Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and when units do not clear, in the retirement of units. Federal and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[2]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to all RICE.[3] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[4]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[5] On February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[6] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[7]
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[8]

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the September 9, 2018, auction for the 2015/2018 compliance period was $4.50 per ton. The clearing price is equivalent to a price of $4.96 per metric tonne, the unit used in other carbon markets. The price increased by $0.48 per ton, 11.9 percent, from $4.02 per ton from June 13, 2018, to $4.50 per ton for September 9, 2018.

1 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
2 CAA § 110(a)(2)(D)(i)(I).
3 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
4 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).
5 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."
6 North Dakota v. EPA, et al., Order 15A793.
7 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).
8 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

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- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. As of September 30 2018, 93.1 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.9 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

Renewable Generation

Total wind and solar generation was 2.6 percent of total generation in PJM for the first nine months of 2018. Tier I generation was 4.2 percent of total generation in PJM and Tier II generation was 2.8 percent of total generation in PJM for the first nine months of 2018.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the data more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[9]

RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based

9 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is 'in connection with' or 'affects' jurisdictional rates or charges.").

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on the year of origination. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

The economic logic of RPS programs and the associated REC and SREC prices is not clear. The price of carbon implied by REC prices ranges from $4.70 per tonne in Washington, D.C. to $35.41 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $17.76 per tonne in Pennsylvania to $839.29 per tonne in Washington, D.C. The effective prices for carbon compare to the 2018 average RGGI clearing price of $4.52 per tonne and to the social cost of carbon which is estimated in the range of $40 per tonne.[10] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $283.56 per MWh. The impact of a $40 per tonne carbon price would be $14.18 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensure that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

10 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899", Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (August 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[11] [12]

The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

11 42 U.S.C. § 7401 et seq. (2000).

12 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

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Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[13] The rule established a compliance deadline of April 16, 2015.

In a related EPA rule, also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).[14]

The future of MATS is currently uncertain. On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[15] The U.S. Supreme Court ruled in 2015 that "the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[16] The remand did not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.[17] On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[18] The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[19] On April 28, 2017, the Court granted the EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[20]

Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances.

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[21] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) then in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2 emissions effective January 1, 2017.[22] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state

13 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

14 NSPS are promulgated under CAA § 111.

15 Michigan et al. v. EPA, Slip Op. No. 14-46.

16 135 S. Ct. 2699, 2712 (2015).

17 *See Supplemental Finding That It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

18 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; see also White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

19 *See* Case No. 16-1127, et al.

20 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

21 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

22 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.

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prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[23] The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[24] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[25]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[26] Group 2 does not include any states in the PJM region.[27] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[28] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

23 CAA § 110(a)(2)(D)(i)(I).
24 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).
25 *Id.*
26 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.
27 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
28 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_X emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 (CSAPR Update).[29] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_X emissions level was lowered to 0.075 ppm from 0.08 in 1997.[30] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[31] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_X from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[32] The EPA has removed North Carolina from the ozone season NO_X trading program.[33]

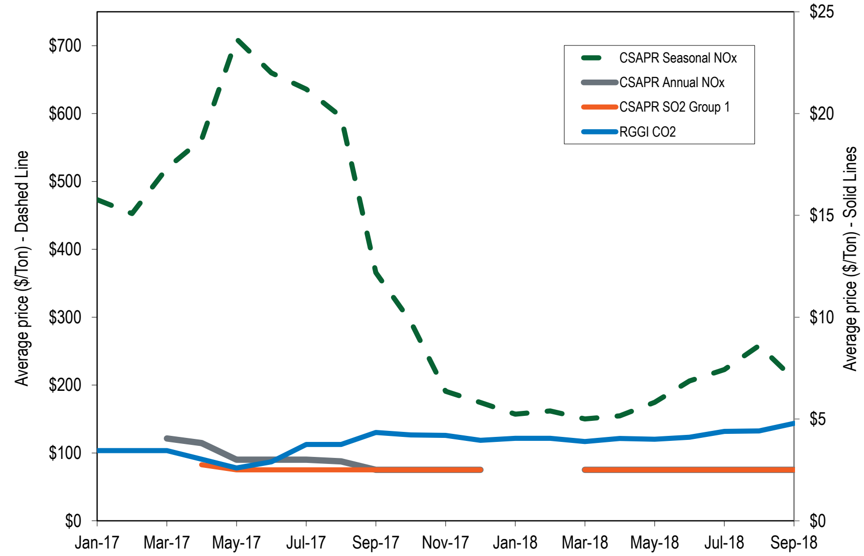
29 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (–Oct. 26, 2016) ("CSAPR Update").
30 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).
31 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*
32 *Id.* at 74554.
33 *Id.* at 74507 n.13.

During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR NO_X ozone season trading program by the start of the 2017 ozone season control period."[34] The EPA is concerned that "[w]ithout imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive ozone seasons."[35] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[36]

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for January 1, 2017 through September 30, 2018. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first nine months of 2018, CSAPR annual NO_X prices were 21.4 percent lower than in the first nine months of 2017. There were not any reported CSAPR Annual NO_X cleared purchases for January or February 2017. The CSAPR Seasonal NO_X price hit a peak of $710.12 in May 2017. The CSAPR Update resulted in fewer CSAPR Seasonal NO_X allowances.[37]

Figure 8-1 Spot monthly average emission price comparison: January, 2017 through September, 2018[38]



Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. Delaware has filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland has filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia.[39] The EPA has not acted on any of the petitions, and has sought to extend the deadlines for action. Maryland has

34 *Id.* at 74588.
35 *Id.*
36 *Id.* at 74560. The EPA states: "The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or 'true-up')s for the 2016 ozone season program is completed." *Id.*
37 There were no reported cleared purchases for January through March, 2017, or January through February, 2018, for CSAPR SO_2 allowances.

38 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 2, 2018).
39 The units are located at the following plants: Alcoa Allowance Management Inc., Clifty Creek, Gibson, Petersburg in Indiana; East Bend, Elmer Smith, Paradise in Kentucky; Killen Station, Kyger Creek, W H Zimmer Generating Station in Ohio; Bruce Mansfield, Cambria Cogen, Cheswick, Homer City, Keystone, Montour in Pennsylvania; Grant Town Power Plant, Harrison Power Station, Pleasants Power Station in West Virginia.

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sued and Delaware has given notice of its intent to sue the EPA seeking to require action.[40]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[41] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).[42]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[43]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[44] The proposed rule would have allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[45] As a result, the national emissions standards uniformly apply to all RICE.[46] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[47] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[48]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[49] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[50] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[51]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

40 *See* Maryland v. Pruitt, Complaint for Injunctive Relief, No. 1:17-cv-02873 (USDC Md. Sept. 27, 2017). Delaware provided notice by letter dated January 2, 2018.

41 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ ("2010 RICH NESHAP Rule").

42 *Id.*

43 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

44 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

45 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

46 *Id.*

47 DENREC v. EPA at 3, 20–21.

48 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.

49 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

50 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

51 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

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The MMU is currently taking steps to ensure resource portfolios remain in compliance. The MMU contacted all CSPs with demand resources using diesel fuel to ensure compliance is met among all PJM resources.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[52] [53]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[54] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[55] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[56] [57] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 MMBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 MMBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[58] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[59]

The future of the Clean Power Plan is currently uncertain. On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the EPA Act.[60] On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.[61]

Federal Regulation of Environmental Impacts on Water

The Clean Water Act (CWA) applies to the waters of the United States (WOTUS). The CWA defines WOTUS as "navigable waters."[62] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[63] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[64] The U.S. Supreme Court reversed the stay, but the EPA amended the 2015 Clean Water Rule to establish an applicability date of February 6, 2020.[65] The proposed

52 See CAA § 111.
53 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
54 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (August 8, 2016).
55 *Id.*
56 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.
57 79 Fed. Reg. 1352 (January 8, 2014).
58 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."
59 North Dakota v. EPA, et al., Order 15A793.
60 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).
61 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).
62 33 U.S.C. § 1362(7).
63 80 Fed. Reg. 37054 (June 29, 2015).
64 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.
65 *See Definition of "Waters of the United States"—Addition of an Applicability Date to 2015 Clean Water Rule*, Final Rule, EPA Docket No. EPA-HQ-OW-2017-0644, 83 Fed. Reg. 5200 (Feb. 6, 2018); National Assoc. of Mfg. v Dept. of Defense, No. 16-299 (S. Ct. Jan. 22, 2018).

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rule would restore the pre 2015 rule to the code and the interpreting precedent applicable to the pre 2015 rule. As a result of the new applicability date, the pre 2015 rule is now in effect. The pre 2015 rule includes all navigable waters and waters with a "significant nexus" to such waters.[66]

Water cooling systems at steam electric power generating stations are subject to regulation under the CWA. EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[67] Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from WOTUS and has a design intake flow of greater than two million gallons per day (mgd).[68]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[69]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal

66 Rapanos v. U.S., 547 U.S. 715 (2006).

67 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve. EPA issued a rule providing an expansive definition of "waters of the United States" in 2015 that the current administration has indicated intent to review. See Executive Order: Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the "Waters of the United States" Rule (February 28, 2017) referring to "Clean Water Rule: Definition of 'Waters of the United States,'" 80 Fed. Reg. 37054 (June 29, 2015).

68 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

69 42 U.S.C. §§ 6901 *et seq.*

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ash, produced by electric utilities and independent power producers.[70] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

Table 8-1 describes the criteria and anticipated implementation dates.

