Mid-Atlantic-Region.pdf, sourced from Schwartz, *et al.* 2010.

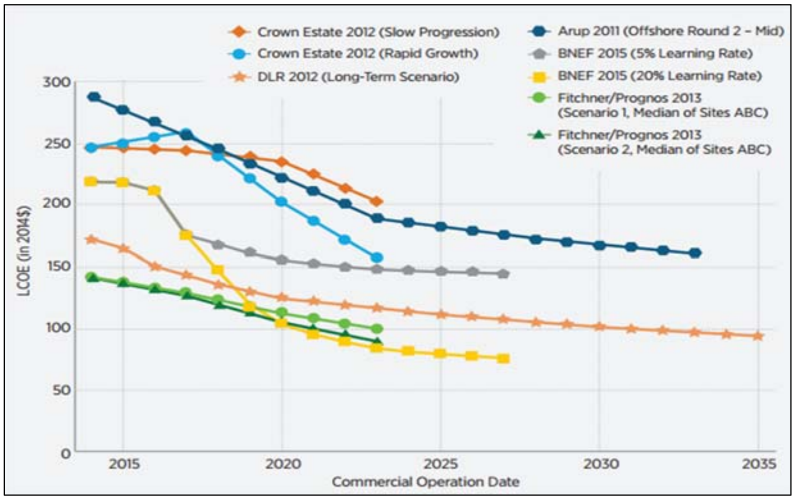
Cost data for off-shore wind is very limited as the first U.S. off-shore wind project will go online in late 2016.[61] Available information is primarily based on actual industry experience in Europe and models developed for markets in the U.S.

One analysis performed by the National Renewable Energy Laboratory (NREL) estimated that off-shore wind could reach cost levels at or below $100/MWh by 2030.[62] Based on the costs in Figure 10.6, and the results of the analysis by NREL, there will be a significant premium for off-shore wind power compared to conventional energy and other renewable energy technologies for well over a decade.

[61] DeepwaterWind Block Island Wind Farm, http://dwwind.com/project/block-island-wind-farm/.

[62] Philipp Beiter, Walter Musial, and Aaron Smith, *et al.*, *A Spatial-Economic Cost-Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015-2030*, 2016, National Renewable Energy Laboratory, http://www.nrel.gov/docs/fy16osti/66579.pdf.

Figure 10.6 International Levelized Cost of Electricity Estimates for Off-shore Wind (2014-2033) (MWh)



Note: The labels represent different source documents relied upon by NREL.

Source: Energy.gov, "National Off-shore Wind Strategy: Facilitating the Development of the Off-shore Wind Industry in the United States," September 8, 2016, http://energy.gov/eere/win/downloads/national-off-shore-wind-strategy-facilitating-development-off-shore-wind-industry.

Net Metering and Distributed Generation

Net metering has been another major force driving the adoption of distributed generation, especially solar power, in the United States. Net metering is the use of a single meter for both generation and consumption, where the generator is also the primary user of the electricity; this enables the customer to consume electricity from an on-site generator, and distribute any excess generation to the local distribution grid. Generators operating under net metering arrangements are sometimes referred to as behind-the-meter (because most, if not all generation, occurs on the customer side of the meter, not the bulk power side). The behind-the-meter generation serves the customer's demand, and any excess generation is distributed to the grid. The individual provisions of state net metering requirements can vary considerably, such as technology eligibility, capacity limitations, and compensation for excess generation (e.g., compensation at retail electric rates versus wholesale).

Maryland's net metering policy places a 1,500 MW aggregate limit on eligible net-metered generating capacity. Furthermore, each individual project must be less than 2 MW. When compared to the State's peak demand of approximately 15,000 MW, this cap reflects approximately 10 percent of the State's peak demand. As of June 2015, the total amount of net-metered capacity in Maryland was about 239 MW, reflecting rapid growth in recent years (see Table 10.3).[63] Eligible technologies include solar, wind, biomass, micro combined heat and power, fuel cell, and closed conduit hydro electric generators.

[63] Public Service Commission of Maryland, *Report on the Status of Net Metering in the State of Maryland*, January 2016, http://www.psc.state.md.us/wp-content/uploads/2015-MD-PSC-Report-on-the-Status-of-Net-Metering-Report.pdf.

Any surplus generation is credited to the next bill at the utility's retail rate, and is balanced annually at the commodity energy supply rate.[64]

Table 10.3 Installed Net-metered Generating Capacity Growth in Maryland

Year	kW	Annual Growth
2011	31,739	--
2012	58,514	84%
2013	101,692	74%
2014	143,706	41%
2015	238,913	66%

Source: Report on the Status of Net Metering in the State of Maryland, Public Service Commission of Maryland, January 2016, http://www.psc.state.md.us/wp-content/uploads/2015-MD-PSC-Report-on-the-Status-of-Net-Metering-Report.pdf.

10.1.4 Renewable Energy Policies: Federal and State

A variety of state and federal policies have been adopted to help lower the costs of renewable energy and to stimulate market demand. Three of the more important policies—the federal production tax credit (PTC) and the investment tax credit (ITC), and state renewable portfolio standards (RPS's)—are discussed below.

Federal Production Tax Credit

The federal PTC was first enacted as part of the Energy Policy Act of 1992 and has since been extended multiple times. The PTC provides an inflation-adjusted federal tax credit, currently at 2.3 cents/kWh for every kWh of production from wind, geothermal, and closed-loop biomass; and 1.2 cents/kWh for tidal, wave, and ocean thermal technologies, open-loop biomass, qualified hydro,[65] landfill gas, and municipal solid waste, all for the first ten years of a plant's operations. In December 2015, the U.S. Congress extended the PTC for wind power until the end of 2019, and until the end of 2016 for all other eligible technologies. The PTC for wind is reduced by 20 percentage points per year after 2016 until the end of 2019, when the PTC for wind is at 40 percent of full value. After that, the PTC for wind expires. Plants that began construction in a particular year are eligible to take the PTC for that year, and for up to four years following that year.[66]

[64] Ibid.
[65] The term "qualified hydroelectric facility" means a turbine or other generating device, owned or solely operated by a non-federal entity, that generates hydroelectric energy for sale and which is added to an existing dam or conduit.
[66] The Internal Revenue Service allows investment of 5 percent or more in the plant, or for work, such as road construction and site excavation, to qualify as commencing construction. See Internal Revenue Service, "Beginning of Construction for Sections 45 and 48," Internal Revenue Service Notice 2016-31, https://www.irs.gov/pub/irs-drop/n-16-31.pdf.

The American Wind Energy Association (AWEA) states that the PTC has helped wind capacity more than quadruple since 2008 and has helped decrease the cost of wind power by 66 percent.[67] With the recent extension of the PTC, forecasts are calling for 8 GW of new wind construction annually through 2020, and AWEA says 15 GW of wind is already under construction or in advanced development.[68]

Federal Investment Tax Credit

The federal ITC currently provides a 30 percent federal tax credit for investments in solar, fuel cells, and small wind electric projects, and 10 percent credit for investments in geothermal, microturbines, and combined heat and power (CHP) systems. At least for solar power, the recent extension of the ITC is predicted to result in over 70 GW of new solar capacity by 2020, representing about $130 billion in overall investment.[69]

Eligibility for the ITC, and the amount of the ITC, varies by technology (see Table 10.4). The ITC for solar systems remains at 30 percent through 2019, then declines to 26 percent in 2020, 22 percent in 2021, and 10 percent in 2022. In 2022 and beyond, a 10 percent tax credit for both utility and commercially operated solar projects will be available, while the tax credits for residential solar projects will expire in 2022. Large wind power projects can take the ITC in lieu of the PTC, subject also to a 20 percent reduction each year beginning in 2017, and ending altogether at the end of 2019 (see Table 10.4).[70] The "commence construction" provision, discussed in the PTC section above, applies to commercial and utility-scale solar and wind systems, but not residential systems.

[67] American Wind Energy Association, "Production Tax Credit," http://www.awea.org/Advocacy/Content.aspx?ItemNumber=797.
[68] Ryan Wiser and Mark Bolinger, *2015 Wind Technologies Market Report,* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, August 2016, https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.
[69] Solar Energy Industries Association, "Impacts of Solar Investment Tax Credit Extension," http://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension.
[70] This is only a high-level overview of which technologies are eligible for the ITC, but there are numerous other provisions, such as restrictions on the amount of the ITC or the capacity of the individual system, that are not discussed here because of level of detail and complexity. See North Carolina Clean Energy Technology Center, Database on State Incentives for Renewables and Efficiency, "Business Energy Investment Tax Credit," last updated on December 21, 2015, http://programs.dsireusa.org/system/program/detail/658.

Table 10.4 Eligibility and Amount of the Investment Tax Credit, by Year and Technology

Technology	Year Ending December 31							Future Years
	2016	2017	2018	2019	2020	2021	2022	
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%[1]
Hybrid Solar Lighting, Fuel Cells, Small Wind	30	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Heat Pumps, Microturbines, Combined Heat and Power Systems	10	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Electric	10	10	10	10	10	10	10	10
Large Wind	30	24	18	12	N/A	N/A	N/A	N/A

[1] This percentage is only for business and utility systems beyond 2022. For residential systems, the ITC expires altogether at the end of 2022.

Source: North Carolina Clean Energy Technology Center, Database on State Incentives for Renewables and Efficiency, "Business Energy Investment Tax Credit," last updated on December 21, 2015, http://programs.dsireusa.org/system/program/detail/658.

State Renewable Portfolio Standards

An RPS requires electricity providers to provide a minimum percentage or amount of eligible sources of renewable energy to retail electric customers. An RPS typically includes non-compliance penalties of some type and often incorporates renewable energy credits (RECs), where one REC equals one MWh of production, to help with RPS compliance. As with net metering, state RPS policies differ considerably in terms of the level of the RPS, the rate of growth of the RPS, type and amount of non-compliance penalties, whether there are carve-outs or set-asides within the RPS, cost containment mechanisms (if any), and eligible technologies, to name just a few examples.

Twenty-nine states and the District of Columbia currently have an RPS. To date, state RPS policies collectively have resulted in 135 terawatt-hours (TWh) of additional renewable energy generation since 2000, representing 60 percent of the growth in non-hydro generation. State RPS policies have also resulted in 100 GW of new renewable energy capacity, also since 2000. Assuming no change in state RPS policies, renewable energy demand will increase to 431 TWh by 2030, representing 9.3 percent of U.S. retail electricity sales. By capacity, an additional 60 GW of renewable energy will be required by 2030.[71]

Maryland enacted an RPS, the Maryland Renewable Energy Portfolio Standard and Credit Trading Act, in 2004. The Maryland RPS consists of two tiers. The technologies eligible for Tier 1 are:

- Solar and solar water heat;
- Wind;
- Qualifying biomass (including black liquor);
- Methane from a landfill or wastewater treatment plant;
- Geothermal;

[71] Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Report*, Lawrence Berkeley National Laboratory, April 2016, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf.

- Ocean;
- Fuel cell (methane or biomass-powered);
- Small hydro (less than 30 MW);
- Poultry litter incineration;
- Waste-to-energy;
- Refuse-derived fuel; and
- Thermal energy from biomass.

Tier 1 also includes carve-outs for solar and off-shore wind.

Tier 2 is comprised of hydropower that is greater than 30 MW, other than pumped storage hydropower. The Tier 2 requirements exist only through 2018 and may be fulfilled using Tier 1 renewables. The Maryland RPS requirements are as shown in Table 10.5.

Table 10.5 Maryland Renewable Energy Portfolio Standard
(Percent of Energy Sales)

Year	Solar	Other Tier 1	Maximum Off-shore Wind*	Tier 2
2015	0.50%	10.00%	0%	2.50%
2016	0.70	12.00	0	2.50
2017	0.95	12.15	2.50	2.50
2018	1.40	14.40	2.50	2.50
2019	1.75	15.65	2.50	0
2020	2.00	16.00	2.50	0
2021	2.00	16.70	2.50	0
2022+	2.00	18.00	2.50	0

* This represents a maximum percent and would be treated as part of "Other Tier 1" renewables.

<u>Compliance with the Maryland RPS through RECs</u>

PJM maintains the Generation Attribute Tracking System (GATS), a registry of electricity providers and non-generation attributes such as RECs. States and electricity suppliers rely upon GATS for generating reports for purposes of determining compliance with state policies such as RPS policies and electricity disclosure requirements. Electricity suppliers in Maryland with an insufficient amount of RECs for purposes of complying with the Maryland RPS can make alternative compliance payments, or ACPs, as shown in Table 10.6. Note that the ACP for Tier 1 remains at $40 per MWh, while the Tier 2 ACP falls to zero after 2018, consistent with the expiration of that tier. The solar ACP was set for $400 per MWh from 2009 to 2014 but began declining $50 per MWh every two years and will continue to decline until it reaches $50 per MWh in 2023 and thereafter.

Table 10.6 Alternative Compliance Payment Schedule for the Maryland RPS ($/MWh)

Year	Solar	Other Tier 1	Tier 2
2015	$350	$40	$15
2016	350	40	15
2017	195	40	15
2018	175	40	15
2019	150	40	N/A
2020	150	40	N/A
2021	100	40	N/A
2022	100	40	N/A
2023+	50	40	N/A

The Maryland General Assembly has modified the Maryland RPS several times since it was enacted in 2006. In 2007, a solar set-aside or "carve-out" was applied to Tier 1, where a certain percentage of the Tier 1 requirement must be met by solar. The solar carve-out started at 0.005 percent in 2008, increases up to 2 percent in 2020, and remains at that level thereafter. To be eligible for the solar carve-out, a solar facility must be interconnected to the distribution grid that serves Maryland. A separate Tier 1 carve-out was created for off-shore wind in 2013. Beginning in 2017, the Maryland PSC may set aside up to 2.5 percent of the Tier 1 level for qualified off-shore wind projects. To be eligible, the off-shore wind plant must be located on the outer continental shelf between 10 to 30 miles off the coast of Maryland in a U.S. Department of Interior designated leasing zone, and interconnect to PJM at a point on the Delmarva Peninsula.

Several other changes have been made to the Maryland RPS, as described below:

- Waste-to-energy facilities connected to the Maryland distribution grid were redefined as Tier 1 resources in 2011; they were previously defined as Tier 2 resources.
- Refuse-derived fuels were added as an eligible Tier 1 resource in 2011. Like waste-to-energy, these facilities must be connected to the distribution grid in Maryland.
- Geothermal heating and cooling systems were added as a Tier 1 resource in 2012. To be eligible, geothermal heating and cooling systems must be installed and connected to the distribution grid in Maryland in 2013 and thereafter. These systems must replace or displace heating or cooling systems primarily fueled by electricity or non-natural gas fuel source.

Thermal energy generated by thermal biomass systems was added as an eligible Tier 1 resource in 2012. Such systems must be connected to the Maryland distribution grid and generate energy using primarily food waste, crop waste, crops grown for energy production, or animal manure (including poultry litter).

10.2 Environmental Protection Agency Regulations

10.2.1 Introduction

The EPA is responsible for implementing and administering 11 pollution control statutes as enacted by Congress, such as the Clean Air Act (CAA); the Clean Water Act (CWA); and the Comprehensive Environmental Response, Compensation and Liability Act, better known as Superfund. In recent years, the EPA has issued several proposed and final regulations of importance to the electric power industry in response to statutory requirements to reexamine existing regulations because of court orders, technological change, or new scientific information suggesting a change in EPA standards is warranted. In some instances, EPA's requirements will impose sufficiently high costs such that a generator will need to decide whether to install pollution control equipment to meet EPA's regulatory requirements or to simply retire the generating facility. EPA requirements will also affect investment in new generation plants.[72]

EPA regulations affect the LTER modeling results. The compliance cost of EPA regulations affects the capital and operating costs of individual power plants, which in turn affect the model's selection of new generating capacity to meet electric demand, as well as the costs which affect the dispatch of existing and newly constructed plants. The costs of complying with EPA regulations, such as adding air pollution control equipment, also affect whether power plant operators choose to continue operating their plants or retire them.

Below is a description of proposed and finalized EPA regulations that are especially relevant to the electric power industry. As a general rule, the LTER modeling approach assumes all EPA regulations remain in effect during the forecast period, with the exception of the Clean Power Plan (CPP), which is modeled as an alternative scenario. The model employed is not designed to address regulatory limits on the amount of cooling water that power plants can consume, or the disposal of coal combustion residuals, and thus cannot reflect EPA's regulatory requirements with respect to these activities.

10.2.2 Cross-State Air Pollution Rule

The CAA's "good neighbor" provision requires the EPA and the states to address the interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). In response, EPA developed the Cross-State Air Pollution Rule (CSAPR) in 2011. Via cap-and-trade programs, CSAPR requires 28 eastern and central states to reduce SO_2 emissions, annual NOx emissions, and/or ozone season NOx emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. The states that are required to reduce SO_2 emissions are divided into two groups, both of which must reduce their emissions in Phase I. Phase I implementation began in 2015 and Phase II begins in 2017. Group 1 states are required to make additional emissions reductions in Phase II (see Figure 10.7).

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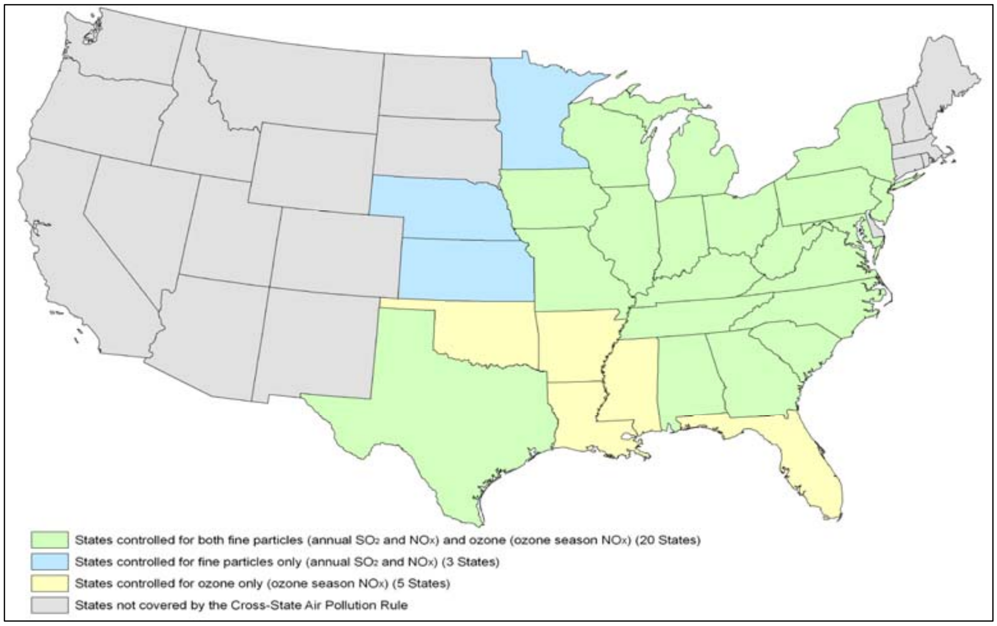
[72] James E. McCarthy and Claudia Copeland, *EPA Regulations: Too Much, Too Little, or On Track?* Congressional Research Service, February 9, 2016, https://www.fas.org/sgp/crs/misc/R41561.pdf.

Figure 10.7 EPA Map Depicting States Impacted by CSAPR Regulation



Source: EPA, Cross-State Air Pollution Rule, https://www3.epa.gov/crossstaterule/.

Maryland

Currently, all of Maryland is in compliance with CAA standards for SO_2, NOx particulate matter less than 2.5 micrometers (PM2.5), particulate matter less than 10 micrometers (PM10), carbon monoxide (CO), and lead. The urbanized areas of Maryland are not meeting CAA standards for ozone. Much of the progress Maryland has made to improve air quality is attributable to the Maryland HAA. Enacted in 2006, the HAA requires substantial emissions reductions from the State's coal-burning electric generating power plants and is the toughest power plant emissions law on the East Coast. The facilities affected are Brandon Shores, C.P. Crane, Chalk Point, Dickerson, H.A. Wagner, Morgantown, and R.P. Smith. The HAA reduced NOx emissions at these generating stations by about 75 percent and SO_2 emissions by about 85 percent, in aggregate, from the 2002 baseline.[73] According to the Maryland Department of the Environment (MDE), power plant owners have invested approximately $2.6 billion in emissions-reducing technology to comply with the HAA.[74] As a result of these investments and the HAA, Maryland is in near compliance with all federal air quality standards for the first time in 30 years.[75]

[73] Maryland Department of the Environment, *Maryland 2016 Clean Air Progress Report*, May 2016, http://www.mde.state.md.us/programs/Air/Documents/GoodNewsReport/CleanAirProgress2016.pdf.
[74] Maryland Department of the Environment, "Maryland Department of the Environment Releases Annual Clean Air Progress Report, Launches Air Quality Awareness Week," May 2, 2016, http://news.maryland.gov/mde/2016/05/02/maryland-department-of-the-environment-releases-annual-clean-air-progress-report-launches-air-quality-awareness-week/.
[75] Maryland Department of the Environment, *Maryland 2016 Clean Air Progress Report*, May 2016, http://www.mde.state.md.us/programs/Air/Documents/GoodNewsReport/CleanAirProgress2016.pdf.

10.2.3 Mercury and Air Toxics Standards

MATS is a set of national emission standards to reduce mercury and other toxic air pollution from coal- and oil-fired power plants. These plants are by far the largest U.S. source of mercury and, on a national basis, emit more than half of several other air toxics, including selenium, hydrogen chloride, and hydrogen fluoride emissions. These power plants are a significant source of other metallic hazardous air pollutants (HAP) including arsenic, chromium, and nickel. Due to compliance with the HAA, 90 percent of mercury emissions in Maryland were controlled by 2013.[76]

In February 2012, EPA published the final MATS for coal- and oil-fired power plants. The standards require existing coal- and oil-fired plants 25 MW or larger to meet emission levels set by the average of the top 12 percent best-controlled sources. EPA stated the standards could be met by 56 percent of coal- and oil-fired generation plants using existing pollution control equipment, while the remaining 44 percent would have to install control technologies to reduce mercury and toxic air pollutants by about 90 percent, at an annual aggregate cost of $9.6 billion.

The U.S. Supreme Court remanded MATS to the United States Court of Appeals for the District of Columbia (D.C. Circuit) in June 2015, finding that EPA needed to better justify the cost and benefits of MATS. In April 2016, EPA updated its analysis of MATS and, based on that analysis, determined that it should regulate toxic air and mercury emissions for power plants.[77] As of this writing, the matter is before the D.C. Circuit.

10.2.4 Carbon Pollution Standards for New Power Plants

In August 2015, the EPA set new standards under CAA section 111(b) to limit CO_2 emissions for most newly constructed, modified, and reconstructed fossil fuel-fired electric generating units (EGUs). This action establishes separate standards of performance for fossil fuel-fired electric steam generating units and fossil fuel-fired stationary combustion turbines.

The Carbon Pollutions Standards for New Power Plants provides the following definitions:

- A new source is any newly constructed fossil fuel-fired power plant that commenced construction after January 8, 2014.
- A modification is any physical or operational change to an existing source that increases the source's maximum achievable hourly rate of air pollutant emissions. This standard would apply to units that are modified after June 18, 2014.

[76] Ibid.
[77] U.S. Environmental Protection Agency, "Fact Sheet: Final Consideration of Cost in the Appropriate and Necessary Finding for the Mercury and Air Toxics Standards for Power Plants," April 2016, https://www.epa.gov/sites/production/files/2016-05/documents/20160414_mats_ff_fr_fs.pdf.

- A reconstructed source is a unit that replaces components to such an extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable facility. This standard would apply to units that reconstruct after June 18, 2014.[78]

These standards reflect the degree of emission limitation achievable through the application of the Best System of Emission Reduction (BSER) that EPA has determined has been adequately demonstrated for each type of unit. Table 10.7 describes the type of plant, the BSER, and the applicable standard.

Table 10.7 Summary of Best System of Emission Reduction and Final Standards for Affected Electric Generating Units

Affected EGU	BSER	Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units	Efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS)	1,400 lbs CO_2/MWh-gross
Modified Fossil Fuel-Fired Steam Generating Units	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1. 1,800 lbs CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h OR 2. 2,000 lbs CO_2/MWh-gross for sources with heat input $\leq$2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units	Most efficient generating technology at the affected EGU.	1. 1,800 lbs CO_2/MWh-gross for sources with heat input >2,000 MMBtu/h OR 2. 2,000 lbs CO_2/MWh-gross for sources with heat input $\leq$2,000 MMBtu/h.
Newly Constructed and Reconstructed Natural Gas-Fired Stationary Combustion Turbines	Efficient natural gas combined cycle technology for natural gas-fired base load units and clean fuels for non-base load and multi-fuel-fired units.	1. 1,000 lbs CO_2/MWh-gross to 1,030 lbs CO_2/MWh-net for base load natural gas-fired units 2. 120 lbs CO_2/MMBtu for non-base load natural gas-fired units 3. 120 to 160 lbs CO_2/MMBtu multi-fuel-fired units.

Source: U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, October 2015, https://www.epa.gov/sites/production/files/2015-08/documents/cps-ria.pdf.

[78] U.S. Environmental Protection Agency, *EPA Fact Sheet: Final Limits on Carbon Pollution from New, Modified and Reconstructed Power Plants*, September 14, 2015, https://www.epa.gov/sites/production/files/2015-11/documents/fs-cps-overview.pdf.

10.2.5 Clean Power Plan for Existing Power Plants

In August 2015, EPA issued the final Clean Power Plan regulations for existing power plants under the authority of Section 111(d) of the CAA. The CPP requires a reduction in carbon emissions nationwide by 20 percent from 2005 levels by 2022 and 32 percent by 2030. States would be required to file compliance plans with EPA—for those that do not, EPA would implement a federal implementation plan. Each state would comply with the CPP in one of two ways: (1) meeting a statewide maximum carbon dioxide (CO_2) emissions rate, in lbs/MWh, and termed the "rate-based" approach; or (2) not exceeding a maximum allowable tons of CO_2 emissions per year, referred to as the "mass-based" approach. EPA established interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired EGUs—steam generating units (coal, oil, and natural gas) and natural gas combined-cycle units. A Clean Energy Incentive Program would offer early credit to states that bring wind and solar plants on-line, or implement energy efficiency programs in low-income communities after 2012. States can petition EPA to revise their CPP plans if unexpected reliability issues emerge.[79]

In February 2016, the U.S. Supreme Court stayed the CPP pending resolution of legal challenges to the CPP in the D.C. Circuit.[80] Assuming the Supreme Court agrees to hear an appeal of any decision from the D.C. Circuit, a ruling on the CPP is not anticipated until late 2017 or perhaps 2018.[81] EPA said it will still assist states that wish to proceed with preparing their CPP implementation plans.[82]

Maryland

In 2009, the Maryland General Assembly enacted the Greenhouse Gas Reduction Act (GGRA) which required the State to develop plans and implement initiatives to reduce greenhouse gas (GHG) emissions by 25 percent from 2006 levels by 2020. In October 2015, the MDE issued a status report which showed the State is on track to achieve the initial 25 percent reduction by 2020.

In April 2016, the Maryland General Assembly reauthorized the 2009 law and raised the goal to reduce Statewide GHG emissions by 40 percent from 2006 levels by 2030. MDE is required to submit a GHG emissions reduction plan by the end of 2018 and to adopt a final plan by the end of 2019.[83] While these goals are not binding, they provide an overarching framework for Maryland's continued participation in the Regional Greenhouse Gas Initiative (RGGI) (see Section 3.5.3) as well as the State's implementation of State-level conservation programs such as EmPOWER Maryland (see Section 10.5).

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[79] U.S. Environmental Protection Agency, *Fact Sheet: Overview of the Clean Power Plan*, https://www.epa.gov/sites/production/files/2015-08/documents/fs-cpp-overview.pdf.

[80] U.S. Supreme Court, *West Virginia, et al. v. EPA, et al.*, February 9, 2016, http://www.scotusblog.com/wp-content/uploads/2016/02/15A773-Clean-Power-Plan-stay-order.pdf.

[81] Sidley Austin LLP, *Effect of Supreme Court Stay on Clean Power Plan Deadlines*, http://www.chamberlitigation.com/sites/default/files/scotus/files/2016/White%20Paper%20on%20Impact%20of%20Stay%20on%20CPP%20Deadlines.pdf.

[82] U.S. Environmental Protection Agency, "Clean Power Plan for Existing Power Plants," https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

[83] General Assembly of Maryland, "Greenhouse Gas Emissions Reduction Act – Reauthorization," April 22, 2016, http://mgaleg.maryland.gov/webmga/frmMain.aspx?pid=billpage&stab=01&id=sb0323&tab=subject3&ys=2016RS.

10.2.6 Cooling Water Intake

Water usage by electric generating plants and manufacturers accounts for over half of all daily water withdrawals. Drawing water into a generating plant via cooling water intake structures can also draw in fish, shellfish, and small organisms, causing injury or death.[84] To mitigate these adverse events, the EPA implemented a final rule governing cooling water intake by power plants in August 2014. This rule establishes requirements under section 316(b) of the CWA governing cooling water intake structures at existing facilities that: (1) are designed to withdraw more than two million gallons per day (Mgd) of water from waters of the United States, and (2) use at least 25 percent of this water for cooling purposes.[85] EPA allows several options such as closed-cycle recirculating systems or maximum intake screens as methods of compliance.

10.2.7 Disposal of Coal Combustion Residuals from Coal-Fired Power Plants

Overview

In December 2008, a large coal ash spill occurred at the Tennessee Valley Authority's (TVA's) coal plant in Kingston, Tennessee, resulting in the release of 1.1 billion gallons of coal ash slurry. This incident, and EPA's previous determination that coal combustion residual (CCR) disposal in unlined landfills and surface impoundments can result in the release of toxics such as arsenic and selenium into surface water and groundwater, prompted EPA to regulate the CCRs from coal ash removal. The final rule regulates the disposal of CCRs as solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). This rule finalizes national minimum criteria for existing and new CCR landfills, existing and new CCR surface impoundments, and all lateral expansions consisting of location restrictions; design and operating criteria; groundwater monitoring and corrective action; closure requirements and post closure care; and recordkeeping, notification, and Internet posting requirements. The final rule requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCRs and either retrofit or close, except in limited circumstances. It also requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Finally, those CCR surface impoundments that do not receive CCRs after the effective date of the rule, but still contain water and CCRs, will be subject to all applicable regulatory requirements, unless the owner or operator appropriately seals these inactive units no later than three years from publication of the rule.[86]

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[84] James E. McCarthy and Claudia Copeland, *EPA Regulations: Too Much, Too Little, or On Track?*, Congressional Research Service, February 9, 2016, https://www.fas.org/sgp/crs/misc/R41561.pdf.

[85] U.S. Environmental Protection Agency, *Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities*, May 2014, https://www.epa.gov/sites/production/files/2015-04/documents/final-regulations-cooling-water-intake-structures-at-existing-facilities_fact-sheet_may-2014.pdf.

[86] U.S. Environmental Protection Agency, *Fact Sheet: Final Rule on Coal Combustion Residuals Generated*

Maryland

The State of Maryland implemented regulations governing coal combustion byproducts (CCBs) in December 2008. The regulations were a result of the contamination of groundwater in parts of Anne Arundel County due to the disposal of 200,000 to 400,000 tons of CCBs at an unlined sand and gravel mine reclamation site. The Maryland regulations require the following:

- Disposal facilities must meet all of the same standards required for industrial solid waste landfills. This includes leachate (rainwater mixed with waste) collection, groundwater monitoring, the use of liners, and routine analysis of CCBs.
- A CCB disposal facility must conform to all local zoning and land-use requirements as well as each county's ten-year solid waste management plan.
- For coal and non-coal mine reclamation sites, the use of CCBs must meet standards similar to those required for industrial solid waste landfills. Standards for coal mine reclamation will ensure that only alkaline CCBs are used.
- For both disposal and mine reclamation sites, dust control measures must be implemented and post closure monitoring and maintenance must be performed. MDE may also impose other requirements in addition to the regulations as part of the permitting process for new CCB disposal or mine reclamation sites.
- New annual reporting requirements for generators of CCBs covering how the material was recently used or disposed, as well as future plans for disposal or use.

A total of approximately 1.5 million tons of coal ash were generated from Maryland power plants in 2014. CCBs are either disposed or beneficially used. Beneficial uses of coal ash include mine reclamation, structural fill applications, or as a substitute for cement in the production of concrete. Currently, about 1.3 million tons of coal ash is beneficially used in Maryland.[87]

10.3 Natural Gas Prices and Factors Affecting Prices

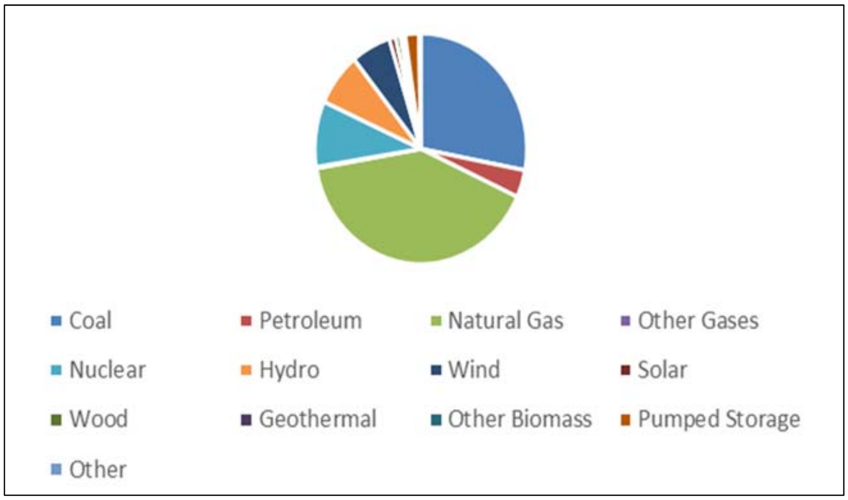
10.3.1 Introduction

Historically, coal units have been the marginal resource setting energy prices in PJM for a large majority of hours in the year. Low natural gas prices and the planned (or actual) retirements of coal plants are affecting which types of plants typically represent the marginal dispatched plant. In the first half of 2016, coal and natural gas prices were nearly equal in PJM's real-time energy market, with coal

by Electric Utilities, December 2014, https://www.epa.gov/sites/production/files/2014-12/documents/factsheet_ccrfinal_2.pdf.
[87] Maryland Department of Natural Resources, Power Plant Research Program, *Cumulative Environmental Impact Report 18 (Draft)*, 2016.

on the margin 44.4 percent of the time and natural gas 43.4 percent.[88] By comparison, coal was on the margin in PJM's real-time energy market 51.7 percent of the time in 2015 as compared to 35.5 percent for natural gas.[89] The increasing importance of natural gas is being seen nationally as well. Already, most installed capacity is natural gas (see Figure 10.8) and, other than renewables, natural gas represents most of the capacity that is presently planned (see Figure 10.9).[90,91] For these reasons, natural gas price projections have significant influence on the modeling results. The LTER includes alternative scenarios which explore the impacts of relatively high and also relatively low natural gas price projections.

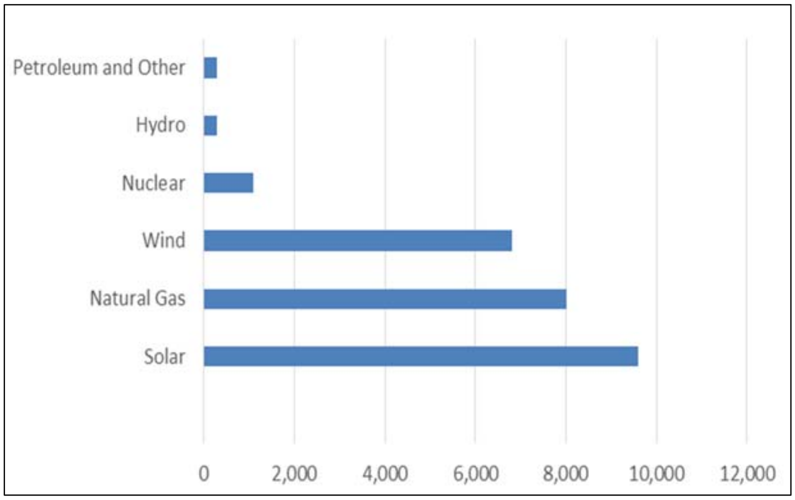
Figure 10.8 Existing Net Summer Electric Generating Capacity by Fuel Source in the U.S., 2014



Source: U.S. Energy Information Administration, *Electric Power Annual 2014*, Table 4.3, http://www.eia.gov/electricity/annual/pdf/epa.pdf.

[88] Monitoring Analytics, LLC, *2016 State of the Market Report for PJM – January through June*, August 11, 2016, www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016q2-som-pjm-sec3.pdf, 78.
[89] Monitoring Analytics, LLC, *2015 State of the Market Report for PJM*, March 10, 2016, www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2-sec3.pdf, 76.
[90] U.S. Energy Information Administration, *Electric Power Annual 2014*, http://www.eia.gov/electricity/annual/pdf/epa.pdf, Table 4.3.
[91] U.S. Energy Information Administration, Today in Energy, "Solar, natural gas, wind make up most 2016 generation additions," March 1, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=25172.

Figure 10.9 Planned Electric Generation Capacity in the U.S. for 2016 by Fuel Source

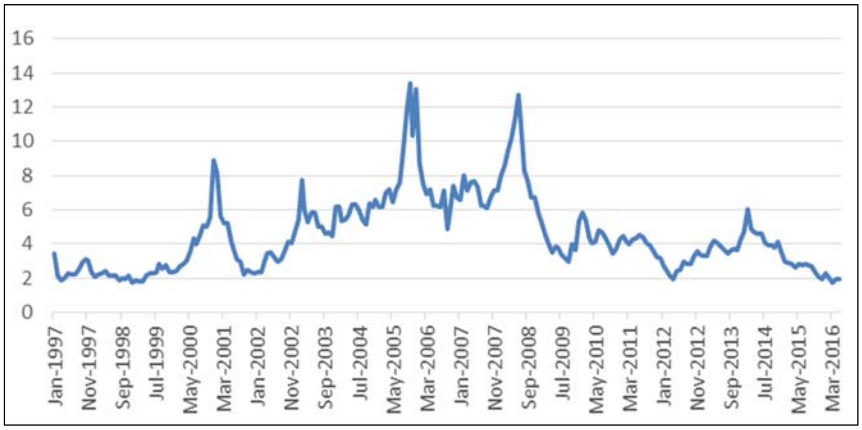


Source: U.S. Energy Information Administration, "Solar, Natural Gas, Wind Make Up Most 2016 Generation Additions," Today in Energy, March 1, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=25172.

Natural gas prices have historically been volatile, ranging from below $2/MMBtu earlier in 2016 to as much as $13/MMBtu in 2005 in nominal dollars (see Figure 10.10).[92] Supply- and demand-side factors contribute to this volatility. On the supply side, variations in natural gas storage, production, and imports, as well as delivery constraints, can contribute to natural gas price volatility. Variations in natural gas storage are particularly impactful because storage represents a physical hedge to demand for natural gas, and also because it is seen as an indicator of overall natural gas supply and demand. Therefore, natural gas storage levels either higher or lower than historical averages may place downward or upward pressure, respectively, on natural gas prices. Similarly, below-normal or above-normal withdrawals or injections to storage can also contribute to the price volatility of natural gas. For demand, temperature changes can affect short-term price volatility, either during cold snaps, causing an increase in natural gas consumption for heating, or heat waves, as incremental electric generation to meet higher demand is often fueled by natural gas. Overall economic activity also affects natural gas prices, as higher production in the commercial and industrial sectors contributes to an increase in natural gas demand. Natural gas serves as both a fuel and a feedstock for products such as fertilizers and pharmaceuticals. Economic growth can also increase personal disposable income, possibly leading to an increase in residential demand.[93]

[92] U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price, http://www.eia.gov/dnav/ng/hist/rngwhhda.htm.
[93] Erin Mastrangelo, *An Analysis of Price Volatility in Natural Gas Markets*, U.S. Energy Information Administration, Office of Oil and Gas, August 2007, https://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2007/ngprivolatility/ngprivolatility.pdf.

Figure 10.10 Monthly Average Natural Gas Spot Price at Henry Hub, 1997-2016 ($/MMBtu)

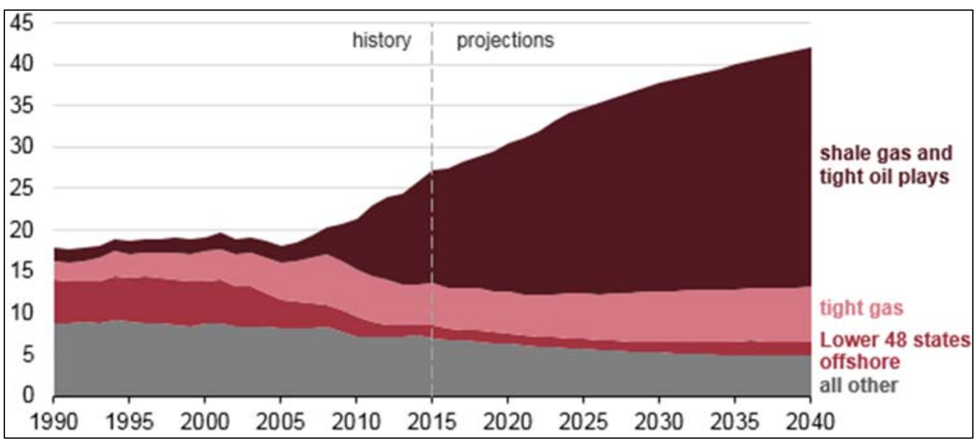


Source: U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price, http://www.eia.gov/dnav/ng/hist/rngwhhda.htm.