Table 8-1 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

70 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

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On March 1, 2018, the EPA proposed a rule amending the CCRR.[71] The proposal includes:

- A change to allow a state regulatory program to establish alternative risk-based groundwater protection standards for constituents that do not have an established maximum contaminant level (MCL), rather than the use of background levels that are currently required. The proposal also requests public comment on whether a facility may be allowed to establish alternative risk-based standards using a certified professional engineer or other means, subject to EPA oversight.
- A request for comment on whether the current deadlines for groundwater monitoring and analysis remain appropriate in light of the new legal authorities and potential regulatory changes.
- A request for public comment on modifying the location restrictions and associated deadlines concerning construction or operation of a CCR landfill or surface impoundment in certain areas.
- Changes to allow states to establish alternative requirements for how facilities respond to and remediate releases from CCR landfills and surface impoundments. The proposal also requests comment on allowing states to determine when an unlined surface impoundment that is leaking may undertake corrective action rather than be forced to stop receiving CCR and close.
- The addition of boron to the list of constituents for which facilities would need to perform assessment monitoring.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days.[72] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[73] NO_x emissions limits for coal units became effective December 15, 2012.[74] NO_x emissions limits for other unit types became effective May 1, 2015.[75] As of December 31, 2017, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[76] In total, 37 NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

Table 8-2 shows the HEDD emissions limits applicable to each unit type.

Table 8-2 HEDD maximum NO_x emission rates[77]

Fuel and Unit Type	NO_x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

71 EPA Press Release, EPA Proposes First of Two Rules to Amend Coal Ash Disposal Regulations, Saving Up To $100M Per Year in Compliance Costs <https://www.epa.gov/newsreleases/epa-proposes-first-two-rules-amend-coal-ash-disposal-regulations-saving-100m-year>, (March 1, 2018.)

72 N.J.A.C. § 7:27-19.

73 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

74 N.J.A.C. § 7:27-19.4.

75 N.J.A.C. § 7:27-19.5.

76 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

77 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

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Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS).[78] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[79] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[80]

State Regulation of Greenhouse Gas Emissions

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[81] On January 29, 2018, New Jersey Governor Phil Murphy signed an executive order to take all steps necessary to rejoin the RGGI program but New Jersey is still not part of RGGI.[82] Virginia is considering joining RGGI. The Virginia Air Pollution Control Board is in the process of developing administrative rules that would facilitate its participation.[83] A final rule is expected to be approved at the end of the 2018, which would allow for Virginia to join in 2019.

RGGI generates revenues for the participating states which have spent approximately 64 percent of revenues on energy efficiency, 16 percent on clean and renewable energy, 4 percent on greenhouse gas abatements and 10 percent on direct bill assistance.[84]

Table 8-3 shows the RGGI CO_2 auction clearing prices and quantities for the 2008/2011 compliance period auctions, the 2012/2014 compliance period auctions and 2015/2018 compliance period auctions held as of September 30, 2018, in short tons and metric tonnes.[85] Prices for auctions held September 9, 2018, were at $4.50 per allowance (equal to one ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[86] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the last auction clearing price of $4.02 in June 2018.

78 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

79 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).

80 See *Id.*

81 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

82 *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

83 Regulation for Emissions Trading, 9 VAC 5–140.

84 *The Investment of RGGI Proceeds Through 2015*, The Regional Greenhouse Gas Initiative, <https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2015.pdf> (October, 2017).

85 The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

86 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

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Table 8-3 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009/2011, 2012/2014 and 2015/2018 Compliance Periods[87]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459
March 8, 2017	$3.00	14,371,300	14,371,300	$3.31	13,037,428	13,037,428
June 7, 2017	$2.53	14,597,470	14,597,470	$2.79	13,242,606	13,242,606
September 8, 2017	$4.35	14,371,585	14,371,585	$4.80	13,037,686	13,037,686
December 8, 2017	$3.80	14,687,989	14,687,989	$4.19	13,324,723	13,324,723
March 14, 2018	$3.79	13,553,767	13,553,767	$4.18	12,295,774	12,295,774
June 13, 2018	$4.02	13,771,025	13,771,025	$4.43	12,492,867	12,492,867
September 9, 2018	$4.50	13,590,107	13,590,107	$4.96	12,328,741	12,328,741

87 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed October 2, 2018).

Zero Emissions Credits (ZEC) Programs

On December 7, 2016, the State of Illinois enacted legislation that, among other things, provides subsidies, known as zero emission credits (ZECs), for certain existing nuclear-powered generation units that indicated they would otherwise retire.[88] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under 10 year contracts with select Illinois nuclear power plants.[89]

IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[90] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[91] The base price is reduced by the amount that "the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016."[92]

The revenues provided by the ZEC legislation are expected to forestall the retirement of a specific PJM nuclear unit in Illinois, the Quad Cities Generating Station.[93]

On February 14, 2017, the Electric Power Supply Association (EPSA) and others filed a complaint in the U.S. District Court for the Northern District of Illinois Eastern Division.[94] State defendants have filed a motion to dismiss and EPSA et al. have filed a motion for a stay. On April 24, 2017, the MMU filed an amicus curiae brief opposing the motion to dismiss and supporting the motion for a stay. The District Court granted the motion to dismiss on July 14, 2017. EPSA appealed to the U.S. Court of Appeals for the Seventh Circuit.

88 See Illinois 99th Gen. Assemb., S.B. 2814 (Dec. 7, 2016), which can be accessed at: <http://www.ilga.gov/legislation/99/SB/09900SB2814lv.htm>. The Governor of Illinois signed the ZEC legislation, amending the Illinois Power Agency Act ("IPAA"), on December 7, 2016; see also ICC, et al., Potential Nuclear Power Plant Closings in Illinois (Jan. 5, 2015), which can be accessed at: <http://www.ilga.gov/reports/special/report_potential%20nuclear%20power%20plant%20closings%20in%20il.pdf>.

89 See IPAA § 1-75(d-5)(1).

90 See *id.*

91 See IPAA § 1-75(d-5)(1)(B).

92 See *id.*

93 See Ted Caddell, RTO Insider "Exelon's Crane Reports 'Monumental Year,'" (Feb. 8, 2017); Exelon, Press Release, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants" (June 2, 2016) (citing "lack of progress on Illinois energy legislation" as a key factor), <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 7, 2016) (reporting Exelon statement that Byron is "economically challenged"), <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.

94 Case No. 17-cv-01164.

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On September 6, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

The ZEC legislation creates subsidies for existing units that create the same price suppressive effects as subsidies for new entry that are addressed by the Minimum Offer Price Rule.[95] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[96] The MMU's proposed modification of the MOPR rules would, if in place, apply to nuclear units receiving subsidies. Such subsidies may otherwise result in noncompetitive offers in PJM markets that would be addressed on a unit specific basis.

A similar issue has arisen in New York, where the New York Public Service Commission (New York PSC) established a program requiring the purchase of ZEC credits from specific nuclear facilities in upstate New York. The constitutionality of the New York PSC's program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[97] On January 9, 2017, the MMU filed an amicus curiae brief supporting plaintiffs on the grounds that the ZEC subsidies interfere with the operation of wholesale power markets in New York and have price suppressive effects in the energy markets in PJM.[98] In a decision issued July 25, 2017, the District Court dismissed the case. The Coalition for Competitive Electricity appealed to the U.S. Court of Appeals for the Second Circuit. On October 23, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

On April 12, 2018, the New Jersey legislature passed Senate Bill No. 2313, which would establish a ZEC program for the state. The legislation directs the New Jersey Board of Public Utilities (BPU) to issue certificates representing one MW of electricity generated by an eligible nuclear power plant. An eligible plant must be licensed at least until 2030. The single unit Hope Creek and two units Salem nuclear power generating stations owned by Public Service Electric & Gas are expected to be eligible to receive ZECs.

The BPU has initiated proceedings to implement the ZEC program.[99] One proceeding concerns establishing the criteria to receive ZECs.[100] The BPU has solicited comments on a number of questions, to which the Market Monitor and others have responded.[101] The BPU also has initiated dockets to implement the statutorily specified $0.004/kWh rate for ZEC charges rate for each New Jersey electric utility.[102] These matters are now pending.

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of September 30, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

95 OATT Attachment DD § 5.14(h).
96 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).
97 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).
98 Brief of Amicus Curiae of Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM, USDC SDNY Case No. 1:16-cv-08164-VEC (Jan. 9, 2017).
99 See BPU Docket No. EO18080899 et al.
100 *Id.; see, e.g.* Comments of the Independent Market Monitor for PJM, BPU Docket No. EO18080899 (Oct. 22, 2018).
101 *In the Matter of the Implementation of H 2018, C. 16 Regarding the Establishment of a Zero Emission Certificate Program for Eligible Nuclear Power Plants,* Order Initiating the Zero Emission Certificate Program, Designating Commissioner, and Setting Manner of Service and Bar Date, BPU Docket No. EO18080899 (Sept. 8, 2018).
102 BPU Docket Nos. EO18091004, et al.

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Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of September 30, 2018, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

Renewable energy sources form or replenish naturally in a short period of time and consist of solar, geothermal, wind, biomass from plants and hydropower from flowing water. Nonrenewable energy sources do not form or replenish in a short period of time and consist of crude oil, natural gas, coal and uranium (nuclear energy).[103] Some state portfolios allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[104]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[105]

How each state satisfies the requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not readily publish this information. The MMU recommends that jurisdictions with a renewable portfolio standard make the data more transparent.

103 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home>, (Accessed August 3, 2018).
104 See the Indiana Utility Regulatory Commission's "2018 Annual Report," at 36 (Oct. 2018) <https://www.in.gov/iurc/files/IURC%20AR%202018%20WEB3.pdf>.
105 See Enr. Com. Sub. For H. B. No. 2001.

Table 8-4 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year. New Jersey passed legislation in May 2018 that increased their RPS substantially. New Jersey increased the standard for class I renewables from 16.0 percent to 21.0 percent for 2020 and the class I standard increases to 35.0 percent in 2025, and to 50.0 percent in 2030.[106] Washington, DC will require 38 percent of load to be served by renewable resources in 2029. In October 2016, the Council of the District of Columbia passed legislation that expanded the District's RPS program and increased the percent of retail load in the District that must be served by clean energy resources to 50 percent by 2032.[107] On December 15, 2016, the Michigan State Senate approved Senate Bill 438 (S.B. 438) which increased the Michigan RPS percent requirements. The previous version of the bill required that 10 percent of retail electric load in Michigan be served by renewable and alternative energy resources in 2015 and subsequent years. S.B. 438 increased the percent of retail electric load to be served by renewable and alternative energy resources in Michigan to be 12.5 percent in 2019 and 2020 and 15 percent in 2021 and subsequent years.[108] In February 2017, the Maryland State House approved House Bill 1106 which increased the total RPS requirement from 20 percent by 2022 to 25 percent by 2020.

106 "Assembly, No. 3723", State of New Jersey, 218th Legislature, (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
107 See Council of the District of Columbia. B21-0650—Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed April 26, 2018).
108 See Michigan Legislature. Senate Bill 0438 (2015) <http://legislature.mi.gov/doc.aspx?2015-SB-0438> (Accessed April 26, 2018).

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Table 8-4 Renewable standards of PJM jurisdictions: 2018 to 2030[109]

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Illinois	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	18.30%	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Michigan	10.00%	12.50%	12.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	19.13%	21.58%	28.60%	28.60%	28.60%	28.40%	28.30%	42.00%	41.85%	41.24%	40.57%	39.71%	54.08%
North Carolina	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Pennsylvania	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	42.00%
Jurisdiction with Voluntary Standard													
Indiana	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Virginia	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Jurisdiction with No Standard													
Kentucky	No Renewable Portfolio Standard												
Tennessee	No Renewable Portfolio Standard												
West Virginia	No Renewable Portfolio Standard												

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM states with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Though there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources.

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In Delaware, Illinois, North Carolina, and Ohio, eligible technologies are for the most part identical to Tier I resources. Michigan is the only state with an RPS that does not classify eligible technologies into tiers and also permits technologies that differ markedly from those classified as Tier I resources in states that do classify technologies. Michigan's RPS includes coal gasification, industrial cogeneration, and coal with carbon capture and storage as eligible technologies.

RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs typically have a shelf life of five years until they cannot be used to satisfy a state's RPS requirement.

Figure 8-2 shows the number of RECs eligible monthly by state for January 1, 2005, through August 31, 2018.[110] The figure includes Tier I or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and Wester Virginia classify these RECs as renewable or eligible. West Virginia repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard.

109 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.

110 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 3, 2018).

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Figure 8-2 Number of RECs eligible monthly by state: January 2005 through August 2018

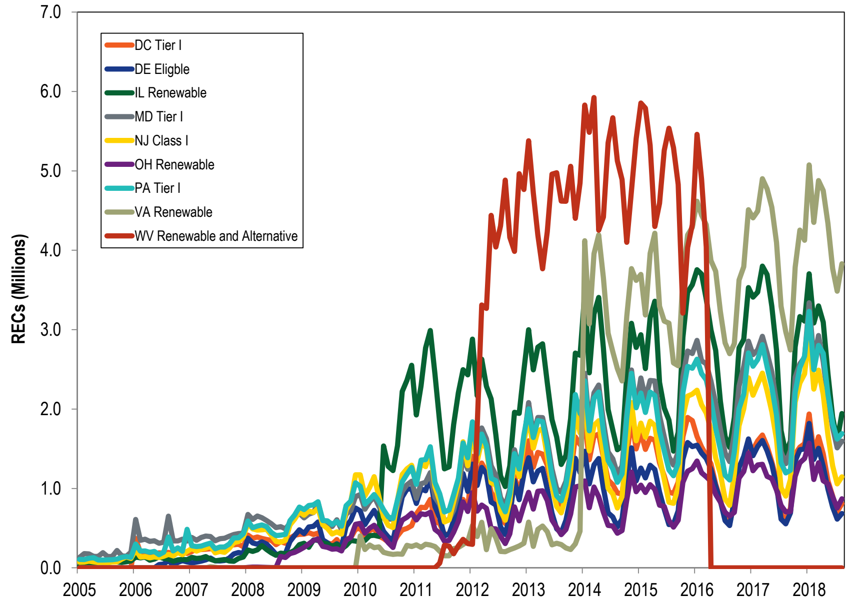
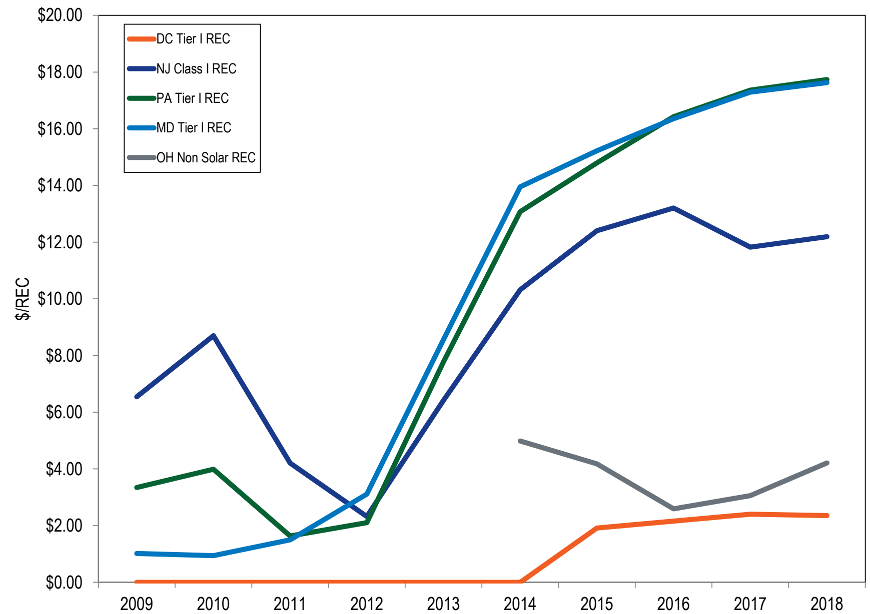


Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through September 2018



The REC prices are the average price for each vintage of REC, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2018. Tier I REC prices are lower than SREC prices.

Table 8-5 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-5 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-5 are included in the total RPS requirements presented in Table 8-4. Illinois requires that a defined proportion of retail load be served by wind and solar resources, increasing from 9.75 percent of load served in 2018 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or "Class 2" standards, which allow specific technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2021, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste.

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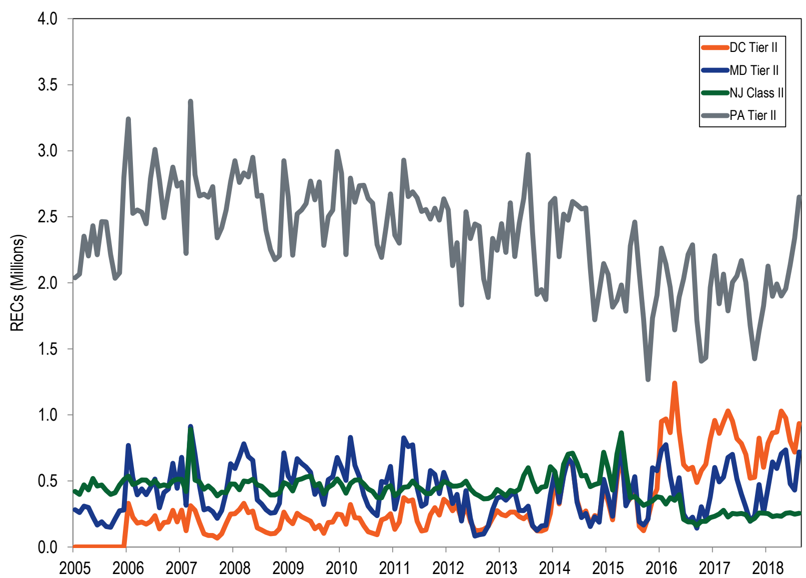
Table 8-5 Additional renewable standards of PJM jurisdictions: 2018 to 2030

Jurisdiction	Type of Standard	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Illinois	Wind and Solar	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009 through September 30, 2018. Pennsylvania had the lowest average Tier II REC prices at $0.08 per REC while New Jersey had the highest average Tier II REC prices at $5.61 per REC.[112]

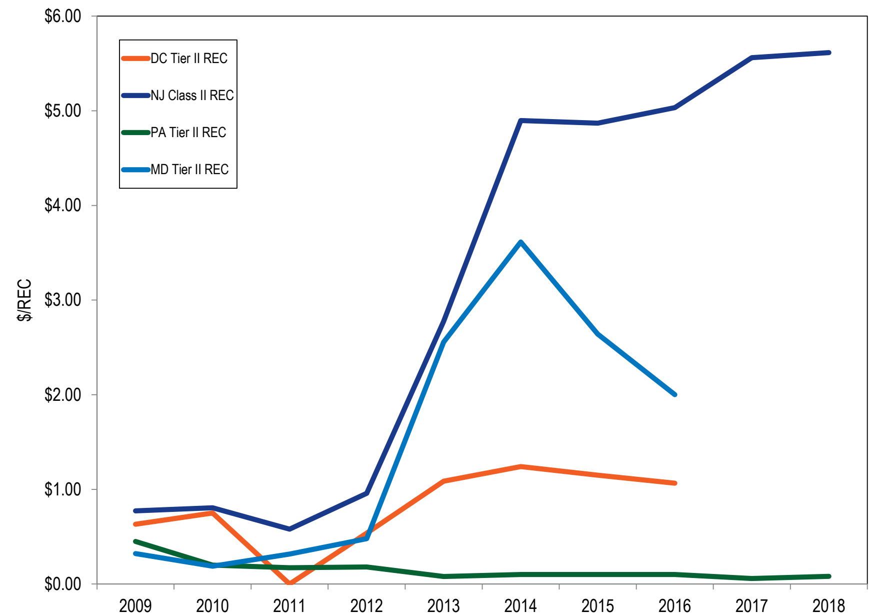
Figure 8-4 shows the number of Tier II RECs eligible monthly by state for January 1, 2005 through August 31, 2018.[111] The figure includes Tier II or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

Figure 8-4 Number of Tier II RECs eligible monthly by state: January 2005 through August 2018



111 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 3, 2018).