10.3.2 Natural Gas Supply and Storage

The emergence of shale gas in recent years has upended natural gas supply and prices in the U.S. Shale gas has grown from accounting for 1.6 percent of total U.S. dry natural gas production in 2000 to 48 percent in 2014, and is expected to grow to 69 percent by 2040 (see Figure 10.11).[94] Annual natural gas production in the U.S. is over 25 trillion cubic feet (TCF), the most ever in U.S. history.[95]

Figure 10.11 U.S. Natural Gas Production by Source, 1990-2040 (TCF)



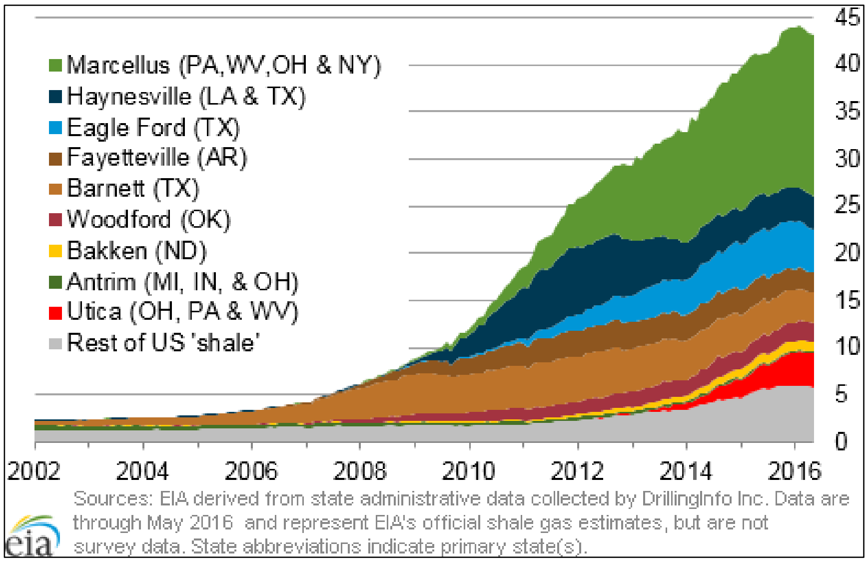
Source: U.S. Energy Information Administration, "Most Natural Gas Production Growth is Expected to come from Shale Gas and Tight Oil Plays," Today in Energy, June 7, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=26552.

[94] U.S. Energy Information Administration, Today in Energy, "Most natural gas production growth is expected to come from shale gas and tight oil plays," June 7, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=26552.

[95] U.S. Energy Information Administration, Office of Oil, Gas, and Coal Supply Statistics, *Natural Gas Annual 2014*, September 2015, http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf.

Figure 10.12 shows monthly dry shale gas production by region. The Marcellus shale gas resource, encompassing Pennsylvania, Ohio, New York, West Virginia, and Western Maryland, is the largest source of shale gas production in the United States.

Figure 10.12 Monthly Dry Shale Gas Production, 2002-2016 (Bcf/day)



Source: U.S. Energy Information Administration, *Natural Gas Weekly Update for Week Ending July 6, 2016*, http://www.eia.gov/naturalgas/weekly/.

The rise of shale gas led to large increases in natural gas production in the United States, with production growing every year since 2006.[96] Natural gas production and consumption both surged to record levels during the 2011 through 2014 period. Total U.S. natural gas imports have declined for seven straight years,[97] and EIA projects that the U.S. will be a net exporter of natural gas by late 2017.[98]

Record amounts of natural gas are also being put into storage. Typically, natural gas is bought and stored between April and October and withdrawn from November through March, as natural gas prices are higher during the latter period. A warmer-than-expected winter in 2015 led to lower levels of natural gas consumption than anticipated and resulted in unprecedented amounts of natural gas being stored underground. In its summer forecast, the Natural Gas Supply Association found that the amount of underground natural gas storage reached approximately 2.5 TCF in 2016 as compared to 1.5 TCF in

[96] U.S. Energy Information Administration, Today in Energy, "Growth in domestic natural gas production leads to development of LNG export terminals," March 4, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=25232.
[97] U.S. Energy Information Administration, Office of Oil, Gas, and Coal Supply Statistics, *Natural Gas Annual 2014*, September 2015, http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf.
[98] U.S. Energy Information Administration, "Short-Term Energy and Winter Fuels Outlook," Release date: July 12, 2016, http://www.eia.gov/forecasts/steo/report/natgas.cfm.

2015.[99] EIA projects that total stored natural gas will be at 4.2 TCF later in 2016, the highest amount ever recorded, representing 96 percent of total demonstrated natural gas storage capacity.[100]

10.3.3 Pipeline Capacity and Demand Impacts on Regional Natural Gas Prices

While there has been major growth in natural gas supply and storage, delivery constraints and demand, as mentioned previously, have also played a role in the price of natural gas, particularly on a regional basis. Natural gas pipeline capacity is an important consideration when projecting long-term electric power generation. The anticipation that there will be a significant increase in natural gas electricity generation forces the question of whether the current natural gas transmission infrastructure is capable of handling the associated rise in the demand, and if not, what the future needs will be in terms of additional natural gas pipeline capacity. In the context of the LTER, the availability of adequate natural gas pipeline capacity is critical since all new capacity constructed to meet load requirements is fueled by natural gas. Evaluating the issue of natural gas pipeline capacity requires consideration of seasonal demand, the locations of existing natural gas-fueled electric generation plants and natural gas sources, the current utilization of existing pipeline infrastructure, and whether there is sufficient natural gas demand to justify investment in additional infrastructure.

Seasonal demand for natural gas can vary significantly, with the greatest demand occurring during the winter season. The highest demand during the winter season occurs on the coldest days. An example of the impact that temperature (and location) can have on natural gas pricing, as influenced by demand as well as congestion, is presented in Figure 10.13. As the figure shows, constrained natural gas pipeline capacity in the Northeast during the winter drives up the delivered price of natural gas which in turn results in high electric energy prices.

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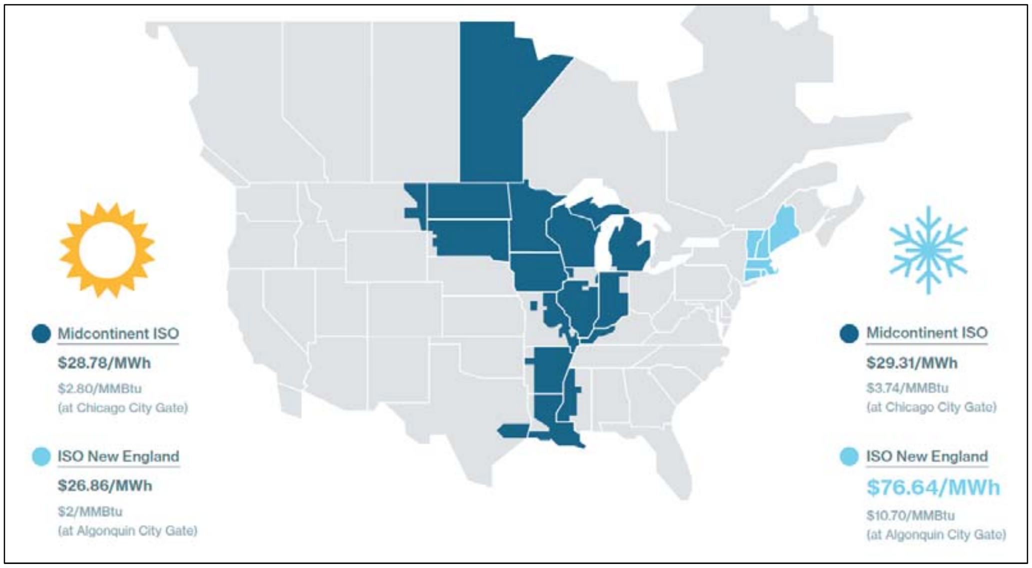
[99] Energy Ventures Analysis, Inc., *Outlook for Natural Gas Demand for the Summer of 2016*, May 26, 2016, http://www.ngsa.org/download/analysis_studies/Final-EVA-Summer-2016-Demand-Outlook-Report.pdf.
[100] U.S. Energy Information Administration, "Natural Gas Weekly Update," week ending June 22, 2016, http://www.eia.gov/naturalgas/weekly/.

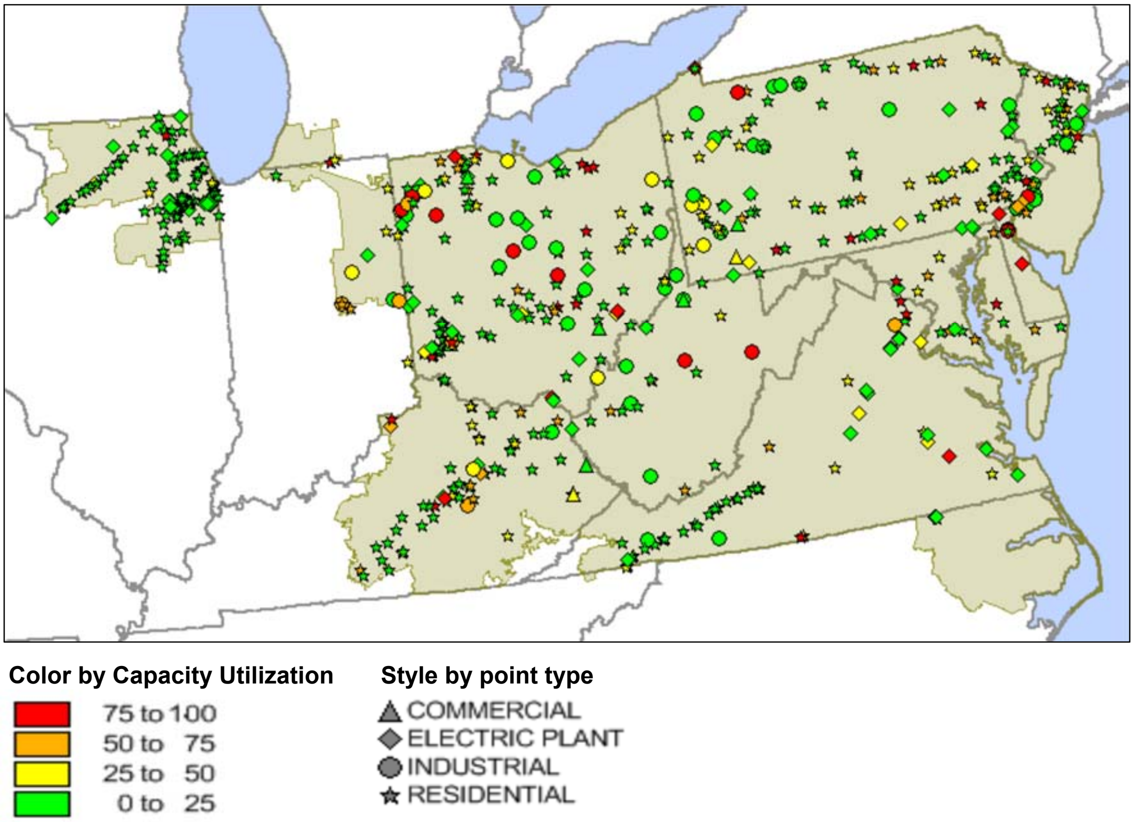
Figure 10.13 New England's Average Summer (June – August 2015) and Winter (December 2014 – February 2015) Prices for Real-time Wholesale Electricity Compared to Those in the Midwest



Source: Independent System Operator of New England, https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf, 24.

Consideration of existing pipeline capacity is also critical when evaluating natural gas infrastructure. An example of pipeline utilization is provided in Figure 10.14, which offers an analysis of pipeline usage within PJM on the day of maximum natural gas demand in 2014 during the Polar Vortex. Analyses such as Figure 10.14 are not comprehensive when it comes to determining the maximum capacity of current transmission line infrastructure; however, optimizing in-place pipeline use is essential to the efficient operation of the energy industry as a whole.

Figure 10.14 Natural Gas Delivery Point Capacity Utilization, 2014



Source: U.S. Department of Energy – National Energy Technology Laboratory, *Driving Innovation, Delivering Results*, Tribal leader Forum Series, August 18, 2015, http://energy.gov/sites/prod/files/2015/09/f26/SEAP_TLF.pdf, 46.

The process for obtaining approval to construct new natural gas transmission pipelines has become more difficult over time. FERC requites evidence of the demand for natural gas in order to approve a pipeline project, including signed capacity contracts even before any new pipeline construction takes place.

Over the coming five years, PJM should not face significant natural gas transmission pipeline constraints, with some exceptions on extremely cold winter days when there may be congestion and possible natural gas supply issues. These exceptions will translate to high natural gas prices for a period but, as stated in a report by the U.S. Department of Energy (DOE), "…a price spike may or may not provide sufficient revenue to justify additional infrastructure investment."[101] In addition, according to a FERC Staff analysis, "…new capacity additions should significantly relieve transportation constraints in

[101] U.S. Department of Energy, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015, http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf, 4.

[Ohio, West Virginia, Pennsylvania, New York, Boston, and the Mid-Atlantic] by 2019 if projects that are planned and under construction are approved and completed by the scheduled in-service dates."[102]

Although existing PJM natural gas pipeline capacity may exhibit periodic constraints, it appears to have some underutilized areas. In order to optimize the operation of existing natural gas pipeline capacity, PJM has begun to take a more proactive approach. In 2015, PJM initiated a cooperative arrangement with natural gas companies to share data in order to be better prepared for periods of high natural gas demand, i.e., extremely cold winter days.

While the short-term outlook for PJM suggests that the situation is manageable, the long-term outlook may prove more challenging. An example of an area that is struggling with natural gas constraints is New England. Due to natural gas supply congestion, New England has experienced shortages of natural gas, primarily in the winter. These shortages lead to high natural gas prices, as well as the use of more pollution-intensive fuel sources such as coal and oil as substitutes.

To alleviate these issues, additional pipeline capacity has been proposed, but these proposals have encountered substantial obstacles. The first challenge is related to the policy, most notably stemming from a controversial finding by the Massachusetts' Attorney General's office that no additional capacity is needed,[103] and a formal ruling by the Massachusetts Supreme Judicial Court that independent power producers could not generate revenue from ratepayers to cover additional pipeline costs.[104]

A second major obstacle is environmental concerns. Arguments on the environmental front are two-pronged, including concern over the increased reliance on natural gas and also concern about the environmental implications of the construction and operation of these new pipelines. Some New England residents are lobbying diligently against proposed pipelines, bringing attention to the projects through rallies, legal filings, public meetings, and the media. In an article in the *Hartford Courant* about opposition to new natural gas pipeline development, the arguments of the environmental groups are described as follows:

> *Opponents insist that new pipelines will only increase the region's long-term dependence on a fossil fuel that will continue to contribute to greenhouse gas emissions linked to climate change. They warn that investing billions in gas pipelines will take money from alternative energy projects and commit New England to more fossil fuel use for*

[102] U.S. Department of Energy, *State of the Markets Report 2015*, Item No. A-3, March 17, 2016, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2015-som.pdf, 5.
[103] Attorney General of Massachusetts, "AG Study: Increased Gas Capacity Not Needed to Meet State's Electric Reliability Needs," November 18, 2015, http://www.mass.gov/ago/news-and-updates/press-releases/2015/2015-11-18-electric-reliability-study.html.
[104] UtilityDIVE, "Massachusetts court bars electric utilities from charging ratepayers for gas pipeline construction," August 18, 2016, http://www.utilitydive.com/news/massachusetts-court-bars-electric-utilities-from-charging-ratepayers-for-ga/424694/.

decades, leaving gas and electricity consumers to pay off the massive cost of building the pipelines.[105]

Two major natural gas pipeline proposals were the focus of the article—the Northeast Energy Direct (NED) project financed by Kinder Morgan, and the Access Northeast Project, jointly developed by Spectra, Eversource Energy, and National Grid. Since publication of this article in January 2016, Kinder Morgan formally withdrew the NED FERC application. The Access Northeast Project is not anticipated to proceed due to Eversource Energy's and National Grid's withdrawal following the Massachusetts ruling against ratepayer funding for natural gas pipeline projects. These projects exemplify the difficulties facing future natural gas pipeline projects and may foreshadow the obstacles that will affect natural gas pipeline expansion in Maryland and other parts of PJM.

10.3.4 Current Natural Gas Market Status

On a national basis, increases in natural gas supply and lower-than-expected demand caused natural gas prices to decline significantly in late 2015 and early 2016. Even before this time, federal environmental requirements, such as the EPA's MATS rule, led to greater growth in demand for natural gas from the electric power industry. Since 2011, coal power capacity has decreased by over 38 GW, while combined cycle and combustion turbine natural gas plant capacity has increased by over 27 GW. An additional 19 GW of coal power capacity is expected to retire by 2017, while another 19 GW of combined cycle natural gas plant capacity is projected to come on-line. The retirement of coal-fired capacity and the addition of new natural gas capacity accounts for 70 percent of the higher demand for natural gas from the electric power industry. Fuel switching, where natural gas generation displaces other forms of generation, particularly coal, accounts for the remaining 30 percent.[106]

Natural gas spot prices at Henry Hub have increased relative to the historical lows earlier in 2016, increasing to $2.75/MMBtu as of early July 2016.[107] Both ABB and EIA project that natural gas prices will continue to rise because of greater demand, declining production, and increases in exports.[108]

10.4 PJM Capacity Market Reforms

In order to ensure long-term electricity reliability, PJM requires load serving entities (LSEs), such as Baltimore Gas and Electric Company (BGE) and Potomac Electric Power Company (Pepco), through their Standard Offer Service (SOS) arrangements, to have sufficient capacity to cover their coincident load plus a reserve margin. To help suppliers that do not own sufficient generation, PJM conducts an

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105 Hartford Courant, "Gas Pipeline Plans Face Stiff Opposition," January 18, 2016, http://www.courant.com/news/connecticut/hc-new-gas-pipeline-battles-20160117-story.html.
106 Energy Ventures Analysis, Inc., *Outlook for Natural Gas Demand for the Summer of 2016*, May 26, 2016, http://www.ngsa.org/download/analysis_studies/Final-EVA-Summer-2016-Demand-Outlook-Report.pdf.
107 U.S. Energy Information Administration, "Natural Gas Weekly Update," week ending July 6, 2016, http://www.eia.gov/naturalgas/weekly/.
108 U.S. Energy Information Administration, *Annual Energy Outlook 2016*, August 2016, http://www.eia.gov/forecasts/aeo/pdf/0383(2016).pdf.

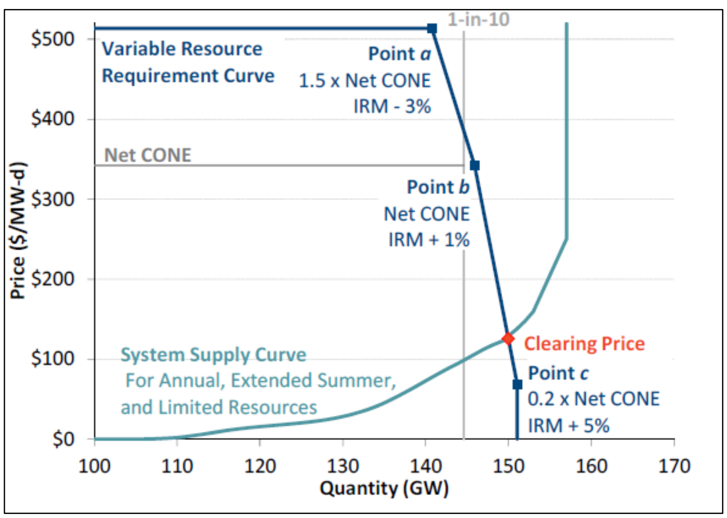
annual auction (and several smaller, supplemental auctions) where the LSEs purchase capacity three years in advance, based on their predicted loads in their service territories. The auction's market-clearing price lies at the intersection of an administratively defined capacity demand curve and a market-generated capacity supply curve.

For each locational delivery area (LDA) within its footprint, PJM develops a segmented downward-sloping demand curve known as the Variable Resource Requirement (VRR). As shown in Figure 10.15, the curve is anchored at point "b" where:

- The quantity (on the X axis) is 1 percent above the installed reserve margin (IRM) needed to maintain reliability during a 1-in-10 years loss-of-load event; and
- The price (on the Y axis) is equal to Net Cost of New Entry (Net CONE), i.e., the estimated fixed cost of entry for a new combustion turbine *net* of revenues the turbine would receive for producing energy and providing ancillary services.

Points "a" and "c" are also based on Net CONE and the IRM, as shown below. Use of the VRR—instead of a purely vertical demand curve—is intended to reflect the incremental value of capacity at points beyond the IRM, avoid extreme price volatility for capacity suppliers, and mitigate the potential exercise of market power by moderating the change in price produced by a change in supply.

Figure 10.15 PJM Capacity Supply and Demand
(Example: 2014/15 Base Residual Auction)



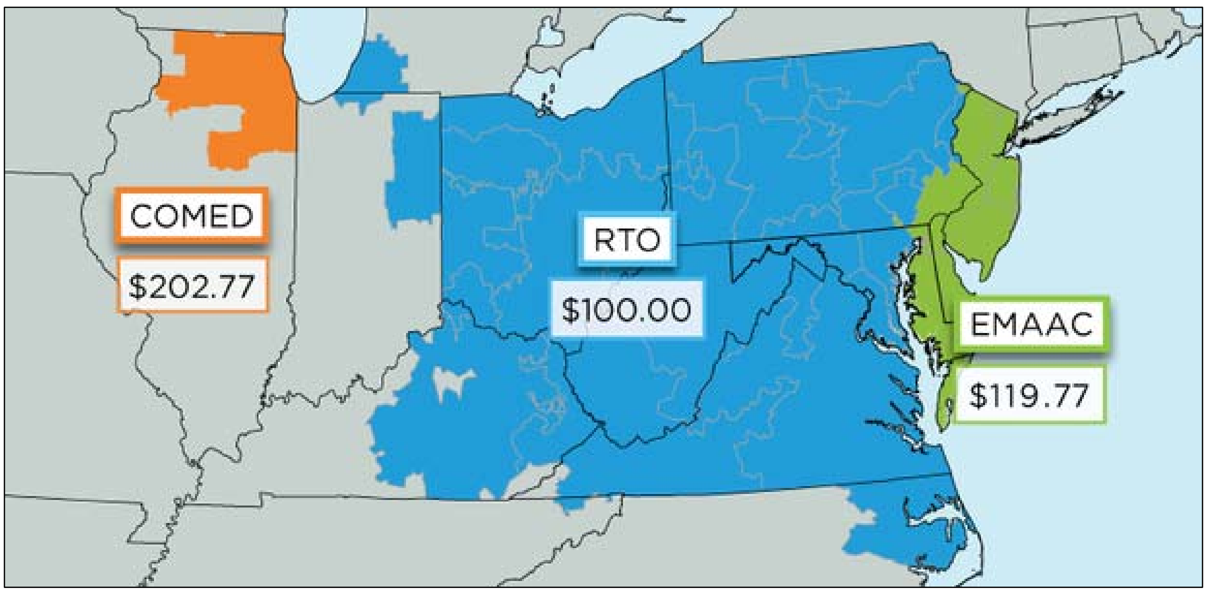
Source: Johannes Pfeifenberger, Samuel Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli, *Third Triennial Review of PJM's Variable Resource Requirement Curve* (The Brattle Group, 2014), http://www.brattle.com/system/news/pdfs/000/000/658/original/Third_Triennial_Review_of_PJM's_Variable_Resource_Requirement_Curve.pdf, 4.

The supply curve is obtained by PJM through the capacity bids offered by capacity owners. Eligible capacity includes existing plants, new plants, plants upgrades, energy efficiency projects, demand-side resources (e.g., load response), and qualified transmission upgrades. The capacity offers resulting from the auction are stacked (lowest cost to highest cost), resulting in an upward-sloping supply curve.

Note that a substantial portion of the capacity supply curve is associated with a zero, or very low, price. This is because certain capacity owners operate as price-takers, that is, they are willing to receive the market-clearing price regardless of what that price is. By bidding a zero (or near zero) price, they assure that their resource clears the market and is therefore eligible to receive capacity payments.

PJM's auction produces regionally-specific clearing prices in order to influence decisions on whether and where to construct new power plants or pursue other capacity projects. Figure 10.16 shows the results of PJM's auction for the delivery year starting June 1, 2019, with certain LDAs varying from the rest of the Regional Transmission Organization (RTO) due to local transmission constraints. The ABB Model simulates the regional nature of PJM's capacity market in order to determine when and where it should build/retire non-renewable capacity over the LTER's study period.

Figure 10.16 PJM Capacity Prices for Delivery Year 2019/2020 ($/MW-day)



Source: PJM, *PJM Capacity Auction Continues to Attract New Resources at Competitive Prices,* http://www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160524-rpm-auction-results-for-2019-20-news-release.ashx.

In the May 2016 auction, PJM continued phasing in market reforms prompted by the Polar Vortex of 2014, when fuel shortages—caused by natural gas pipeline interruptions, frozen coal piles, and snowed-in fuel delivery trucks—disabled 22 percent of PJM's capacity. In order to compel capacity providers to conduct better contingency planning (such as securing firm fuel supplies), PJM has created a new product called capacity performance (CP). Under this product, capacity must be available at all times or the owners may face stiff monetary penalties. In June 2016, CP represented over 80 percent of the capacity that cleared in PJM's auction. In 2017, all suppliers will be required to meet CP requirements.[109] However, in July 2016, a coalition of environmental groups filed a lawsuit with the D.C. Circuit to challenge PJM's new CP rules. The litigants claim that the new rules unfairly and counter-productively limit participation by demand response and renewable energy resources.

10.5 EmPOWER Maryland

10.5.1 Background

After the restructuring of Maryland's electricity industry in 1999, utility-based energy efficiency programs shrank and electricity usage increased at a faster rate than in the 1990s. By the mid-2000s, projections for continued growth were raising concerns about strain on the electric system and potential brownouts. In 2008, the Maryland Legislature enacted the EmPOWER Maryland Efficiency Act (Act),[110] which is designed to reduce Maryland's electricity use. The Act set a State goal of achieving a 15 percent reduction in per capita electricity consumption by 2015, compared to 2007 levels. Electric utilities were assigned responsibility for achieving 10 percentage points of the 15 percent reduction, and the rest was to be achieved independent of utilities. The Act also set a goal of a 15 percent reduction in per capita peak electricity demand by 2015, compared to 2007 levels. The utilities were responsible for the entirety of the demand reduction goal. Only electric utilities with more than 250,000 customers were required to offer programs to contribute towards the goals.

The Act established that the PSC would be responsible for monitoring progress on these goals and submitting, in consultation with the Maryland Energy Administration (MEA), annual progress reports to the Maryland General Assembly. There were also additional stipulations in the Act, one of which was that the MEA, in consultation with the PSC, would determine whether electricity consumption and peak demand reduction targets should be modified beyond 2015. This resulted in the MEA submitting a final report to the General Assembly with recommendations to extend the energy efficiency goals beyond 2015.

From 2009 through 2014, EmPOWER programs were offered by five utilities: BGE, Pepco, Delmarva Power & Light Company (DPL), Potomac Edison (PE, formerly Allegheny Power), and the Southern Maryland Electric Cooperative (SMECO). In 2011, the PSC ordered the companies to transition their low-income energy efficiency programs to the Maryland Department of Housing and Community Development (DHCD).[111] In 2014, the PSC approved a set of natural gas energy efficiency and conservation programs, which led Washington Gas Light (WGL) to begin offering natural gas energy efficiency programs in 2015.

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[109] PJM, *2019/2020 RPM Base Residual Auction Results*, May 24, 2016, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.
[110] §7-211 of the Public Utilities Article, *Annotated Code of Maryland*, http://mgaleg.maryland.gov/WEBMGA/frmStatutesText.aspx?article=gpu&section=7-211&ext=html&session=2016RS&tab=subject5.
[111] Maryland Public Service Commission Order 84569, dated December 2011.

A summary of the electric utilities' individual goals for 2015 is provided in Table 10.8.

Table 10.8 EmPOWER Maryland 2015 Goals

Utility	MWh	MW
BGE	3,593,750	1,267
DPL	143,453	18
PE	415,228	21
Pepco	1,239,108	672
SMECO	83,870	139
Total	**5,475,409**	**2,117**

Source: Maryland Public Service Commission Mail Log Nos. 182966, 182975, 189920, 182974, and 182937. There is a mail log search on the Commission's website: www.psc.state.md.us.

10.5.2 Program Offerings

The Maryland utilities have developed portfolios of energy efficiency programs, demand response programs, and other energy-saving programs, such as dynamic pricing. Some of these programs are described in greater detail below.

Energy Efficiency Programs

Energy efficiency programs aim to reduce both electricity usage (MWh) and peak demand (MW) among residential and commercial/industrial (C&I) customers. The five electric utilities have utilized the following residential programs: (1) energy efficient lighting; (2) appliance rebates and recycling; (3) quick home energy check-up; (4) home performance with Energy Star; (5) new construction; (6) heating and cooling; and (7) behavioral/home energy reports. Additionally, SMECO has initiated a smart thermostat pilot program.

DHCD offers a program where qualified limited income customers have the opportunity to weatherize their homes at no additional cost. While limited-income customers may participate in any of the EmPOWER Maryland programs, to qualify for the DHCD weatherization program, a customer's annual household income must be equivalent to or less than 200 percent of the federal poverty level. Participants in the DHCD weatherization program can receive energy efficient lighting; heating, ventilation and air conditioning (HVAC); insulation; and refrigerators.

With regard to the C&I programs, BGE, DPL, and Pepco all offer: (1) small business solutions; (2) multi-family (i.e., apartment building) programs; (3) retro-commissioning; (4) prescriptive/existing buildings programs; (5) custom programs; and (6) combined heat and power (CHP). PE offers a small business program, a prescriptive/existing buildings program, and a custom program. SMECO offers a small business program, a prescriptive/existing buildings program, custom programs, and a multi-family program. DPL and Pepco also have a program for new commercial buildings, while BGE offers benchmarking and analytical tools.

Demand Response Programs

BGE, Pepco, DPL, and SMECO offer direct load control programs via devices (outdoor switches on air conditioners or programmable thermostats) to reduce the customer's load at peak times. The first three utilities also offer peak energy savings credits, which are given to customers who reduce their consumption at peak times on select days. PE does not offer demand response programs, as the programs were not found to be cost-effective within the PE service territory.

Other Programs

Pepco, DPL, and SMECO each have Conservation Voltage Reduction (CVR) programs which reduce the voltage at affected substations by 1.5 percent by using Advanced Metering Infrastructure (AMI) systems to verify that customer voltages are maintained within specified limits. CVR leads to both reduction of energy use and of peak demand.[112] In addition, DPL, Pepco, and PE each have a High Efficiency Transformer Program, which leads to energy use and peak demand reductions as older transformers are replaced with newer, more efficient models.

BGE, DPL, and Pepco each offer dynamic pricing programs for residential customers through their respective AMI systems. On energy savings days, identified by the utilities, customers that reduce energy usage can earn $1.25 per kWh saved.

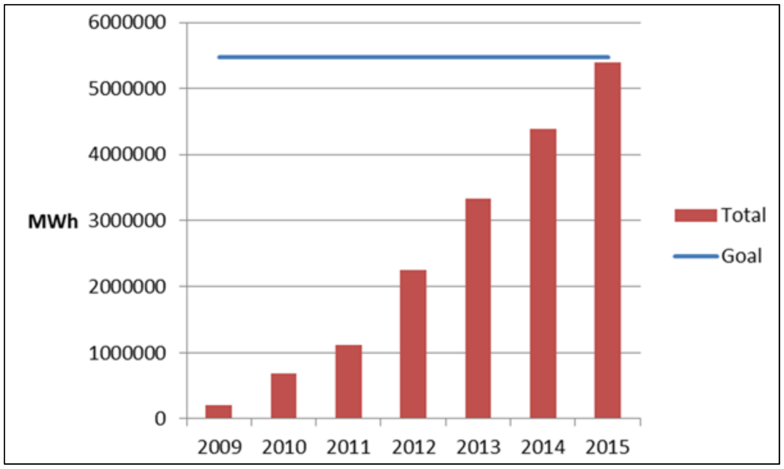
DPL and Pepco also offer their customers a variety of Energy Management Tools (EMTs), as part of their AMI systems. These EMTs provide residential and small commercial customers with more detailed information about their electricity use and help them to make better informed choices with respect to their electricity consumption.

10.5.3 Achievement of 2015 Goal

Collectively, the five EmPOWER Maryland utilities achieved 99 percent of the energy savings goal and 100 percent of the demand reduction goal for 2015. As noted in Figure 10.17, the savings were slow to accumulate during the first three years the Act was in effect. However, beginning in 2012, the energy savings increased significantly, by at least one million MWh of additional savings each year.

[112] Due to the fact that power on the grid must have enough voltage to make it to the last house on a distribution line, utilities typically increase the voltage from 114V, the ideal voltage, to 126V. Through the use of smart meters, utilities can reduce the amount of electricity that is lost between the substation and a home or business by lowering the voltage levels, while still ensuring safe and reliable delivery of electricity.

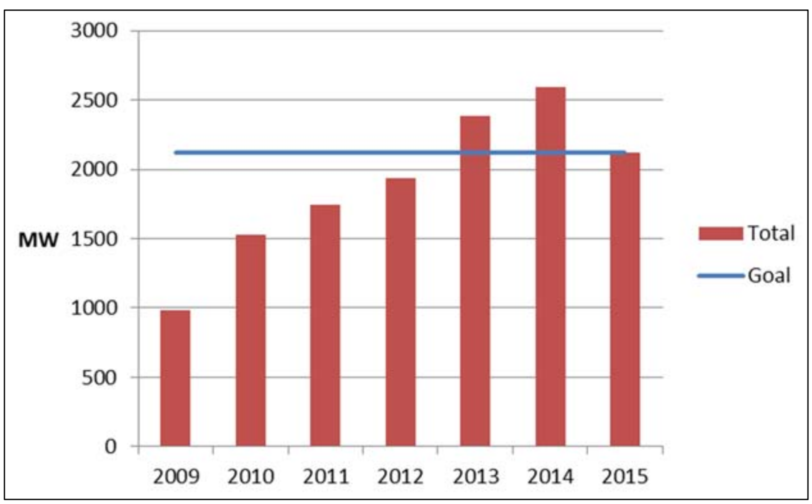
Figure 10.17 Total EmPOWER Maryland Annual Energy Savings (MWh)



Source: Individual Utility EmPOWER Maryland Semi-Annual Filings

Figure 10.18 indicates that, collectively, the utilities surpassed the demand reduction targets in 2013 and 2014. However, the decrease in demand reduction in 2015 was the result of some participants opting out of demand response cycling programs and fewer dynamic pricing events by BGE, DPL, and Pepco. Despite the decrease in savings, the utilities continued to achieve 100 percent of the demand response goal.

Figure 10.18 Total EmPOWER Maryland Annual Demand Reduction (MW)



Source: Individual Utility EmPOWER Maryland Semi-Annual Filings

10.5.4 Beyond 2015

In July 2015, the PSC concluded that there was still a substantial potential for cost-effective energy efficiency savings in Maryland.[113] Commission Order No. 87082 established energy efficiency goals for the EmPOWER Maryland electric utilities beyond 2015, as presented in Table 10.9. The Commission adopted an annual incremental gross energy savings reduction of 2 percent from each utility's weather-normalized gross retail sales baseline, which will be implemented during the 2018 through 2020 program cycle.[114] The Commission stated that utilities should continue to use the demand reduction targets established for program years 2016 and 2017, and declined to establish specific goals for natural gas or low-income programs.

The Commission also issued a 2017 goal that is intended to ramp utilities up to the formal 2018-2020 program cycle. In 2017, each utility that is *not* forecasted to achieve its 2018-2020 targets must increase its forecasted 2016 plan savings by 0.2 percent in 2017. Based upon the 2017 goals, SMECO is the only utility that is projected to achieve at least a 2 percent energy reduction.

Table 10.9 EmPOWER Maryland Annual Energy Efficiency Goals (MWh)

Utility	2016	2017
BGE	565,933	631,138
DPL	66,931	76,060
PE	73,434	88,557
Pepco	237,311	268,599
SMECO	75,900	78,284
Total	**1,019,509**	**1,142,638**

Source: Maryland Public Service Commission Order No. 87082.

10.5.5 Factors/Barriers That Influence EmPOWER Maryland Savings

Changes to PJM markets, economic growth, environmental regulations, and natural gas prices could affect the savings that the EmPOWER Maryland efforts can generate going forward. Each of these could have either positive or adverse impacts on the program's efforts.

1. To date, the electric utilities have bid demand and energy savings into the PJM capacity market to generate revenue streams used to offset program costs. However, recent proposed rule changes at PJM will limit the level of savings that can be bid-in, reducing the economic viability of programs such as demand response. The new rule allows for demand response to be offered as a base capacity resource through the 2019/2020 auction. However, beginning in auction year 2020/2021, capacity bids must be available

[113] Maryland Public Service Commission Order No. 87082, dated July 16, 2015.
[114] For the 2018-2020 program cycle, the 2016 weather-normalized gross retail sales will serve as the baseline.

year-round, not just in the summer like many of the demand response products. PJM did form a Seasonal Capacity Resources Senior Task force but, as of September 2016, no recommendations have been released. If a seasonal product is not available, demand response programs would need to be aggregated with other products such as wind and solar to be considered year-round.

2. Increased economic growth could increase load, which can adversely impact a utility's ability to achieve the 2 percent energy reduction. Conversely, positive economic growth could increase the number and size of commercial sector projects.

3. Changes to environmental regulations and adoption of more stringent codes and standards within the State could adversely affect the cost-effectiveness of the energy efficiency programs. Energy savings under EmPOWER Maryland are calculated as the incremental energy savings between a baseline measure and the efficient measures. When regulations and codes and standards are strengthened, it reduces the incremental energy savings between the baseline and efficient measure, thus shrinking the cost savings associated with a given measure.

4. Changes in natural gas prices can affect the savings achieved by energy efficiency programs, which in turn affects which programs are cost-effective. Lower natural gas prices, for example, can reduce the number of energy efficiency programs that are cost-competitive.

10.6 Smart Grid Technology and Its Status in Maryland

A smart grid involves a network of two-way communications that connect 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, and largely self-balancing to ensure reliability in real-time. The basis of a smart grid is the implementation of AMI, also known as smart meters. The implementation of smart meters provides a multitude of benefits including, but not limited to, communication of outages which may reduce response time and allow for the efficient deployment of repair crews, remote reads for billing, and the ability to provide dynamic pricing programs allowing customers to react to time-of-use (TOU) rate programs. Smart grid technologies are an important trend, and as noted below, costs for smart grid are being rolled into rates. The modeling tools used in the LTER do not have the fidelity to address smart grid technologies and the associated costs and improvements in smart grid technologies over time. Therefore, these technologies are not directly modeled in the LTER.

BGE, DPL, and Pepco submitted individual requests to deploy AMI throughout their respective service territories with the Maryland PSC in 2009.[115] The PSC held hearings throughout 2009 and 2010 regarding the approval for the implementation of smart meters. Prior to approval, BGE and Pepco were awarded federal funding from the U.S. Department of Energy (DOE) of $200 million and $105 million, respectively.[116] On August 13, 2010, the PSC approved AMI implementation for BGE and Pepco.[117] DPL, at the time, was required to file an updated AMI business case. The PSC issued approval for DPL's implementation of AMI in May 2012.[118] In June 2012, SMECO filed a request with the PSC to implement AMI and was given approval one year later.[119,120] At this time, PE has not filed plans to implement AMI.

As part of each approval, the PSC predicated the recovery of AMI costs on a utility's ability to deliver a cost-effective AMI project. To monitor implementation, the PSC required each utility to file quarterly reports that detailed the number of meters installed, expenditures, incremental benefits realized, effectiveness of customer education plans, and customer privacy and cyber-security effects. In addition to the quarterly reports, in January 2013, the PSC established provisions and costs for customers that opt out of receiving a smart meter.[121] Customers that choose to opt out of receiving a smart meter will pay a one-time, up-front fee, as well as a monthly ongoing charge to compensate the utility for the added expense.[122]

BGE, DPL, and Pepco have completed the installation of smart meters in their respective territories; SMECO's installation is not yet complete. On November 9, 2015, BGE filed with the PSC to recover costs associated with the implementation of its AMI project.[123] Pepco filed for recovery of its AMI costs in a base rate case in April 2016.[124] As of this writing, both cases are pending before the PSC.

10.7 Electric Reliability in Maryland

There are two levels to electric reliability: supply and delivery. In Maryland, the North American Electric Reliability Corporation (NERC), ReliabilityFirst Corporation (RFC) and PJM Interconnection, LLC (PJM) are responsible for supply reliability, while PJM and the Maryland PSC are responsible for delivery reliability.

NERC and RFC establish reliability standards and guidelines for PJM. Using those standards and guidelines, PJM calculates a reserve requirement or reserve margin for the entire RTO. The reserve requirement is the level of installed reserves needed to maintain reliability with a Loss of Load

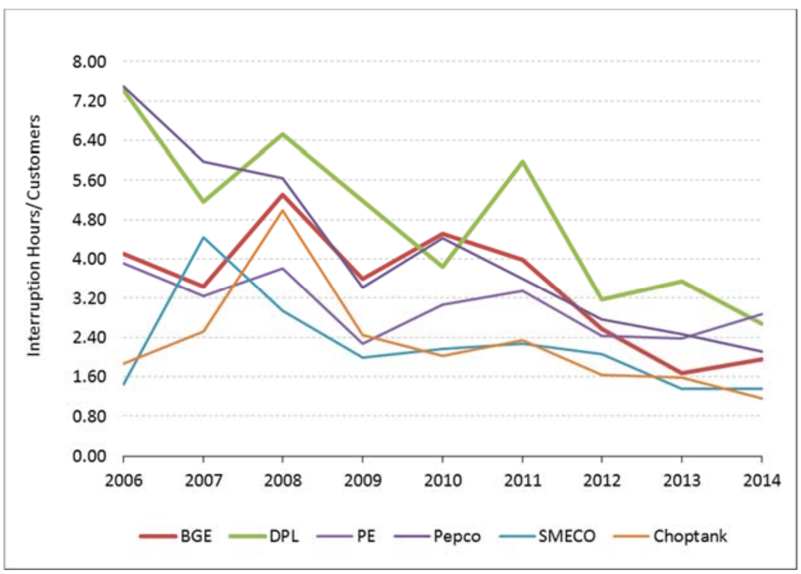
115 Maryland Public Service Commission Docket Nos. 9207 and 9208.
116 U.S. Department of Energy, "Recovery Act Selections for Smart Grid Investment Grant Awards – by State," November 2011, http://www.energy.gov/sites/prod/files/SGIG%20Awards%20%20By%20State%202011%2011%2015.pdf.
117 Maryland Public Service Commission Order Nos. 83571 (Pepco) and 83531 (BGE).
118 Ibid., Order No. 84890.
119 Ibid., Docket No. 9294.
120 Ibid., Order No. 85678.
121 Ibid., Order No. 85294.
122 Ibid., Docket No. 86200.
123 Ibid., Docket No. 9406.
124 Ibid., Docket No. 9418.

Expectation (LOLE) to occur once every ten years for the entire PJM RTO.[125] The reserve margin is a built-in modeling constraint for the Reference Case and all alternative scenarios. In addition, PJM is responsible for ensuring the reliability of high-voltage electric transmission for the entire PJM footprint, which is a form of delivery reliability.[126] Although neither of these responsibilities provides PJM with the authority to mandate the operation of power plants, it does require power plants to file deactivation requests with PJM to allow for system changes and upgrades as needed to keep the system stable.

At the distribution level, the PSC ensures that distribution systems throughout the State comply with reliability and service standards codified in the Code of Maryland Regulations (COMAR). COMAR outlines the system-wide reliability standards, vegetation management standards, electric feeder standards, and reporting requirements including annual performance reports. Maryland's distribution system reliability is measured using two reliability indices: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The SAIDI measures the average interruption time for a customer and the SAIFI measures the average number of times a customer experiences an outage during a one-year period.

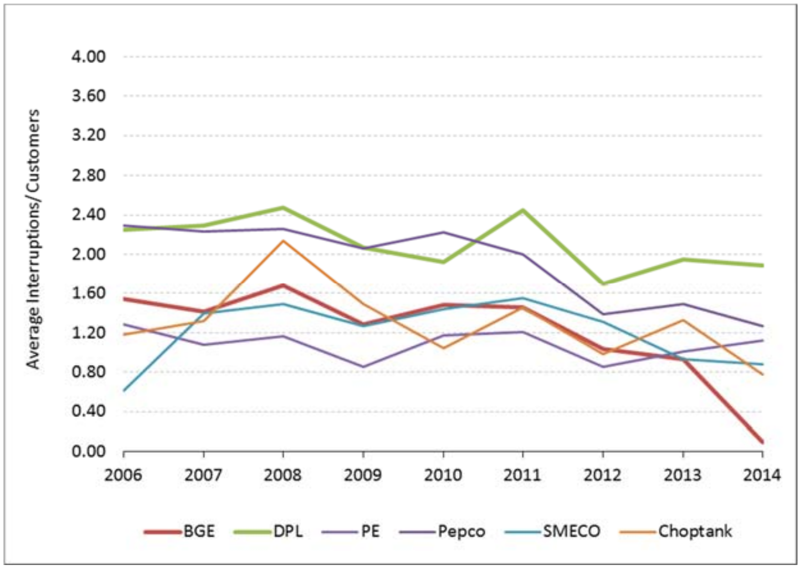
Between 2006 and 2014, the SAIDI and SAIFI for the major electric utilities in Maryland decreased over time, indicating an overall improvement in reliability. The utilities with the highest number of outages and duration time in 2006 were DPL and Pepco, and the utilities with the lowest number were BGE and SMECO. Over time, the difference between the SAIDI and SAIFI among the utilities decreased; however, the SAIFI for DPL has remained notably higher in 2014 (see Figure 10.19 and Figure 10.20).

Figure 10.19 Maryland Utility SAIDI, 2006-2014



[125] PJM, *"PJM Manual 20: PJM Resource Adequacy Analysis,"* Resource Adequacy Planning, August 1, 2015, http://www.pjm.com/~/media/documents/manuals/m20.ashx.
[126] PJM, "Explaining Power Plant Retirements in PJM," PJM Learning Center, http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx.

Figure 10.20 Maryland Utility SAIFI, 2006-2014



In response to Maryland Senate Bill (SB) 692, "Maryland Electricity Service Quality and Reliability Act – Safety Violations," the PSC initiated Rule Making 43 in January 2011 to consider revisions to reliability and service quality standards for electric companies under COMAR.[127] As part of the rulemaking, the PSC proposed changes to define a major event interruption as well as the requirements of annual operating and maintenance programs. The most significant of the proposed regulations related to the establishment of vegetation management requirements. In addition to setting vegetation management protocols, the proposed regulations required each utility to file an annual report describing their progress in terms of miles of trimming completed and annual expenditures on vegetation management. On August 17, 2012, the PSC adopted the proposed regulations.

In 2015, the PSC issued a notice for a rulemaking session regarding the utilities' proposed 2016-2019 annual SAIDI and SAIFI reliability standards and proposed modifications to the regulations.[128] Following several hearings, the PSC adopted the proposed regulations that establish 2016-2019 SAIDI and SAIFI reliability standards,[129] as shown in outage minutes in Table 10.10.

[127] Notice of Initiating Rule Making, Notice of Comment Period, and Notice of Rule Making Session dated January 12, 2011, Maryland Public Service Commission Rule Making 43.
[128] Notice of Rule Making Session dated March 3, 2015, Maryland Public Service Commission Rule Making 43.
[129] Maryland Public Service Commission Mail Log No. 175300.

Table 10.10 Utility Reliability Requirements, 2015-2019 (SAIDI and SAIFI)[1],[2]

		2015	2016	2017	2018	2019
BGE	SAIDI (outage)	206.40	192.00	177.60	162.60	142.20
	SAIFI (outages/year)	1.39	1.33	1.27	1.22	1.08
Choptank	SAIDI (outage)	154.80	152.40	151.20	149.40	148.20
	SAIFI (outages/year)	1.39	1.38	1.37	1.37	1.36
DPL	SAIDI (outage)	157.20	151.00	145.00	139.00	125.00
	SAIFI (outages/year)	1.46	1.41	1.36	1.32	1.22
PE	SAIDI (outage)	167.40	165.00	162.60	160.20	153.00
	SAIFI (outages/year)	1.08	1.08	1.08	1.08	1.08
Pepco	SAIDI (outage)	143.40	125.00	116.00	109.00	101.00
	SAIFI (outages/year)	1.49	1.25	1.14	1.04	0.95
SMECO	SAIDI (outage)	139.20	138.00	136.80	136.20	135.60
	SAIFI (outages/year)	1.36	1.35	1.34	1.33	1.32

[1] COMAR 20.50.12.02

[2] In the 2015 Rule Making session, the PSC established that going forward, SAIDI would be reported in minutes.

In addition to the reliability requirements set forth in COMAR, DPL and Pepco have more stringent SAIDI and SAIFI requirements as part of the Exelon Corporation merger with Pepco Holdings, Inc. In its May 15, 2015 Commission Order, the PSC set forth annual SAIDI and SAIFI targets for both utilities with penalty payments (see Table 10.11 and Table 10.12).[130]

Table 10.11 Exelon/Pepco Merger Annual SAIDI and SAIFI Commitments[1]

		2016	2017	2018	2019	2020
DPL	SAIDI (outage)	151	145	139	105	97
	SAIFI (outages/year)	1.41	1.36	1.31	1.17	1.12
Pepco	SAIDI (outage)	124	116	101	96	91
	SAIFI (outages/year)	1.05	0.99	0.95	0.92	0.9

[1] Maryland Public Service Commission Order No. 86990, 61.

Table 10.12 Reliability Non-Compliance Penalty[1]

	2016	2017	2018	2019	2020
DPL	--	--	$0.5 Million	$1 Million	$3 Million
Pepco	--	--	$2 Million	$3 Million	$6 Million

[1] Maryland Public Service Commission Order No. 86990, 62.

The modeling conducted for the Reference Case and all alternative scenarios implicitly assumes that all reliability requirements imposed by NERC, RFC, PJM, and the Maryland PSC are met. Additionally, PJM's capacity requirements that relate to the reliability requirements of NERC and RFC are used directly in the modeling. These requirements are used to determine the need for new power plants which are consequently "constructed" by the model to avoid reliability violations.

130 Maryland Public Service Commission Order No. 86990, dated May 15, 2015, p. 61.

10.8 Climate Change in Maryland

Over the course of the last several years, the concept of anthropogenic climate change has become widely accepted. Federal, state, and local governments have implemented polices to reduce GHG emissions to combat the rate at which the climate is changing. In Maryland, the GGRA was signed into law in 2009 and required the State to achieve a minimum 25 percent reduction in statewide GHG emissions from 2006 levels by 2020 while having a positive impact on the economy, especially maintaining and expanding the current work force. In 2016, the Maryland Legislature modified the law to reflect a 40 percent reduction by 2030, still based on 2006 levels.

To achieve the reduction, the GGRA required the MDE to develop a statewide GHG reduction plan: Maryland's Greenhouse Gas Reduction Act Plan (GGRA Plan)[131] which was published in October 2013. Subsequently, the GGRA required an update to the Plan by October 1, 2015. The 2015 GGRA Update reviewed progress towards the 2020 emissions goal and found that Maryland was on track to meet, and possibly exceed, the current goal, noting the caveat that while the GGRA Plan strategies have resulted in emissions reductions, some of this progress was due to changing transportation behaviors and energy markets.[132] As stated above, the goal has since been increased to 40 percent below 2006 levels by 2030.

According to the GGRA Plan, Maryland is particularly vulnerable to climate change impacts due to its coastal characteristics and the agricultural nature of the State. As a coastal state, sea-level rise is already presenting challenges, as demonstrated by some island residents having to vacate their homes. In terms of agriculture, climate change can affect farms by intensifying current stressors such as drought frequency, winter flooding, pests and disease, and ozone levels, all of which are situations that can have serious repercussions on the economy. In addition, climate change may affect the water supply and the quality of that water. Health risks increase with an increase in temperatures as well, including issues such as: heat-related stress, changes in infectious disease patterns, and injuries/death due to extreme weather events.

Changes in weather conditions will also affect energy usage. The extreme weather events brought about by increases in the average temperature cause stress on energy infrastructure. According to the DOE, the leading cause of power outages in the U.S. is extreme weather events.[133]

Higher temperatures may also have impacts on energy generation, specifically energy generation efficiencies. For fossil fuel power generation, power plants could face diminished efficiency

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[131] Maryland Department of the Environment, *Maryland's Greenhouse Gas Reduction Act Plan*, October 2013, http://www.mde.state.md.us/programs/Marylander/Documents/MCCC/Publications/2012GGRAPlan/GGRAPlan2012.pdf.
[132] Maryland Department of the Environment, *The 2015 Greenhouse Gas Emissions Reduction Act Plan Update*, October 2015, http://www.mde.state.md.us/programs/Air/ClimateChange/Documents/2015GGRAPlanUpdate/GGRA%20Report%20FINAL%20(11-2-15).pdf.
[133] United States Department of Energy Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages,* August 2013, http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf, 4.

due to operating in hotter weather, as well as dealing with warmer cooling intake water at potentially reduced volumes. In terms of renewables, solar power generation may face issues of reduced equipment efficiency in higher temperatures, while wind power generation is vulnerable to changes in wind production.

Other renewable energy production, such as hydro, landfill gas, and biomass, will also be affected. Hydropower plants could face significant efficiency problems with lower, and potentially inconsistent, water volumes. Landfill gas energy production would increase in the short term due to higher temperatures, but there would be a shorter timeframe for that production. Biomass, in addition to similar issues as those posited above, also faces additional insecurity as an energy source due to the potential uncertainty of the state of the agricultural industry under a warmer climate.

Warmer temperatures will also affect how energy is being used. Air conditioning and refrigeration requirements in the summer will be increased (which will also tend to result in higher peak demands given that PJM is a summer-peaking system), and heating requirements in the winter season will be reduced. Because of a greater disparity between summer and winter energy use, the overall costs of providing service to customers may increase since the plants required to meet load in the summer will, in part, be idle in the winter.

In the LTER, climate change is modeled but only in a limited manner. Given the limitations of any modeling approach, combined with the complexities of the interrelationships associated with climate change, steps to mitigate impacts, steps to adapt to impacts, and the implications for the level of electricity use (and the patterns of energy use), the results presented in the LTER should not be viewed as covering the spectrum of associated weather-related effects.

10.9 Land Use Requirements for Electricity Generation

The amount of land required to accommodate electric generation facilities varies significantly depending upon the specific attributes of each generating facility, such as the type of resource used for energy production, the capacity of the power plant, and the features of the development site. This section is included in the LTER to estimate the amount of land required to accommodate the wind, solar, and natural gas resources associated with each of the scenarios considered in this analysis. Note that this section only addresses the amount of land directly utilized by a power plant, and does not consider the “cradle-to-grave” footprint (i.e., factors such as natural gas wells, pumping stations, and pipelines are not included). Table 10.13 displays the estimated amount of land (on a per-MW of capacity basis) required to accommodate electricity generation for three generation types. These estimates are derived from a review of the existing literature combined with recent experience in Maryland. Further background on each technology type is provided in the following paragraphs.

Table 10.13 Land Use by Energy Source

Resource	Land Area Used for Electricity Generation (acres per MW)	
	Total[1]	Exclusive Use
Wind	60	5
Solar	5-8	--
Natural Gas	1.4	--

[1] The ranges provided reflect differences in the technologies used, site topography, and the intensity of land use for other purposes, as discussed below.

The information presented in this section addresses different types of electric generation and their land-use impacts affecting Maryland. As shown and discussed in the following pages, the largest land-use impacts are associated with renewable generating capacity, particularly wind generation. It is important to keep in mind, however, that while renewable technologies entail significant land-use impacts, both wind and solar generation entail little air and water impacts. Other technologies that entail little land impacts (on a per-MW of capacity basis), on the other hand, may entail other impacts not addressed in this section of the LTER. For example, nuclear generation, which requires the least land area per MW of installed capacity and results in few airborne emissions, can entail substantial water use impacts and also results in nuclear waste. Both natural gas-fired and coal-fired generation entail harmful air emissions, can consume large amounts of water, and (in the case of coal) result in waste disposal issues. Each of the technologies commonly used to generate electric power, and considered in the LTER, provide a unique set of environmental, reliability, and economic attributes, with one such attribute being land use. Trade-offs between land use and these other factors need to be considered in interpreting the information presented in the remainder of this report section.

10.9.1 Wind

On-shore wind energy power plants span across hundreds and often thousands of acres, but the turbines used for collecting wind energy typically utilize less than 10 percent of the total land area. Because the wind resource potential and turbine capacities vary among existing wind energy facilities, it is difficult to estimate a generic acre-per-MW figure. Nevertheless, according to an estimate from NREL, a survey of wind facilities indicates a range of between 30 and 138 acres per MW.[134] In terms of the direct impact area (the area where turbine pads, roads, and stations are located), the average wind facility typically uses less than five acres per MW.[135] However, as on-shore wind facilities utilize a significant amount of land, they have the potential to fragment the ecological habitats of rare, threatened, and endangered species. The construction and maintenance of wind facilities can alter ecosystem structures that can be difficult to restore, such as deserts and forests. Finally, appropriate measures must be taken during construction to minimize erosion and control sediment runoff into nearby waterways.

[134] Paul Denholm, Maureen Hand, Maddalena Jackson, and Sean Ong, *Land-Use Requirements of Modern Wind Power Plants in the United States*, National Renewable Energy Laboratory, August 2009, http://www.nrel.gov/docs/fy09osti/45834.pdf, 22.
[135] Ibid.

For purposes of the land-use analysis, an estimate of 60 acres per MW for land-based wind facilities was relied upon, which includes separation and setback requirements. Maryland's recent experience with wind power development (e.g., the Dan's Mountain wind power project) suggests an acre-per-MW figure of slightly above 50. An estimate of 60 acres per MW is relied upon to recognize the Maryland experience with an upward adjustment of approximately ten acres per MW to partially reflect the NREL findings and to incorporate a degree of conservationism. It is important to note that for any given land-based wind facility, total acreage requirements may be higher or lower than the 60 acres used for this analysis.

Since the land used for a particular wind power project may be used, in part, for additional alternative activities such as grazing or crop farming, estimated land-use estimates based on a narrower definition of land use, i.e., exclusive wind power land use (principally the pad and electric facilities) are also presented. These estimates are based on five acres per MW, as shown above in Table 10.13.

Each of the scenarios addressed in the LTER analysis, including the Reference Case, includes 200 MW of off-shore wind attributed to Maryland. Although off-shore wind does not require any land area for energy production, it is noted that such a project would still have impacts on the State. The decision to site an off-shore wind facility in Maryland waters (i.e., within three miles of the coastline) would require careful consideration of potential impacts to shipping lanes, sensitive ocean habitats, avian and marine life, and tourism in beach communities in Maryland.[136] Furthermore, even if an off-shore wind project were to be developed in federal waters (i.e., more than three miles from Maryland's coast), the State could see impacts similar to those incurred with construction of an off-shore wind project in Maryland waters. Nevertheless, Maryland has limited land area for on-shore wind generation and the State's greatest wind energy potential is located off-shore, presenting certain important advantages to utilizing off-shore wind energy as opposed to on-shore wind energy for renewable energy production.

10.9.2 Solar

NREL published a report in June 2013 documenting a survey of the land utilized by 150 different solar projects, of which 113 projects were completed and 37 were under construction.[137] These were split between 120 small projects (1-20 MW) and 30 larger projects (>20 MW). The projects were also categorized by technology: PV fixed; PV two-axis flat panel; two-axis concentrator photovoltaics (CPV); and concentrated solar power (CSP). For purposes of this report, PPRP selected the acreage values associated with one-axis PV panel; the range shown in Table 10.13 represents the spread between the typical amount of land required for small one-axis PV panel projects and large ones (i.e., five to eight acres per MW).

[136] National Renewable Energy Laboratory, *Large-Scale Offshore Wind Power in the United States*, September 2010, http://www.nrel.gov/docs/fy10osti/49229.pdf.

[137] Sean Ong, Clinton Campbell, Paul Denholm, *et al.*, *Land-Use Requirements for Solar Power Plants in the United States*, National Renewable Energy Laboratory, June 2013, http://www.nrel.gov/docs/fy13osti/56290.pdf.

Smaller solar projects, ranging in size from kilowatt- to megawatt-sized systems, can often be located on rooftops. Placement of solar panels on rooftops is common for residential installations, and commercial and government buildings have also used roof space to facilitate installation of solar panels. For these types of projects, land use requirements are minimal since the panels are placed on pre-existing structures.

The solar carve-out in the Maryland RPS, like the solar carve-out in other states (e.g., New Jersey), generally requires that the solar resource be located within the State. Issues have periodically emerged in the context of utility-scale solar licensing that the location of utility-scale solar facilities on agricultural land, particularly on agricultural land on Maryland's Eastern Shore, could erode the economic viability of agriculture in that part of the State. It has been argued that by diverting agricultural land to other uses, the businesses that support agriculture may themselves no longer be economical. It should be noted that, unlike land used for wind power development, land used for solar power development cannot be easily used for additional economic activity.

To put these issues into perspective, Table 10.14 provides estimates of the percentage of agricultural acreage needed to meet the solar carve-out portion of the Maryland RPS under varying levels of RPS requirement, i.e., 2 percent (the existing requirement), 2.5 percent, 3.0 percent, and 5.0 percent. The last three percentage requirements correspond to the solar carve-out levels assumed for the 25 percent renewables case, the 35 percent renewables case, and the 50 percent renewables case, respectively. The calculations used to derive the acreage requirements are based on an estimated 2035 energy consumption level for Maryland of 70,962 GWh.[138] The other assumptions included in the calculations are:

- A solar capacity factor of 15 percent;
- Eastern Shore agriculture acreage stays constant at the most recent census levels (1,011,322 acres);[139]
- Total Maryland (less Western Maryland—Allegheny, Garrett, and Washington Counties) agriculture acreage stays constant at the most recent census levels (1,769,687 acres);[140] and
- All solar requirements for the Maryland solar carve-out are located on Maryland Eastern Shore agricultural land and, alternatively, on Maryland agricultural land excluding Western Maryland.

[138] The 2035 Maryland energy consumption estimate is based on the most recent Maryland PSC 10-Year Plan (2015) terminal year projection (2023) extended to 2035 using the 2014-2023 average annual growth rate of 0.57 percent.
[139] U.S. Department of Agriculture, 2012 Census of Agriculture, https://www.agcensus.usda.gov/Publications/2012/Online_Resources/County_Profiles/Maryland/index.asp.
[140] Ibid.

This last assumption regarding the location of the solar generation needed to meet the Maryland solar carve-out means that the currently in-place and operating solar generation in the State, approximately 450 MW, is assumed to play no role in meeting the solar carve-out. Consequently, the calculations shown in Table 10.14 represent an extreme case.

Maryland's Eastern Shore contains the highest concentrations of prime farmland in the State. To address concerns about potential adverse impact to the State resulting from the location of solar power generation projects on prime farmland on the Eastern Shore, Table 10.14 also includes calculations that show impacts on Eastern Shore prime farmland as if all the solar power development needed to meet the Maryland RPS solar carve-out was located on the approximately 601,200 acres of prime farmland on the Maryland Eastern Shore. This estimate of Eastern Shore prime farmland is based on the assumption that 75 percent of the State's 801,600 acres of prime farmland (as of 2007) are located on the Eastern Shore.

Table 10.14 Agricultural Land Required to Meet Maryland RPS Requirements in 2035

Solar Carve-out	2.0%	2.5%	3.0%	5.0%
Solar Capacity Required to Meet Generation Requirement (MW)	1,061	1,326	1,591	2,652
Land Requirements at Five Acres per MW (acres)	5,305	6,630	7,955	13,258
Percentage of Eastern Shore Agricultural Land Required to Meet Solar Carve-out (%)	0.52	0.66	0.79	1.31
Percentage of Eastern Shore Prime Farmland Required to Meet Solar Carve-out (%)	0.88	1.10	1.32	2.21
Percentage of Maryland Agricultural Land (excl. Western Maryland) Needed to Meet Solar Carve-out (%)	0.30	0.37	0.45	0.75

Note: These estimates should be viewed as higher than what would actually be expected given currently existing solar generating capacity in the State, future rooftop solar installations, and the realistic expectation that some significant portion of new solar installations would be located on property not zoned as agricultural.

When interpreting the land requirements shown in Table 10.14, it should be recognized that the figures provide only a rough gauge as to the percent of agricultural land (both on the Eastern Shore and in Maryland as a whole less the Western Maryland counties) that would be absorbed to accommodate compliance with the Maryland RPS solar carve-out. As noted above, the existing inventory of solar generating capacity in Maryland, presently used to meet the Maryland RPS solar carve-out, is in no way accounted for in the Table 10.14 calculations, which skews the percentages higher than they otherwise would be by about 30 percent for the 2.0 percent calculation and by about 12 percent for the 5.0 percent calculation. In addition to upward bias generated by the treatment of the existing solar generation inventory, other relevant considerations include:

- The assumed 15 percent capacity factor for solar is relatively conservative. To the extent that the capacity factor for solar is higher, a smaller number of MW of solar generation would be needed to meet the Maryland RPS carve-out and a correspondingly lower number of acres would be required to support those MW of solar capacity.

- The total number of agricultural acres is not adjusted downward to reflect use restrictions, for example, wet lands, forested areas, or agricultural preservation areas. To the degree that a portion of the land is not amenable to solar project development, the development of solar projects would be more concentrated among those land parcels more suitable for renewable energy development.

- Not all of the future development of solar energy capacity in Maryland will be related to satisfaction of the Maryland RPS solar carve-out and as a consequence, a larger amount of solar capacity than is suggested solely by the RPS carve-out figure can be expected. This would have the effect of increasing the acres that may be subject to solar development and hence the percentage figures represented in Table 10.14.

- Unlike the total land requirements for wind generation projects, the land used for solar project development is not available for other uses such as growing crops or allowing livestock to graze.

10.9.3 Natural Gas

Natural gas power plants require less land area per MW than wind and solar facilities. Review of the literature suggests that natural gas turbines require between 0.4 acres and 2.0 acres per MW of capacity.[141] For this analysis, an acres-per-MW figure of 1.2 acres, which is the mid-point of the 0.4 – 2.0 acres-per-MW range, is relied upon.

10.9.4 Brownfield Sites in Maryland

Considerations Regarding Renewable Energy Development on Brownfields in Maryland

According to the EPA database related to renewable energy opportunities on brownfields in Maryland, there are only limited options for wind development, meaning that the development would entail primarily solar projects.[142] Siting solar projects requires certain locational characteristics, including suitable layout of the land and slope. In terms of developing a site on brownfields, extensive landscaping and/or earth moving to provide an appropriate set-up for a solar project could entail significant costs.

In addition, the potential clustering of solar projects in an area with multiple brownfield sites will need to recognize current infrastructure limitations. Any proposed projects greater than 2 MW require an interconnection study to be performed by PJM to ensure the adequacy of the transmission system.

[141] Adam Blair, Rod Howe, and David Kay, "Transitioning to Renewable Energy: Development Opportunities and Concerns for Rural New York," *NYSBA Government, Law and Policy Journal*, Summer 2013, Vol. 15, No. 1, http://www.edrgroup.com/pdf/Blair-Renewable-Energy.pdf, 37.
[142] U.S. Environmental Protection Agency, "Re-Powering Mapping and Screening Tools," https://www.epa.gov/re-powering/re-powering-mapping-and-screening-tools.

Developers have expressed hesitation when considering whether to site renewable energy projects on brownfields. Issues such as uncertainty regarding liability and potential unanticipated costs can detract from the brownfields positive attributes, such as re-use of land and proximity to infrastructure.

Finally, issues related to economic justice also require recognition in order to avoid the potential clustering of projects in economically depressed areas.

Description of Brownfields Locations in Maryland

Brownfield locations can be found scattered throughout Maryland. Predominantly, however, they are clustered around major interstate highways and metropolitan areas. Using MDE's Land Restoration Program mapping application, brownfield sites are abundant along the I-270 and I-95 corridors, and in and around the following areas: Cumberland, Frostburg, Hagerstown, Frederick, City of Baltimore, Easton, Cambridge, Salisbury, and the Maryland suburbs adjacent to Washington, D.C.[143] In aggregate, there are approximately 30,000 acres of brownfield sites in Maryland, which excludes EPA Superfund sites and Resource Conservation and Recovery Act sites but includes Landfill Methane Outreach Program sites.

10.9.5 Summary

The land-use analysis that follows assumes a range of per-MW solar project acreage requirements of between 5 MW and 8 MW. In general, projects put in place in Maryland tend towards the lower end of this range. In developing the total land-use figures for each of the scenarios shown in Table 10.15 and Table 10.16 (based on five acres per MW and eight acres per MW, respectively), it is implicitly assumed that all solar energy required to meet the Maryland RPS solar carve-out would be located in Maryland. Further, it is assumed that no solar generation (including the solar generation already in place) is located on rooftops.

[143] Maryland Department of the Environment, Land Restoration Program, http://mdewin64.mde.state.md.us/LRP/index.html.

Table 10.15 Maryland Land Use by Energy Source
(5 acres per MW for solar; 5 acres per MW for wind)

Scenario	Solar Acres at 5 acres/MW	Natural Gas Acres at 1.2 acres/MW	On-shore Wind Power Acres at 5 acres/MW Percentage in Maryland			
			25%	50%	75%	100%
Reference Case	5,303	5,599	5,226	10,451	15,677	20,903
HPNG	5,303	5,599	5,226	10,451	15,677	20,903
LPNG	5,303	5,599	5,226	10,451	15,677	20,903
High Load	5,945	7,135	5,948	11,896	17,844	23,792
Low Load	4,871	4,351	4,739	9,478	14,218	18,957
Climate Change	5,303	6,079	5,226	10,451	15,677	20,903
MD 25% RPS	6,629	5,599	6,717	13,434	20,152	26,869
MD 35% RPS	7,955	5,599	9,866	19,732	29,598	39,464
MD 50% RPS	13,258	5,407	14,175	28,350	42,525	56,700
PJM 25% RPS	6,629	5,119	6,717	13,434	20,152	26,869
CPP	5,154	5,791	5,058	10,115	15,173	20,230
ECPR	5,303	6,079	5,226	10,451	15,677	20,903
NOx Emissions Compliance	5,303	6,559	5,226	10,451	15,677	20,903

Note: Solar requirements are not adjusted to reflect rooftop and other "behind-the-meter" capacity.

Table 10.16 Maryland Land Use by Energy Source
(8 acres per MW for solar; 60 acres per MW for wind)

Scenario	Solar Acres at 8 acres/MW	Natural Gas Acres at 1.2 acres/MW	On-shore Wind Power Acres at 60 acres/MW Percentage in Maryland			
			25%	50%	75%	100%
Reference Case	8,485	5,599	62,708	125,416	188,124	250,832
HPNG	8,485	5,599	62,708	125,416	188,124	250,832
LPNG	8,485	5,599	62,708	125,416	188,124	250,832
High Load	9,512	7,135	71,376	142,752	214,129	285,505
Low Load	7,794	4,351	56,871	113,742	170,613	227,484
Climate Change	8,485	6,079	62,708	125,416	188,124	250,832
MD 25% RPS	10,606	5,599	80,606	161,213	241,819	322,426
MD 35% RPS	12,726	5,599	118,392	236,784	355,176	473,568
MD 50% RPS	21,213	5,407	170,099	340,198	510,296	598,148
PJM 25% RPS	10,606	5,119	80,606	161,213	241,819	322,426
CPP	8,246	5,791	60,690	121,380	182,070	242,760
ECPR	8,485	6,079	62,708	125,416	188,124	250,832
NOx Emissions Compliance	8,485	6,559	62,708	125,416	188,124	250,832

Note: Solar requirements are not adjusted to reflect rooftop and other "behind-the-meter" capacity.

Table 10.15 and Table 10.16, above, show the approximate amount of land area needed to build new capacity in Maryland. To properly interpret the data contained in these tables, it should be recognized that intermittent renewable generation capacity (e.g., solar and wind) in the ABB model is increased as a direct input by the user. That is, the model does not add intermittent renewable generation to meet either reliability requirements or to meet the requirements of state renewable portfolio standards. Further, the user must specify the type of renewable generation capacity to be added, when the renewable generating capacity is to be added, and the location of the renewable generation capacity. Since the Maryland RPS requires that Maryland-eligible solar RECs must be generated from projects located in Maryland, development of the relevant assumptions regarding new solar generating capacity to be input into the ABB model is straightforward. The user, however, needs to specify how much of the new renewable generating capacity is located in each of the three transmission zones – PJM-SW, PJM-APS, or PJM-MidE.

In the case of land-based wind power, which the Maryland RPS classifies as a Tier 1 resource, the generating capacity need not be located in Maryland in order to be eligible to satisfy Maryland RPS requirements. Rather, the wind generating capacity can be located not only anywhere in PJM, but can also be located in an adjacent RTO or ISO if the energy from the project is transmitted into Maryland. As a consequence, the ABB Model user has much more latitude in assigning the location of new wind power capacity needed to meet renewable portfolio standard requirements than for new solar capacity. The assumptions relied upon for the location of the wind power, that is, whether the wind power generating capacity is located in Maryland and the transmission zone in which it is located, have significant implications for the land-use impact presentations. As an example, if all of the new wind power generation needed to meet the Maryland RPS requirements were assigned to the PJM-APS zone outside of Maryland, then Maryland would see none of the land-use impacts associated with an increase in the Tier 1 requirements of the RPS. This assumption would likely understate the land-use impacts to the State. Similarly, if all of the increased Tier 1 generating capacity associated with a more aggressive RPS scenario were to be assigned to Maryland, the land-use impacts to the State would likely be overstated. The land-use results shown in Table 10.15 and Table 10.16 are sensitive to the assumptions made regarding whether the Tier 1 renewable energy generating capacity needed to satisfy the increased RPS requirements is located within Maryland or located outside the State. For this reason, alternative assumptions are presented regarding the percentage of wind power assumed to be located in Maryland—25 percent, 50 percent, 75 percent, and 100 percent.

An additional issue is that regardless of whether a particular renewable generation facility, such as a wind farm, is located in Maryland, there will still be land-use impacts, but those impacts would be felt out of State. Table 10.15 and Table 10.16 show land-use impacts to Maryland only, but it should be recognized that, in the case of out-of-state renewable energy development, the land-use impacts are not eliminated but rather are shifted to other states.

The acreage requirement results shown in both Table 10.15 and Table 10.16 include adjustments for 200 MW of Maryland off-shore wind assumed to be constructed in the future, approximately 24 MW of Maryland landfill gas generation currently in place, and approximately 116 MW of Maryland biomass generation currently in place. If the assumption is made that the Maryland RPS will be modified in the future to disallow biomass and landfill gas from being eligible Maryland Tier I RPS resources, then the energy output of those installations (856,000 MWh annually based on assumed

70 percent capacity factors for both landfill gas and biomass) will need to be replaced by other Tier I generation, e.g., wind generation. The additional wind generation requirement would entail 326 MW of additional wind power capacity and, for each scenario, will add 1,630 acres to the Maryland land-use figures shown in Table 10.15 (under the assumption that 100 percent of the wind power will be located in Maryland, and that land use equals five acres per MW of installed wind power capacity). For Table 10.16, 19,560 acres of land-use requirements would be added (under the assumption of 100 percent of the wind power being located in Maryland and land use of 60 acres per MW of installed wind power capacity). For the 25 percent, 50 percent, and 75 percent in-State assumptions, the acreage requirements would be proportionately reduced. The added acreage related to the elimination of the biomass and landfill gas resources, as eligible to contribute to the satisfaction of the Maryland Tier I RPS, does not vary among the various scenarios.

Figure 10.21 compares land-use requirements among scenarios assuming 50 percent of wind resources to meet the RPS requirements are located in Maryland (excluding 200 MW of off-shore wind assumed for all scenarios) and solar and wind generation projects entail use of five acres per MW. Figure 10.22 shows analogous information but based on the assumption of eight acres per MW of solar generation and 60 acres per MW of wind.

Figure **10.23** and Figure 10.24 show data in graphic form similar to the information presented in Figure 10.21 and Figure 10.22, but based on the assumption that 100 percent of wind resources required to meet the Maryland RPS are located in Maryland (excluding 200 MW of off-shore wind assumed for all scenarios).

In all cases except one, the 100 percent in-Maryland data are twice as large as the 50 percent data. The data for the 100 percent in-Maryland assumption for the 50 percent RPS scenario is less than twice the 50 percent in-Maryland figure for the same scenario. This is because the amount of wind power required to meet the RPS requirement at 50 percent exceeds the wind capacity acreage potential of Maryland (598,148 acres) based on an analysis of suitable areas for wind power development that recognizes restrictions due to local ordinances, restrictions due to proximity to airports and military installations, proximity to electric transmission lines, and restrictions due to proximity to highly populated and developed areas.[144] Absent the land-use restrictions, the amount required to accommodate the 50 percent RPS scenario, assuming all wind generation facilities were to be located in Maryland, would be 707,015 acres.

The data shown in Table 10.15 and Table 10.16 are represented in Figure 10.21 through Figure 10.24. The figures, however, are restricted to 50 percent of wind power located in-State and 100 percent of wind power locate in-State. To put these data in perspective, the following data is provided for seven counties plus Baltimore City for comparison. These data represent total land acreage in each of the areas, that is, both inland and Chesapeake waters are excluded.

[144] This estimate was based on statewide application of PPRP's SmartDG program which provides guidance on acceptable areas for distributed generation, by county.

Total acres in Maryland: 6.3 million

Total acres in Baltimore City: 51,400

Total acres in Baltimore County: 382,500

Total acres in Calvert County: 136,500 (smallest county)

Total acres in Frederick County: 424,100 (largest county)

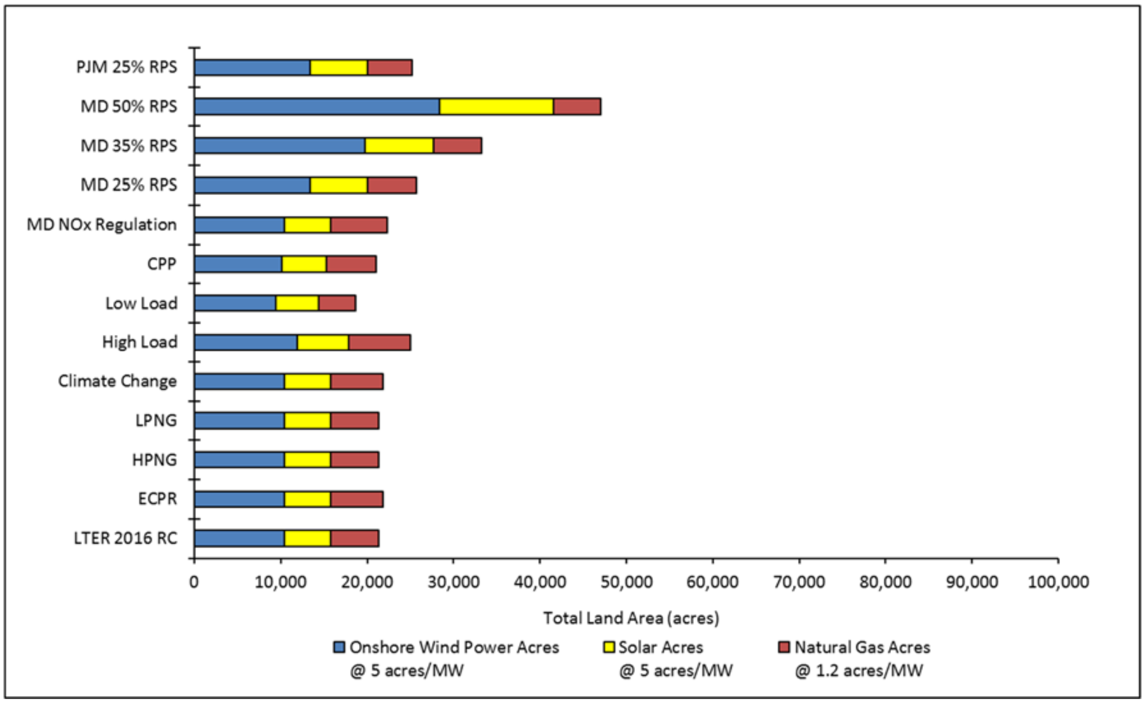
Total acres in Garrett County: 420,400

Total acres in Kent County: 178,100

Total acres in Prince Georges County: 311,700

Total acres in Worcester County: 303,900[145]

Figure 10.21 Total Estimated Land Area Required for Capacity Additions in Maryland
(5 acres per MW for solar; 5 acres per MW for wind—50 percent of wind located in Maryland)



[145] Data obtained from http://msa.maryland.gov/msa/mdmanual/01glance/html/area.html in square miles and converted to acres using a conversion factor of 640 acres per square mile.