Figure 8-5 Average Tier II REC price by jurisdiction: January 2009 through September 2018[113]



112 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed October 4, 2018). There were not any reported cleared purchases for January 1, through September 30, 2018, for DC Tier II REC or MD Tier II RECs.

113 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed July 20, 2018). There were not any reported cleared purchases for January 1, through June 30, 2017 for DC Tier II REC, PA Tier II REC or MD Tier II RECs.

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Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-4 but must be met by solar RECs (SRECs) only. Table 8-6 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdictions' RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for the 2018. The new solar standard is 5.1 percent for energy years 2020 through 2022 and the standard gradually decreases to 1.1 percent for 2032.[114]

Table 8-6 Solar renewable standards by percent of electric load for PJM jurisdictions: 2018 to 2030

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	1.50%	1.95%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Michigan	No Minimum Solar Requirement												
New Jersey	4.30%	4.90%	5.10%	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%	0.50%	0.50%
Pennsylvania	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%
Jurisdiction with Voluntary Standard													
Indiana	No Minimum Solar Requirement												
Virginia	No Minimum Solar Requirement												
Jurisdiction with No Standard													
Kentucky	No Renewable Portfolio Standard												
Tennessee	No Renewable Portfolio Standard												
West Virginia	No Renewable Portfolio Standard												

Figure 8-6 shows the number of SRECs eligible monthly by state for January 1, 2005 through August 31, 2018.[115]

114 "Assembly, No. 3723", State of New Jersey, 218th Legislature, (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
115 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 3, 2018).

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Figure 8-6 Number of SRECs eligible monthly by state: January 2005 through August 2018

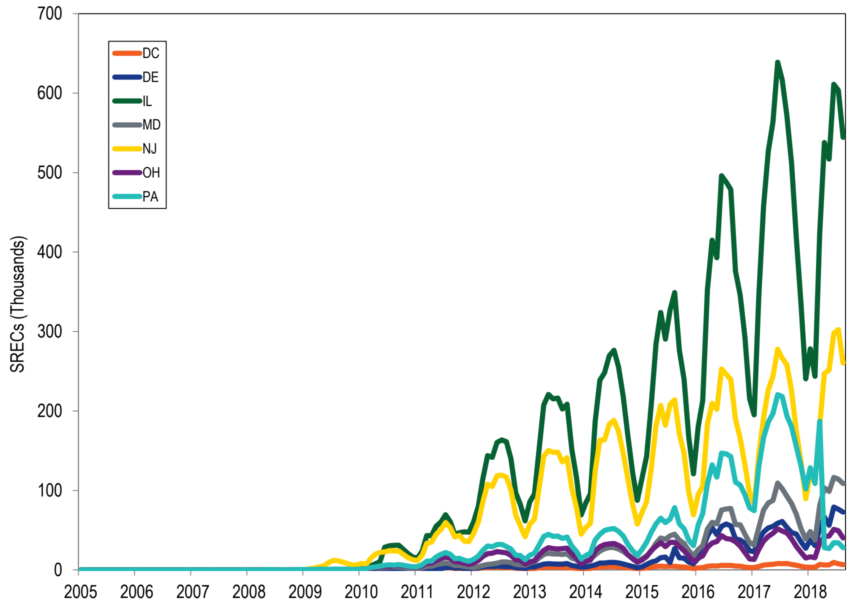

Figure 8-7 Average SREC price by jurisdiction: January 2009 through September 2018

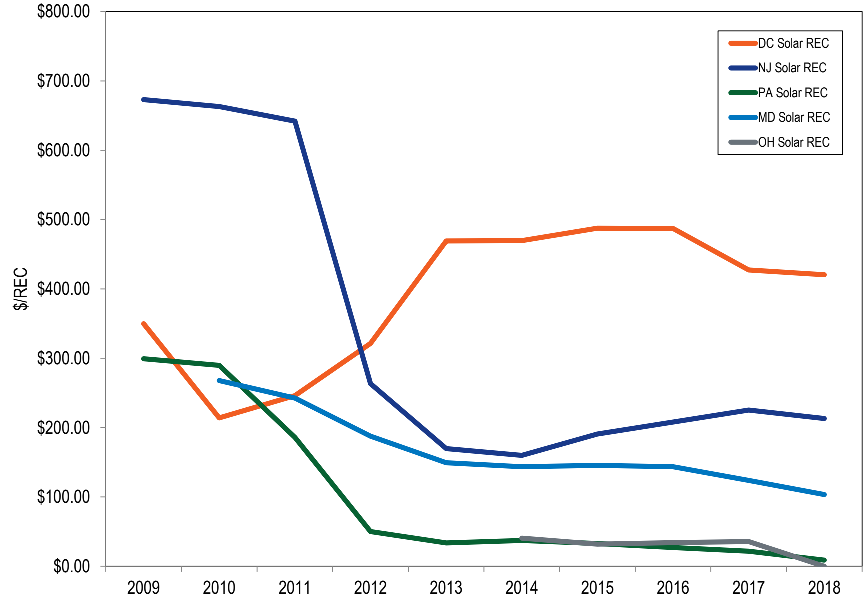

Figure 8-7 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009 through September 30, 2018. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from $673 per SREC in 2009 to $213 per SREC in the first nine months of 2018. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $420 per SREC in the first nine months of 2018.[116]

116 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 4, 2018).

Figure 8-8 and Figure 8-9 show the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. Figure 8-8 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-8. Figure 8-9 shows the percent of retail load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. Like all other PJM states with mandatory RPS, the Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind,

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geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. The 14.7 percent number in Figure 8-9 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS - Tier I resources only: 2018

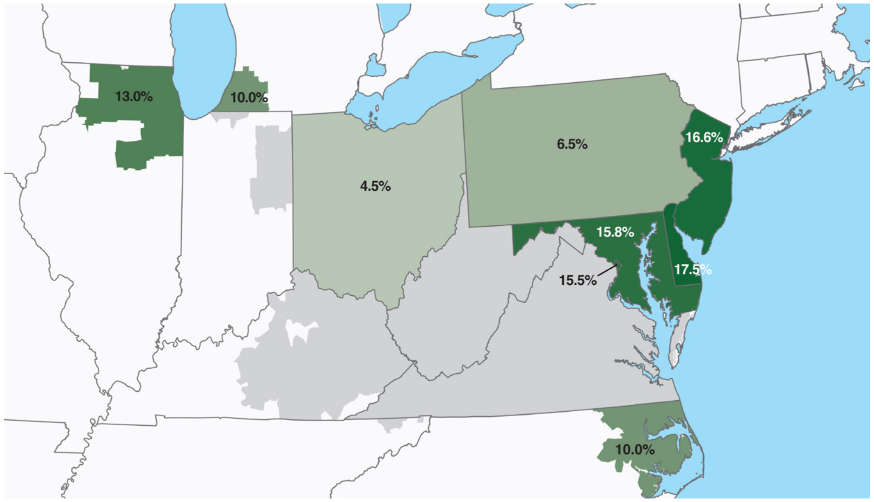
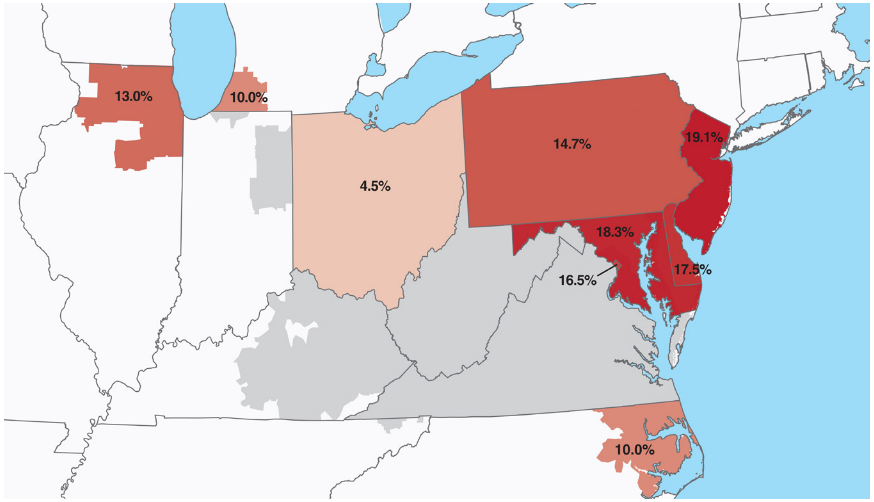


Figure 8-9 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2018



Under the existing state renewable portfolio standards, approximately 9.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2018 and, if the proportion of load among states remains constant, 16.3 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 7.4 percent of PJM load must be served by Tier I renewables in 2018 and, if the proportion of load among states remains constant, 14.1 percent of PJM load must be served by Tier I renewables in 2028 under defined RPS rules.