Figure 10.22 Total Estimated Land Area Required for Capacity Additions in Maryland
(8 acres per MW for solar; 60 acres per MW for wind—50 percent of wind located in Maryland)

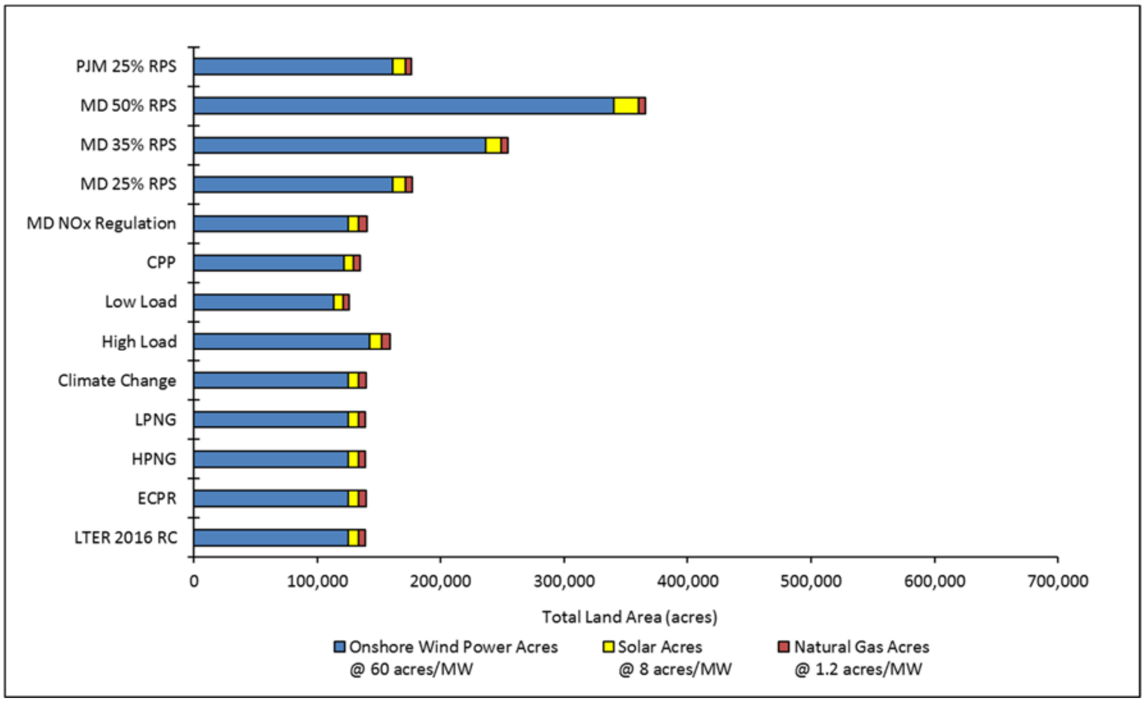


Figure 10.23 Total Estimated Land Area Required for Capacity Additions in Maryland
(5 acres per MW for solar; 5 acres per MW for wind—100 percent of wind located in Maryland)

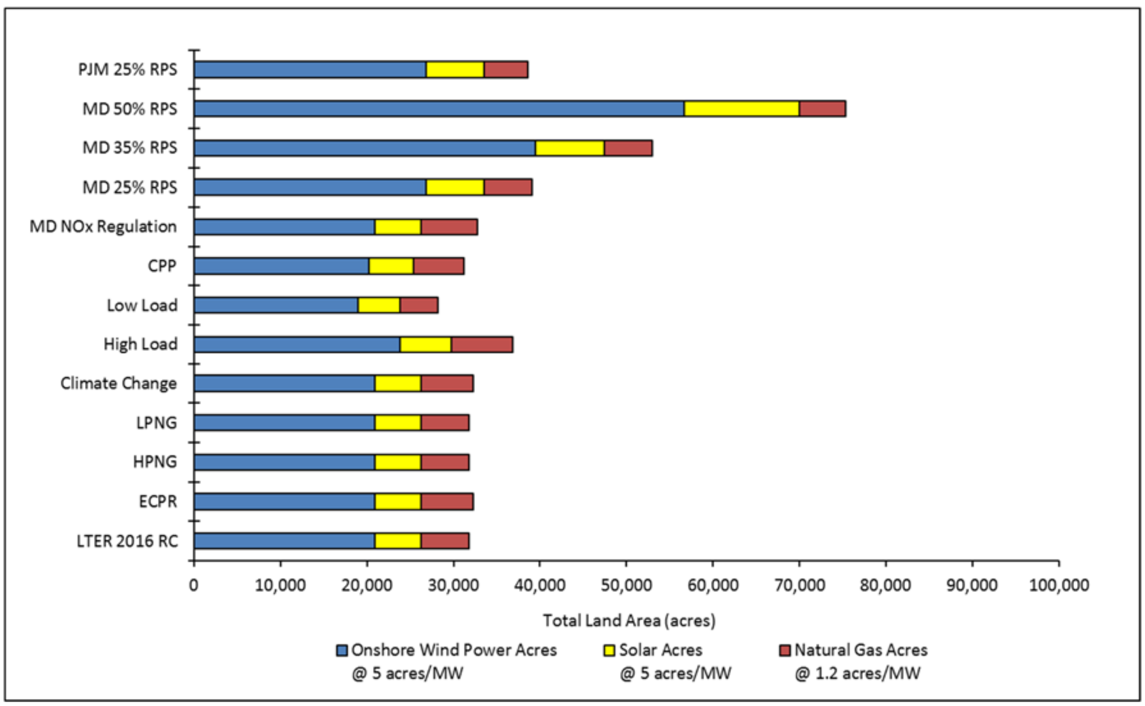
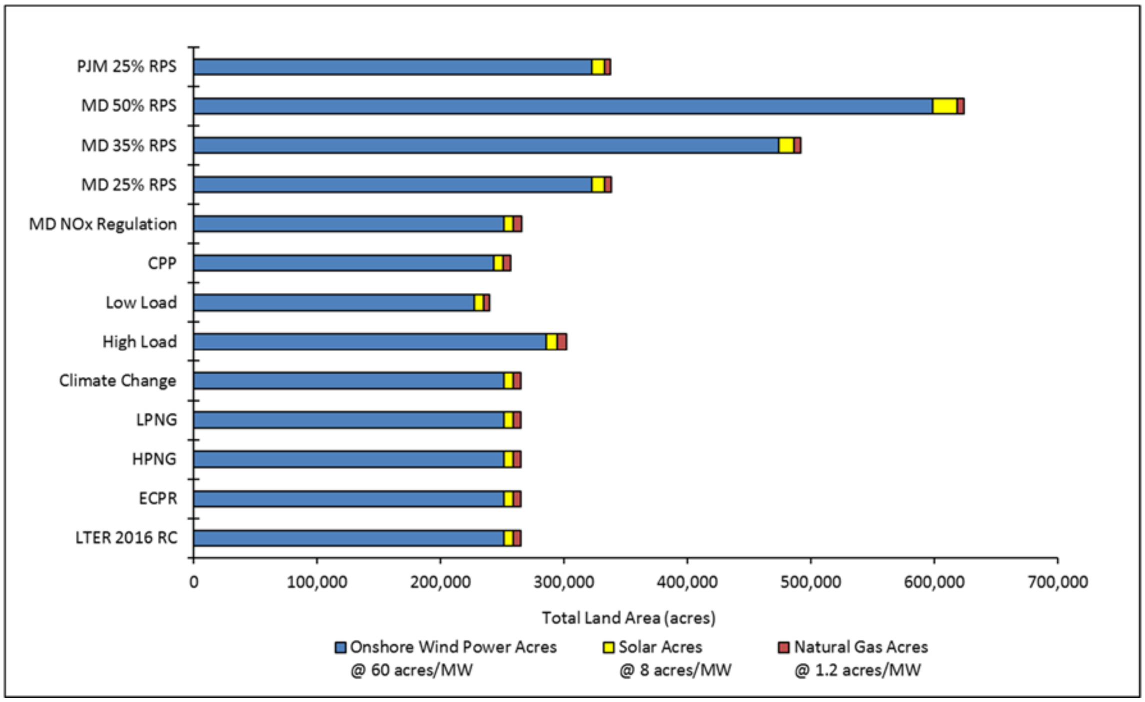


Figure 10.24 Total Estimated Land Area Required for Capacity Additions in Maryland
(8 acres per MW for solar; 60 acres per MW for wind—100 percent of wind located in Maryland)



APPENDICES

APPENDIX A
Executive Order

The State of Maryland
Executive Department

EXECUTIVE ORDER
01.01.2010.16

Long-Term Electricity Report for the State of Maryland

WHEREAS, A sustainable energy future for all Marylanders requires an evaluation of the long-term electricity needs of the State and a comprehensive review of alternative and innovative approaches to meet those needs;

WHEREAS, A Long-Term Electricity Report is critical to securing Maryland's energy future by addressing our long-term energy needs and providing a blueprint for achieving a clean, reliable, and affordable energy future; and

WHEREAS, Input from a variety of stakeholder groups including government agencies, electricity customers, utilities, electric suppliers, and organizations representing environmental and consumer interests will help develop and achieve support for policy changes needed to implement the Long-Term Electricity Report.

NOW, THERFORE, I, MARTIN O'MALLEY, GOVERNOR OF THE STATE OF MARYLAND, BY VIRTUE OF THE AUTHORITY VESTED IN ME BY THE CONSTITUTION AND THE LAWS OF MARYLAND, HEREBY PROCLAIM THE FOLLOWING EXECUTIVE ORDER, EFFECTIVE IMMEDIATELY:

A. On or before December 1, 2011, the Department of Natural Resources' Power Plant Assessment Program (Department) shall prepare a Long-Term Electricity Report (Report) for the State of Maryland.

B. The Report shall assess future electric energy use requirements and peak electric demand requirements, and identify sources and alternative resources to meet any gaps in these requirements through the end of calendar year 2030.

C. The Report shall:

(1) Analyze electric energy use and peak electric demand forecasts, including:

(a) Existing and planned electric generating and demand response capacity in Maryland;

(b) Demand related to the transition to an electricity-based transportation system;

(c) Existing electric transmission system in the PJM Interconnection region along with planned improvements and expansion of the system; and

(d) The extent to which Maryland's power supply requirements over the 20-year analysis period exceed the capabilities of existing and planned electric generation resources, including projected demand response resources and transmission system capacity.

(2) Examine alternative and feasible sources of electric capacity to address any gaps between power supply requirements and the capabilities of existing and planned electric generation and transmission system resources, considering among other factors:

(a) Costs of generation, including capital, operational and maintenance costs;

(b) Reliability of supply;

(c) The extent of and ability to avoid, minimize or mitigate, adverse environmental impacts;

(d) Conventional and renewable generation capacity additions, including small scale distributed generation sources;

(e) Options for fuel-switching, including use of natural gas and biomass;

(f) Energy conservation and energy efficiency;

(g) Demand response;

(2) The Department of the Environment;

(3) The Department of Agriculture;

(4) The Department of Business and Economic Development;

(5) The Department of Transportation;

(6) The Department of Planning;

(7) The Technical Staff of the Public Service Commission;

(8) The Office of People's Counsel;

(9) PJM Interconnection, LLC;

(10) Electric companies and electricity suppliers;

(11) Natural gas companies and pipeline suppliers;

(12) Renewable energy generators;

(13) Energy service companies specializing in demand reduction;

(14) Large electricity consumers, including commercial and institutional consumers;

(15) Organizations representing environmental interests in the State;

(16) Organizations representing consumer interests in the State; and

(17) Any other relevant interests.

E. Prior to final publication of the Report, the Department shall hold public meetings to review the draft findings of the Report with members of the public.

F. The Department shall review and update this report at least every five years in consultation with the organizations listed in paragraph (D) above and after holding public meetings to review any updated draft findings with members of the public.

G. The Department shall submit the Long-Term Electricity Report with any updates to the Governor, General Assembly, and Maryland Public Service Commission.

H. The Department shall file the Report with the Maryland Public Service Commission in conjunction with the Department's testimony in proceedings relating to certificates of public convenience and necessity described in Sections 7-207 or 7-208 of the Maryland Public Utility Companies Article and other cases concerning electricity generation, electric transmission, demand management, and energy efficiency.

GIVEN Under My Hand and the Great Seal of the State of Maryland, in the City of Annapolis, this 23rd Day of July, 2010.

Martin O'Malley
Governor

ATTEST:

John P. McDonough
Secretary of State

5

APPENDIX B
PPRAC Members and Interested Parties

Table B-1 Summary of LTER Alternative Scenarios

Name	Organization
Kenneth M. Capps	Southern Maryland Electric Cooperative
Ted J. Garrish	Maryland Department of Natural Resources
Alison Prost	Chesapeake Bay Foundation
Jana Davis	Chesapeake Bay Trust
Rob Etgen	Eastern Shore Land Conservancy
Anne M. Lindner	Exelon
Carlton Haywood	Interstate Commission on the Potomac River Basin
Les Knapp	Maryland Association of Counties
Kathy Magruder	Maryland Clean Energy Center
James McGarry	Maryland Climate Change Action Network
Matthew Teffeau	Maryland Department of Agriculture
Michael Leslie	Maryland Department of Commerce
Angelo Bianca	Maryland Department of the Environment
Bill Paul	Maryland Department of the Environment
Bruce Michael	Maryland Department of Natural Resources
Ren Serey	Maryland Department of Natural Resources – Chesapeake Bay Critical Area Commission
Susan Gray	Maryland Department of Natural Resources – Power Plant Research Program
John Sherwell	Maryland Department of Natural Resources – Power Plant Research Program
Pat Goucher	Maryland Department of Planning
Dixie Henry	Maryland Department of Planning
Tyson Byrne	Maryland Department of Transportation
Chris Rice	Maryland Energy Administration

Table B-1 Summary of LTER Alternative Scenarios

Name	Organization
Mary Tung	Maryland Energy Administration
C. Ferguson	Maryland Farm Bureau
Bill Fields	Maryland Office of People’s Counsel
Beth Cole	Maryland Office of Preservation Services, Historical Trust
Morris Schreim	Maryland Public Service Commission
Craig Taborsky	Maryland Public Service Commission
Steve Arabia	NRG Energy
David Smith	Old Dominion Electric Cooperative
James Wright	Old Dominion Electric Cooperative
Gia Clark	One Energy
Ray Bourland	Pepco
Jack Barrar	Pepco Holdings, Inc.
Evelyn Robinson	PJM Interconnection, LLC
Thomas Weissinger	Raven Power
Jeff Walker	St. Mary's County Public Schools

APPENDIX C
LTER Alternative Scenarios

Table C-1 Summary of LTER Alternative Scenarios

Category	Scenario	Assumptions
Natural Gas Prices	Low Natural Gas Prices	Prices rise $2.35/MMBtu less than Reference Case by 2035
	High Natural Gas Prices	Prices rise $2.64/MMBtu more than Reference Case by 2035
Load Growth	Low Load Growth	Annual load growth 0.5 percentage points less than Reference Case
	High Load Growth	Annual load growth 0.5 percentage points more than Reference Case
	Climate Change	Annual load growth higher than Reference Case due to rising temperatures
Renewables in MD	Moderate Renewables	MD RPS rises to 25% by 2020, including 2.5% solar 2020
	High Renewables	MD RPS rises to 35% by 2030, including 3.0% solar by 2025
	Very High Renewables	MD RPS rises to 50% by 2030, including 5.0% solar by 2030
Renewables in PJM	Moderate Renewables	PJM RPS rises to 25% by 2020, including 2.5% solar by 2020
EPA Regulations	Clean Power Plan	Five strategies used nationwide to comply with CPP CO_2 standards for power plants
Early Coal Plant Retirements	Early Coal Plant Retirements	Five MD coal plants retire in 2018, rather than in later years
NOx Emissions Compliance	NOx Emissions Compliance	Eight coal plant units retire by 2020 based on the implementation of enhanced NOx regulations which were introduced in Maryland in 2015. Other Reference Case assumptions unchanged.

APPENDIX D
Summary of Input Assumptions

Table D-1 Summary of Input Assumptions

Item	2011 LTER Reference Case	2013 LTER Reference Case Update	2016 LTER Reference Case	Comments
Load growth	**December 2010 PJM Forecast (adjusted for EE and conservation programs):** Average Annual Growth Rate (2010-2030) Base Peak Demand: 0.87% Energy: 0.92%	**January 2013 PJM Forecast (adjusted for EE and conservation programs):** Average Annual Growth Rate (2012-2030) Base Peak Demand: 1.1% Energy: 1.4%	**December 2015 PJM Forecast:** Average Annual Growth Rate (2016-2035) Base Peak Demand: 0.5% Energy: 0.7%	Decreased due to economic trends and new PJM methodology, which accounts for energy efficiency programs and behind-the-meter solar
Callable Demand Response (DR)	DR projected to be developed in PJM by 2015	Callable DR cleared in 2012 PJM RPM Auction	Callable DR projected by PJM	--
Natural gas prices in PJM	**Ventyx Fall 2010 Reference Case:** HH prices increase from $4.46/MMBtu in 2011 to $8.01/MMBtu in 2030. *Represented in 2010 $/MMBtu	HH prices increase from approximately $3.00/MMBtu in 2013 to approximately $5.80/MMBtu in 2030. (2015 $)	**ABB Spring 2016 Reference Case:** HH prices increase from $2.15/MMBtu in 2016 to approximately $6.00/MMBtu in 2035. (2015$)	Decreased due largely to new natural gas shale plays in the United States and elsewhere
Coal fuel prices	**Ventyx Fall 2010 Reference Case:** PJM-SW prices increase from $2.89/MMBtu in 2011 to $2.90/MMBtu in 2030.	**Ventyx Fall 2012 Reference Case:** PJM-SW coal prices increase from approximately $3.05/MMBtu to approximately $3.60/MMBtu (2015$)	**ABB Spring 2016 Reference Case:** PJM-SW prices increase from approximately $3.00/MMBtu in 2016 to approximately $4.00/MMBtu in 2035 (2015$)	--
Other fuel prices	Ventyx Fall 2010 Reference Case	Ventyx Fall 2012 Reference Case	ABB Spring 2016 Reference Case	--
Generic biomass capacity constructed in Maryland by 2030	40 MW	82 MW	0 MW	Decreased to reflect development trends in Maryland (no new major biomass projects)
Generic landfill gas capacity constructed in Maryland by 2030	80 MW	80 MW	0 MW	Decreased to reflect development trends in Maryland (no new major LFG projects)

Table D-1 Summary of Input Assumptions

Item	2011 LTER Reference Case	2013 LTER Reference Case Update	2016 LTER Reference Case	Comments
Generic land-based wind capacity constructed in Maryland by 2030	80 MW	250 MW	0 MW	Decreased to reflect development trends in Maryland (no new major wind projects)
Generic off-shore wind capacity constructed in Maryland by 2030	0 MW	200 MW	200 MW	Kept at 200 MW to reflect the Maryland-waters portion of an anticipated 500 MW project
Generic solar PV capacity constructed in Maryland by 2030	498 MW	515 MW	898 MW (does not include distributed solar generation)	Increased to reflect recent trends in Maryland and national projections for PV growth
Solar RPS achievement in Maryland	50%	50%	100%	Increased to reflect recent trends in Maryland and national projections for PV growth
Wind capacity factor Land-based	30%	30%	30%	--
Wind capacity factor Off-shore	40%	--	40%	--
Solar PV capacity factor	15%	14%	15%	--
Overnight construction costs for new renewable energy generation	PV - \$5,000/kW Land-based Wind - \$2,220/kW Off-shore Wind - \$4,260/kW Biomass - \$3,330/kW	PV - \$3,709/kW Land-based Wind - \$1,770/kW Off-shore Wind - \$4,482/kW Biomass - \$3,772/kW	PV - \$2,250/kW Land-based Wind - \$1,800/kW Off-shore Wind - \$4,260/kW Biomass - \$4,500/kW	Increases/decreases reflect recent cost trends and projections
Overnight construction costs for new non-renewable energy generation	Simple Cycle Gas Turbine - \$680/kW Combined Cycle - \$1,000-\$1,035/kW Nuclear - \$5,870/kW	Simple Cycle Gas Turbine - \$680/kW Combined Cycle - \$1,000/kW - \$1,035/kW Nuclear - \$6,000/kW	Simple Cycle Gas Turbine - \$680/Kw Combined Cycle - \$1,000 - \$1,035/kW Nuclear - \$5,800/kW	--
EPA SO_2 and NOx Regulations	Clean Air Interstate Rule (CAIR)	Cross-State Air Pollution Rule (CSAPR)	Cross-State Air Pollution Rule (CSAPR)	--
RGGI Prices	\$2/ton through 2030	\$2/ton through 2030	Between \$5 and \$16 per ton	Increased to reflect progressively lower carbon allowances and retirement of nuclear generation

APPENDIX E
Price Variability

Pursuant to the EO, this report considers how each of the scenarios affects price variability in Maryland. This section addresses two types of energy price variability: (1) price changes over time; and (2) on-peak and off-peak price differentials. The hourly variability in wholesale electricity prices is not considered since almost all end-use electricity consumers purchase electricity under arrangements that entail fixed energy prices.

Price Changes Over Time

The all-hours wholesale energy prices in the Reference Case and the alternative scenarios exhibit the same general pattern, with steady growth in the first ten years of the study period (2015 through 2025) followed by much slower growth in the second half of the study period (2025 through 2035). Table E-1 presents the compound average annual growth rates of the annual average all-hours energy price for the first and second half of the study period and the study period as a whole. For example, in the Reference Case, the real PJM-SW all-hours energy price is projected to grow at an average annual growth rate of 4.35 percent between 2015 and 2025, with average annual growth slowing to 1.48 percent between 2025 and 2035. Real all-hours prices in PJM-MidE and PJM-APS follow the same general pattern, with faster growth in the first ten years of the study period followed by much slower growth in the second half.

Table E-1 Price Variability: Compound Average Annual Growth Rates of All-hours Wholesale Energy Prices (%)

	PJM-APS			PJM-MidE			PJM-SW		
Scenario	2015 to 2025	2025 to 2035	2015 to 2035	2015 to 2025	2025 to 2035	2015 to 2035	2015 to 2025	2025 to 2035	2015 to 2035
Reference Case	4.35%	1.48%	2.91%	4.50%	2.14%	3.31%	4.26%	1.91%	3.08%
HPNG	6.84	2.10	4.44	7.20	2.73	4.94	6.60	2.55	4.55
LPNG	2.11	0.33	1.22	1.93	0.97	1.45	1.85	0.70	1.28
High Load	4.38	1.47	2.91	4.63	2.16	3.39	4.34	2.08	3.21
Low Load	4.37	1.58	2.96	4.34	2.07	3.20	4.23	1.78	3.00
Climate Change	4.24	1.48	2.85	4.40	2.06	3.23	4.16	1.85	3.00
MD 25%	4.29	1.52	2.90	4.44	2.14	3.29	4.20	1.93	3.06
MD 35%	4.29	1.53	2.90	4.43	2.09	3.25	4.21	1.89	3.04
MD 50%	4.24	1.55	2.88	4.34	2.07	3.20	4.15	1.85	3.00
PJM 25%	3.75	1.86	2.80	4.08	2.31	3.19	3.74	2.19	2.96
CPP	3.81	1.93	2.86	3.96	2.02	2.99	3.66	2.17	2.91
ECPR	4.38	1.46	2.91	4.53	2.14	3.33	4.31	1.93	3.11
NOx Emissions Compliance	4.34	1.49	2.90	4.50	2.14	3.31	4.27	1.93	3.09

The asymmetric growth pattern over the 2015 through 2035 study period is largely the same pattern of prices for natural gas, which heavily influences wholesale PJM energy prices.

Reference Case all-hours prices grow at an average annual rate of 2.91 percent in PJM-SW over the 2015 through 2035 period, compared with 3.31 percent and 3.08 percent for PJM-MidE and PJM-APS, respectively. Energy prices tend to increase faster in the PJM-SW zone compared to the PJM-APS and PJM-MidE zones because of a slightly sharper increase at the end of the analysis period, which reflects increasing congestion.

The highest growth in prices is associated with the High Price Natural Gas scenario, which entails average annual growth over the 20-year of analysis period of between 4.44 percent (in PJM-SW) and 4.94 percent (PJM-MidE). The slowest growth over the analysis period is associated with the Low Price Natural Gas scenario, with average annual growth over the period of between 1.22 percent (PJM-SW) and 1.45 percent (PJM-MidE). For all the remaining scenarios, average annual growth in the all-hours wholesale prices vary in a relatively narrow range of between 2.68 percent and 3.39 percent. The relative consistency in prices is driven by the significance of natural gas prices as the most important factor setting prices and the fact that all the scenarios other than the high and low natural gas prices scenarios rely on the same sets of natural gas prices.

On- and Off-peak Prices

Wholesale energy prices vary depending upon the time of day and prices are typically higher in peak periods, defined by PJM as 6:00 a.m. to 11:00 p.m., Monday through Friday as compared to off-peak periods (weekends, the late night/early morning period, and holidays). Table E-2 shows how the real average annual on-peak price compares to the real average annual off-peak price on a percentage basis. Results for the year 2015 are not included in Table E-2, as the results are virtually identical across scenarios at the beginning of the study period with on-peak prices approximately 40 percentage points higher than off-peak prices in all three of the PJM zones that include portions of Maryland. However, as loads and resources change, so too does the relationship between the on-peak and off-peak prices. In most of the scenarios, the spread between the on-peak and off-peak prices decreases (i.e., on-peak and off-peak prices move closer together) over the first ten years of the study period and then decreases further, though to a lesser degree in the second half of the period. This pattern is very similar to the pattern in the all-hours energy prices and is driven by the same factor—changes in the price of natural gas and increasing reliance on natural gas over the analysis period.

Table E-2 On-peak/Off-peak Price Variability: Percentage Point Differential in On-peak Relative to Off-peak Periods (%)

Scenario	PJM-APS		PJM-MidE		PJM-SW	
	2025	2035	2025	2035	2025	2035
Reference Case	40.74%	37.18%	30.42%	29.51%	36.04%	31.31%
HPNG	36.23	30.10	24.53	20.85	34.98	26.75
LPNG	38.73	38.47	34.19	32.85	38.11	34.31
High Load	40.08	37.12	30.99	29.60	34.94	31.13
Low Load	41.05	39.18	29.26	28.48	36.65	33.03
Climate Change	39.12	35.06	28.74	27.05	34.12	28.39
MD 25%	40.22	36.88	29.99	29.20	35.30	31.20
MD 35%	40.37	36.88	29.82	28.69	35.48	30.84
MD 50%	39.75	36.70	28.79	28.01	34.83	30.60
PJM 25%	34.64	33.14	25.69	26.71	30.27	29.33
CPP	35.02	38.58	29.35	31.12	31.98	33.40
ECPR	40.87	37.10	30.62	29.46	36.25	30.61
NOx Emissions Compliance	40.42	37.02	30.05	28.98	35.51	30.05

The Reference Case on-peak/off-peak spread in PJM-SW decreases over the 2015-2025 period from approximately 40 percentage points in 2015 to 36.5 percentage points in 2025. Similarly, the on-peak/off-peak spread decreases from 40 percentage points in 2015 to 30.4 percentage points by 2025 in PJM-MidE. In PJM-APS, the spread marginally increases from 40 percentage points to 41 percentage points between 2015 and 2025. The addition of new natural gas generation reduces the on-peak/off-peak spread. In general, the scenarios with relatively higher levels of new natural gas capacity tend to have the lower on-peak/off-peak price spreads.

Natural gas prices are an important factor in determining the relationship between on-peak and off-peak prices. The on-peak/off-peak price spread is greatest in the low natural gas price scenarios. The marginal fuel in PJM is typically natural gas. When natural gas prices are low, natural gas capacity increasingly operates as baseload capacity rather than as mid-merit or peaking capacity which is the case when natural gas prices are normal or high. When natural gas prices are low, more natural gas units are built and operate as base load plants. As a result, periods of high demand are increasingly served by less efficient units with higher running costs.

APPENDIX F
Fuel Diversity

Introduction

Fuel diversity is addressed to help gauge Maryland's exposure to fuel supply disruptions and to generally facilitate assessment of the State's risk with regard to the availability of generation. To calculate a fuel diversity measure for electric generation in Maryland, we have applied a variation of the Herfindahl-Hirschman Index (HHI). This index is normally used to estimate market concentration in a particular industry. The index is defined as the sum of the squares of each firm's market share. The HHI is given by the formula:

$$HHI = \sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the i^{th} firm.[146]

When an industry is occupied by only one firm (i.e., a monopoly), the index takes a value of 1. As more firms enter the market, the value of the index declines; however, the greater the inequality among market participants, that is, the more concentrated the industry, the higher the value of the index. By definition, the minimum value of the index is equal to (1/*N*), where *N* is the number of firms participating in the market.

For use in this report, S_i is defined as the share of generation for the i^{th} fuel. Four fuel types have been allowed for electricity generation in Maryland: natural gas (*g*), coal (*c*), nuclear (*n*), and renewables (*r*). Two other modifications were made to make the index more intuitive. First, the index is subtracted from one, so that the higher the index value, the higher the degree of diversity. Second, the index is multiplied by four-thirds (i.e., 1.333) so the index value covers the range of zero to one. Therefore, the fuel diversity factor (FDF) is defined by the following formula:

$$FDF_t = (1-(S_{gt}^{\,2} + S_{ct}^{\,2} + S_{nt}^{\,2} + S_{rt}^{\,2})) \times 1.333$$

Where: FDF_t is the fuel diversity factor in time period t;

S_{gt} is the share of total MWh generation attributable to natural gas in time period *t*;

S_{ct} is the share of total MWh generation attributable to coal in time period *t*;

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[146] Jean Tirole, *The Theory of Industrial Organization* (London: The MIT Press, 2003), https://mitpress.mit.edu/books/theory-industrial-organization, 221; and
F. M. Scherer, *Industrial Market Structure and Economic Performance, Second Edition* (Boston: Houghton Mifflin Company, 1980), 58.

S_{nt} is the share of total MWh generation attributable to nuclear in time period *t*; and

S_{rt} is the share of total MWh generation attributable to renewables in time period *t*.

As stated above, the maximum value of FDF (i.e., maximum diversity) is 1.0 and results when all fuels have an equal share of total MWh generation:

$$FDF = (1-(0.25^2 + 0.25^2 + 0.25^2 + 0.25^2)) \times 1.333 = 1.0$$

The minimum value of FDF (i.e., minimum diversity) is zero and occurs only in the case where one fuel accounts for all generation. For example, if all electricity in Maryland were to be generated using coal as a fuel, the index would take the following value:

$$FDF = (1-(0^2 + 1^2 + 0^2 + 0^2)) \times 1.333 = 0.0$$

In a case where there are unequal shares of generation, but no one fuel accounts for all generation, the FDF value will be between 0.0 and 1.0. For example, if natural gas accounts for 15 percent of generation, coal accounts for 60 percent, nuclear accounts for 20 percent, and renewables account for 5 percent, the FDF would equal:

$$FDF = (1-(0.15^2 + 0.60^2 + 0.20^2 + 0.05^2)) \times 1.333 = 0.77$$

For any particular scenario, the Fuel Diversity Factor will vary from year to year depending on the degree to which new generating resources are added, the degree to which new generation facilities differ from existing generation facilities in terms of fuel, and the degree to which the existing stock of generating facilities is retired.

Diversity in Maryland Generation

The tables below show the calculated FDFs for Maryland generation for each of the scenarios considered, including the Reference Case. To allow the data to be presented in a way that can be meaningfully interpreted, the FDF values are shown for 2015, 2025, and 2035.

Table F-1 Maryland Fuel Diversity, 2015

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	45.5%	30.1%	13.8%	10.6%	0.90
HPNG	45.5	30.1	13.8	10.6	0.90
LPNG	45.5	30.1	13.8	10.6	0.90
High Load	45.5	30.1	13.8	10.6	0.90
Low Load	45.5	30.1	13.8	10.6	0.90
Climate Change	45.5	30.1	13.8	10.6	0.90
MD 25% RPS	45.5	30.1	13.8	10.6	0.90
MD 35% RPS	45.5	30.1	13.8	10.6	0.90
MD 50% RPS	45.5	30.1	13.8	10.6	0.90
PJM 25% RPS	45.5	30.1	13.8	10.6	0.90
CPP	45.5	30.1	13.8	10.6	0.90
ECPR	45.5	30.1	13.8	10.6	0.90
MD NOx Regulation	45.5	30.1	13.8	10.6	0.90

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table F-2 Maryland Fuel Diversity, 2025

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	39.5%	28.7%	17.7%	14.1%	0.95
HPNG	32.4	44.6	11.4	11.6	0.89
LPNG	40.6	16.3	28.6	14.5	0.94
High Load	38.1	28.9	19.5	13.6	0.95
Low Load	41.6	29.5	14.1	14.8	0.93
Climate Change	38.8	27.6	19.8	13.8	0.95
MD 25% RPS	39.7	28.2	17.0	15.1	0.95
MD 35% RPS	39.2	28.0	16.9	15.8	0.95
MD 50% RPS	39.6	27.7	16.4	16.4	0.95
PJM 25% RPS	43.6	27.6	12.2	16.5	0.92
CPP	40.2	27.2	18.2	14.3	0.95
ECPR	41.0	21.7	22.7	14.6	0.95
MD NOx Regulation	40.6	19.0	26.0	14.5	0.95

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table F-3 Maryland Fuel Diversity, 2035

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	23.2%	38.7%	19.7%	18.5%	0.97
HPNG	17.6	57.7	10.7	14.0	0.81
LPNG	26.0	19.5	33.8	20.7	0.98
High Load	21.3	39.0	22.8	17.0	0.96
Low Load	25.4	38.2	16.2	20.2	0.96
Climate Change	22.7	37.3	21.9	18.1	0.97
MD 25% RPS	23.2	38.0	19.1	19.7	0.97
MD 35% RPS	23.0	37.5	18.8	20.8	0.97
MD 50% RPS	22.5	35.3	17.7	24.5	0.98
PJM 25% RPS	24.6	38.4	16.2	20.9	0.96
CPP	22.4	30.6	29.1	17.9	0.99
ECPR	24.2	31.0	25.6	19.2	0.99
MD NOx Regulation	23.9	27.5	29.6	19.0	0.99

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table F-4 PJM Fuel Diversity, 2015

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	31.8%	32.2%	31.9%	4.1%	0.92
HPNG	31.8	32.2	31.9	4.1	0.92
LPNG	31.8	32.2	31.9	4.1	0.92
High Load	31.8	32.2	31.9	4.1	0.92
Low Load	31.8	32.2	31.9	4.1	0.92
Climate Change	31.8	32.2	31.9	4.1	0.92
MD 25% RPS	31.8	32.2	31.9	4.1	0.92
MD 35% RPS	31.8	32.2	31.9	4.1	0.92
MD 50% RPS	31.8	32.2	31.9	4.1	0.92
PJM 25% RPS	31.8	32.2	31.9	4.1	0.92
CPP	31.8	32.2	31.9	4.1	0.92
ECPR	31.8	32.2	31.9	4.1	0.92
MD NOx Regulation	31.8	32.2	31.9	4.1	0.92

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table F-5 PJM Fuel Diversity, 2025

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	25.5%	36.4%	32.3%	5.9%	0.93
HPNG	25.6	41.4	27.2	5.9	0.91
LPNG	25.6	27.2	41.3	5.9	0.92
High Load	24.3	34.9	35.2	5.6	0.92
Low Load	26.7	38.0	29.2	6.1	0.93
Climate Change	25.3	36.0	33.0	5.8	0.93
MD 25% RPS	25.4	36.2	32.1	6.3	0.93
MD 35% RPS	25.4	36.2	31.9	6.5	0.93
MD 50% RPS	25.4	36.1	31.5	7.0	0.93
PJM 25% RPS	24.8	34.4	24.8	16.0	0.98
CPP	26.4	34.2	30.7	8.7	0.95
ECPR	25.5	36.2	32.5	5.9	0.93
MD NOx Regulation	25.5	35.9	32.8	5.8	0.93

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

Table F-6 PJM Fuel Diversity, 2035

Scenario	Nuclear	Coal	Natural Gas	Renewables	Diversity Factor*
Reference Case	16.8%	33.5%	43.9%	5.7%	0.88
HPNG	16.8	36.4	41.1	5.7	0.89
LPNG	17.1	19.6	57.5	5.8	0.80
High Load	15.4	30.8	48.5	5.3	0.86
Low Load	18.5	36.8	38.3	6.3	0.91
Climate Change	16.7	33.3	44.3	5.7	0.88
MD 25% RPS	16.8	33.4	43.6	6.2	0.89
MD 35% RPS	16.8	33.4	43.0	6.8	0.89
MD 50% RPS	16.8	33.3	40.8	9.1	0.91
PJM 25% RPS	16.6	32.8	34.8	15.7	0.96
CPP	17.8	31.1	35.1	15.9	0.96
ECPR	16.9	33.4	44.0	5.8	0.88
MD NOx Regulation	16.8	33.2	44.2	5.8	0.88

* Diversity Factor = (1-((%Nuclear^2)+(%Coal^2)+(%Gas^2)+(%Renewable^2)))*(4/3)

In 2015, the FDF is 0.9 for all scenarios since this is the base year of the analysis. By 2025, all of the scenarios exhibit increases in the FDF as natural gas plants begin to be added and as the share of renewables increases. The bulk of scenarios show FDFs of between 0.90 and 1.0 in 2035. The highest increases, that is, those scenarios showing the highest FDFs in 2035, are those scenarios based on high renewables assumptions. The HPNG scenario exhibits the lowest index, since generation is more heavily concentrated in coal. By 2035, the addition of significant natural gas generation and renewables results in FDFs above 0.95 for all scenarios with the exception of the HPNG scenario, which is calculated as 0.82.

APPENDIX G
Emissions Comparisons

The electricity consumed by Maryland end-users may or may not be generated from within the State since power generated in other states may be imported into Maryland and power generated in Maryland may be exported to other states. The emissions section for each scenario addressed in Chapters 4 through 9 presents data regarding projected emissions from power plants that are located in Maryland. The data, however, does not represent emissions related to consumption of electricity, but rather from the generation of electricity. This section is included to provide estimates of emissions associated with electricity consumed in Maryland.

To estimate the consumption-based emissions levels, the ratio for each pollutant was calculated for PJM-wide emissions to the level of energy consumption in PJM for each year during the study period. The annual ratios were calculated for all of the LTER scenarios for SO_2, NOx, mercury, and CO_2. These ratios were then applied to the projected annual levels of energy consumption in Maryland under each scenario to estimate Maryland's *pro rata* share of PJM emissions.[147]

A specified percentage of Maryland's electricity is required to come from renewable energy sources each year pursuant to Maryland's RPS. Because of this requirement, Maryland's projected level of energy consumption was adjusted to account for this difference. For example, in 2018, Maryland's RPS stipulates that 15.8 percent of the electricity consumed in the State must come from Tier 1 renewable resources, but only about 4 percent of the electricity in PJM is projected to come from such resources.[148] Thus, in 2011, the emissions-to-consumption ratios were multiplied by 88.2 percent of the State's projected annual energy consumption to exclude the amount of renewable energy over and above the PJM system mix that must be consumed in Maryland to comply with Maryland's RPS. The 88.2 percent figure represents 100 percent of the PJM system generation mix, which includes 4 percent renewables, less the 11.8 percentage points of additional renewables required under the RPS.

Based on these calculations, the following figures illustrate the level of emissions associated with energy consumption in Maryland for each scenario considered in the main body of the LTER. There are three graphs for each pollutant which display the level of emissions in 2015, 2025, and 2035. Additionally, there are three more graphs for each pollutant that show annual averages for the periods 2015 through 2025, 2025 through 2035, and 2015 through 2035.

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[147] Maryland energy consumption projections were based on the *Public Service Commission of Maryland Ten-Year Plan (2014-2023) of Electric Companies in Maryland* for years 2015 through 2023, then the estimated growth rate during that timeframe (approximately 0.7 percent) was applied to years 2024 through 2035. http://webapp.psc.state.md.us/intranet/Reports/2014%20-%202023%20TYP%20Final.pdf.

[148] Maryland's required level of renewable energy consumption was increased for the High and Moderate Renewables scenarios.