In jurisdictions with RPS, load serving entities must either generate power from eligible technologies identified in their jurisdictions' RPS or purchase RECs from resources classified as eligible technologies. Table 8-7 shows generation by jurisdiction and resource type for the first nine months of 2018. Wind output was 15,096.5 GWh of 26,637.9 Tier I GWh, or 56.7 percent, in the PJM footprint. As shown in Table 8-7, 44,158.0 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 60.3 percent. Total wind and solar generation was 2.4 percent of total generation in PJM for the

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first nine months of 2018. Tier I generation was 4.2 percent of total generation in PJM and Tier II was 2.8 percent of total generation for the first nine months of 2018. Landfill gas, solid waste and waste coal were 13,530.0 GWh of renewable resource generation or 30.6 percent of the total Tier I and Tier II.

Table 8-7 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through September, 2018

	Tier I					Tier II				
Jurisdiction	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	25.6	0.0	0.0	0.0	25.6	0.0	0.0	0.0	0.0	25.6
Illinois	88.2	0.0	12.3	6,106.3	6,206.8	0.0	0.0	0.0	0.0	6,206.8
Indiana	14.4	36.3	11.7	3,378.3	3,440.7	0.0	0.0	0.0	0.0	3,440.7
Kentucky	0.0	256.2	0.0	0.0	256.2	0.0	0.0	0.0	0.0	256.2
Maryland	48.4	0.0	317.3	505.7	871.3	0.0	513.0	0.0	513.0	1,384.4
Michigan	19.4	48.4	6.5	0.0	74.3	0.0	0.0	0.0	0.0	74.3
New Jersey	207.6	25.1	499.1	8.9	740.7	313.6	1,055.8	0.0	1,369.4	2,110.1
North Carolina	0.0	436.0	447.8	393.3	1,277.0	0.0	0.0	0.0	0.0	1,277.0
Ohio	273.4	495.5	1.1	1,118.8	1,888.8	0.0	0.0	0.0	0.0	1,888.8
Pennsylvania	573.8	4,878.7	18.5	2,482.1	7,953.1	1,610.1	937.7	5,442.0	7,989.8	15,942.8
Tennessee	0.0	852.3	0.0	0.0	852.3	0.0	0.0	0.0	0.0	852.3
Virginia	450.1	421.9	382.4	0.0	1,254.4	3,801.5	645.0	2,439.3	6,885.9	8,140.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	34.4	659.2	0.0	1,103.1	1,796.7	0.0	0.0	761.9	761.9	2,558.6
Total	1,735.2	8,109.6	1,696.6	15,096.5	26,637.9	5,725.2	3,151.5	8,643.2	17,520.0	44,158.0
Percent of Renewable Generation	3.9%	18.4%	3.8%	34.2%	60.3%	13.0%	7.1%	19.6%	39.7%	100.0%
Percent of Total Generation	0.3%	1.3%	0.3%	2.4%	4.2%	0.9%	0.5%	1.4%	2.8%	6.9%

Figure 8-10 shows the average hourly output by fuel type for January 1 through September 30 of 2014 through 2018. Tier I includes landfill gas, run-of-river hydro, solar and wind resources, as defined by the relevant states. Tier II includes pumped storage, solid waste and waste coal resources, as defined by the relevant states. Other includes biomass, miscellaneous, heavy oil, light oil, coal gas, propane, diesel, distributed generation, other biogas, kerosene and batteries.[117]

117 *2018 Quarterly State of the Market Report for PJM, January through September*, Section 3: Energy Market, Table 3-9.

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Figure 8-10 Average hourly output by fuel type: January through September, 2014 through 2018

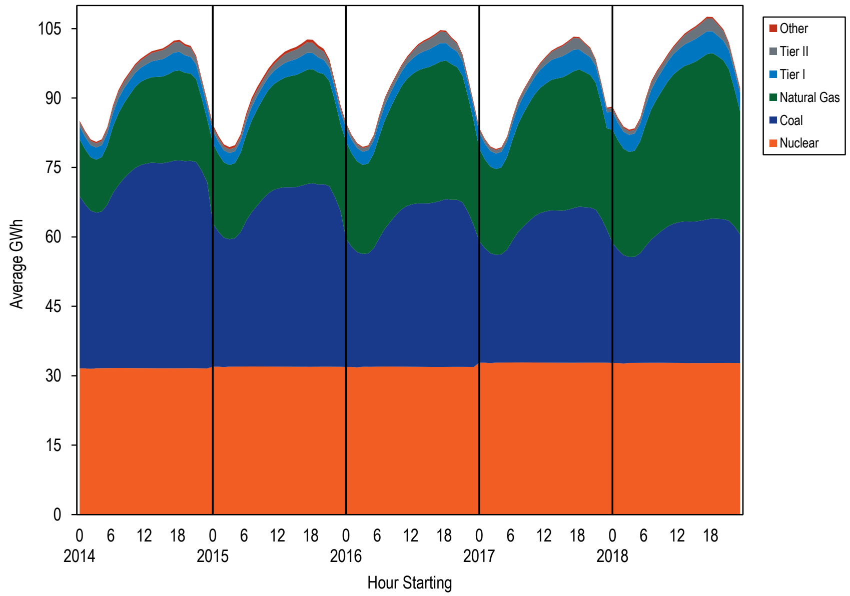

Table 8-8 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. New Jersey has the largest amount of solar capacity in PJM, 529.8 MW, or 33.6 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2009 at $673 per REC, and in the first nine months of 2018 are at $213 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,974.2 MW, or 61.1 percent of the total wind capacity.

Table 8-8 PJM renewable capacity by jurisdiction (MW): September 30, 2018

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	45.8	360.0	0.0	0.0	0.0	9.0	0.0	0.0	3,152.2	3,567.0
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	1,822.1	1,848.4
Kentucky	0.0	0.0	0.0	0.0	0.0	166.0	0.0	0.0	0.0	0.0	166.0
Maryland	0.0	24.3	0.0	69.0	0.0	494.4	204.3	128.2	0.0	190.0	1,110.2
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	26.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.0	529.8	162.0	0.0	4.5	1,237.9
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	375.8	0.0	0.0	208.0	1,048.8
Ohio	9,910.0	68.2	0.0	156.0	0.0	119.1	1.1	0.0	0.0	569.8	10,824.2
Pennsylvania	0.0	201.8	2,346.0	0.0	1,269.0	893.3	19.5	261.8	1,611.0	1,367.2	7,969.6
Tennessee	0.0	0.0	0.0	0.0	0.0	156.6	0.0	0.0	0.0	0.0	156.6
Virginia	0.0	134.1	0.0	17.0	5,347.5	169.2	421.8	123.0	585.0	0.0	6,797.6
West Virginia	0.0	5.4	0.0	0.0	0.0	257.9	0.0	0.0	165.0	686.3	1,114.6
PJM Total	9,910.0	581.3	4,503.0	255.0	7,069.5	2,754.5	1,576.0	675.0	2,361.0	8,146.0	37,831.3

Table 8-9 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 4,796.0 MW of which 1,976.1 MW is in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions.

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Table 8-9 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on September 30, 2018[118]

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Alabama	0.0	0.0	0.0	0.0	0.0	0.0	0.0	141.5	0.0	141.5
Arkansas	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	18.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	103.5	0.0	2.1	107.8
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	151.2	258.9	0.0	410.1
Illinois	0.0	21.4	97.3	0.0	5.5	0.0	72.6	0.0	300.3	497.1
Indiana	0.0	0.0	46.4	0.0	5.2	94.6	70.3	0.0	180.0	396.4
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	3.2	0.0	258.0	262.7
Kentucky	600.0	162.2	18.6	0.0	0.4	0.0	36.6	93.0	0.0	910.8
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.2	0.0	129.2
Maryland	65.0	0.0	12.7	129.0	0.0	0.0	834.4	15.0	0.3	1,056.4
Michigan	55.0	1.3	4.8	0.0	0.0	0.0	4.9	31.0	0.0	97.0
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	19.6	0.0	451.0	476.2
New Jersey	0.0	0.0	43.5	0.0	14.5	0.0	1,976.1	0.0	4.8	2,038.9
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.4
North Carolina	0.0	430.4	0.0	0.0	0.0	0.0	826.6	151.5	0.0	1,408.5
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	0.0	3.3	30.8	52.0	14.2	32.4	190.9	92.8	39.9	456.3
Pennsylvania	109.7	31.7	45.2	88.5	15.1	5.0	322.4	8.6	3.3	629.3
South Carolina	0.0	0.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	30.8
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	17.9	11.3	0.0	0.9	0.0	122.8	287.6	0.0	440.5
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	3.9	0.0	0.0	3.9
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.3	44.6	0.0	53.9
District of Columbia	0.0	0.0	0.0	0.0	14.4	0.0	56.4	0.0	0.0	70.8
Total	829.7	677.1	350.8	269.5	88.1	132.0	4,796.0	1,311.4	1,599.7	10,054.3

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[119] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets.

118 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed October 1, 2018).

119 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA… And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, … do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

FERC has found that such revenues can be appropriately considered in the rates established through the operation of wholesale organized markets.[120] This decision is an important recognition of the integration of the RECs markets and the other PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[121] This is equivalent to providing a REC price equal to three times its stated value per MWh. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.[122]

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-10 shows the REC tracking systems used by each state within the PJM footprint.

120 See *ISO New England, Inc.*, 146 FERC ¶ 61,084 (2014) at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. [footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition.").

121 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

122 GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

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Table 8-10 REC Tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		
Virginia	PJM-GATS			

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-11 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with states' standards to be generated by in-state resources. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard, be sourced from resources located in Pennsylvania.

Pennsylvania requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint. Virginia requires that every load serving entity that chooses to participate in its voluntary renewable energy standard purchase RECs from the control area or RTO in which it is located. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

Table 8-11 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. Additionally, all SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.

Table 8-12 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[123] [124] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-12 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.50	$5.01	$7.51	$25.04	$50.08	$100.16	$200.33
CC	$1.77	$3.54	$5.32	$17.72	$35.45	$70.89	$141.78
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-12 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the price of an SREC in New Jersey in third quarter of 2018 was $213.16 per MWh. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh produced by the solar resource resulted in avoiding the production of a MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price of approximately $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $25.04 per MWh.

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-13. The carbon price implied by the 2018 average REC price in Ohio of $8.41 per tonne is higher than the RGGI clearing price of $4.52 per tonne and lower than the social cost of carbon which is estimated in the range of $40 per tonne.[125] The carbon price implied by the 2018 average REC price in Washington, D.C. is $4.70 per tonne. The carbon prices implied by REC prices in Maryland, New Jersey, and Pennsylvania for 2018 are more consistent with the social cost of carbon than the RGGI price. The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. Except for Pennsylvania, the carbon prices implied by SREC prices are significantly greater than the prices implied by REC prices in each jurisdiction.

123 Heat rates from: *2017 State of the Market Report for PJM*, Vol. 2, Section 7: Net Revenue, p 314, Table 7-4.
124 Carbon emissions rates from: *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 24, 2018).
125 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (August 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

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Table 8-13 Implied carbon price based on REC and SREC prices: 2009 through 2018[126]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per Metric Tonne) Implied by REC Prices**									
Delaware					$35.94	$36.94	$32.05	$33.24	$12.10	
Maryland	$2.03	$1.88	$3.00	$6.21	$17.10	$27.86	$30.40	$32.66	$34.53	$35.20
New Jersey	$13.07	$17.37	$8.40	$4.64	$12.82	$20.60	$24.77	$26.37	$23.61	$24.34
Ohio						$9.95	$8.34	$5.18	$6.10	$8.41
Pennsylvania	$6.68	$7.96	$3.26	$4.20	$15.54	$26.10	$29.55	$32.79	$34.67	$35.41
Washington, D.C.							$3.83	$4.31	$4.79	$4.70
Jurisdiction with Solar REC	**Carbon Price ($ per Metric Tonne) Implied by Solar REC Prices**									
Delaware						$114.81	$83.63	$84.69	$42.45	$56.91
Maryland		$534.77	$484.27	$374.62	$298.21	$286.62	$290.46	$286.56	$247.35	$206.38
New Jersey	$1,343.86	$1,324.06	$1,281.81	$525.92	$338.75	$319.44	$380.66	$415.40	$449.76	$425.61
Ohio						$80.61	$63.52	$68.09	$70.89	
Pennsylvania	$597.38	$578.30	$370.81	$99.69	$66.92	$74.33	$65.50	$53.91	$43.16	$17.76
Washington, D.C.	$698.17	$427.22	$491.20	$641.90	$936.69	$937.57	$973.40	$972.85	$853.26	$839.29
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per Metric Tonne)**									
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.52

PJM jurisdictions have various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $268.00 per MWh.[127] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO plus the value of any solar rebates. For all states with an alternative compliance payment, the alternative compliance payment creates a cap on REC prices. Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. In Michigan and North Carolina, there are no pre-established values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-14 shows the alternative compliance standards for RPS in PJM jurisdictions.

126 The Delaware 2017 SREC price used in the derivation of the implied carbon price is the weighted average procurement price reported by the SREC Delaware Program <http://www.srecdelaware.com/documentation/>. All other SREC prices used in the derivation of the implied carbon price are average annual prices obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).

127 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/ Policies for Renewables & Efficiency, "Solar Renewables Energy Certificates (SRECs)," <http://programs.dsireusa.org/system/program/detail/5687> (Accessed July 24, 2018).

Table 8-14 Renewable alternative compliance payments in PJM jurisdictions: September 30, 2018[128] [129]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$37.50	$15.00	$195.00
Michigan	No specific penalties		
New Jersey	$50.00		$268.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$50.24		$250.00
Pennsylvania	$45.00	$45.00	200% market value plus rebates
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission. In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public. The RPS compliance reports are released with a lag of up to three years. It is therefore impossible to know the current level of RPS compliance in PJM jurisdictions. The Pennsylvania Public Utility Commission issued their 2017 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 during the first quarter of 2018.[130] Pennsylvania reported that the 20,634,311 credits retired during the compliance year exceeded the amount required by the standards by 1,995 credits. Not all suppliers met the required standard. Supplier obligations for six Tier I credits and 14 Tier II credits, were resolved through alternative compliance payments.

The Public Service Commission of the District of Columbia reported that 1,645,545 credits were retired during the 2017 compliance year and there was a significant increase in compliance payments.[131] Compliance payments were $26,571,010 for 2017, a 74.4 percent increase over the compliance payments for 2016. Solar standards contributed to the increase in compliance payments. Solar REC retirements in 2017 decreased 50.5 percent in 2017 with 30,765 solar RECs retired in 2017 and 62,173 retired in 2016.

The Public Service Commission of Maryland reported that 9.1 million RECs were retired in 2016 at a cost of $135,198,523.[132] The REC retirements exceeded the RPS obligations by 6,316.0 credits due to some suppliers retiring more than their obligation. Not all electricity suppliers met the standards and $33,933 in alternative compliance payments were paid in lieu of purchasing and retiring RECs.

The Public Utilities Commission of Ohio reported that 2,516,992 non solar credits were retired in the 2015 compliance year, exceeding the credit obligation of 2,512,101 credits; and 127,487 solar credits were retired in the 2015 compliance year, exceeding the solar credit obligation of 127,274.[133] There were no alternative compliance payments for the 2015 compliance year.

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 567,372 credits for the compliance year ending May 31, 2018 with zero alternative compliance payments.[134] Delmarva Power satisfied

128 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed July 20, 2018).
129 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed July 24, 2018).
130 "2017 Annual Report – Alternative Energy Portfolio Standards Act of 2004," (March 2018), <http://www.pennaeps.com/reports/>.
131 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017," Public Service Commission of the District of Columbia, (May 1, 2018), <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.
132 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland, January 2018, <https://www.psc.state.md.us/wp-content/uploads/CY16-RPS-Annual-Report-1.pdf>.
133 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2015," Public Utilities Commission of Ohio, (May 19, 2017), <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.
134 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2016 – May 31, 2017," Delmarva Power, (September 25, 2018), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/%3e>

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their solar REC obligation of 105,352 credits with zero alternative compliance payments.

The Illinois RPS requires electricity suppliers to satisfy at least 50 percent of their RPS obligation through alternative compliance payments. The Illinois Power Agency reported that most suppliers satisfied the remaining portion of their obligation for 2017 through the purchase of RECs rather than incur additional alternative compliance payments.[135]

The North Carolina Utilities Commission reported that all electric power suppliers met the 2016 renewable energy portfolio standard, solar energy requirement, and poultry waste energy requirement.[136] The implementation of the swine waste energy requirement has been delayed and electric power suppliers were not subject to the swine waste energy requirement for 2016.

The Michigan Public Service Commission reported that electric power suppliers met the 2016 renewable energy standards by retiring 10,313,552 RECs.[137]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2017.[138] Electric power suppliers retired 7,867,807 class I RECs, 1,875,908 class II RECs, and 2,251,068 solar RECs. The REC retirement levels exceeded the overall obligations by 707 class I credits, 108 class II credits, and 108 solar credits. Not all suppliers met their obligations and alternative compliance payments were submitted for deficiencies of 27 class I credits, 7 class II credits, and 24 solar credits.

135 "Annual Report Fiscal Year 2017," Illinois Power Agency, (February 15, 2018), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
136 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission, (October 1, 2017), <https://www.ncuc.net/reports/repsreport2017.pdf>.
137 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, (February 15, 2018), <https://www.michigan.gov/mpsc/0,4639,7-159-16393---,00.html>.
138 See RPS Report Summary 2005-2017, (November 1, 2017), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[139] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[140] Of the current 62,839.4 MW of coal capacity in PJM, 58,489.1 MW of capacity, 93.1 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[141] [142] [143]

Table 8-15 SO_2 emission controls by fuel type (MW): September 30, 2018[144]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	58,489.1	4,350.3	62,839.4	93.1%
Diesel Oil	0.0	5,379.6	5,379.6	0.0%
Natural Gas	0.0	74,280.9	74,280.9	0.0%
Other	325.0	4,805.7	5,130.7	6.3%
Total	58,814.1	88,816.5	147,630.6	39.8%

NO_X emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 138,684.4 MW, 93.9 percent, of 147,630.6 MW of capacity in PJM, have emission controls for NO_X. Table 8-16 shows NO_X emission controls by unit type in PJM. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether

139 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 24, 2018).
140 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed July 24, 2018).
141 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 9, 2018).
142 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year.
143 The total MW are less than the 184,559.5 reported in Section 5: Capacity, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed October 5, 2018).
144 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.

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a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_X compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[145]

Table 8-16 NO_X emission controls by fuel type (MW): As of September 30, 2018

	NO_X Controlled	No NO_X Controls	Total	Percent Controlled
Coal	62,252.6	586.8	62,839.4	99.1%
Diesel Oil	1,612.6	3,767.0	5,379.6	30.0%
Natural Gas	72,167.5	2,113.4	74,280.9	97.2%
Other	2,651.7	2,479.0	5,130.7	51.7%
Total	138,684.4	8,946.2	147,630.6	93.9%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[146] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 62,505.4 MW out of 62,839.4 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of September 30, 2018. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[147] In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR Currently, 135 of the 152 coal steam units have baghouse or FGD technology installed, representing 56,173.1 MW out of the 62,839.4 MW total coal capacity, or 89.4 percent.

145 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed October 5, 2018).
146 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed October 5, 2018).
147 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed October 5, 2018).