Figure G.1 2015 SO_2 Emissions from Electricity Generation in Maryland

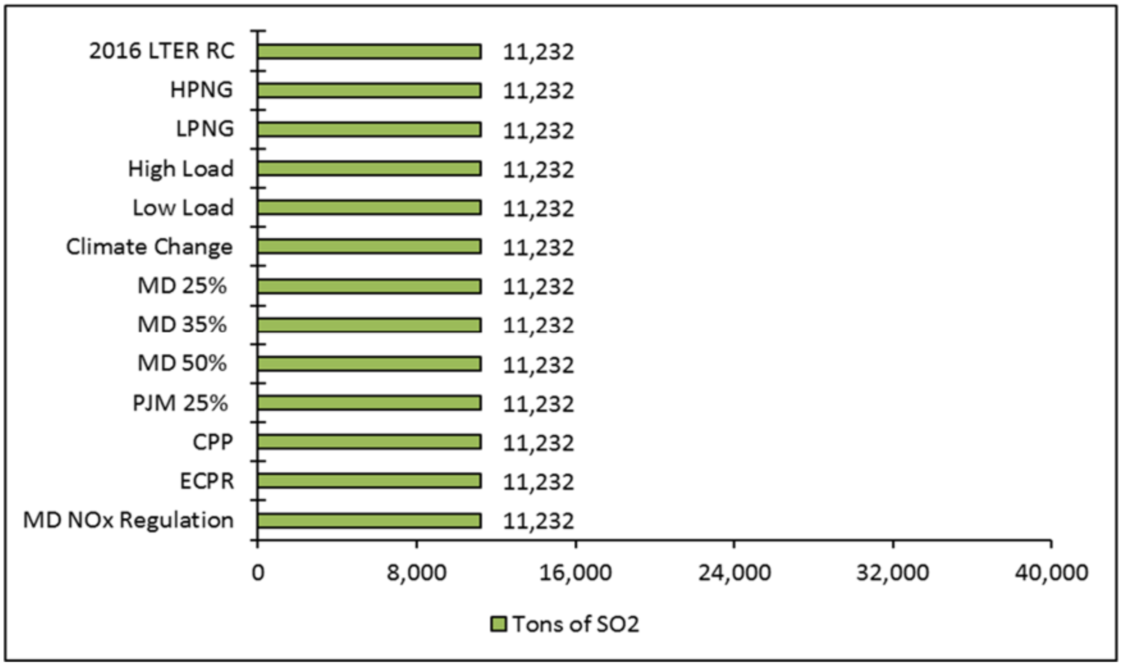


Figure G.2 2025 SO_2 Emissions from Electricity Generation in Maryland

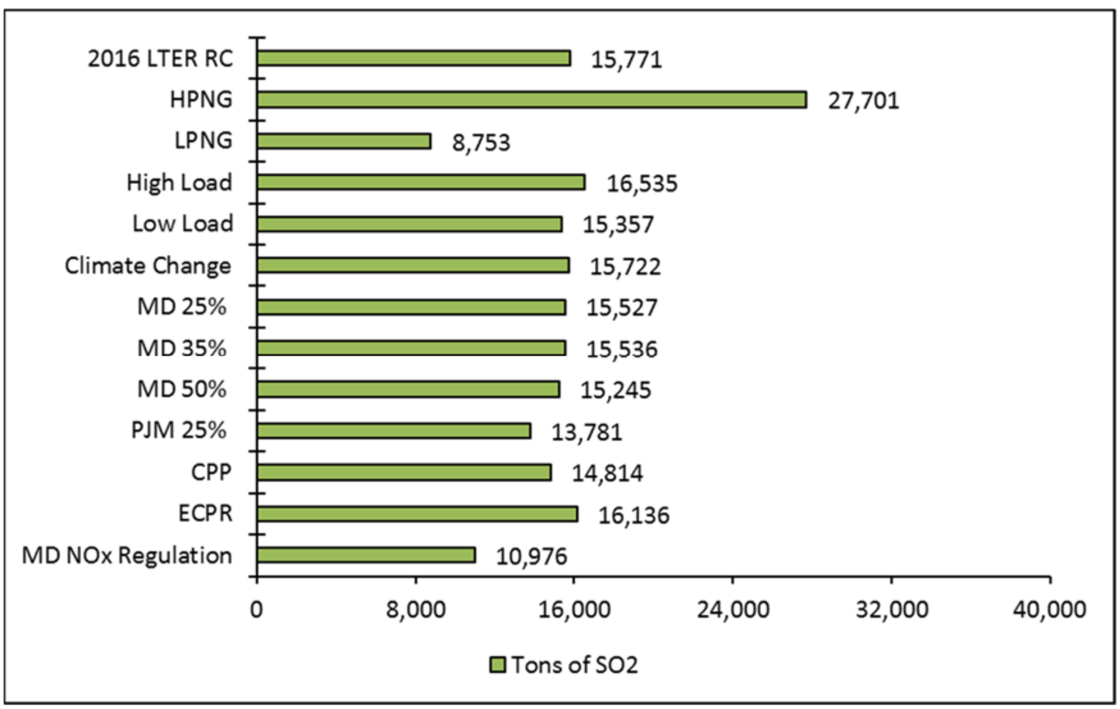


Figure G.3 2035 SO_2 Emissions from Electricity Generation in Maryland

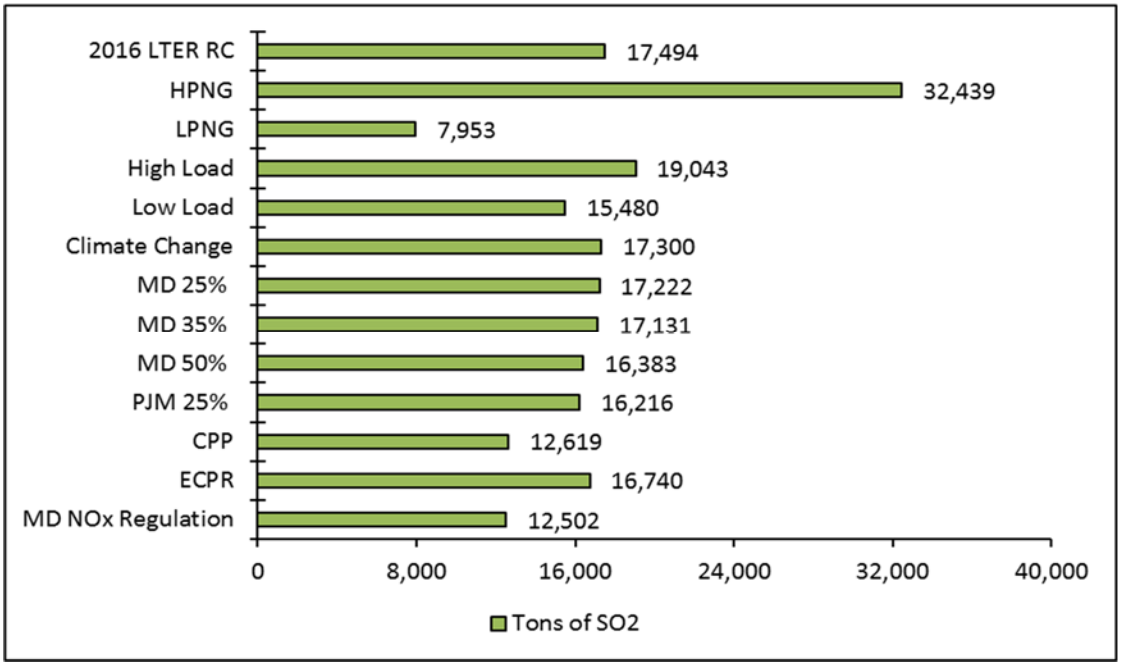


Figure G.4 2015-2025 Average Annual SO_2 Emissions from Electricity Generation in Maryland

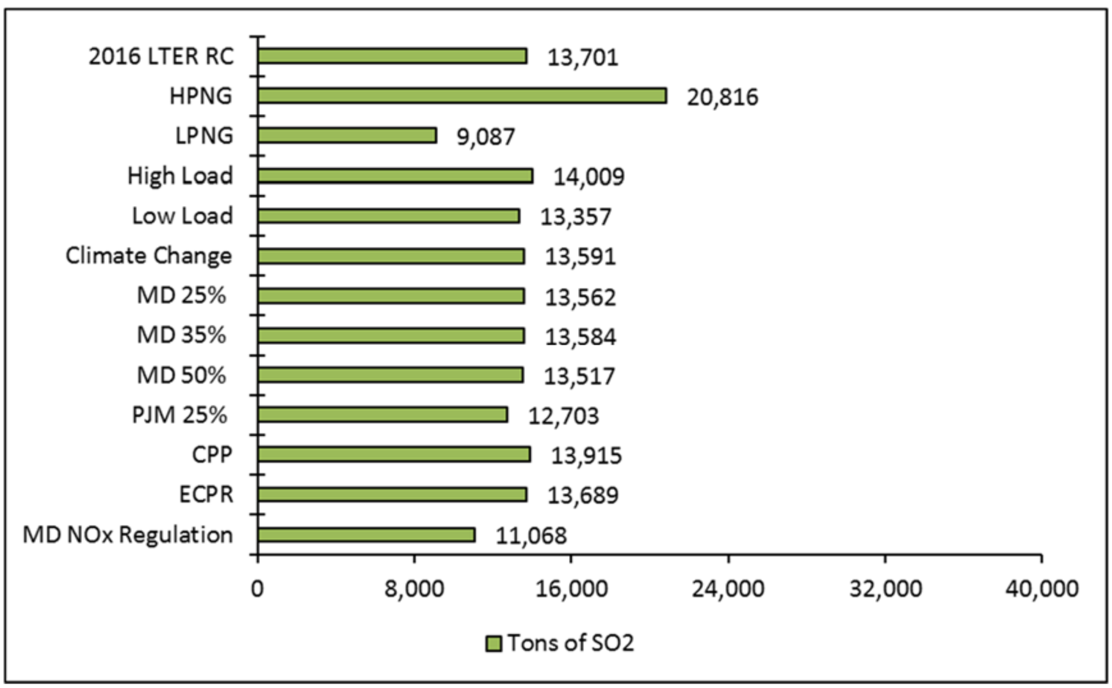


Figure G.5 2025-2035 Average Annual SO_2 Emissions from Electricity Generation in Maryland

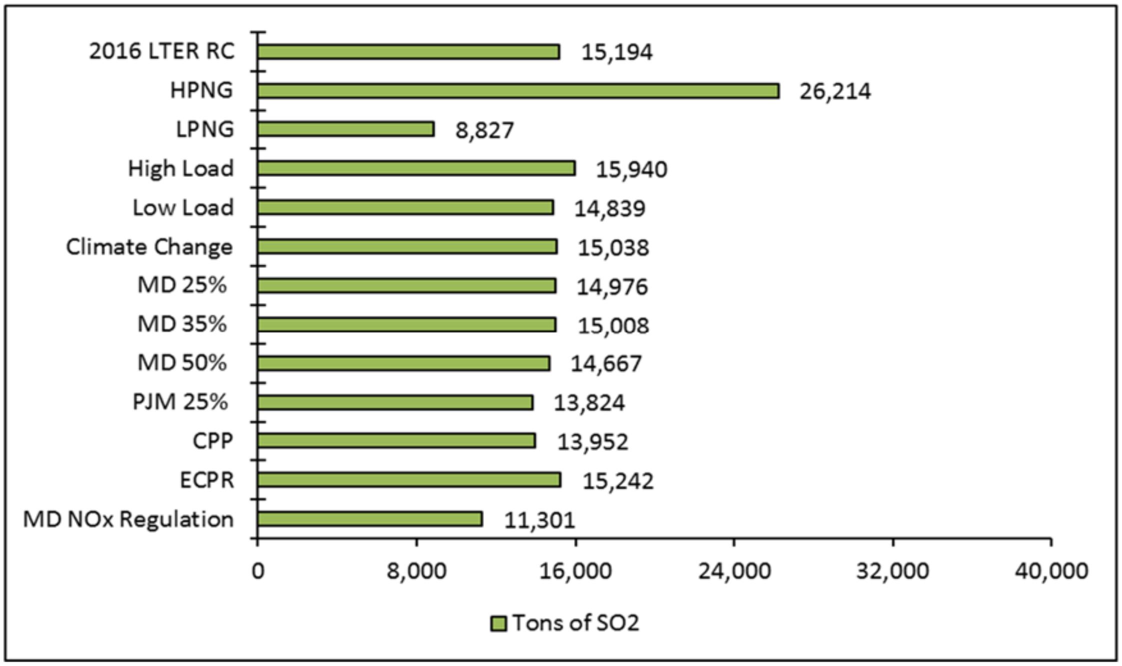


Figure G.6 2015-2035 Average Annual SO_2 Emissions from Electricity Generation in Maryland

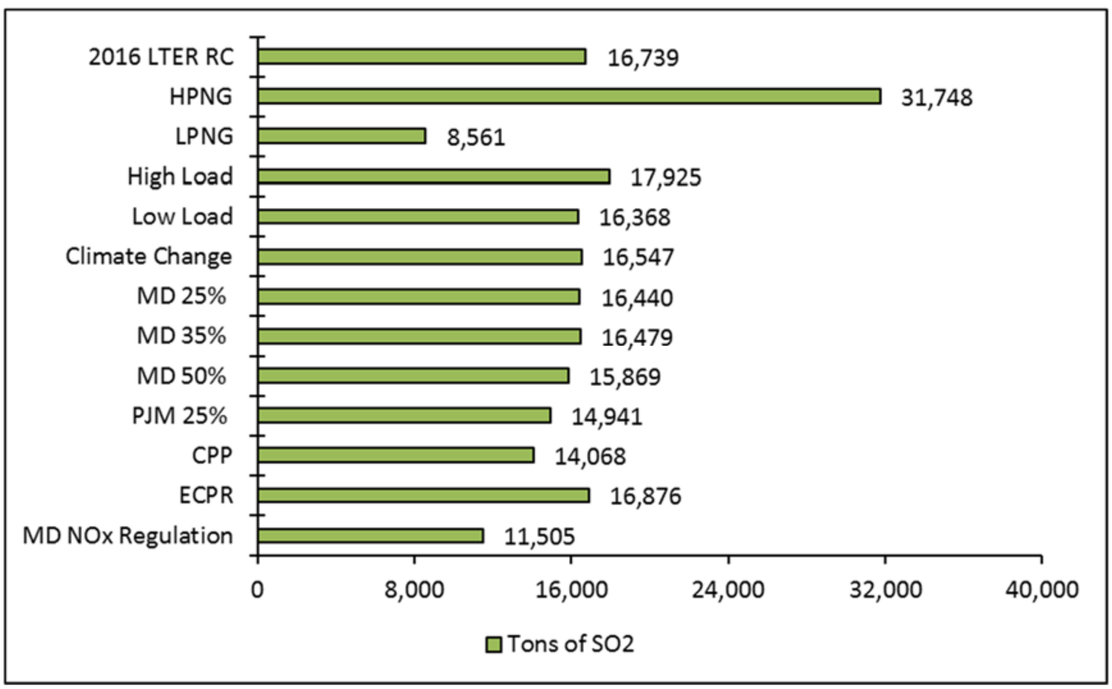


Figure G.7 2015 NOx Emissions from Electricity Generation in Maryland

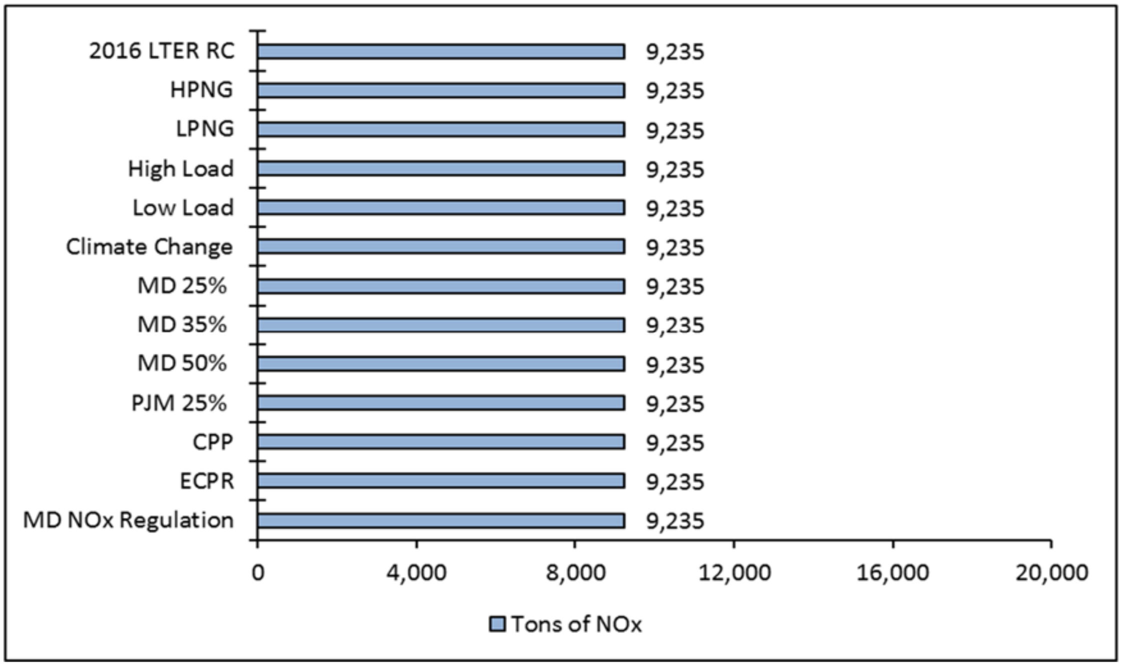


Figure G.8 2025 NOx Emissions from Electricity Generation in Maryland

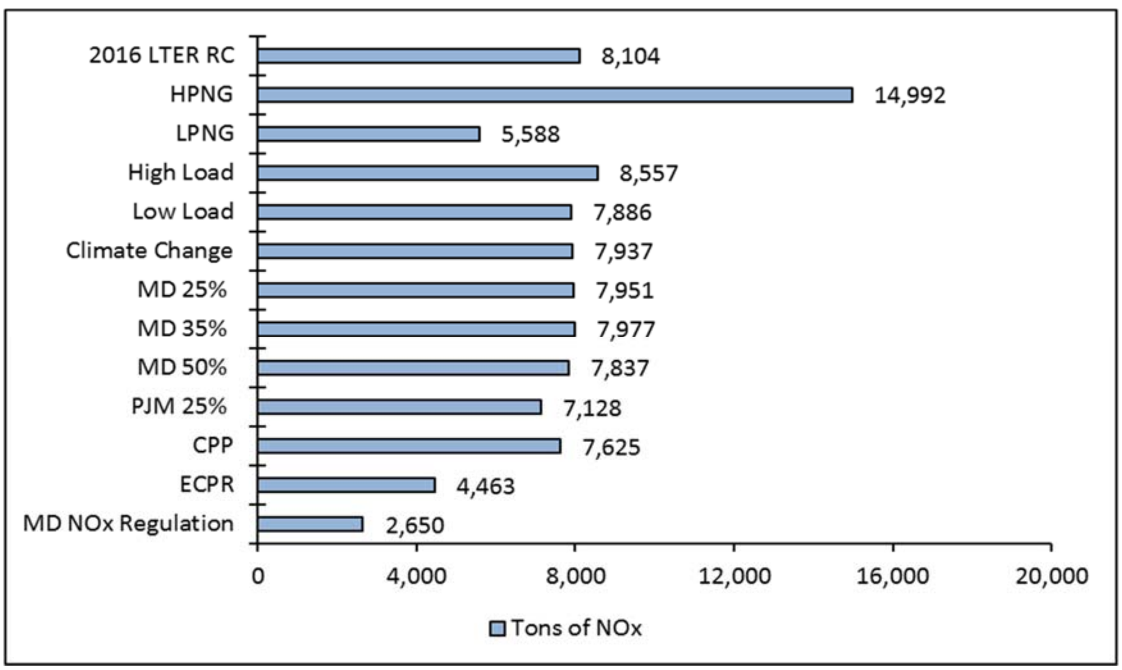


Figure G.9 2035 NOx Emissions from Electricity Generation in Maryland

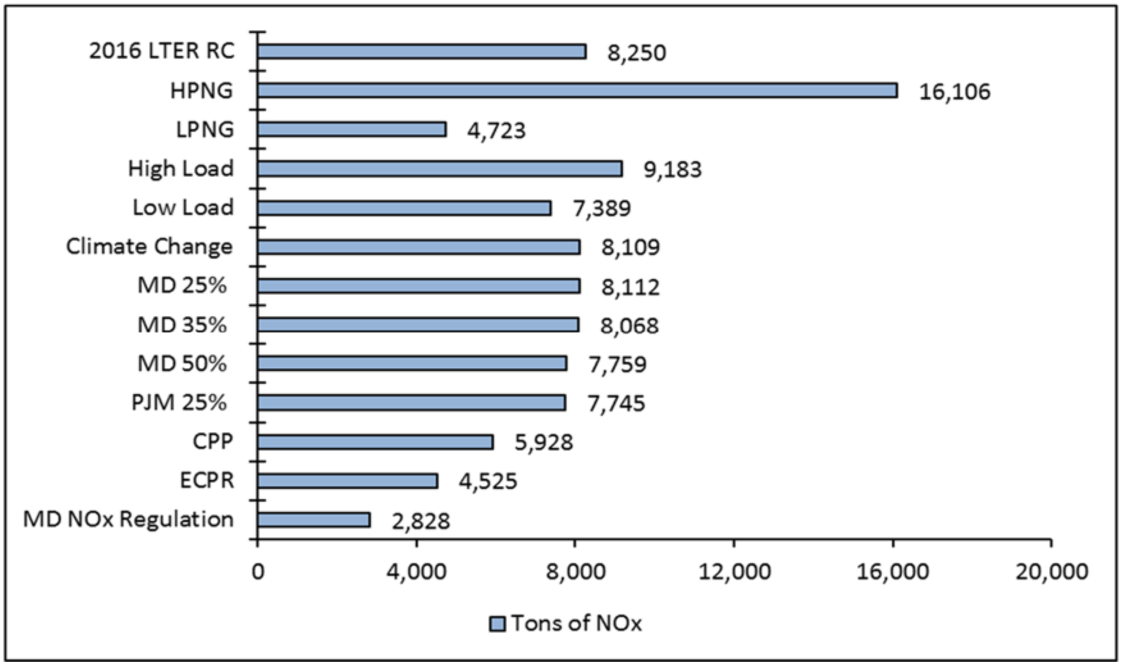


Figure G.10 2015-2025 Average Annual NOx Emissions from Electricity Generation in Maryland

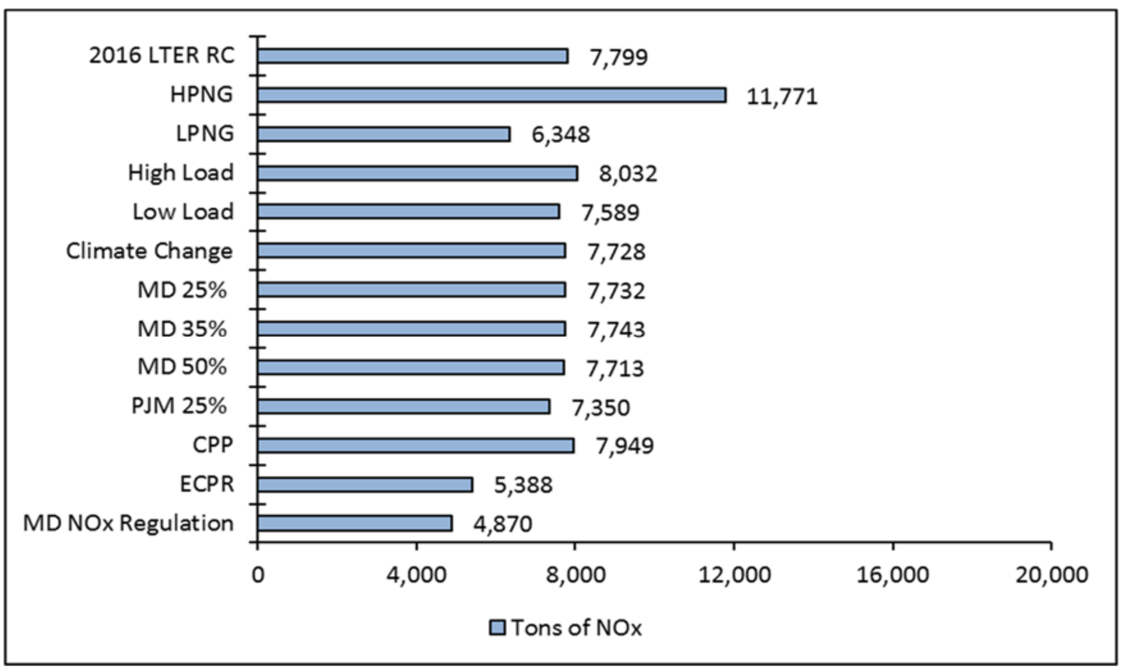


Figure G.11 2025-2035 Average Annual NOx Emissions from Electricity Generation in Maryland

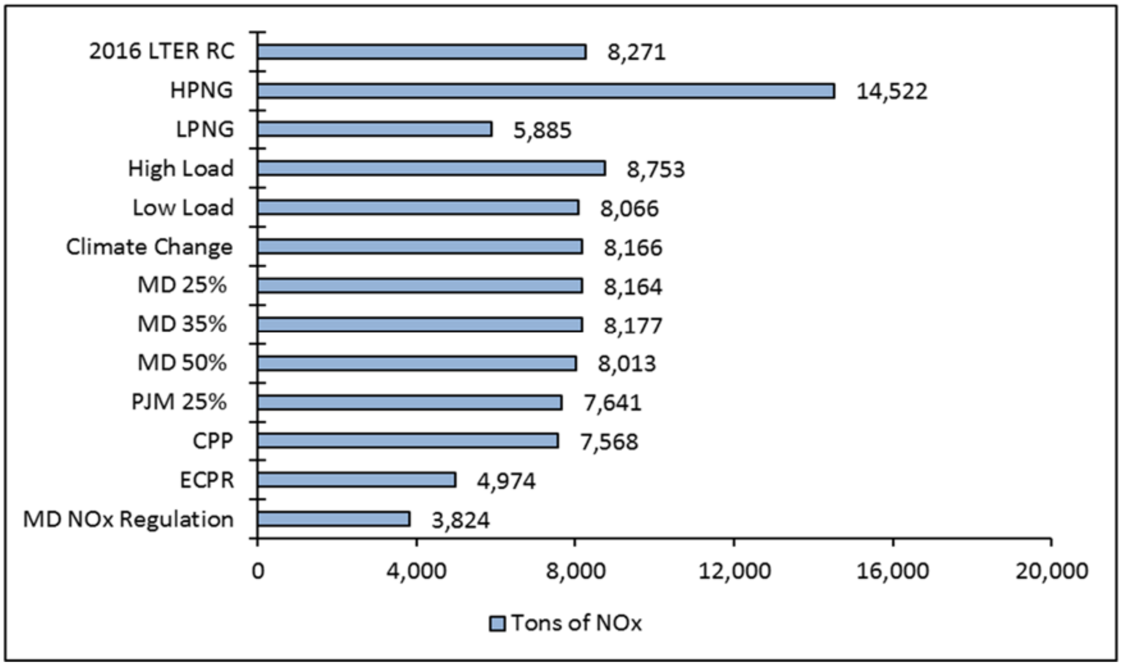


Figure G.12 2015-2035 Average Annual NOx Emissions from Electricity Generation in Maryland

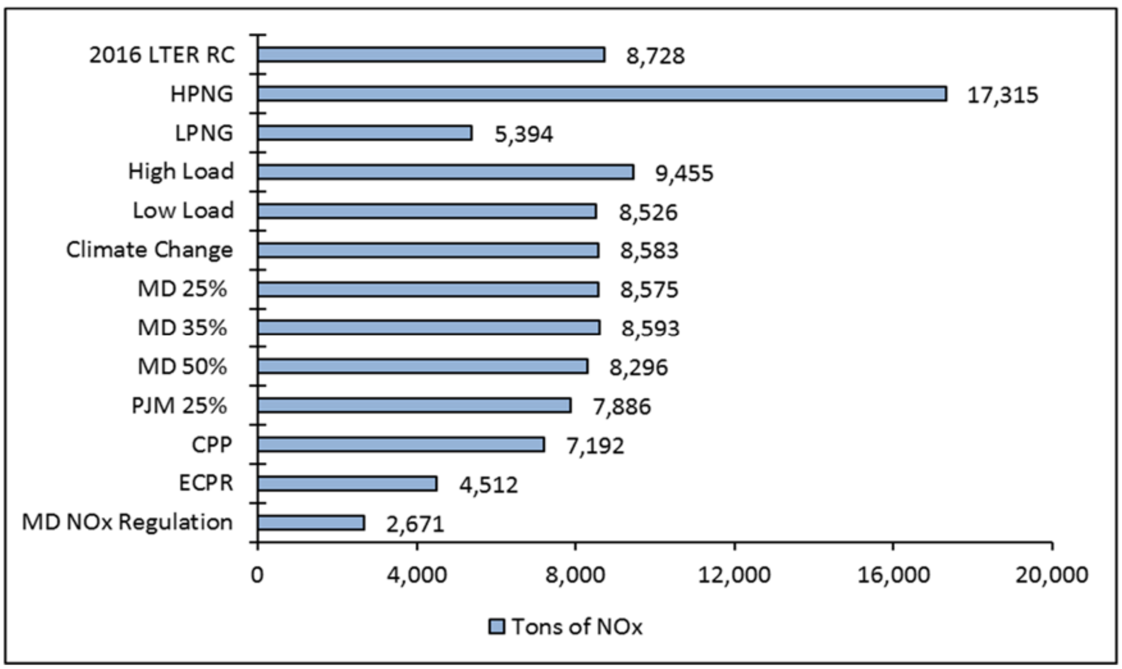


Figure G.13 2015 Mercury Emissions from Electricity Generation in Maryland

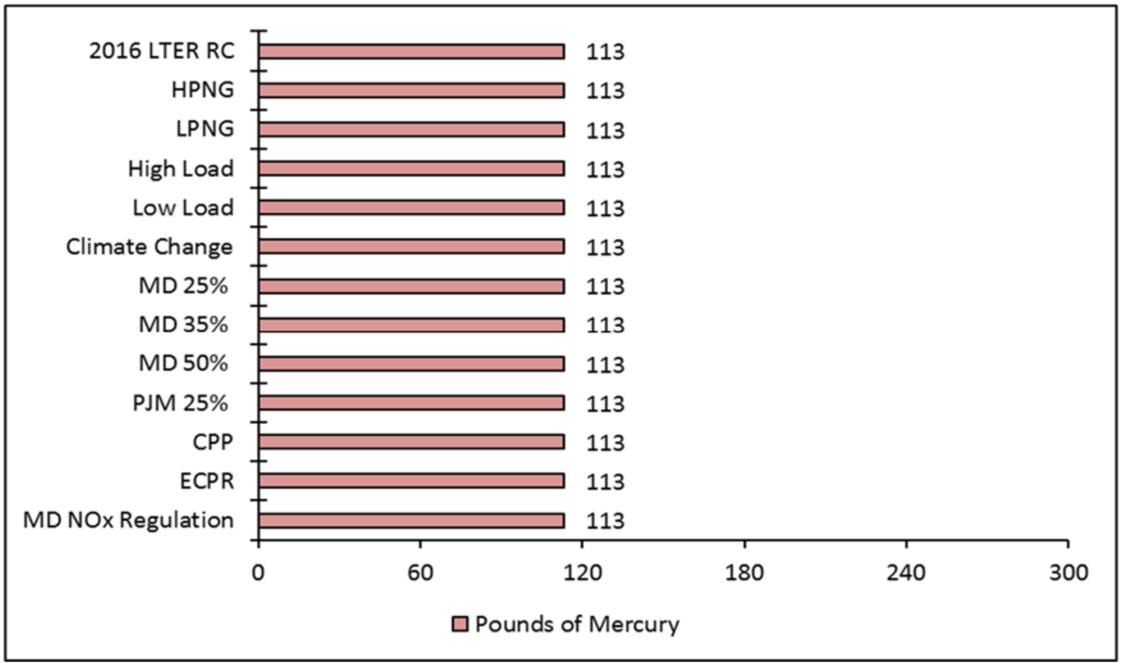


Figure G.14 2025 Mercury Emissions from Electricity Generation in Maryland

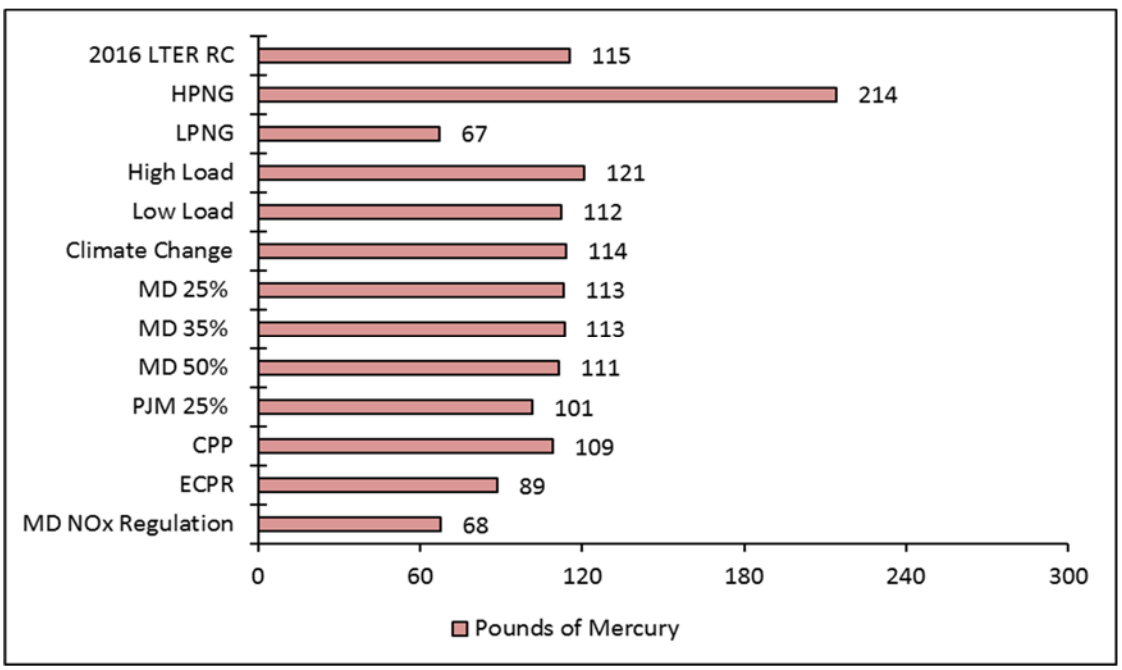


Figure G.15 2035 Mercury Emissions from Electricity Generation in Maryland

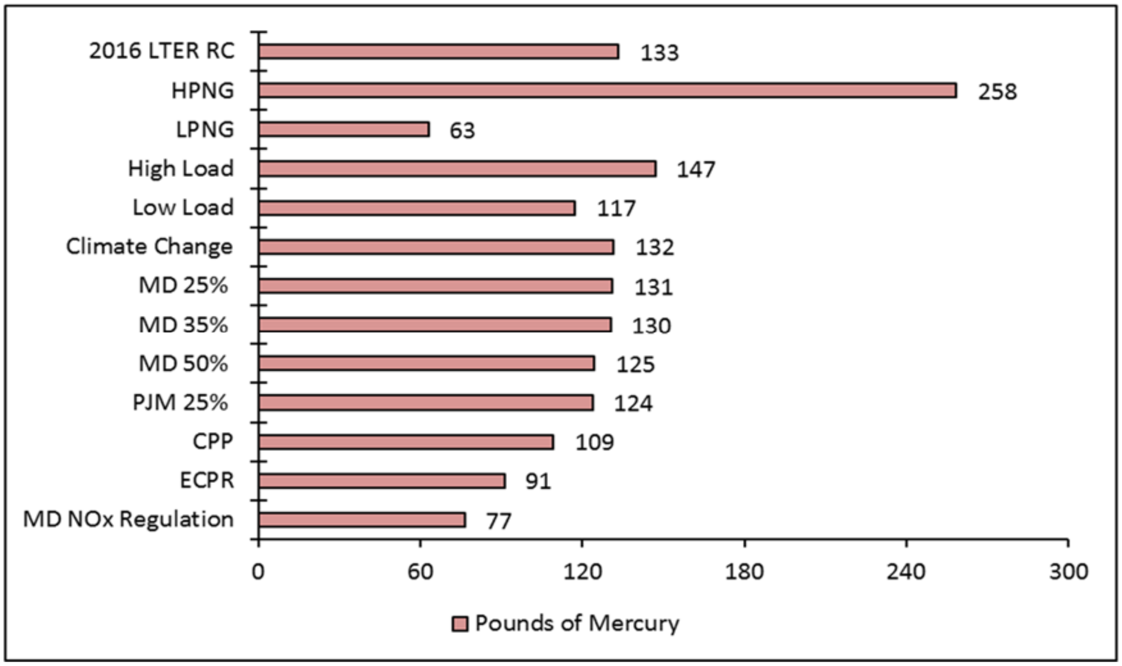


Figure G.16 2015-2025 Average Annual Mercury Emissions from Electricity Generation in Maryland

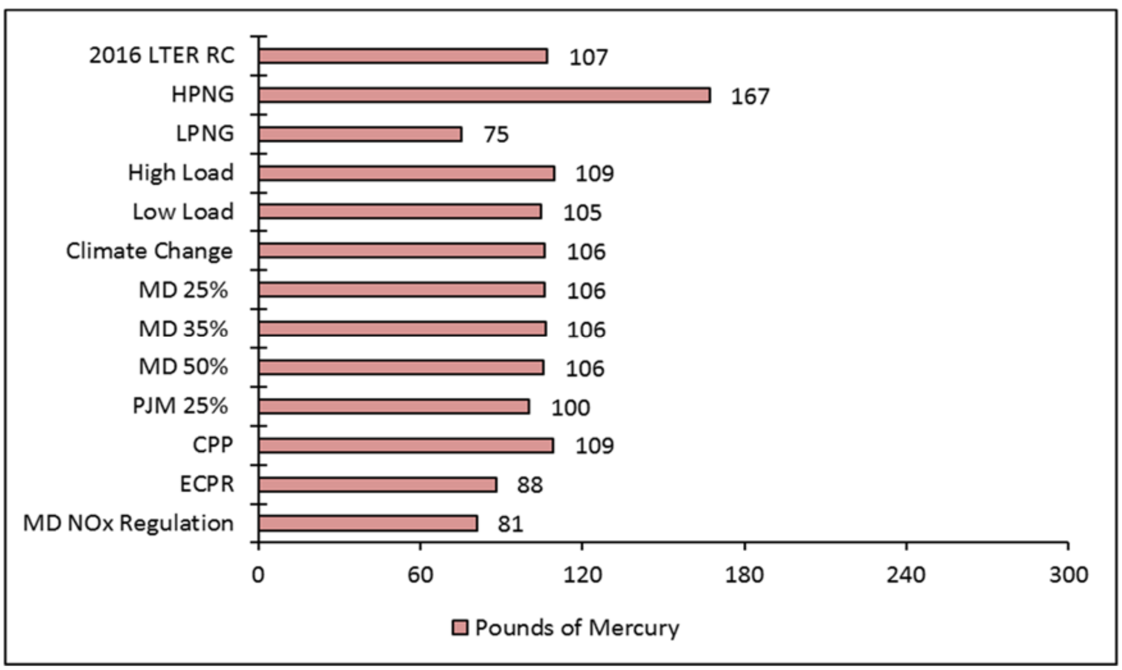


Figure G.17 2025-2035 Average Annual Mercury Emissions from Electricity Generation in Maryland

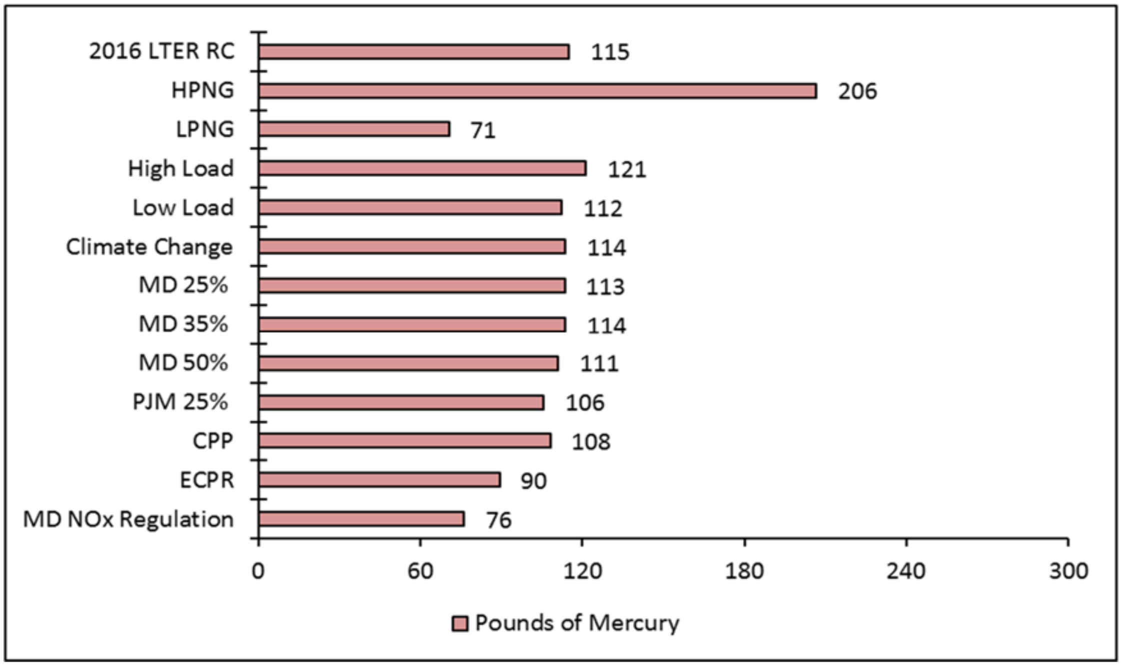


Figure G.18 2015-2035 Average Annual Mercury Emissions from Electricity Generation in Maryland

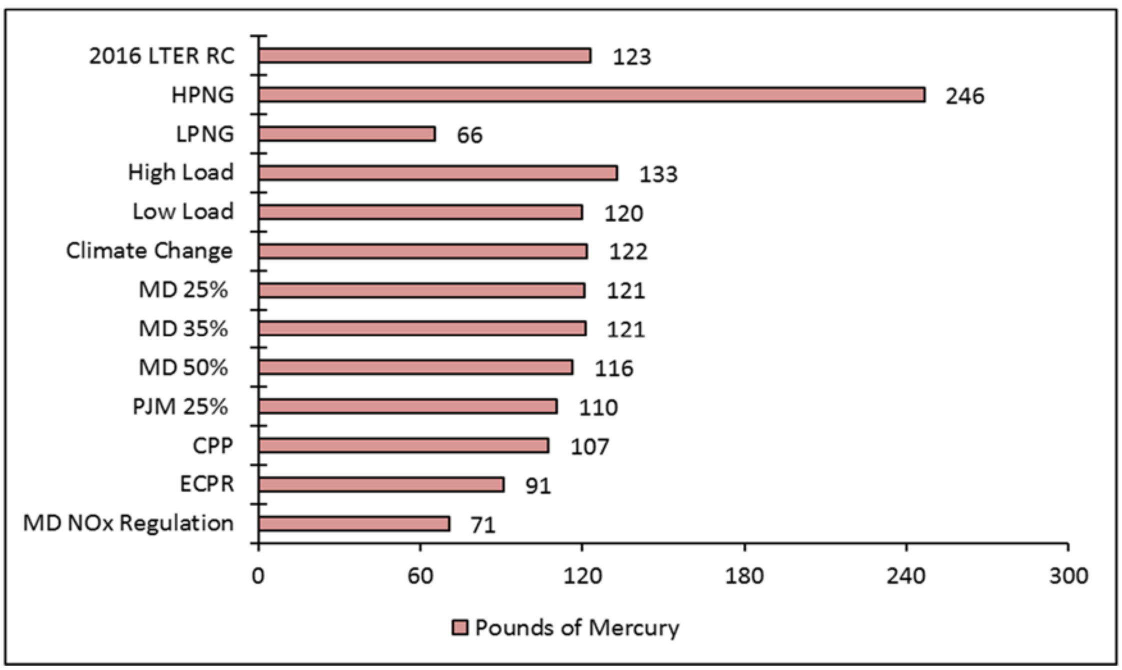


Figure G.19 2015 CO_2 Emissions from Electricity Generation in Maryland

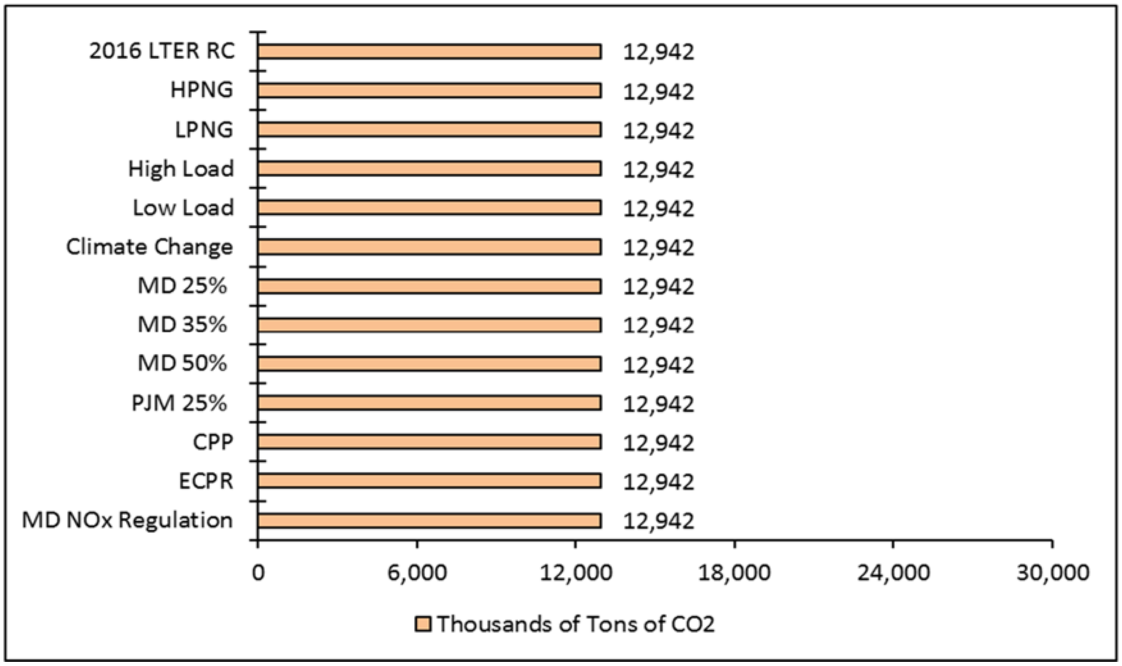


Figure G.20 2025 CO_2 Emissions from Electricity Generation in Maryland

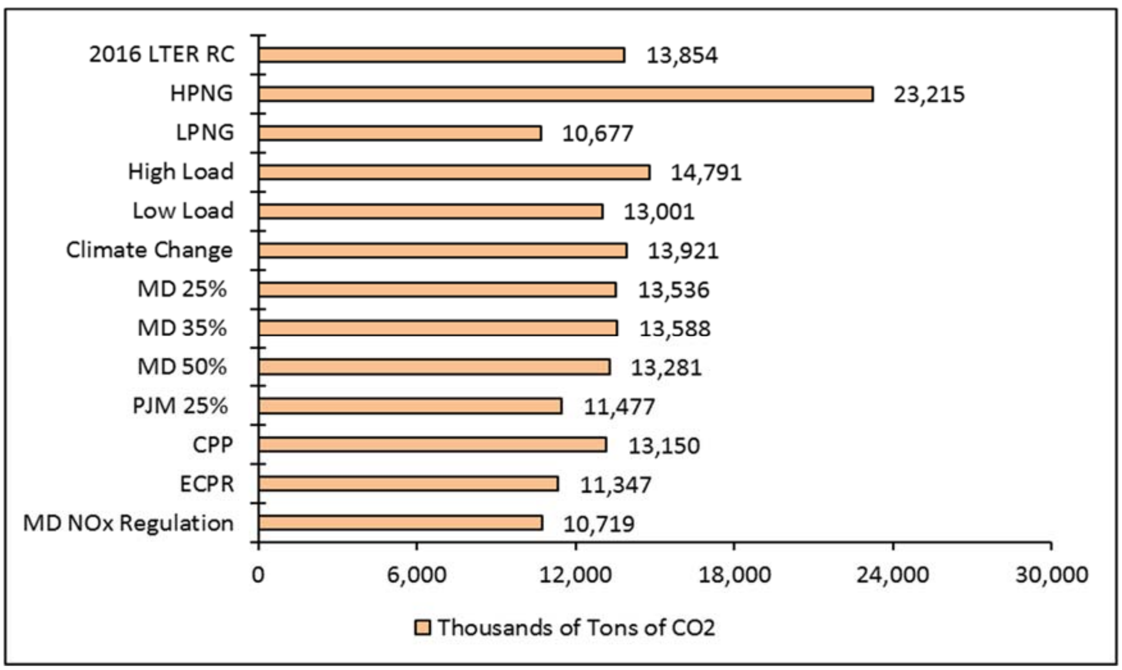


Figure G.21 2035 CO_2 Emissions from Electricity Generation in Maryland

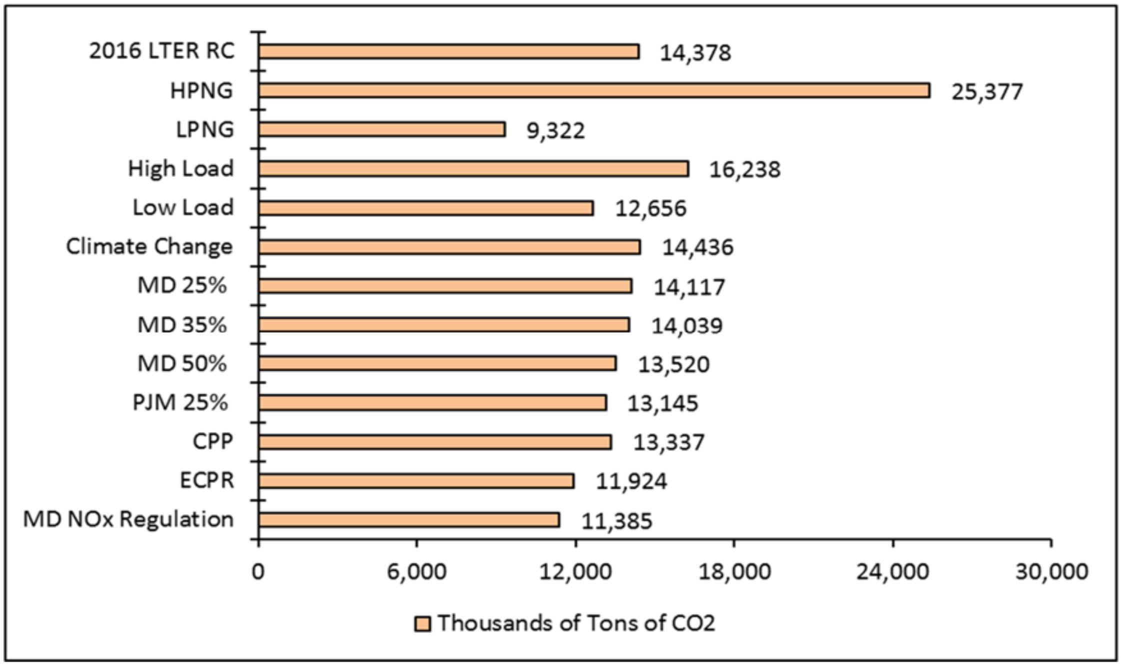


Figure G.22 2015-2025 Average Annual CO_2 Emissions from Electricity Generation in Maryland