Table 8-17 Particulate emission controls by fuel type (MW): As of September 30, 2018

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	62,505.4	334.0	62,839.4	99.5%
Diesel Oil	0.0	5,379.6	5,379.6	0.0%
Natural Gas	2,508.0	71,772.9	74,280.9	3.4%
Other	2,970.5	2,160.2	5,130.7	57.9%
Total	67,983.9	79,646.7	147,630.6	46.1%

Figure 8-11 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for the first nine months of each year from 1999 to 2018, as well as the CO_2 short ton emissions per MWh of total generation within PJM for the first nine months of 2010 to 2018.[148]Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.78 short tons per MWh in the first nine months of 2000, and a maximum of 0.94 short tons per MWh in the first nine months of 2010. In the first nine months of 2018, CO_2 emissions were 0.79 short tons per MWh. Total PJM generation increased from 609,284.8 GWh in the first nine months of 2017 to 635,703.1 GWh in the first nine months of 2018, while CO_2 produced decreased from 305.0 million tons in the first nine months of 2017 to 192.5 million tons in the first nine months of 2018.[149] The reduction in CO_2 emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-12 shows the total on peak hour and off peak hour CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for the first nine months of each year from 1999 to 2018. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.77 short tons per MWh in the first nine months of 2000, and a maximum of 0.96 short tons per MWh in the first nine months of 2010. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.78 short tons per MWh in the first nine months of 2018, and a maximum of 0.92 short tons per MWh in the first nine months of 2010. In the first nine months of 2018, CO_2 emissions were 0.79 short tons per MWh and 0.78 short tons per MWh for off and on peak hours.

148 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
149 See Section 3: Energy Market, Table 3-10.

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Figure 8-11 CO_2 emissions by year (millions of short tons), by PJM units: January through September, 1999 through 2018[150]

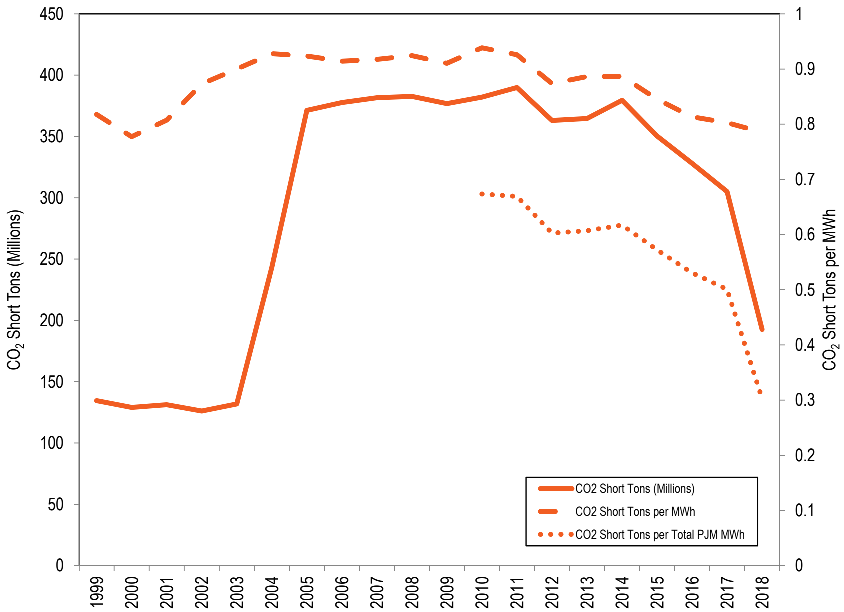


Figure 8-12 CO_2 emissions during on and off peak hours by year (millions of short tons), by PJM units: January through September, 1999 through 2018[151]

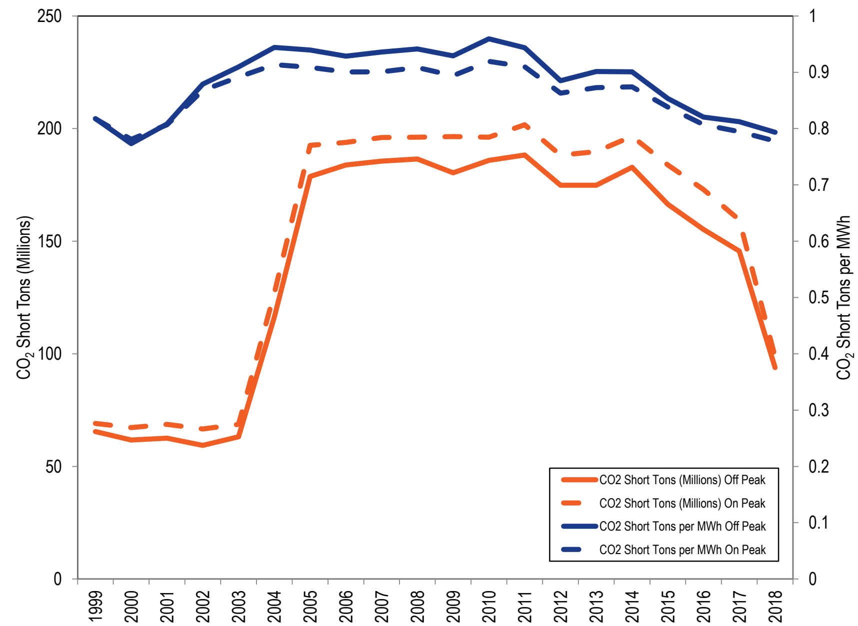


Figure 8-13 shows the total SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for the first nine months of each year from 1999 to 2018, as well as the SO_2 and NO_X short ton emissions per MWh of total generation within PJM for the first nine months of 2010 to 2018. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000572 short tons per MWh in the first nine months of 2017, and a maximum of 0.007202 short tons per MWh in the first nine months of 2003. Since 1999, the amount of NO_X produced per MWh was at a minimum of 0.000417 short tons per MWh in the first nine months of 2017, and a maximum of 0.001923 short tons per MWh in the first nine months of 1999. In the first nine months of 2018, SO_2 emissions were 0.000621 short tons per MWh and NO_X emissions

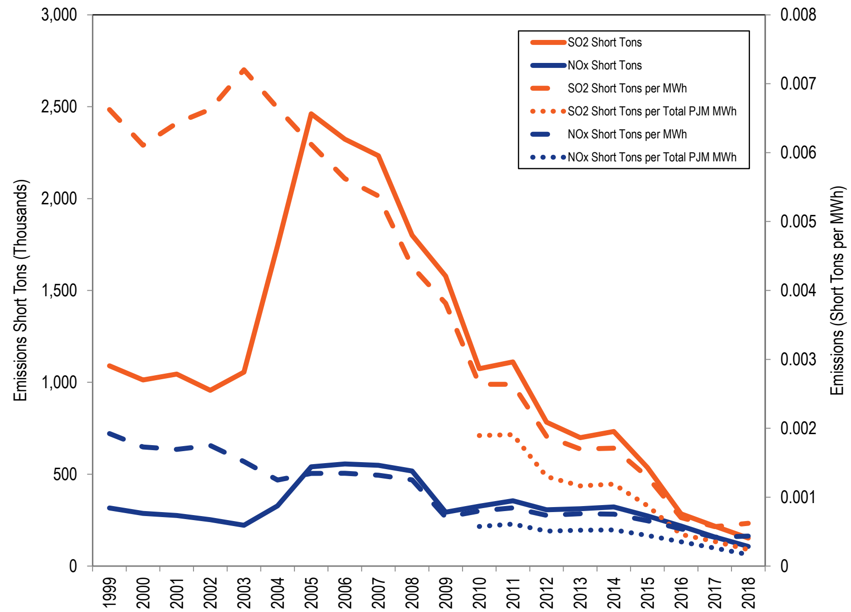
150 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

151 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

were 0.000436 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal from 2006 to 2018.

Figure 8-14 shows the total on peak hour and off peak hour SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for the first nine months of each year from 1999 to 2018. Since 1999 the amount of SO_2 produced per MWh during off peak hours was at a minimum of 0.000555 short tons per MWh in the first nine months of 2017, and a maximum of 0.007432 short tons per MWh in the first nine months of 2003. Since 1999 the amount of SO_2 produced per MWh during on peak hours was at a minimum of 0.000587 short tons per MWh in the first nine months of 2017, and a maximum of 0.006995 short tons per MWh in the first nine months of 2003. Since 1999, the amount of NO_X produced per MWh during off peak hours was at a minimum of 0.000419 short tons per MWh in the first nine months of 2017, and a maximum of 0.001892 short tons per MWh in the first nine months of 1999. Since 1999, the amount of NO_X produced per MWh during on peak hours was at a minimum of 0.000415 short tons per MWh in the first nine months of 2017, and a maximum of 0.001954 short tons per MWh in the first nine months of 1999. In the first nine months of 2018, SO_2 emissions were 0.000620 short tons per MWh and 0.000623 short tons per MWh for off and on peak hours. In the first nine months of 2018, NO_X emissions were 0.000442 short tons per MWh and 0.000431 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NOX emissions by year (thousands of short tons), by PJM units: January through September, 1999 through 2018[152]