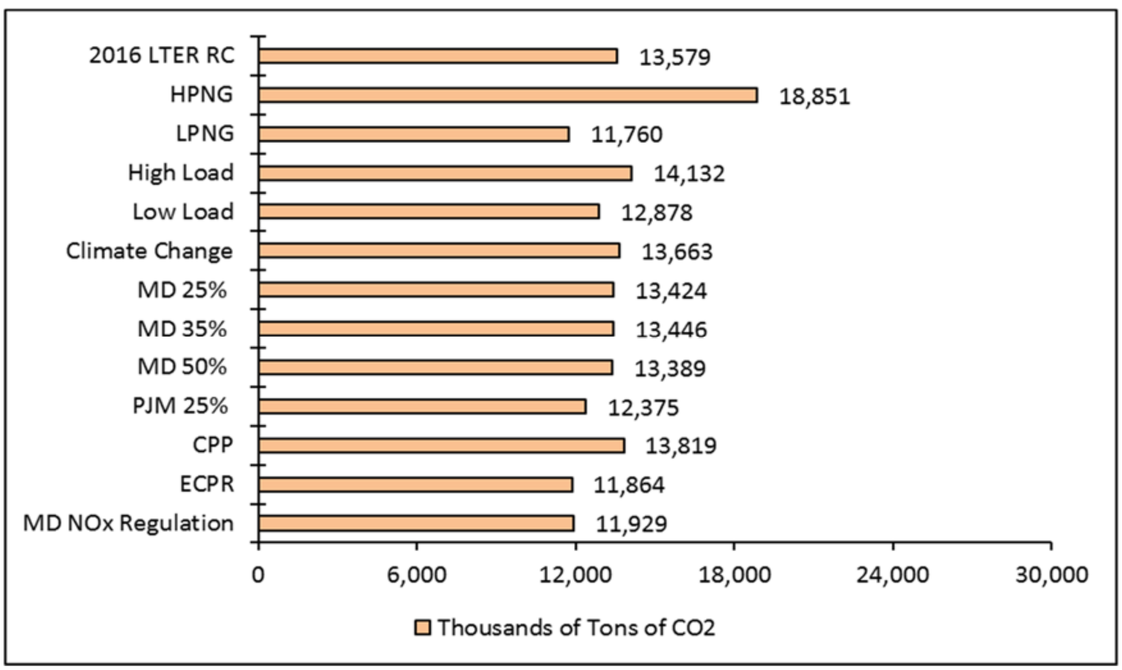


Figure G.23 2025-2035 Average Annual CO_2 Emissions from Electricity Generation in Maryland

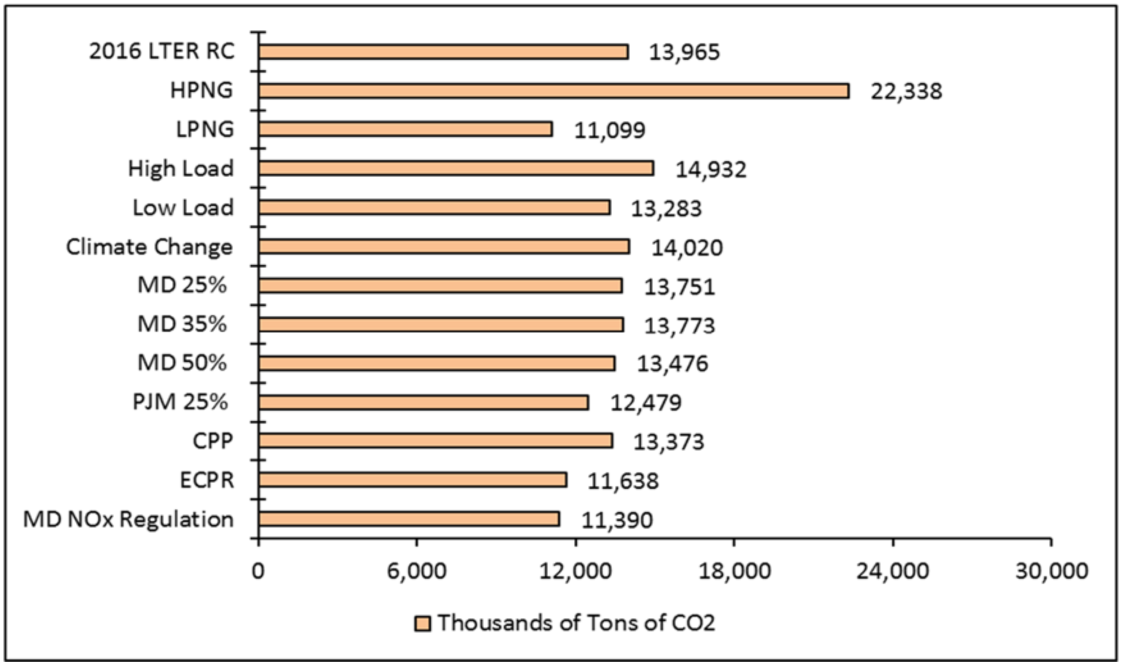


Figure G.24 2015-2035 Average Annual CO_2 Emissions from Electricity Generation in Maryland

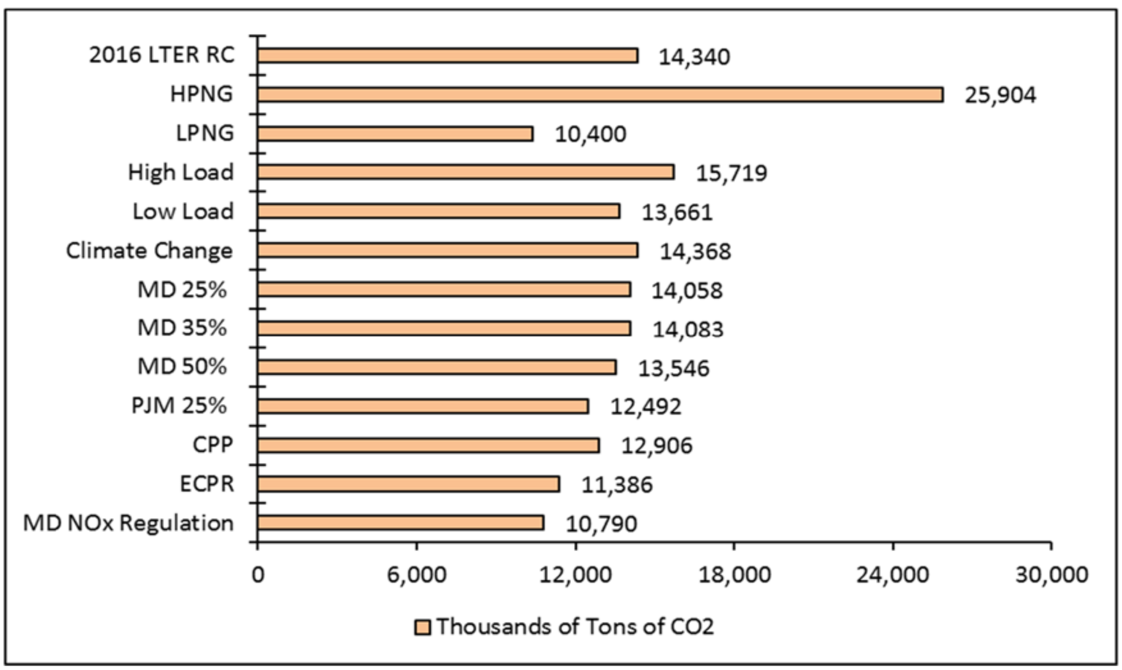


Figure G.25 2015 SO_2 Emissions from Electricity Consumption in Maryland

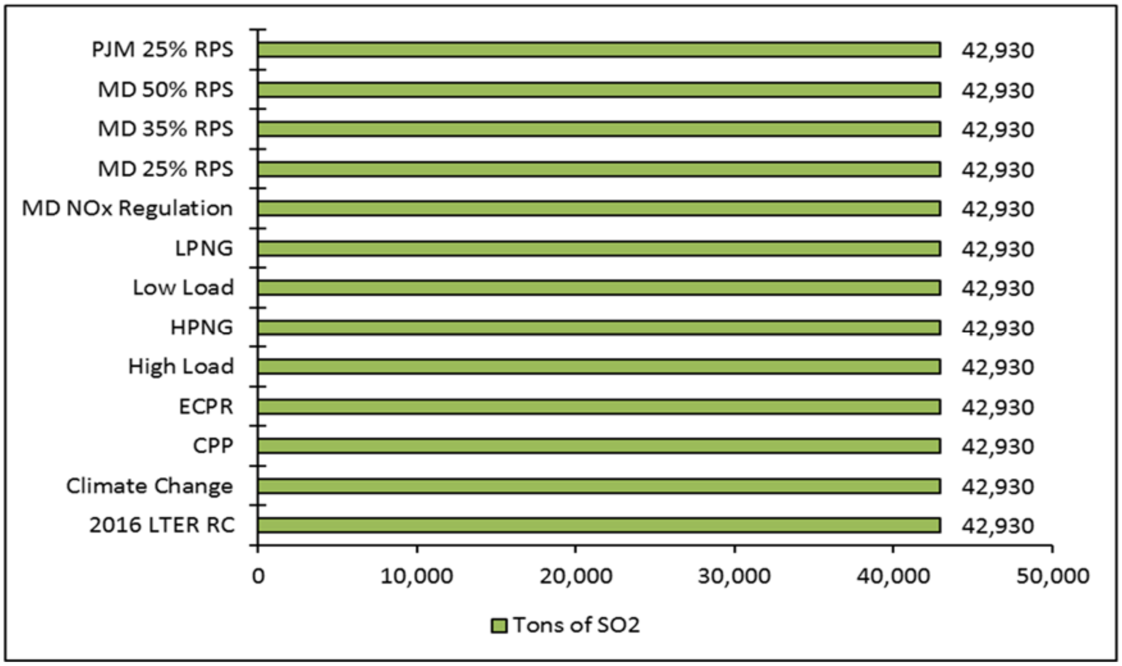


Figure G.26 2025 SO_2 Emissions from Electricity Consumption in Maryland

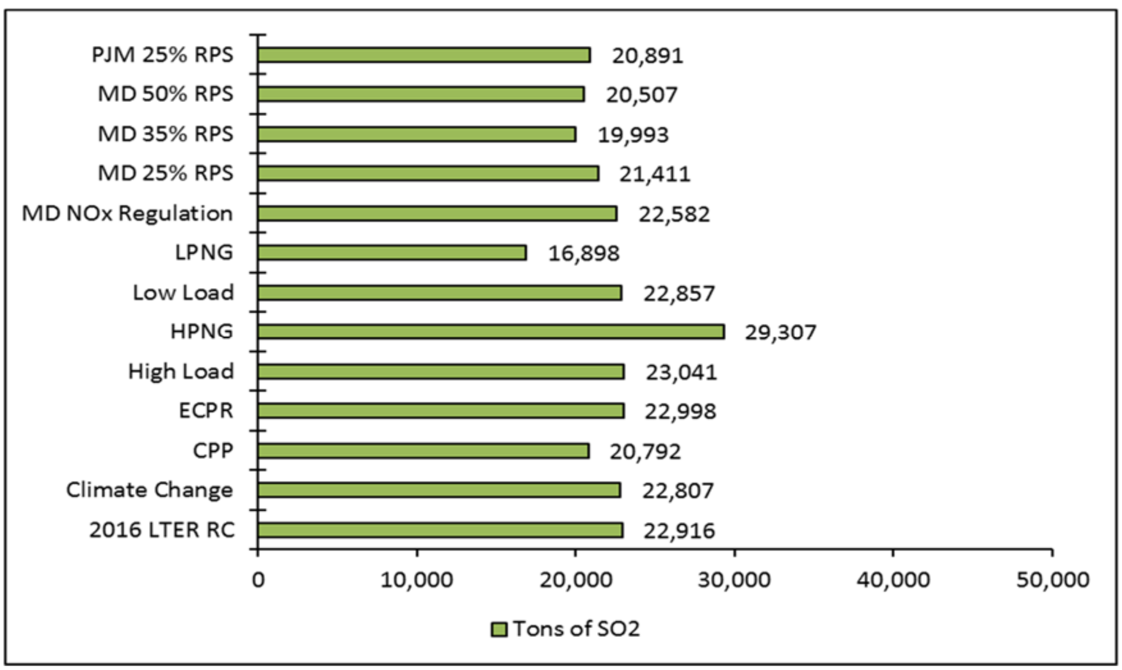


Figure G.27 2035 SO_2 Emissions from Electricity Consumption in Maryland

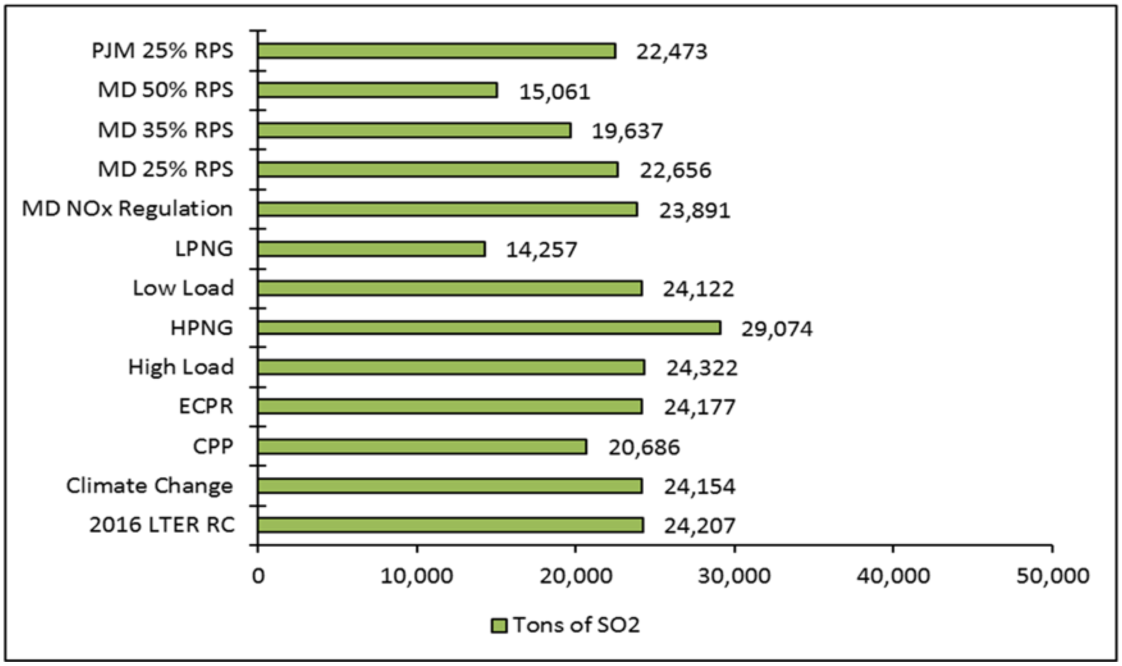


Figure G.28 2015-2025 Average Annual SO_2 Emissions from Electricity Consumption in Maryland

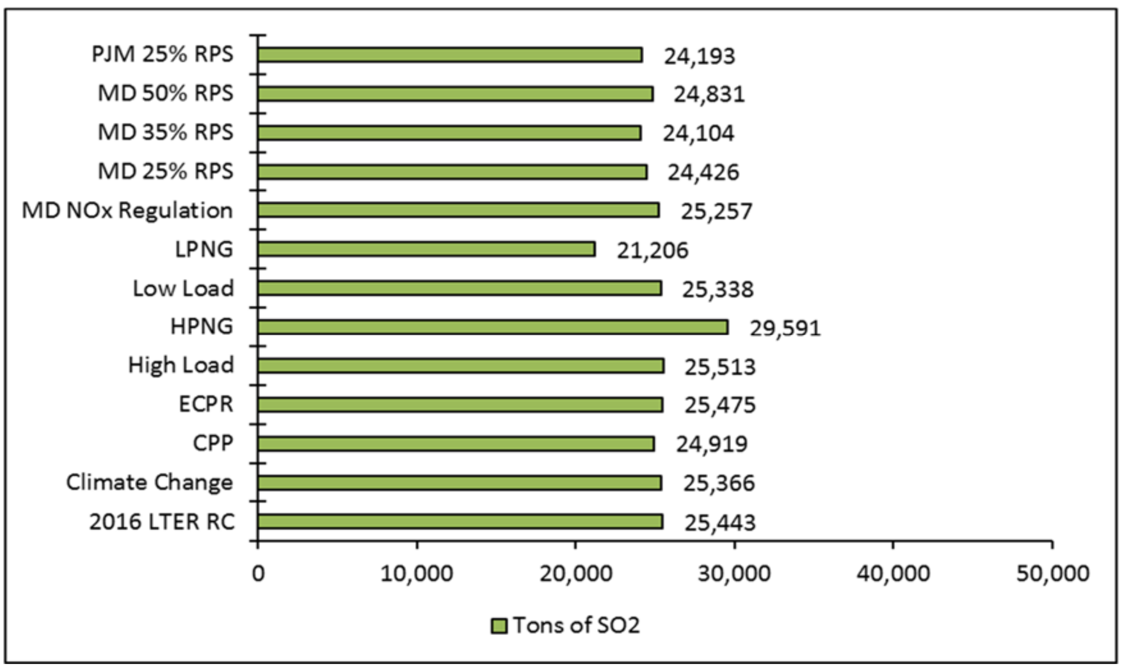


Figure G.29 2025-2035 Average Annual SO_2 Emissions from Electricity Consumption in Maryland

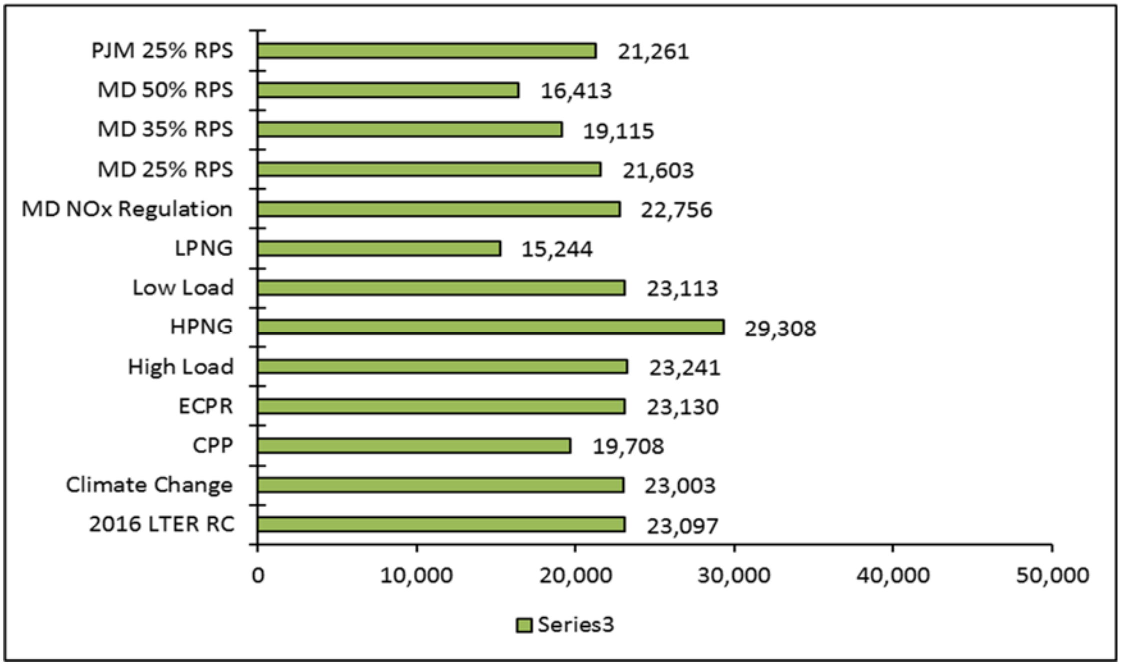


Figure G.30 2015-2035 Average Annual SO_2 Emissions from Electricity Consumption in Maryland

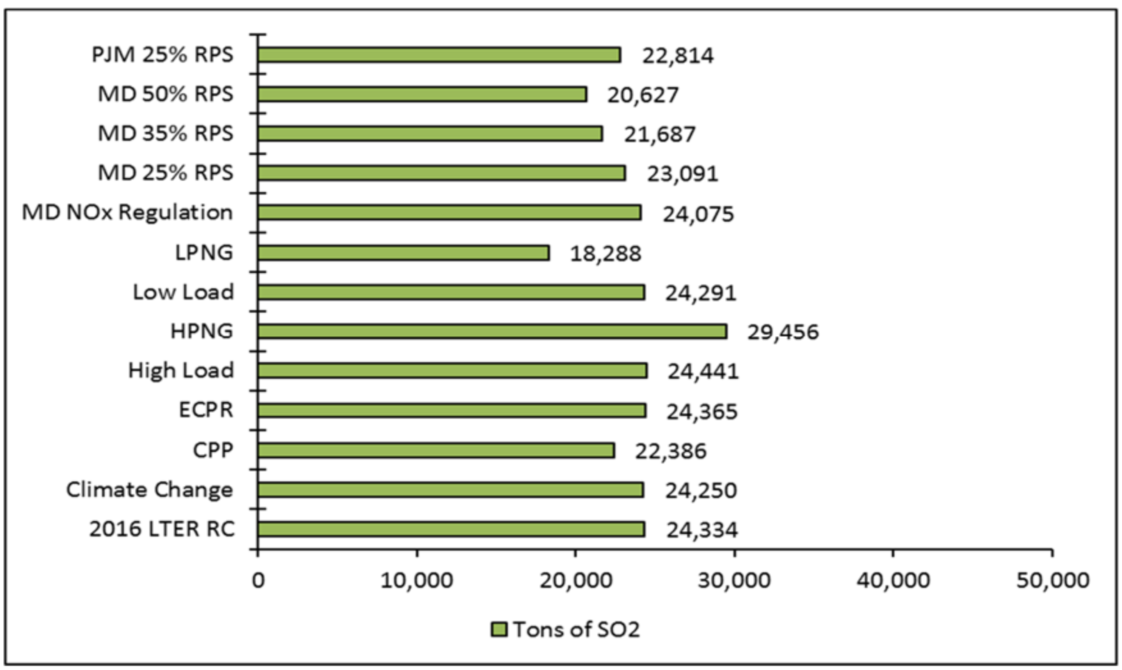


Figure G.31 2015 NOx Emissions from Electricity Consumption in Maryland

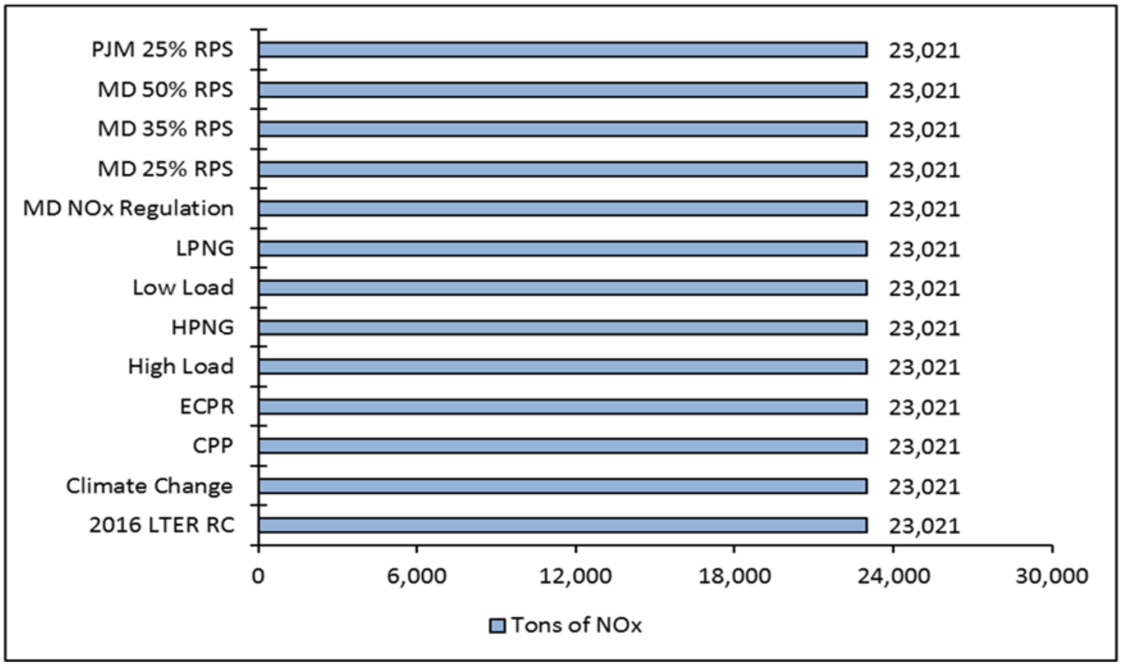


Figure G.32 2025 NOx Emissions from Electricity Consumption in Maryland

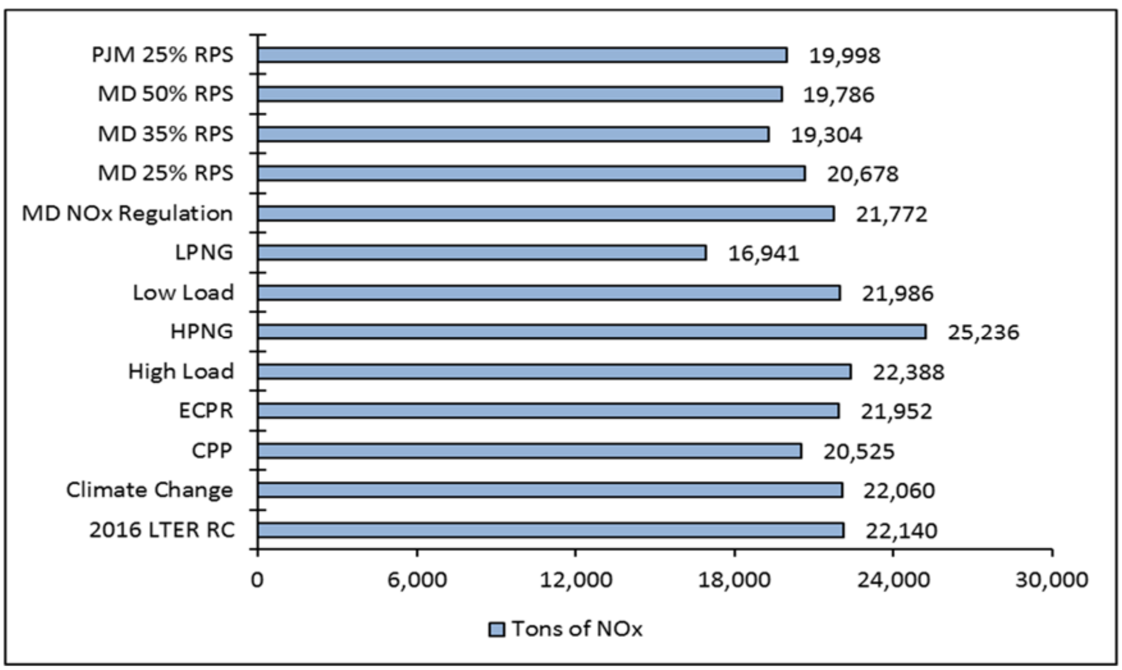


Figure G.33 2035 NOx Emissions from Electricity Consumption in Maryland

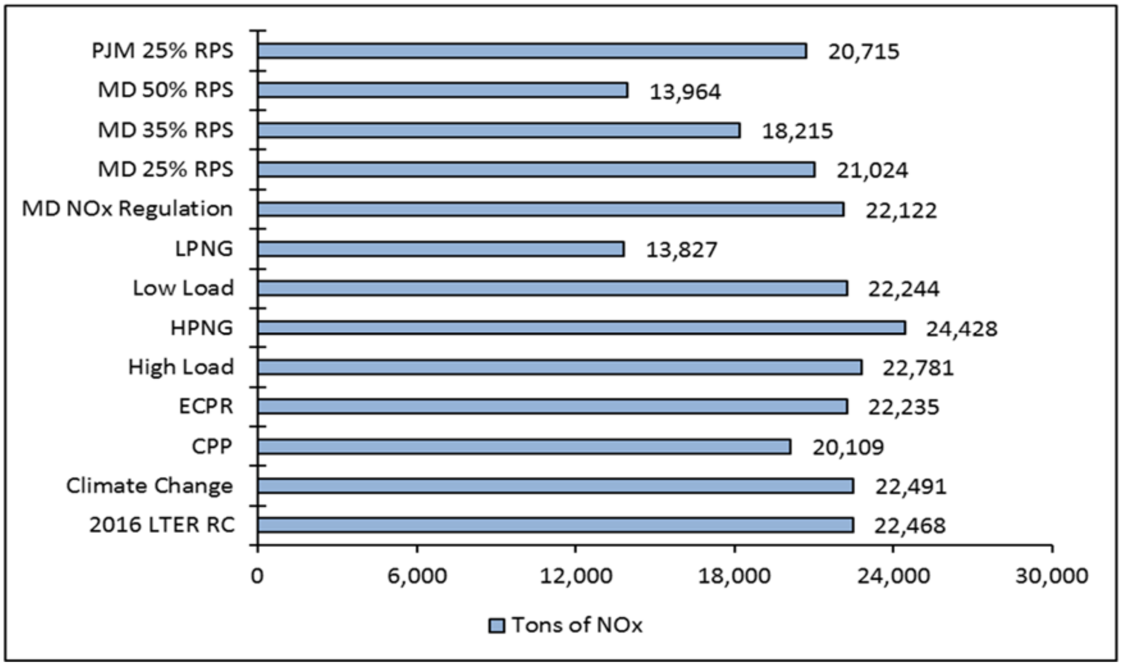


Figure G.34 2015-2025 Average Annual NOx Emissions from Electricity Consumption in Maryland

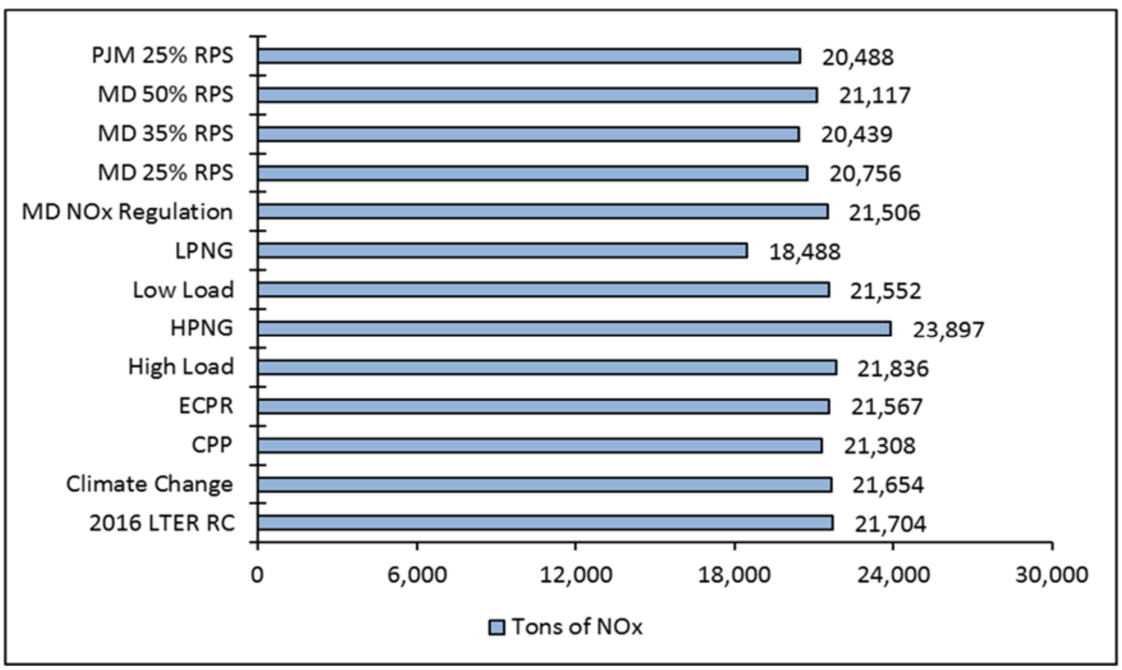


Figure G.35 2025-2035 Average Annual NOx Emissions from Electricity Consumption in Maryland

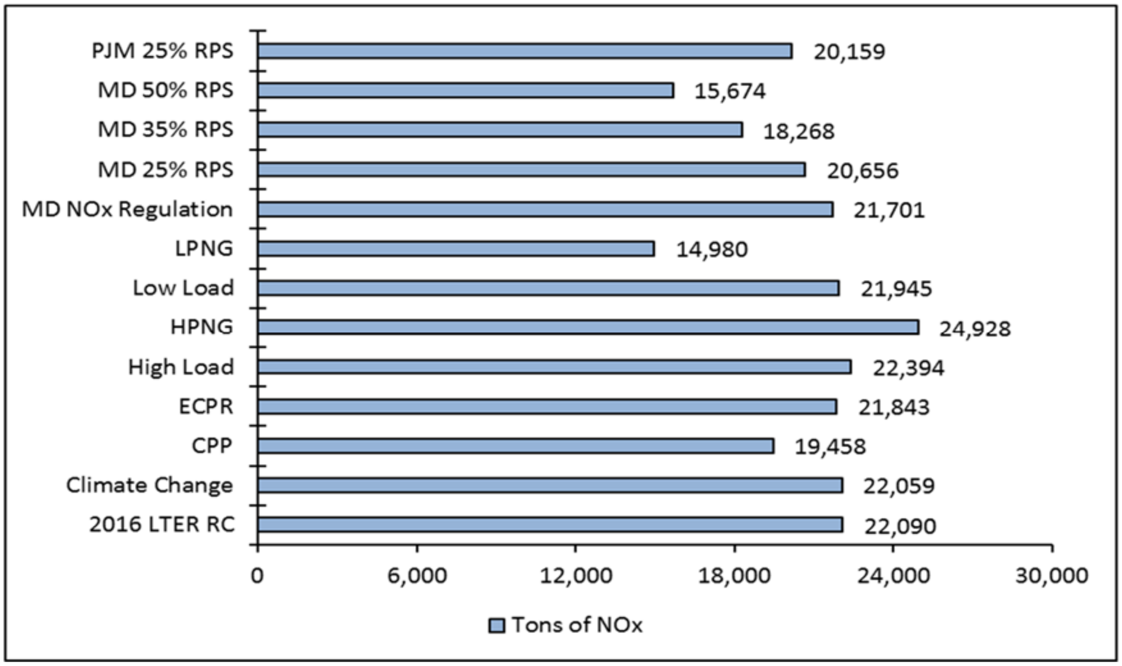


Figure G.36 2015-2035 Average Annual NOx Emissions from Electricity Consumption in Maryland

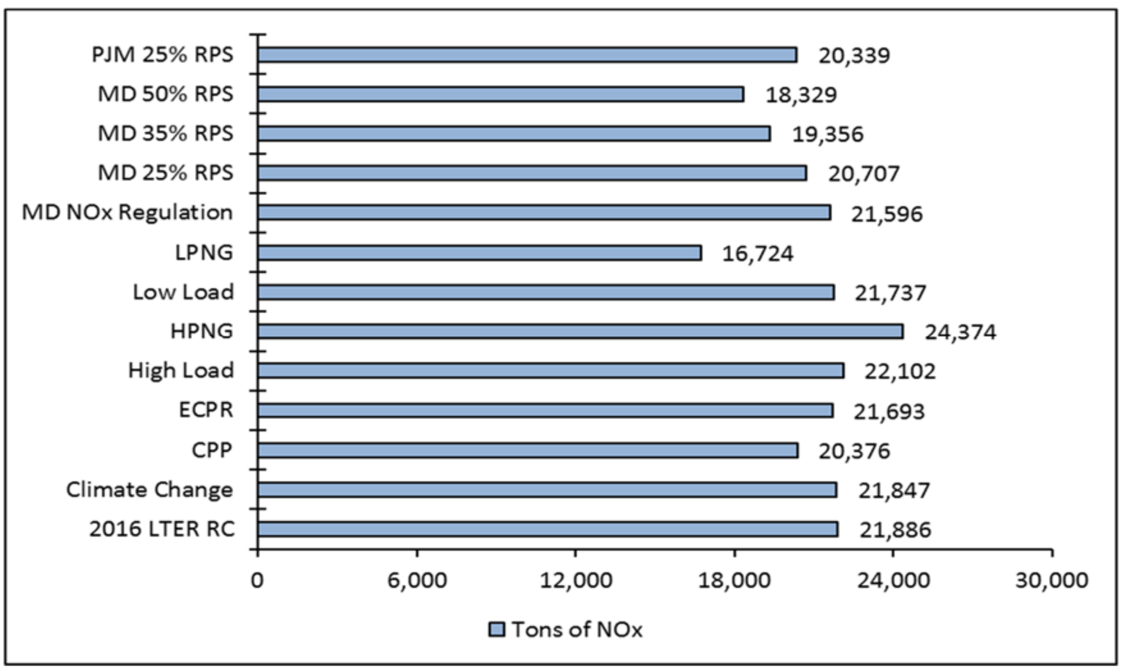


Figure G.37 2015 Mercury Emissions from Electricity Consumption in Maryland

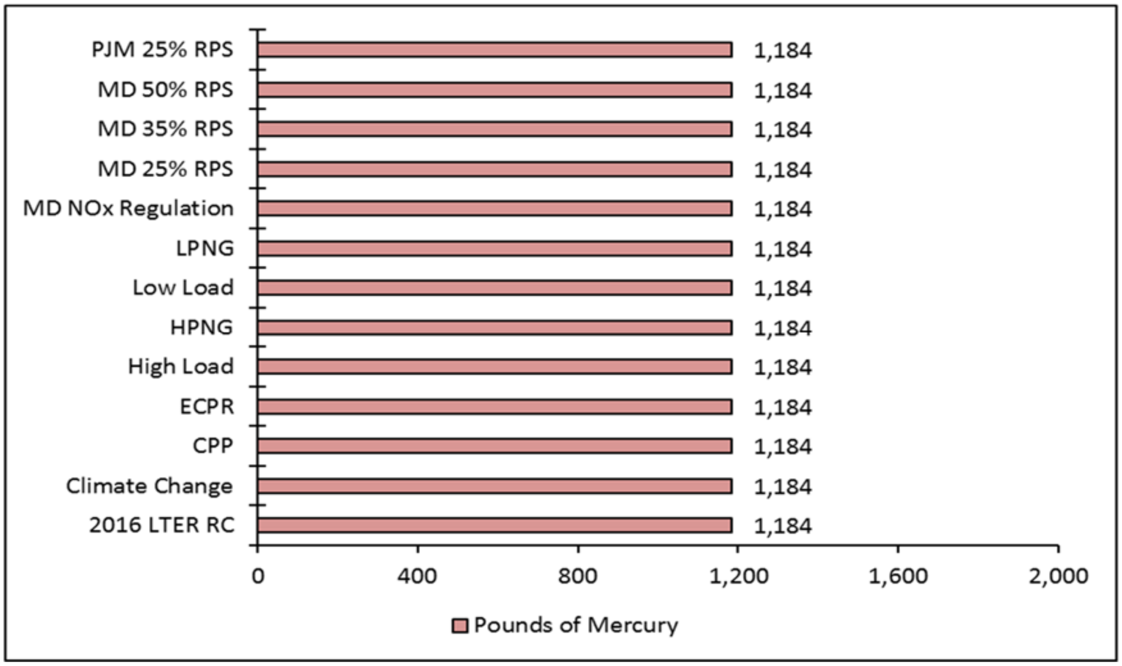


Figure G.38 2025 Mercury Emissions from Electricity Consumption in Maryland

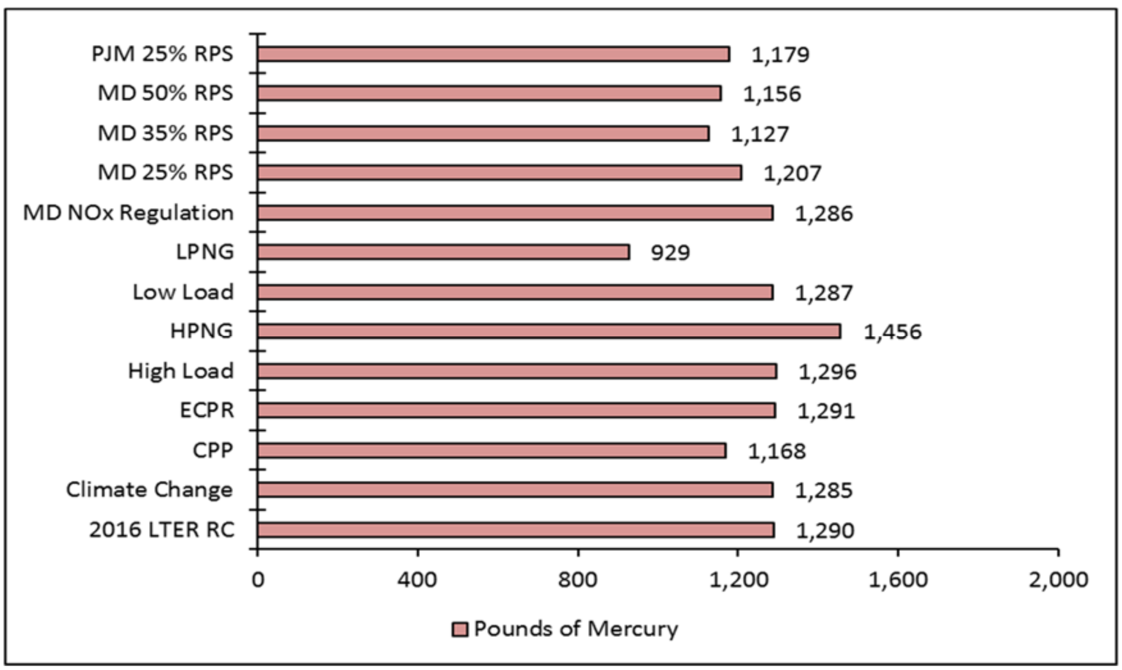


Figure G.39 2035 Mercury Emissions from Electricity Consumption in Maryland

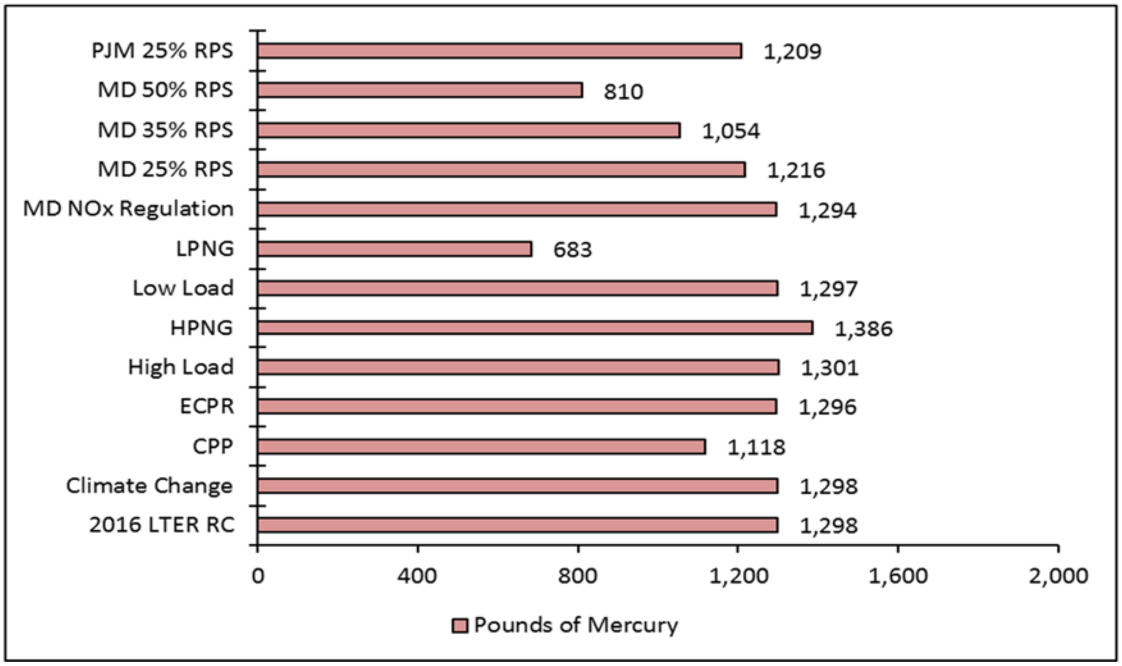


Figure G.40 2015-2025 Average Annual Mercury Emissions from Electricity Consumption in Maryland

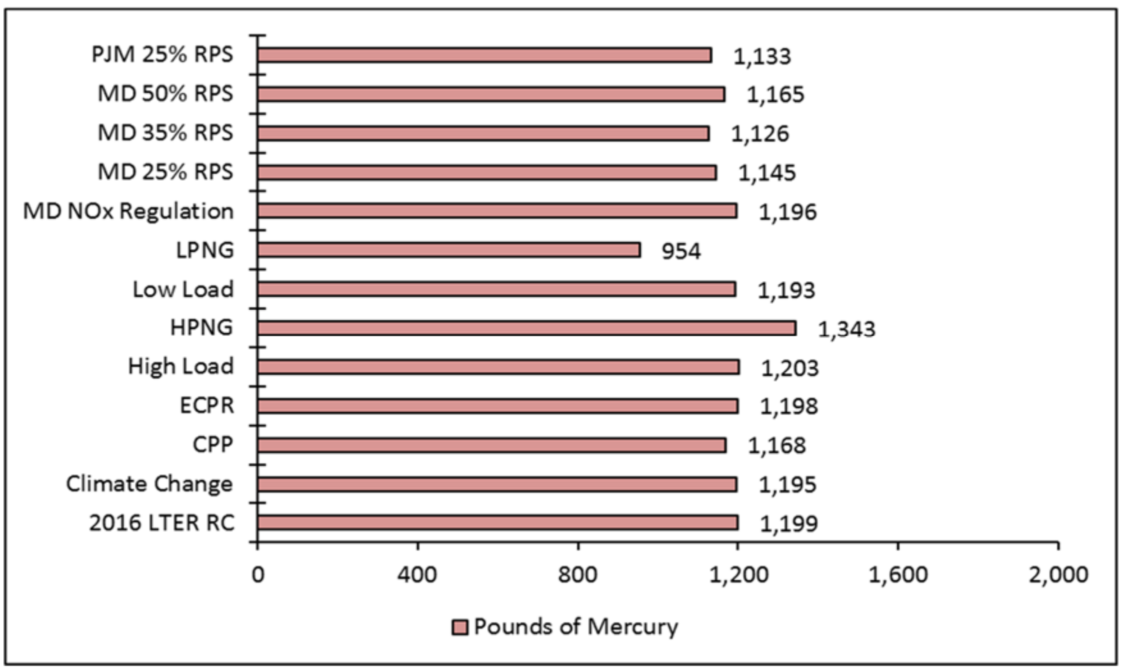


Figure G.41 2025-2035 Average Annual Mercury Emissions from Electricity Consumption in Maryland

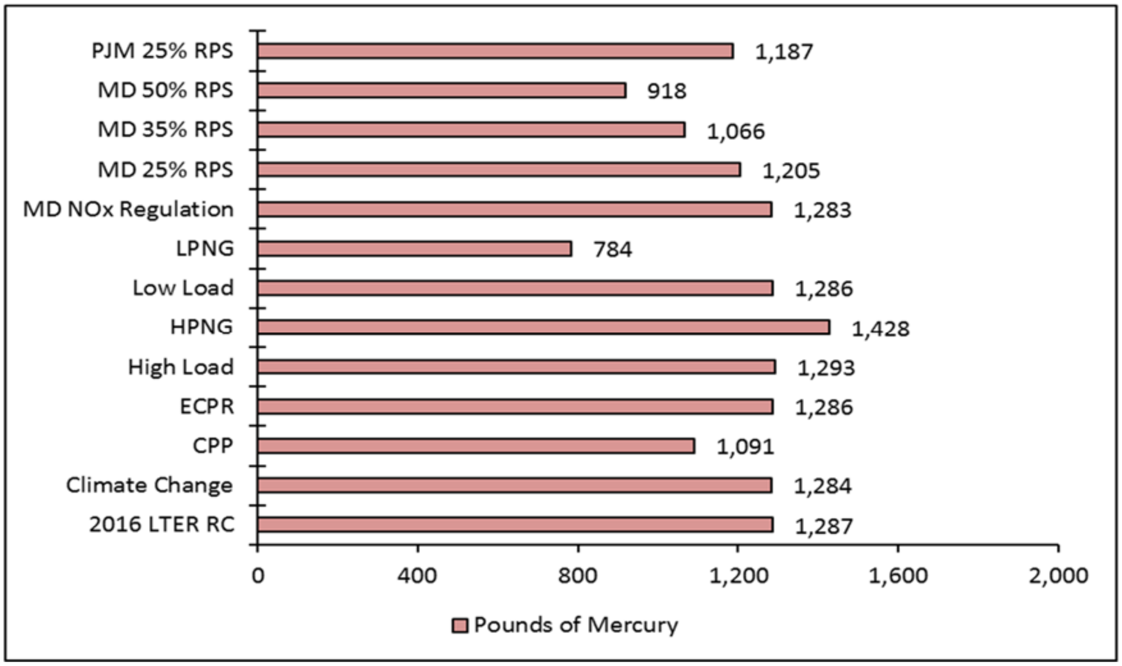


Figure G.42 2015-2035 Average Annual Mercury Emissions from Electricity Consumption in Maryland

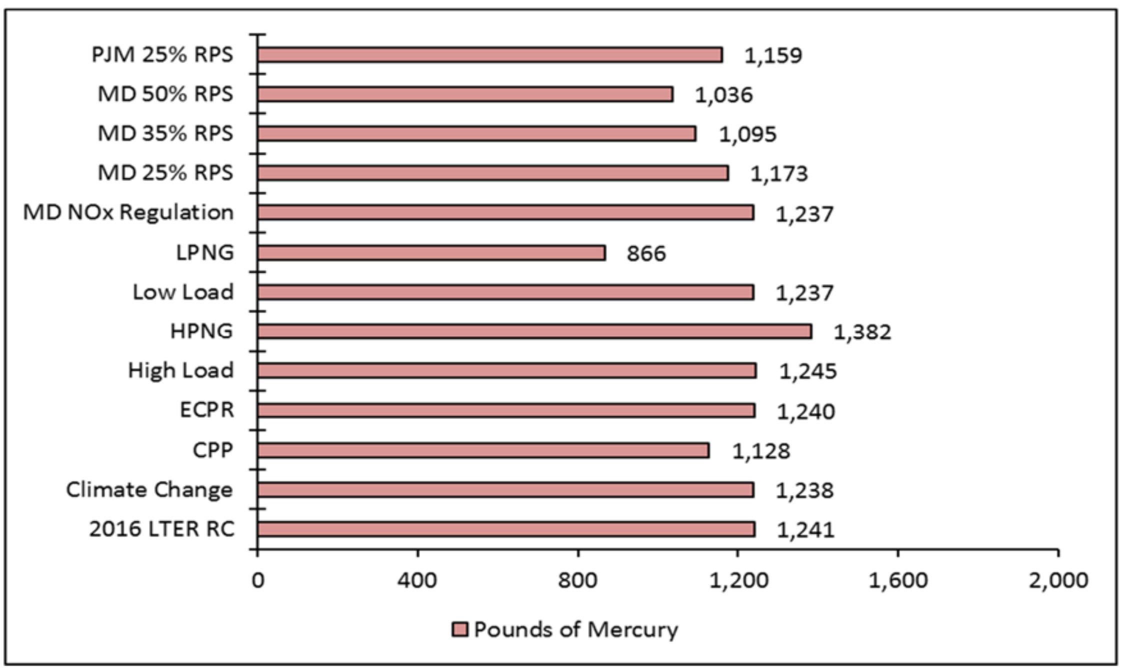


Figure G.43 2015 CO_2 Emissions from Electricity Consumption in Maryland

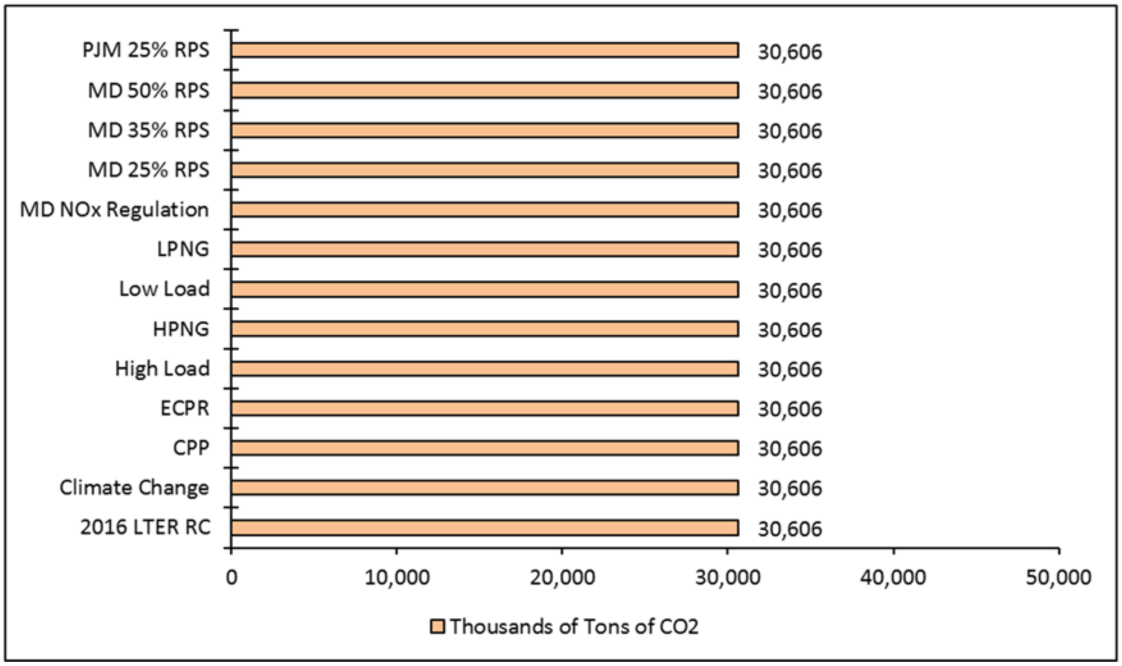


Figure G.44 2025 CO_2 Emissions from Electricity Consumption in Maryland

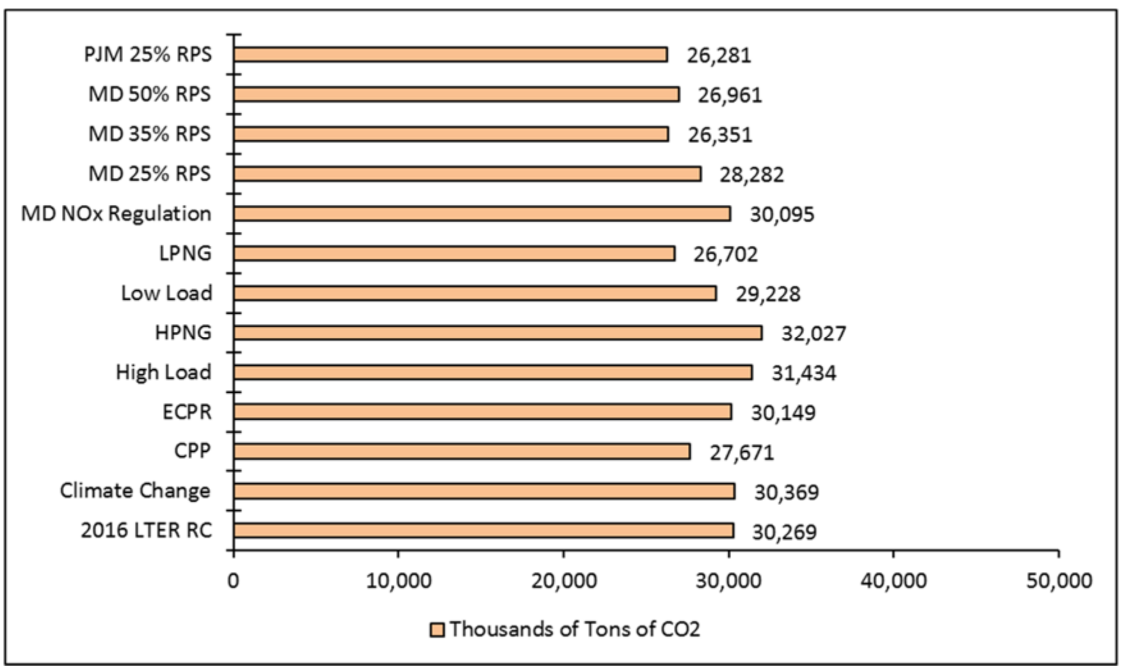


Figure G.45 2035 CO_2 Emissions from Electricity Consumption in Maryland

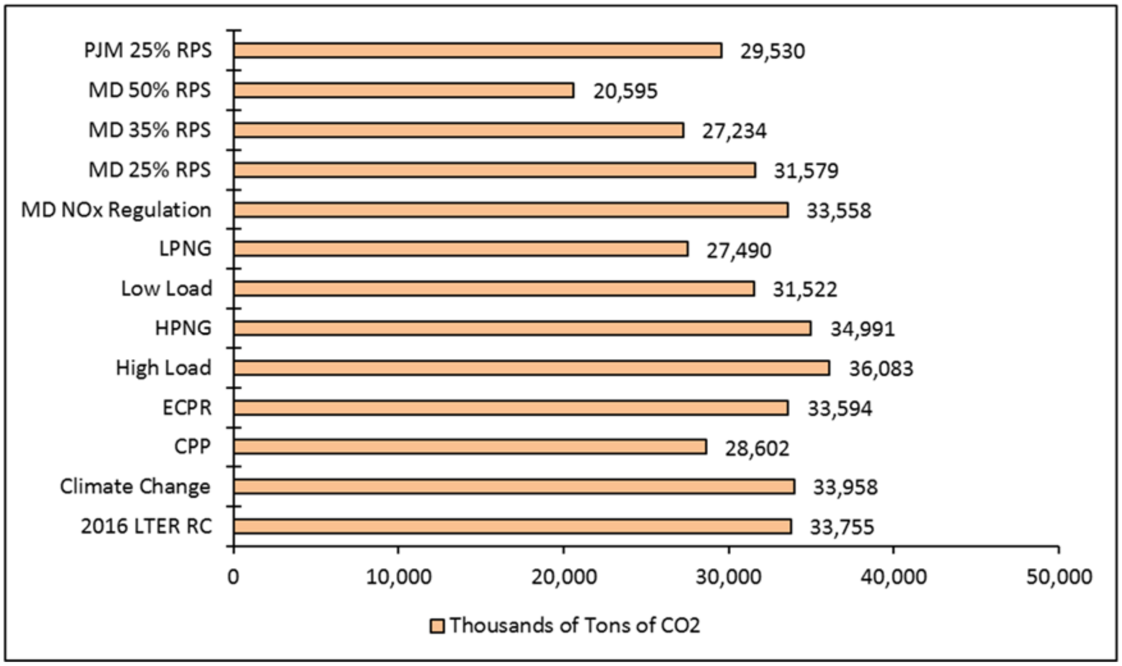


Figure G.46 2015-2025 Average Annual CO_2 Emissions from Electricity Consumption in Maryland

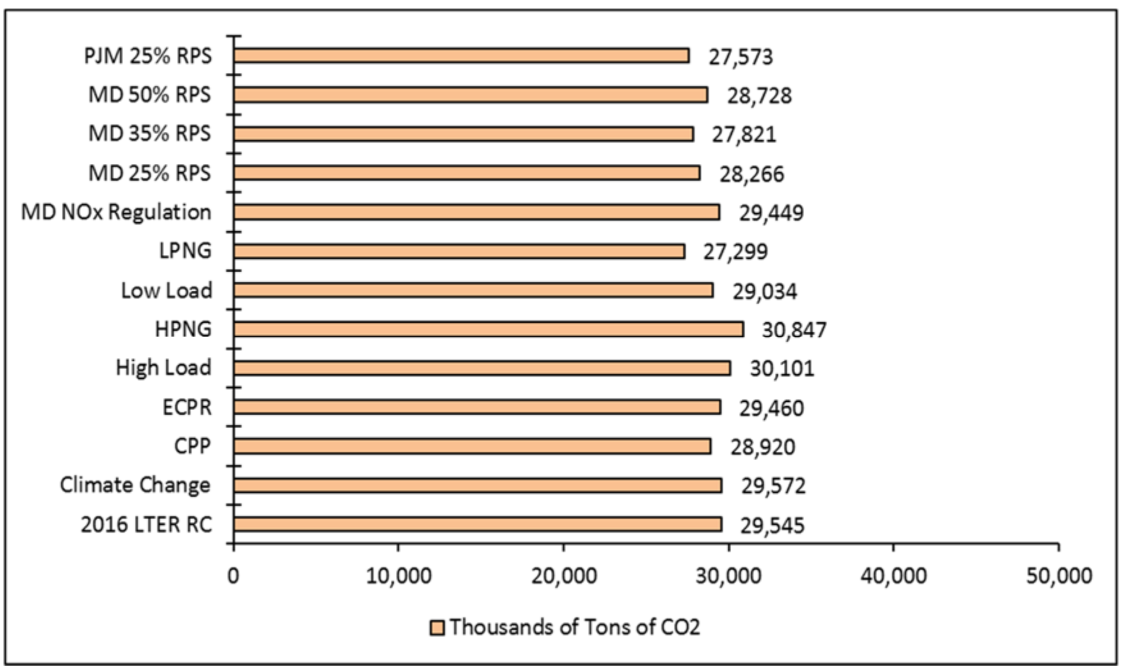


Figure G.47 2025-2035 Average Annual CO_2 Emissions from Electricity Consumption in Maryland

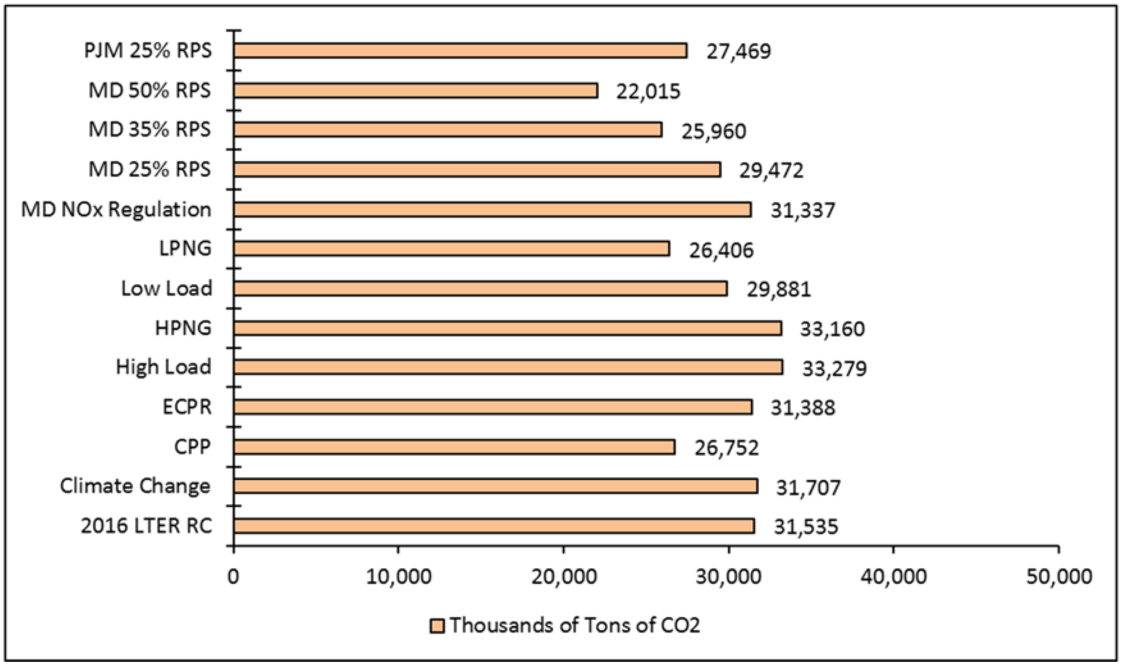
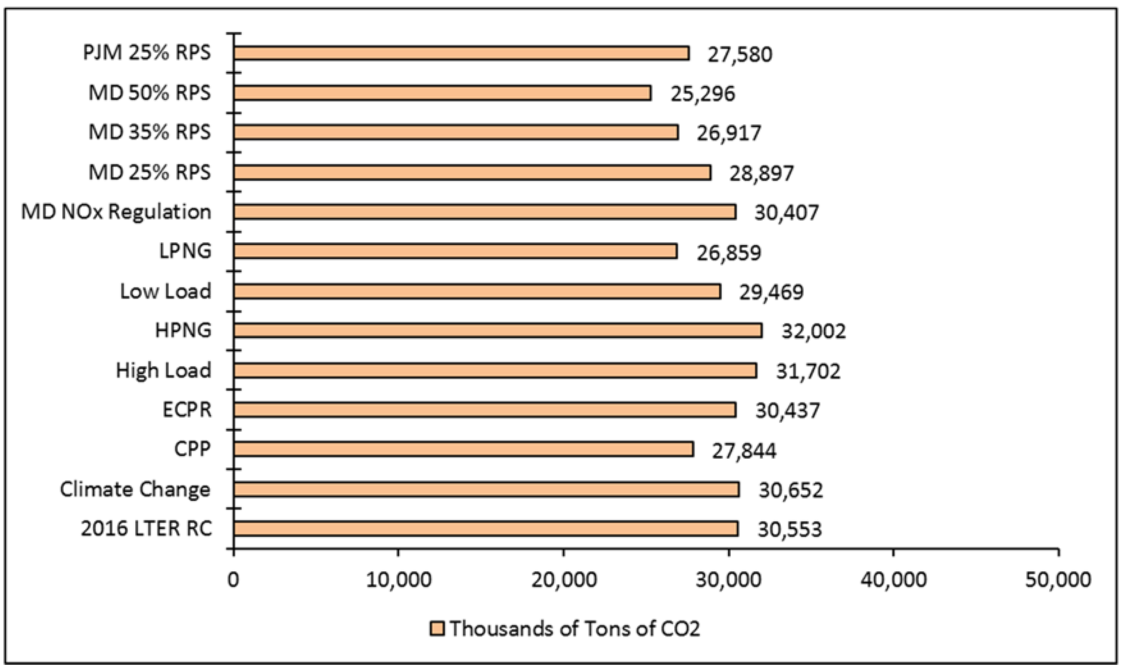


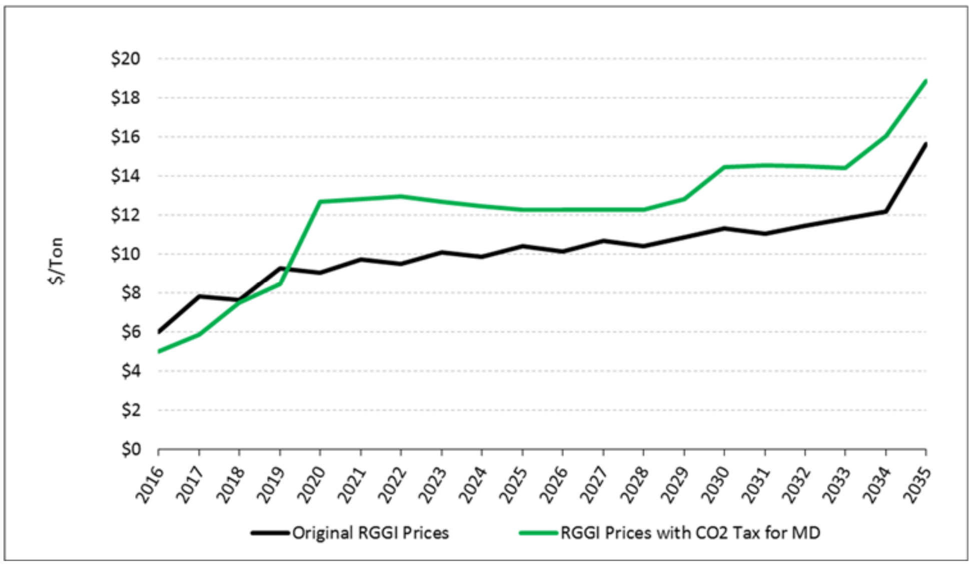
Figure G.48 2015-2035 Average Annual CO_2 Emissions from Electricity Consumption in Maryland



APPENDIX H
Hypothetical RGGI Price-induced Emissions Reductions in Maryland

In addition to noting when CO_2 emissions by Maryland plants would exceed the State's RGGI budget, PPRP estimated the price for RGGI emission allowances that would induce Maryland's plants to operate (in aggregate) below the State's RGGI budget. In order to estimate these higher emissions allowance prices, PPRP assumed that RGGI's price cap could be exceeded and the initiative's Cost Containment Reserve would not be released.[149] Figure H.1 shows the higher emission allowance prices estimated to influence Maryland plant operations relative to those in the Reference Case. (Before 2020, no additional RGGI cost is needed because CO_2 emissions by Maryland plants are currently below the RGGI cap.) From 2020 onwards, a premium—or CO_2 tax—of between $2 and $4 would need to be added to Reference Case RGGI allowance prices in order to drive Maryland plant emissions below the State's RGGI limit.

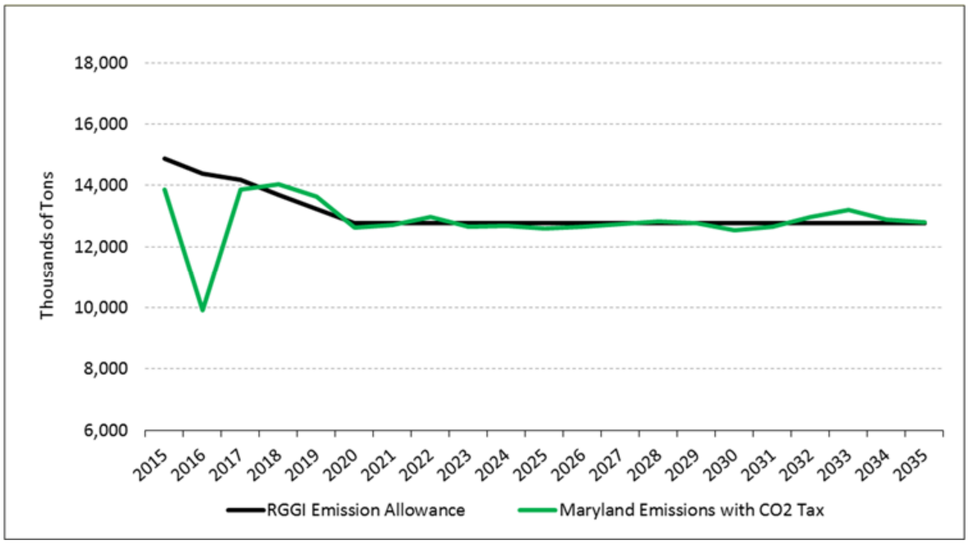
Figure H.1 Comparison of Reference Case and Hypothetical RGGI Prices



When the estimated emissions for each of the two options are considered, the Reference case RGGI price and the RGGI price with the additional carbon tax, the effect is straightforward; the carbon tax compels plant operators to reduce emissions to meet the RGGI budget. Figure H.2 is the graphic representation of this effect.

[149] The RGGI Cost Containment Reserve is a fixed additional supply of CO_2 allowances that are only available for sale if CO_2 allowance prices exceed certain price levels—$8 in 2016, $10 in 2017, and rising by 2.5 percent each year thereafter.

Figure H.2. Comparison of Reference Case and Hypothetical RGGI Emissions



APPENDIX J
Additional Costs

Certain additional costs may affect the price of electricity to end-use customers. These costs are not quantified in this analysis owing principally to high degrees of uncertainty surrounding either the potential magnitude of the costs or the method by which those costs would be assessed or collected. Additional costs not fully accounted for in the modeling approach that are likely to affect end-users include:

- Costs related to new transmission lines;
- Costs associated with uneconomic generation additions;
- Costs related to energy efficiency and conservation programs; and
- Costs resulting from increased renewable energy requirements.

Each additional cost is discussed in turn, below.

New Transmission Lines

The cost of transmission system expansion is not accounted for in the model results and needs to be recognized as a potential cost element facing end-use customers of electricity in Maryland. The recovery of high-voltage transmission projects costs (including the authorized rate of return on invested capital) is set by the FERC. The FERC also determines the group of ratepayers responsible for the cost recovery. If FERC determines that the costs associated with a specific transmission line will be socialized, that is, recovered from all PJM customers, then the costs of that line that would be borne by any individual end-use customer would be significantly less than if the costs were allocated only to a subset of PJM customers.

Uneconomic Generation Additions

In a restructured electric utility industry market, generation owners are not subject to rate-of-return regulation. Any new generation project is subject to regulations governing emissions, other environmental factors (such as water use and land use), and safety. The developers of the project, however, bear the risk that the project may be unprofitable. If the project proves to be uneconomic and is unable to generate revenues adequate to cover costs, that burden would fall on the owners of the project rather than on the general body of ratepayers. However, if a project is constructed under the terms of a long-term power purchase agreement (PPA) that would specify, among other things, the price of the power to be purchased and the duration of the contract, then the counterparty to the contract (for example, the State or one or more utilities) would bear the risk of the project being uneconomic relative to market prices for the duration of the contract term.[150] The generator, however, would

[150] A PPA can contain clauses that effectively cause the price risk to be shared by the buyer and the seller.

continue to bear the risks related to plant performance and elements of cost risk (e.g., construction costs).

Additional benefits that may accrue to end-use customers (and Maryland residents at large) that are not fully captured in a narrow evaluation of economic costs include: (1) system reliability; (2) emissions reductions; (3) increased diversity of fuel; (4) economic development; (5) price stability; and (6) other benefits determined by policy-makers to outweigh the expected additional economic costs. The narrow economic assessment based purely on projected prices may not support the same decision as would be made with reliance on a broader set of recognized benefits.

Energy Efficiency and Conservation Programs

The scenarios considered in the LTER include the assumption of continuation of energy efficiency and conservation programs existing in Maryland (and elsewhere in PJM). The costs of these programs, to the extent that they are funded through a surcharge on electric power supply or services, would result in an additional cost element not accounted for in the LTER analysis. The LTER analysis does capture the impacts of the implementation of such programs (i.e., reduced energy consumption and emissions, power supply price impacts, and total production cost), but does not capture the costs of program implementation.

Increased Renewable Energy Requirements

Three of the variations to the Reference Case entail an increase in the requirements under Maryland's Renewable Energy Portfolio Standard (RPS). Currently, Maryland's RPS calls for qualifying renewable energy to account for 20 percent of Maryland's total energy consumption by 2022, with at least 2 percent carved out for qualifying solar energy projects. Under the Very High Renewables scenarios, the Maryland RPS is assumed to increase from 20 percent in 2022 to 50 percent in 2030, including a 5 percent carve-out for solar. Under the High Renewables scenario, the Maryland RPS is assumed to increase from 20 percent in 2022 to 35 percent by 2030, with 3 percent carved out for solar. Under the Moderate Renewables scenarios, the Maryland RPS is assumed to increase to 25 percent by 2020, with a 2.5 percent carve out for solar.

An increase in the Maryland RPS requirement will likely entail increased costs to Maryland end-use customers through the required purchase of additional Renewable Energy Credits (RECs) needed to meet the higher RPS requirements. RECs costs are not accounted for in the calculations of total revenues to generators.

Estimating the value of RECs under the Reference Case or any of the alternative scenarios is highly complicated given the complexity of the renewable energy markets. Most of the states within PJM have enacted mandatory RPS legislation,[151] and there are marked differences among the percentages of renewable energy required, the types of energy that are considered as eligible for a

[151] Indiana, Kentucky, Tennessee, Virginia, and West Virginia do not have mandatory RPS requirements.

given state's RPS requirement, and the geographical area from which renewable energy may be generated to meet a state's RPS requirement. An additional complicating factor is that satisfaction of a state's RPS may be accomplished either through the purchase of qualifying RECs or through an Alternative Compliance Payment (ACP). The ACPs differ among the states and also differ for different types of renewables; for example, the ACPs for solar RPS compliance are much higher than the ACPs for Tier 1 renewable energy.

The ACPs effectively function as a cap on the price of RECs. If a retail energy supplier can meet the RPS requirement through payment of an ACP for $20, the supplier would not be willing to purchase RECs for $25. Consequently, the ACP represents the maximum amount that a RECs supplier could expect to sell RECs for on the market. Since there are transactions costs associated with the purchase of RECs, a retail energy supplier, in fact, would only be willing to pay a price slightly below the ACP for RECs. Because RECs can be banked only for three years by the RECs generator, the generator has an incentive to sell the RECs below the price of the ACP to avoid the potential of the RECs becoming worthless. An additional complexity is that since RECs generated in one PJM state are typically eligible to satisfy the RPS from another PJM state, the market for RECs in one state is affected by the ACPs in other states.

Finally, it should be recognized that not all RECs are used to satisfy RPS requirements. A firm may purchase RECs over and above the level required for satisfaction of the relevant state RPS for marketing purposes or to comply with company policy. Additionally, residential consumers can opt to purchase renewable energy in excess of RPS requirements for reasons of personal preference, and government entities may also purchase excess renewable energy to satisfy policy directives. For example, each of the service branches of the U.S. Department of Defense (DoD) purchases renewable energy in excess of state RPS requirements to comply with a federal Executive Order.

The degree to which additional costs to comply with higher RPS requirements are borne by consumers depends upon two factors: the price of RECs and the size of the RPS requirement, usually expressed as a percentage of energy consumption. In Maryland, as in other PJM states, the size of the existing RPS requirement is established by legislation. The Very High and High Renewables scenarios rely on the assumption that the percentage requirement for Maryland would increase to 50 and 35 percent by 2030, respectively. As a consequence, the size of the RPS requirement is either known or assumed. Attaching a REC price to the RPS requirement, however, is more complex. The derivation of the REC prices used in the LTER, and the implications for costs to end-use customers, are addressed in Appendix K, which follows.

APPENDIX K
Renewable Energy Credit Prices

Market factors affect the price of RECs in Maryland (as well as in other states) in complex ways. Consequently, any approach to modeling REC prices is likely to provide results that entail a high degree of uncertainty. The REC prices presented below were modeled using a “gap analysis” approach based on relevant model run outputs. The gap analysis estimates the gap in revenue required to fully compensate renewable energy developers for the cost and expense of constructing, owning, and operating a renewable energy facility given the revenue stream obtained from the sale of energy and capacity from the renewable energy project. That is, the REC price is equal to costs (including a reasonable return on investment) minus revenues from provided energy and capacity. In addition to the revenue associated with energy and capacity sales, the reduction in project costs due to the federal Production Tax Credit (PTC) is assumed to also be available to the project developer. The marginal renewable energy project is assumed to be an on-shore wind facility and the estimated REC prices were computed on that basis.

REC prices will vary from scenario to scenario due to differences in the energy prices and the capacity prices. Renewable energy project costs (both fixed and variable) are assumed to be invariant among scenarios. Table K-1 shows the annual REC prices derived from the gap analysis for the Reference Case and all of the scenarios.

Table K-1 Estimated Maryland REC Prices ($2015/MWh)

Year	Reference Case	HPNG	LPNG	High Load	Low Load	Climate Change	MD 25%	MD 35%	MD 50%	PJM 25%	CPP	ECPR	NOx Emissions Compliance
2015	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12
2016	14	14	14	14	15	14	14	14	15	14	14	14	14
2017	15	15	15	15	15	15	15	15	15	15	15	15	15
2018	14	12	16	13	14	14	14	14	14	14	14	14	14
2019	21	17	24	21	21	21	21	21	21	21	21	21	21
2020	22	17	26	22	22	22	22	22	22	22	22	22	22
2021	22	16	28	22	23	23	22	22	22	23	22	22	22
2022	19	12	25	19	19	19	19	19	19	20	19	19	19
2023	17	9	24	17	18	18	18	17	17	19	18	17	17
2024	16	7	23	16	16	16	16	16	16	18	18	16	16
2025	15	5	22	15	15	15	15	15	15	16	17	15	15
2026	14	5	21	14	14	14	14	14	14	15	16	14	14
2027	11	4	19	11	11	12	12	12	12	13	15	12	12
2028	10	2	18	9	9	10	10	10	10	11	13	10	10
2029	8	1	17	7	7	8	8	8	8	9	12	8	8
2030	6	1	15	6	6	6	6	6	6	7	10	6	6
2031	4	1	14	4	4	5	4	4	4	5	8	4	4
2032	2	1	12	2	2	3	2	2	2	3	5	2	2
2033	1	1	11	1	1	2	1	1	1	2	3	1	1
2034	1	1	11	1	1	1	1	1	1	2	2	1	1
2035	1	1	11	1	1	1	1	1	1	2	2	1	1

In the Reference Case, during the early years of the analysis period, REC prices reflect current market conditions, including uncertainty associated with REC supply or changes to the statutory requirements. For 2015-2017, REC prices are the average of prices for the Tier/Class 1 REC prices in the District of Columbia, Maryland, New Jersey, and Pennsylvania; the new renewables tier in Delaware; and non-solar renewable energy RECs in Illinois. As market factors change and RPS percentage requirements increase, any existing renewable energy surplus is reduced, resulting in increases in REC prices. Between 2015 and 2021, REC prices increase to $22 per REC as increases in renewable energy requirements are balanced with increases in renewable energy project development. With increases in capacity prices and increases in energy prices, and with no increases in the percentage requirements for renewable energy (which reach a maximum of 20 percent in 2022 in Maryland), REC prices decline in real terms over the last 14 years of the analysis period under the Reference Case assumptions, falling to about $1 per REC by 2035.

The REC prices under many of the scenarios are projected to be very similar to those estimated for the Reference Case. Exceptions to this include the LPNG, PJM 25 percent renewables, and CPP scenarios.

Under the LPNG scenario assumptions, the market prices for energy are below those for the Reference Case. With lower market prices for energy, a higher portion of the costs of renewable energy project development need to be recovered through REC prices using the gap analysis methodology. Therefore, under the LPNG Scenario, REC prices rise to almost $30 per REC in 2021 and are at levels of $20 per REC and higher between 2019 and 2026.

While the REC prices for the Maryland RPS scenarios are comparable to the Reference Case, the alternative scenario in which there is a PJM-wide RPS of 25 percent exhibits very slightly higher ($1-2) REC prices after 2023. This is due to the lower energy prices based on additional renewable energy inventory off-setting less efficient power plants that would otherwise be used on the margin.

For the CPP scenario, the REC prices follow the same trajectory as in the Reference Case, but at values $1 to $4 higher starting in 2023. This is due to a corresponding drop in energy prices forcing renewable energy project developers to recoup more of their costs through REC sales.

As noted previously in this section, there is significant uncertainty associated with the estimated REC prices shown in the table above. This uncertainty results from the complex market interactions that determine the market price for RECs. Adding to the inherent uncertainty resulting from market complexities is the potential that the existing RPS legislation in Maryland or other PJM states could be modified over the course of the analysis period which could affect the market prices for RECs in Maryland. Modifications to RPS legislation that could affect REC prices include: (1) expanding or contracting the menu of resources that qualify as renewable; (2) expanding or contracting the geographical areas from which qualifying renewable generators may be located; (3) increasing or decreasing the level of ACPs; (4) increasing or decreasing the renewable energy percentage requirements; and (5) establishing carve-outs from the existing RPS percentages for specific renewable technologies, for example, solar energy or energy from off-shore wind. Since its initial implementation, the Maryland RPS legislation has been modified in all of the above respects and the kinds of modifications enumerated above are not uncommon for RPS policies in other states.

An added source of uncertainty stems from the future status of the federal PTC. The PTC provides a tax credit equal to 2.3 cents per kWh produced for certain renewable energy technologies (e.g., wind power, closed loop biomass) for the first ten years that the project is on line. For other technologies (e.g., landfill gas, municipal solid waste, qualified hydro-electric, hydrokinetic), the PTC is limited to 1.2 cents per kWh. The current federal PTC was extended in December 2015 through 2016 for all technologies but wind, where the PTC was extended until 2020. The PTC, however, includes a phasing out for wind such that for projects beginning construction in 2017, the PTC amount is reduced by 20 percentage points; 40 percentage points for 2018 projects, and 60 percentage points for 2019 projects. The PTC for wind expires altogether as of the end of 2019. The Internal Revenue Service allows eligible projects to take the PTC for up to four years after construction has begun or financial commitments of up to 5 percent of the total cost of the project have been made.

Note that for some of the scenarios shown in the table above, the price of RECs drops to $1 per REC in the last years of the analysis period. This means that certain new renewable energy projects, for example, wind power projects, would be capable of nearly covering their full costs through energy and capacity revenues and therefore would be competitive with conventional (natural gas) technologies.

APPENDIX L
Energy Storage

Energy storage technologies and facilities have the potential to provide important and valuable services to the electric grid to enhance system reliability and stability. Energy storage devices currently in use include pumped hydroelectric power, flywheels, batteries, compressed air facilities, thermal storage, and electric and plug-in hybrid vehicles.

Pumped hydro, which generates electricity by reversing water flow between reservoirs, is the most widespread energy storage system in use today. With an efficiency rate of more than 80 percent, pumped storage currently provides over 22 GW of electricity storage in the United States. There is an additional 39 GW of planned hydro energy storage projects in the pipeline. Pumped hydro storage is ideal for peak load shifting. Water is pumped into an upper reservoir during off-peak periods when market energy prices are low, and then used to generate electricity during peak hours. As of 2016, there were approximately 5,800 MW of pumped hydro storage capacity in PJM.[152]

Compressed air energy storage (CAES) makes use of natural and manmade caverns (e.g., abandoned natural gas and oil wells) 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 and when energy prices are high, the air is released from the cavern, mixed with natural gas, and combusted, which leads to the air being expanded. The expanded air is run through a turbine to generate electricity. No compressed air storage projects are currently operating in PJM.

Battery storage systems have gained momentum in recent years. Battery storage systems include solid state batteries which include electrochemical capacitors, lithium-ion batteries, nickel-cadmium batteries, sodium sulfur batteries, and flow batteries. In PJM, any generation project classified as an energy storage resource can only be used for short-term storage and injection of energy at a later time as a net-load resource, and cannot serve as a capacity resource. A 2-MW advanced lithium-ion experimental battery array is housed in a trailer at PJM headquarters, providing regulation energy to the grid. As of April 2016, there were 246 MW of battery storage projects installed in PJM. The majority of proposed energy storage projects in PJM are battery storage projects.

Flywheel systems utilize a massive rotating cylinder, and are a good fit for providing regulation services. Flywheels are commercially available for development as "regulation power plants" providing up to 20 MW of regulation for a 40-MW swing. A flywheel storage regulation power plant is capable of providing full power within four seconds of receiving an ISO control signal. The flywheels have the ability to address both generation and load, acting in a load capacity by recharging using grid energy, and as a generator by releasing energy back. Flywheel energy storage systems also have a quicker

[152] U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, "DOE Global Energy Storage Database," accessed September 29, 2016, http://www.energystorageexchange.org/.

reaction time than other regulation resources, meaning just one MW of this type of project may be able to displace between 2 to 17 MW of traditional regulation resources. There are currently 20-MW flywheel installations operating in the ISO New England and New York ISO grids. In 2013, PJM put into service the first phase of a 20-MW Beacon flywheel in Pennsylvania.

Thermal energy storage is excess thermal energy which is collected to be used at a later time for heating and cooling applications and power generation. There are three types of thermal energy storage systems: sensible, latent, and thermos chemical heat storage. Sensible heat storage stores heating or cooling liquid or solid storage medium, such as molten salts, with water. Latent heat storage is when materials are changed from a solid state to a liquid state to produce energy. Thermo-chemical storage uses chemical reactions to store and release thermal energy.

Overall, storage can be used as a system resource, i.e., to help meet load requirements or to provide ancillary services. Storage systems with very fast response times are ideal for providing grid regulation services, which require minute-to-minute adjustments in demand and supply to keep these in balance on the electric grid. FERC Order 890 allows for non-generation resources to participate in ancillary services markets. Several RTOs, including PJM, the New York ISO, ISO New England, and the Midcontinent ISO have adapted their regulation policies to ensure fast-responding storage systems are able to participate in the ancillary services markets and are compensated adequately for those services.

Electricity storage will be increasingly utilized as technologies advance and will likely play a large role in future electric system operations; however, at this point in time, they are still not economically feasible on a large scale. PJM continues to actively examine storage technologies in preparation for integrating them into the PJM grid and markets. Table L-1 provides a summary of the energy storage projects within PJM's queue by state. Collectively, there are 89 projects in the PJM queue equating to 886.5 MW of storage.[153] The majority of projects are battery storage, with one project proposed in Pennsylvania for a flywheel.[154] For Maryland, there are 22 projects in the queue for a total of 40.1 MW. Many of the Maryland projects are small, approximately 5 kW, and are located throughout the BGE service territory. While the number of battery projects has increased over the last few years, the average project size remains small at approximately 10 MW. At this time, future storage development and costs are too speculative to be effectively modeled. The implications of technological advances, reduced costs, and more widespread application of storage will be addressed in future LTERs as information becomes available.

[153] Per the PJM generation queue as of September 29, 2016.
[154] There are 12 projects in the queue that are for storage, but it is unclear what type of storage project it is.

Table L-1 Energy Storage in PJM Queue

State	Project Type	Number of Projects	Total MW
Illinois	Battery	7	145
	Unknown	4	22
Indiana	Battery	1	20
Maryland	Battery	22	40
New Jersey	Battery	15	154
	Unknown	2	17
Ohio	Battery	15	159
	Unknown	1	20
Pennsylvania	Battery	10	133
	Flywheel	1	20
	Unknown	4	52
Virginia	Battery	2	6
	Unknown	1	20
West Virginia	Battery	4	86
Total		**89**	**894**

Note: Includes projects under construction, under study, active, and suspended.

Source: PJM Generation Interconnection Queue as of September 2016.

APPENDIX M
Questions/Comments Received and PPRP Responses

Pursuant to Executive Order 01.01.2010.16, notice was given in the Maryland Public Register that the LTER was available for public inspection and comment until November 4, 2016. In addition, PPRP reviewed the LTER with PPRAC members at a final meeting and a follow-up webinar. The following section summarizes feedback that was provided orally at the PPRAC meeting and webinar. (PPRP received no written comments from PPRAC members or the public.)

Additional RPS Scenarios – The Chesapeake Climate Action Network (CCAN) requested that PPRP run two additional scenarios to explore the impact of increasing RPS requirements to 50 percent of retail sales by 2030, with a 5 percent solar carve-out, both in Maryland and PJM-wide. As precedent for such a scenario, CCAN noted that several states (i.e., Oregon, California, Vermont, and Hawaii) have passed legislation to raise their RPS goals to 50 percent or higher.

RESPONSE: PPRP has included a scenario that considers a 50 percent Maryland RPS (by 2030) with a 5 percent solar carve-out. Those results are included in the LTER report. The scenario that is based on a 50 percent RPS that includes a 5 percent solar carve-out for all states in PJM will be provided to CCAN but not included in the LTER since the likelihood that all PJM states, several of which have no RPS currently, will meet the criteria of the scenario is judged negligible. The results of the 50 percent PJM RPS scenario will be provided to CCAN following the submission of the LTER report to the Governor, the General Assembly, and the Maryland Public Service Commission.

NOx Emissions Regulations – The Maryland Department of the Environment (MDE) informed PPRAC that enhanced NOx regulations were implemented in Maryland that affect coal-fired plants beginning in 2015. These regulations are intended to allow Maryland to attain and maintain compliance with federal standards for ozone pollution. MDE anticipates that seven of the State's coal units will be retired at the end of 2019, and asked PPRP to run a scenario to model the results of these retirements.

RESPONSE: PPRP has included a scenario based on the January 1, 2020 closure of the coal units identified by MDE. This scenario appears as the "NOx Emissions Compliance" scenario in the LTER.

CO_2 Emissions Using RGGI – MDE asked PPRP to estimate the price for RGGI emission allowances that would prompt Maryland's plants to stay beneath the State's RGGI budget for economic reasons. This question stemmed from discussions among State agencies about using RGGI as a mechanism to comply with CO_2 limits for Maryland that are contained in the EPA's Clean Power Plan (CPP).

RESPONSE: PPRP conducted a series of iterative runs of the ABB model to determine the level of RGGI prices that would result in Maryland CO_2 emission remaining below Maryland's RGGI budget throughout the 20-year projection period. The results of that analysis are presented in Chapter 10 of the LTER.

SO_2 Emissions – When reviewing the results of the Early Coal Plant Retirement (ECPR) alternative scenario, MDE noted that trends for SO_2 emissions by plants in Maryland are almost identical to those in the Reference Case while the emissions of NOx, mercury, and CO_2 declined significantly. They asked PPRP to explain why the early retirement of five coal units, in 2018, has virtually no impact on SO_2 emissions.

RESPONSE: After researching this issue, and in consultation with ABB personnel, PPRP determined that the reason for the lack of significant reduction in SO_2 emissions in the ECPR scenario relative to the Reference Case is that the coal plant units closed in the ECPR scenario have already installed SO_2 controls and, therefore, SO_2 emission levels for those units are extremely low, as reflected in the Reference Case. As a consequence, closure of those units results in little reduction in SO_2 emissions relative to the Reference Case.

Land Use Associated with Meeting RPS Goals – CCAN and the Maryland Energy Administration (MEA) both took particular interest in the assumptions that PPRP used to estimate how much land in Maryland would be needed to meet RPS requirements under each of the RPS scenarios, particularly the scenarios based on more aggressive renewable energy portfolio standards. Both parties were comfortable with PPRP's assumptions that additional requirements for solar generation would be met with in-State facilities and any other additional Tier 1 requirements would be met with wind generation. PPRP was asked to show land consumption by wind and solar projects under a range of assumptions regarding: (a) the acreage required per MW of wind or solar capacity; and (b) the amount of wind capacity that would be located in-State as opposed to elsewhere in PJM or MISO.

RESPONSE: To address these issues, PPRP developed a set of tables and graphs, along with text, to explain the implications of new power plant development (solar, wind, and natural gas) on land use in the State. Calculations were made for different assumptions regarding the degree to which new renewable energy projects would be located in-State (25 percent, 50 percent, 75 percent, and 100 percent). Additionally, calculations were made regarding the alternative assumptions about the amount of land required for solar generation and wind generation. For solar generation, calculations were performed for the assumption that each MW of solar would require five acres of land and, alternatively, eight acres of land. For wind power, PPRP calculated RPS-related land requirements using five acres per MW (for the pad, electrical facilities, and roads) and, alternatively, 60 acres per MW, which includes land required for offsets and separation. The results of the analysis are included in Chapter 10 of the LTER.

Reason for the Increase in Natural Gas-fired Capacity Additions in 2022 – During the June 2016 PPRAC Working Group webinar, a question was raised regarding the reason(s) behind the large increase in natural gas capacity in PJM in 2022 relative to other years.

RESPONSE: Steady growth in load in PJM resulted in potential reliability violations in several PJM zones in 2022, necessitating an increase in generating capacity to ensure that reliability constraints were satisfied. There is no single particular event (e.g., a large increase in load, high levels of power plant retirements, abrupt changes in relative fuel prices) that resulted in the increase in natural gas power plant additions in 2022.

Solar Installation Costs – During the June 2016 PPRAC Working Group webinar, Old Dominion Electric Cooperative (ODEC) asked PPRP to address the potential impacts on RECs and solar build-outs if solar installation costs fell by 50 percent during the forecast period.

RESPONSE: A reduction in solar capital costs would not have any impact from a modeling perspective on solar build-out since solar generating capacity is a user-supplied input, that is, solar capacity is not determined by the model but rather input by the user. Solar REC prices would be affected since the amount of revenue from the sale of RECs necessary to provide a make-whole revenue stream (over and above energy revenue and capacity revenues) would be reduced. It is noted, however, that the REC model employed for the modeling effort, which is used to generate average Tier I (or Class I) REC prices in PJM, could not be used to address this question since solar REC prices are not calculated. Fundamentally, other factors held constant, a 50 percent reduction in the cost of solar capacity costs could be expected to result in an approximate 50 percent reduction in solar REC prices.

Low Natural Gas Prices – ODEC asked PPRP to assess the impact of low natural gas prices for several years into the 20-year analysis period.

RESPONSE: The continuation of low natural gas prices is addressed in the alternative scenario based on natural gas prices below the Reference Case natural gas prices throughout the analysis period.

Long-term Forecasting – During the August 2016 PPRAC Working Group webinar, NRG asked whether projections beyond five to ten years have any utility for planning plant additions, given the many uncertainties involved. NRG and ODEC also asked what assumptions are made regarding the addition of renewable plants and/or nuclear plants.

RESPONSE: Projections beyond ten years have limited usefulness for planning power plant additions. The LTER, however, is not intended for this purpose, but instead for understanding the likely impacts of various policy choices and trends that are beyond the State's control.

Regarding renewable power plant additions, the ABB Model automatically builds capacity to meet reliability requirements, and it precludes intermittent renewables from being used for this purpose. Instead, renewable additions are treated as model inputs and are based on RPS requirements not only in Maryland but throughout PJM and the Eastern Interconnect. Nuclear power plants are eligible to be constructed by the ABB Model to meet reliability requirements but, for economic reasons, are not constructed since natural gas plants are determined throughout the modeling exercise to be the least-cost way of meeting reliability criteria.

RGGI Price Feedback – the Maryland Office of People's Counsel (OPC) asked whether high allowance prices are involved in any feedback loops in the Model.

RESPONSE: RGGI prices are not reflected in any feedback loops related to dispatch or demand in the ABB Model. PPRP did, however, simulate such a feedback loop related to a request made by MDE to estimate the RGGI emission price level that would be required for Maryland power plants to remain below Maryland's RGGI budget. The analysis conducted and the results obtained are contained in Appendix H of the LTER.

Climate Change Scenario – A question was raised as to whether the Climate Change scenario is similar to the High Load scenario. ODEC asked whether capacity additions in the Climate Change scenario are due to increased peak demand.

RESPONSE: The two scenarios (High Load and Climate Change) have similar increases in annual peak demand. However, the Climate Change scenario has less of an increase in energy use than the High Load scenario because warmer summers due to climate change are partially offset by warmer winters due to climate change. In the Climate Change scenario, new capacity is built to meet both higher summer peak demand and energy use.

Clean Power Plan Scenario – Pepco and ODEC asked what assumptions will be made for the CPP scenario given that states can come up with their own compliance plans.

RESPONSE: There are numerous methods by which states can meet the requirements of the CPP. The CPP scenario developed is a general approach that relies on a combination of actions, including increased reliance on renewable generation, increased energy conservation and efficiency measures, continuation of RGGI participation as a method to obtain reduced CO_2 emissions, and closure of certain coal plants. The details of the CPP scenario are addressed in Chapter 8 of the LTER.

Electric Price Feedbacks – ODEC made a general comment about the results of the High Load and Low Load scenarios. In ODEC's modeling, load changes result in more significant changes in electricity prices. This is due in part to a feedback loop involving higher RGGI prices.

RESPONSE: PPRP agreed that the existence of a feedback loop in the ABB Model involving RGGI prices, which does not currently exist, would be highly desirable. Similarly, a feedback loop between prices, in general, and demand would be desirable. These issues, along with other model characteristics, are discussed in Chapter 3 of the LTER.

APPENDIX N
Glossary

All-hours energy price. The weighted average of the on-peak and off-peak energy prices.

Alternative compliance payment (ACP). Payments that serve as a method to penalize load serving entities (LSEs) that do not comply with the Renewable Portfolio Standard (RPS), and to provide suppliers an option for compliance with RPS's in lieu of purchasing Renewable Energy Credits (RECs). This can occur in instances of REC scarcity or unavailability.

Ancillary services. Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services include load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

Annual Energy Outlook (AEO). Annual publication of the U.S. Department of Energy (DOE) Energy Information Administration (EIA) that presents yearly projections and analyses of energy topics.

Base-load plant. A power plant built to operate for almost all the hours of the year. Such plants typically have low operating costs and high capital costs. Coal- and nuclear-fueled plants are typical base-load plants.

Best system of emission reduction (BSER). Requirement under Section 111(d) of the Clean Air Act that directs the EPA to set air emission limits for power plants reflecting use of the BSER. Congress required EPA to set a BSER that has been adequately demonstrated. The BSER can consist of multiple approaches, such as specified technologies or equipment, marketable permits, and emissions cap and trading programs. States are not required to use other approaches besides the BSER as long as states can meet or exceed the air emission limit requirements set by EPA.

British thermal unit (Btu). A Btu is equivalent to 252 calories and serves as the base unit for measuring the heat content of a fuel source.

Business-as-usual. Reflects the modeler's set of assumptions about what is likely to happen over the modeling timeframe in the absence of policy changes.

Cap-and-trade. An environmental policy tool that utilizes a mandatory cap on emissions while providing sources with flexibility related to compliance.

Capacity. The capability to generate electrical power, typically expressed in megawatts (MW).

Capacity factor. The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

Capital cost. The cost of field development, plant construction, and the equipment required for operations.

Carbon capture and storage (CCS). The process by which carbon dioxide (CO_2) is isolated from a power plant's emissions stream, compressed, and transported to an injection site where it is stored underground.

Clean Power Plan (CPP). A federal policy proposed by the U.S. Environmental Protection Agency (EPA) designed to reduce the carbon pollution from existing power plants. The rule, finalized on August 3, 2015, established state-specific goals and guidelines for states to develop and implement plans to reduce CO_2 emission rates. The U.S. Supreme Court has stayed the CPP, pending the outcome of a legal challenge before the United States Court of Appeals for the District of Columbia.

Clean Water Act. Establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters.

Closed-loop cooling. Cooling water is recycled between a cooling tower and a heat exchanger, with cooling water cooled by evaporating a percentage of the water to the environment. Because the water is evaporated, there must be a make-up water supply to account for the consumed water, which typically comes from a nearby water source. A closed-loop cooling system is designed to minimize the amount of water withdrawn from the river.

Cost of New Entry (CONE). The first year net revenue for a new generation resource to recover the capital and fixed costs based upon future cost recovery projected over the economic life of the unit. This is a PJM term used in connection with PJM's Reliability Pricing Model (RPM).

Cooling water. Water used to absorb waste heat rejected from the processes or auxiliary operations of the power plant.

Cooling water intake structure. The total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States.

Combined cycle. An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion turbine. A generating unit in which a combustion turbine engine is the prime mover for an electrical generator. It is typically used during peak periods due to quick response capability and relatively high running costs.

Congestion. Describes a situation where power cannot be moved from where it is being produced to where it is needed for use because the transmission system does not have sufficient capability to carry the electricity.

Cross-State Air Pollution Rule. An EPA rule that requires 27 states to improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.

Debt/equity ratio. A financial ratio indicating the relative proportion of equity and debt used to finance a company's assets.

Demand. The amount of power that must be supplied to a customer or an aggregate of customers (i.e., a load), typically expressed in MW.

Demand-side management (DSM). The use of financial incentives and education to reduce consumer demand and energy usage and to encourage behavioral changes to conserve energy.

Demand response. Refers to shifting demand for electricity to non-peak periods or reducing electricity use during periods of peak demand.

Dispatch (merit order or economic). The practice of utilizing least-cost generation first to serve load. For example, PJM operation stacks generator bids from lowest to highest and uses the energy generation facilities in least-cost order.

Dispatchable generation. Generation capable of varying output in response to grid operator control instruction.

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.

Eastern Interconnection. North America is comprised of two major and three minor alternating current power grids or "interconnections." The Eastern Interconnection 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 operating at an average of 60Hz.

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 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 the Maryland Public Service Commission (PSC)).

Emissions allowance. A representation of an incremental amount of emissions (e.g., one ton of CO_2) that an entity may produce.

Emissions rates. Ratio of emissions per unit of output (e.g., tons of CO_2 per megawatt-hour).

EmPOWER Maryland. Enacted into law in 2008 with the passage of House Bill (HB) 374, the EmPOWER Maryland Energy Efficiency Act of 2008 is an initiative that aims to achieve reductions in Maryland's per capita electricity consumption and peak demand relative to a historical baseline load.

Energy use. A measure of electrical power used over a period of time, usually expressed in kilowatt- hours (kWh) or megawatt-hours (MWh).

Federal Energy Regulatory Commission (FERC). An independent federal commission responsible for regulating wholesale electric power transactions and the interstate transmission and sale of natural gas for resale. FERC is the federal counterpart to state utility regulatory commissions.

Fixed operations and maintenance (O&M) costs. Costs associated with a system after it is installed that do not vary directly with plant power generation and consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fees.

Fuel diversity. The mixture of fuels used to generate electricity in a specified region.

Generation. The process of producing electrical energy.

Generic power plant. See **Prototype unit**.

Greenhouse gas (GHG). Gases, such as CO_2, methane (CH_4), nitrogen oxides (NOx), and fluorocarbons, which trap heat within the atmosphere and emit radiation resulting in the greenhouse gas effect, a warming of the plant's surface temperature.

Greenhouse Gas Emissions Reduction Act of 2009 (Maryland). Mandates a statewide reduction in GHG emissions of 25 percent from 2006 levels by 2020.

Heat rate. A measure of generating station thermal efficiency commonly stated as Btu per kWh, i.e., the amount of fuel that is required to produce a certain amount of output. Since the heat rate increases as more fuel is required to produce the same amount of output, a higher heat rate represents a lower level of generating efficiency.

Henry Hub. A pipeline hub on the Louisiana Gulf Coast. It is the delivery point for the natural gas futures contract on the New York Mercantile Exchange (NYMEX).

Hybrid electric vehicle (HEV). Vehicles powered by an internal combustion engine that can be run on conventional or alternative fuel and an electric motor that uses energy stored in a battery.

Independent power producers (IPPs). Private companies that develop, own, or operate electric power plants.

Independent System Operator (ISO). Former power pools that formed into ISOs as a way to provide non-discriminatory access to transmission as well as open access to retail and wholesale supply. An ISO, regulated by the FERC, serves as an independent, third-party coordinator and operator of the transmission system within a defined area, typically within one state, and ensures the reliability of the electric system.

Interconnection. Two or more electric systems having a common transmission line that permits a flow of energy between them. The physical connection of the electric power transmission facilities allows for the sale or exchange of energy.

Intermittent resources. An electric generating plant with output controlled by the natural variability of the energy resource (e.g., the wind) rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar energy, wind energy, or the energy of free-flowing rivers (that is, run-of-river hydroelectricity).

Investor-owned utility. A for-profit, tax-paying utility company.

Levelized cost. The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Life cycle cost. The total discounted dollar cost of owning, operating, maintaining, and disposing of a building or a building system over a period of time.

Load. Kilowatt or megawatt demand placed on the electric system by consumers of power.

Load serving entity (LSE). Providers of electric service, including competitive retailers, to retail customers.

Locational marginal price (LMP). Electricity prices that vary by time and geographic location. 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 LMPs.

Maryland Department of the Environment (MDE). Government environmental agency that provides environmental licenses and permits, as well as performs environmental inspections. The agency oversees occupational, industrial, and residential hazards; water supply, sewerage, solid waste, and pollution control planning and funding; water pollution; Maryland's CO_2 budget trading program; oil pollution and tank management; air quality; radiation management; disposal of controlled hazardous substances; lead abatement; water management; oil and natural gas resources; mining; coastal facilities; and tidal and non-tidal wetlands.

Maryland Energy Administration (MEA). Government agency that advises the Governor on energy policy in an effort to promote affordable, reliable, and clean energy in the State.

Maryland Healthy Air Act (HAA). Limits the emissions of NOx, SO_2, and mercury from seven coal-burning power plants in Maryland. Under the HAA, emissions limits are set for each plant, but owners of multiple plants can meet the requirement aggregated over all of their affected plants in the State. The HAA also requires that Maryland participate in the RGGI which is aimed at reducing GHG emissions.

Maryland Public Service Commission (PSC). Government agency that regulates public utilities and certain passenger transportation companies doing business in Maryland, including natural gas, electric, telecommunications, water, sewage disposal, passenger motor vehicle, railroad, and taxicab companies.

Mercury and Air Toxics Standards (MATS). A rule, finalized by the EPA in December 2011, which limits the emission of toxic air pollutants, such as mercury, arsenic, and metals from coal- and oil-fired power plants. The rule established emission standards for individual generating facilities with a capacity of 25 MW or greater.

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.

Net energy imports. In the context of this report, net energy imports are the total zonal consumption minus the total in-zone generation. A positive result represents a need to import energy, while a negative result represents the ability to export energy.

New Source Performance Standards (NSPS). EPA technology-based standards that apply to specific categories of stationary sources. These standards apply to new, modified, and reconstructed facilities in specific source categories. Standards consider that the new source facility has an opportunity to design operations to more effectively control pollutant discharges.

New York Mercantile Exchange (NYMEX). A commodities futures exchange.

Nominal price. The price paid for a product or service at the time of the transaction. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred.

Non-dispatchable generation. Generation not capable of varying output in response to grid operator control instruction. (See **Intermittent resources.**)

North American Electric Reliability Corporation (NERC). A non-profit corporation formed in 2006 as the successor to the North American Electric Reliability Council, established to develop and maintain mandatory reliability standards for the bulk electric system, with the fundamental goal of maintaining and improving the reliability of that system. NERC consists of regional reliability entities covering the interconnected power regions of the contiguous United States, Canada, and Mexico.

Off-peak energy price. The energy price for a period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns; these off-peak periods differ for each individual electric utility. For the PJM energy market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours, plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.

Off-shore wind power. Wind power generation projects located in the geographic area that lies seaward of the coastline.

On-peak energy price. The energy price for periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns; these on-peak periods differ for each individual electric utility. For the PJM Energy Market, on-peak periods are weekdays other than NERC holidays, and from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.

On-shore wind power. Land-based wind power generation projects.

Overnight construction cost. The present value cost that would have to be paid as a lump sum up front to completely pay for a construction project (i.e., the cost that would be realized if the power plant could be built instantaneously). It does not incorporate financing charges and inflation during the construction time.

Peak demand. The maximum instantaneous demand on an electric system over 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. A federally regulated Regional Transmission Organization (RTO) that manages the wholesale electricity market and transmission system in a region encompassing the District of Columbia and all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

Planned generating capacity. For purposes of this report, those power plants for which all air permits have been obtained and construction has begun as of mid-2015.

Plug-in electric vehicle (PEV). Vehicles that use electricity either as their primary fuel or to improve the efficiency of conventional vehicle designs, e.g., hybrid electric vehicles, plug-in hybrid electric vehicles, and battery electric vehicles.

Plug-in hybrid electric vehicle (PHEV). Vehicles powered by conventional or alternative fuels and by electrical energy stored in a battery.

Power Plant Research Advisory Committee. An advisory body to the Secretary of the Maryland Department of Natural Resources. The Committee's main tasks are to review the goals, policy practices, and major directions of the Power Plant Research Program (PPRP). Appointment is by the Secretary and terms are indefinite.

Power Plant Research Program (PPRP). A subdivision of the Maryland Department of Natural Resources, the 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.

Production costs. All costs associated with operating and maintaining a power plant, including fixed and variable O&M, capital costs, etc.

Production tax credit. A production-based federal tax incentive that provides income tax credits or deductions at a specified amount for eligible renewable energy facilities.

Prototype unit. For purposes of this report, units input into the model that have been assigned specific, plant-level unit characteristics created as a generic set.

Rate of return. The ratio of net operating income earned by a utility is calculated as a percentage of its rate base.

Real price. A price that has been adjusted to remove the effect of changes in the purchasing power of the dollar. Real prices, which are expressed in constant dollars, reflect buying power relative to a base year.

Regional Greenhouse Gas Initiative (RGGI). An initiative of ten Northeastern and Mid-Atlantic states to reduce CO_2 emissions from electric power plants by means of a cap-and-trade system. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States. Under RGGI, power sector CO_2 emissions are to be reduced by 10 percent by 2018. At the time the analysis in this report was conducted, no agreement had been made regarding extending RGGI beyond 2019.

Regional transmission organization (RTO). An RTO controls, operates, and may independently own the transmission facilities historically held by a region's vertically integrated public and private utilities. An RTO is an organization independent of the transmission facility owners. The RTO operates the high-voltage transmission grid to provide non-discriminatory access to the grid so that the lowest-priced wholesale power can be delivered to wholesale customers (e.g., load serving entities), while the owners still market and sell power. Maryland resides within the PJM RTO.

Reliability. The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Reliability councils. Regional organizations formed by the electric utilities to coordinate utilities' generation and transmission systems and monitor the availability of electric services.

Reliability pricing model (RPM). PJM's resource adequacy construct. The purpose of RPM is to develop a long-term (three-year) pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Plan planning process. RPM adds stability and a locational nature to the pricing signal for capacity.

ReliabilityFirst Corporation (RFC). ReliabilityFirst Corporation is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. It is the successor organization to three former Regional Reliability Councils: the Mid-American Area Council, the East Central Area Coordination Council Agreement, and the Mid-American Interconnected Network organizations. RFC is one of the eight regional reliability organizations in North America.

Renewable energy. Sources of energy that are continually being replaced such as energy from the sun (solar), wind, geothermal, and hydroelectric.

Renewable Energy Credit (REC). Represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source, and typically represents one MWh of renewable energy generation. Also known as a renewable energy certificate.

Renewable energy portfolio standard (RPS). Requires that a specific portion of retail electricity supply comes from specified renewable resources.

Reserve margin. Total system generating capacity minus annual system peak demand, divided by the annual system peak demand, expressed as a percent.

Retail competition. Permitting end-use customers to contract directly with suppliers for their electric or natural gas service, while transmission and distribution companies provide for delivery of the service.

Retail rates. The final price paid by end-use customers.

System Average Interruption Duration Index (SAIDI). One of two indices by which distribution system reliability is measured, the SAIDI measures the average interruption time for a customer.

System Average Interruption Frequency Index (SAIFI). One of two indices by which distribution system reliability is measured, the SAIFI measures the average number of times a customer experiences an outage during a one-year period

Selective catalytic reduction (SCR). A method of converting diesel NOx emissions, by catalytic reaction, into nitrogen gas and water.

Self-generator. A generating facility that consumes most or all of the electricity it produces to meet on-site power demand.

Solar photovoltaics (PV). PV devices use semiconducting materials to convert sunlight directly into electricity.

Solar carve-out (or solar set-aside). A requirement that a certain percentage of an RPS be met specifically with solar energy. Solar technologies eligible for compliance may vary depending on the goals of the policy.

Time-of-use (TOU) rates. A utility rate structure that charges higher rates during peak hours of the day in an effort to shift peak period demand to off-peak hours.

Transmission. The process of delivering electricity from generation plants to entities that serve loads.

Transport rule. An EPA rule that restricts SO_2 and NOx emissions on the grounds that the pollutants are transported long distances across state lines, which interferes with the ability of other states to achieve national clean air standards. The rule covers 31 states and the District of Columbia.

U.S. Energy Information Administration (EIA). An impartial, independent agency within the U.S. Department of Energy (DOE) that develops surveys, collects energy data, and conducts analytical and modeling analyses of energy issues. The Agency must satisfy the requests of the U.S. Congress, other elements within the DOE; FERC; the Executive Branch; and provide assistance to the general public, or other interest groups, without taking a policy position.

U.S. Environmental Protection Agency (EPA). A federal agency whose mission is to protect human health and the environment. The EPA develops and enforces regulations, gives grants, studies environmental issues, sponsors partnerships, educates the public on environmental issues, and publishes information.

Variable operations and maintenance (O&M) cost. Costs associated with a system after it is installed that tend to vary in near direct proportion to the output of the unit, and include costs associated with equipment outage maintenance, utilities, chemicals, and other consumables. Fuel costs are determined separately, and are not included in O&M costs.

Variable Resource Requirement (VRR). The demand for capacity in the PJM RPM Base Residual Auction (BRA). The VRR is a downward-sloping curve (analogous to a demand curve) used to determine (in conjunction with the capacity supply curve) the capacity clearing price for a given delivery year.

Volt. A unit of electrical pressure. 1 kV = 1,000 volts.

Watt. The electrical unit of power or rate of doing work. 1 kW = 1,000 watts; 1 MW = 1,000,000 watts.

Watt-hour. An electric energy unit of measure that is equal to one watt of power supplied or taken steadily from an electric circuit for one hour.

Wholesale energy price. The price at which energy is sold by energy suppliers, in a wholesale energy market, to energy distributers, who buy power for resale to end-use customers.

APPENDIX P
List of Acronyms

ACP – Alternative Compliance Payment

AEO – U.S. Energy Information Administration's Annual Energy Outlook Report

AMI – Advanced Metering Infrastructure

AWEA – American Wind Energy Association

BCF – Billion cubic feet

BGE – Baltimore Gas and Electric Company

BSER – Best System of Emission Reduction

Btu – British thermal unit

C&I – Commercial & Industrial

CAA – Clean Air Act

CAES – Compressed air energy storage

CAGR – Compound Annual Growth Rate

CC – Combined Cycle Unit

CCB – Coal Combustion Byproduct

CCR – Coal Combustion Residual

CCS – Carbon Capture and Storage

CH_4 – Methane

CHP – Combined Heat and Power

CO_2 – Carbon dioxide

COMAR – Code of Maryland Regulations

CONE – Cost of New Entry

CP – Capacity performance

CPP – Clean Power Plan

CPV – Concentrator photovoltaics

CSAPR – Cross-State Air Pollution Rule

CSP – Concentrated Solar Power

CT – Combustion Turbine Unit

CVR – Conservation Voltage Reduction

CWA – Clean Water Act

DHCD – Maryland Department of Housing and Community Development

DoD – United States Department of Defense

DOE – United States Department of Energy

DPL – Delmarva Power & Light Company

DSM – Demand side management

ECPR – Early Coal Plant Retirement

EGU – Electric generating unit

EIA – U.S. Energy Information Administration

EMT – Energy Management Tool

EO – Executive Order 01.01.2010.16

EPA – U.S. Environmental Protection Agency

EPM – Energy Portfolio Management

LBNL – Lawrence Berkeley National Laboratory

FERC – Federal Energy Regulatory Commission

FGD – Flue gas desulfurization

FOB – Free-on-board

GATS – Generation Attribute Tracking System

GGRA – Maryland Greenhouse Gas Emissions Reduction Act of 2009

GHG – Greenhouse gas

GW – Gigawatt

GWh – Gigawatt-hour

HAA – Maryland Healthy Air Act

HAP – Hazardous air pollutant

HL – High Load Scenario

HPNG – High Price Natural Gas Scenario

HVAC – Heating, ventilation and air conditioning

IEA – International Energy Agency

IPP – Independent power producer

IRM – Installed reserve margin

ISO – Independent System Operator

ITC – Federal Investment Tax Credit

kW – Kilowatt

kWh – Kilowatt-hour

L48 – Lower 48

LDA – Locational delivery area

LL – Low Load Scenario

LNG – Liquefied natural gas

LOLE – Loss of Load Expectation

LPNG – Low Price Natural Gas Scenario

LSE – Load serving entity

LTER – Long-term Electricity Report for Maryland

MATS – Mercury and Air Toxics Standard

MDE – Maryland Department of the Environment

MEA – Maryland Energy Administration

Mgd – Million gallons per day

MISO – Midcontinent Independent System Operator

MMBtu – Million British thermal units

$MMtCO_{2e}$ – Million tons of carbon dioxide equivalent

MOR – Maintenance Outage Rate

MW – Megawatt

MW-day – Megawatt per day

MWh – Megawatt-hour

N_2O – Nitrous oxide

NAAQS – National Ambient Air Quality Standards

NEBC – National Energy Board of Canada

NERC – North American Electric Reliability Corporation

NG – Natural gas

NOx – Nitrogen oxides

NPV – Net present value

NREL – National Renewable Energy Laboratory

NSPS – New Source Performance Standards

NYMEX – New York Mercantile Exchange

O&M – Operations and maintenance

PE – Potomac Edison, formerly Allegheny Power

Pepco – Potomac Electric Power Company

PEV – Plug-in Electric Vehicle

PHEV – Plug-in Hybrid Electric Vehicle

PJM-APS – Allegheny Power Systems

PJM-CE – Commonwealth Edison

PJM-MidE – Mid-Atlantic East

PJM-SW – Mid-Atlantic Southwest

PPA – Power Purchase Agreement

PPRAC – Power Plant Research Advisory Committee

PPRP – Power Plant Research Program

PSC – Maryland Public Service Commission

PTC – Federal Production Tax Credit

PV – Photovoltaic

RC – 2016 LTER Reference Case

RCI – Residential, commercial, and industrial

RCRA – Resource Conservation and Recovery Act

RCU – 2013 LTER Reference Case Update

REC – Renewable Energy Credit, also known as Renewable Energy Certificate

RFC – ReliabilityFirst Corporation

RGGI – Regional Greenhouse Gas Initiative

RPM – PJM's Reliability Pricing Model

RPS – Renewable Energy Portfolio Standard

RTO – Regional Transmission Operator

S – Sulfur

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SCPC – Supercritical pulverized coal

SCR – Selective Catalytic Reduction

SMECO – Southern Maryland Electric Cooperative

SO_2 – Sulfur dioxide

SPP – Southwest Power Pool

TCF – Trillion cubic feet

TVA – Tennessee Valley Authority

TWh – Terawatt-hour

V – Volt

VRR – Variable Resource Requirement

WGL – Washington Gas Light

WTI – West Texas Intermediate

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