152 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

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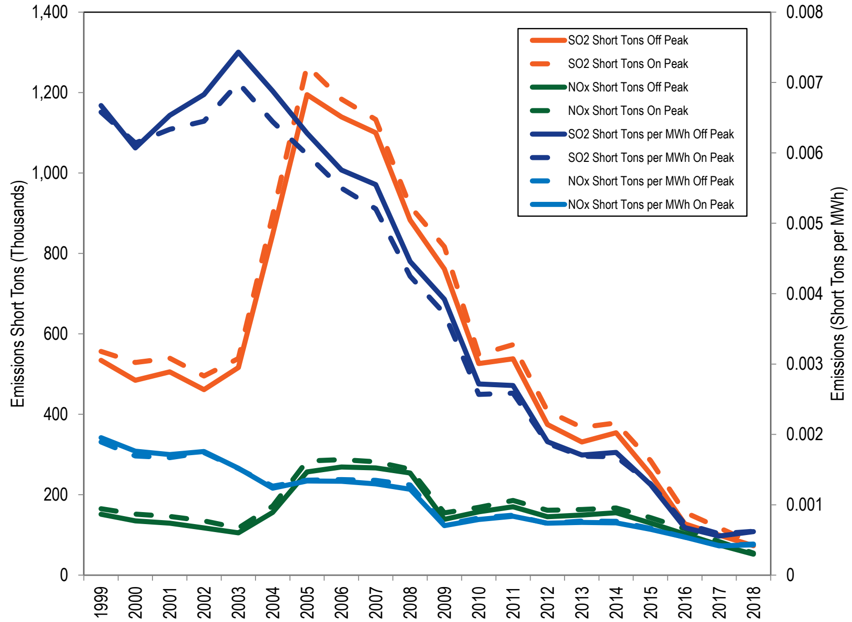
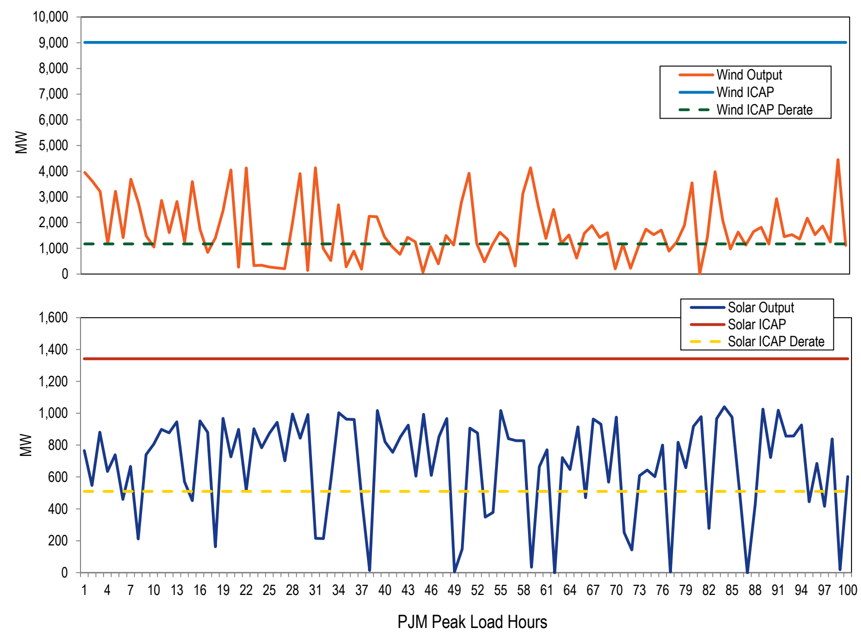
Figure 8-14 SO_2 and NO_X emissions during on and off peak hours by year (thousands of short tons), by PJM units: January through September, 1999 through 2018[153]



Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated for the PJM capacity market based on expected performance during high load hours. Figure 8-15 shows the wind and solar output during the top 100 load hours in PJM for the first nine months of 2018. The top 100 load hours in PJM during the first nine months of 2018, 93 are within PJM defined peak load periods. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total ICAP of wind and solar PJM resources derated to 13 and 38 percent. The actual output of the wind and solar resources during the top 100 peak load hours are above and below the derated values. Wind output was above the derated ICAP for 65 hours and below the derated ICAP for 35 hours of the top 100 peak load hours of the first nine months of 2018. Wind output was above the derated ICAP 4,509 hours and below the derated ICAP for 2,042 hours for the first nine months of 2018. The wind capacity factor for the top 100 peak load hours of the first nine months of 2018 is 19.0 percent. Solar output was above the derated ICAP for 75 hours and below the derated ICAP for 25 hours of the top 100 peak load hours of the first nine months of 2018. Solar output was above the derated ICAP 1,665 hours and below the derated ICAP for 4,886 hours for the first nine months of 2018. The solar capacity factor for the top 100 peak load hours of the first nine months of 2018 is 50.7 percent.

Figure 8-15 Wind and solar output during the top 100 peak load hours in PJM: January through September, 2018



153 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Wind Units

In 2017, the Maryland Public Service Commission announced two awards of ORECs to two commercial wind projects, Deepwater Wind's 120-MW Skipjack Wind Farm and U.S. Wind's 248-MW project. These project awards are the first under Maryland's 2010 OREC program.

Table 8-18 shows the capacity factor of wind units in PJM. In the first nine months of 2018, the capacity factor of wind units in PJM was 30.9 percent. Wind units that were capacity resources had a capacity factor of 30.7 percent and an installed capacity of 7,669 MW. Wind units that were classified as energy only had a capacity factor of 32.8 percent and an installed capacity of 965 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[154]

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW for generation from qualified offshore wind projects by 2030 (plus 2,000 MW of energy storage capacity).[155] Governor Murphy has directed the preparation of a 2018 Energy Master Plan for New Jersey providing a "comprehensive blueprint for the total conversion of the State's energy profile to 100% clean energy sources on or before January 1, 2050."[156] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities.

In 2017, the Maryland Public Service Commission announced two awards of ORECs to two commercial wind projects, Deepwater Wind's 120-MW Skipjack Wind Farm and U.S. Wind's 248-MW project. These project awards are the first under Maryland's 2010 OREC program.

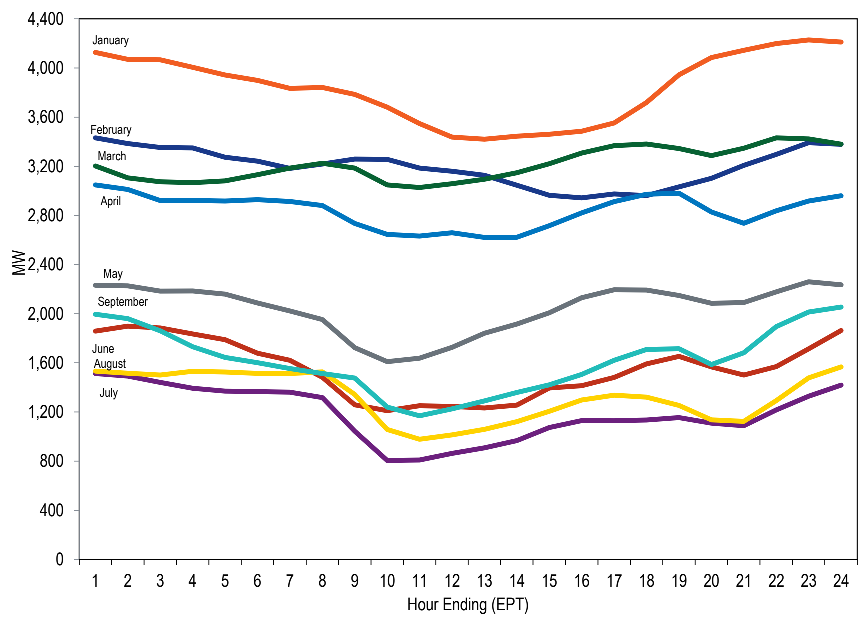
154 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
155 N.J. S. 2314/A. 3723.
156 N.J. Exec. Order No. 28.

Table 8-18 Capacity factor of wind units in PJM: January through September, 2018[157]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	32.8%	965
Capacity Resource	30.7%	7,669
All Units	30.9%	8,633

Figure 8-16 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through September 30, 2018. The hour with the highest average output, 4,228 MW, occurred in January, and the hour with the lowest average output, 805 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-16 Average hourly real-time generation of wind units in PJM: January through September, 2018



157 Capacity factor is calculated based on online date of the resource.

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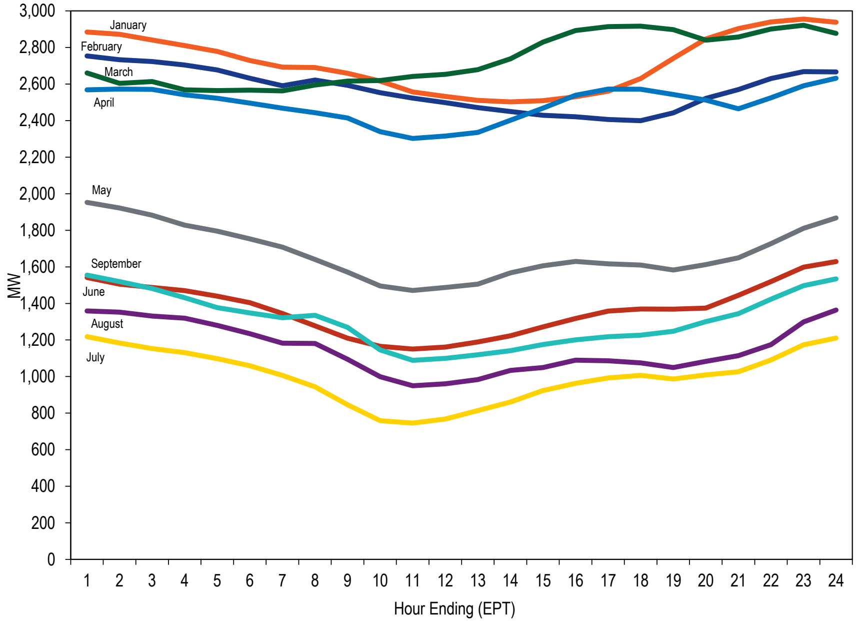
Table 8-19 shows the generation and capacity factor of wind units in each month of January 1, 2017 through September 30, 2018.

Table 8-19 Capacity factor of wind units in PJM by month: January 2017 through September 2018

	2017		2018	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,016,120.9	37.8%	2,856,292.5	48.3%
February	2,178,159.8	44.4%	2,148,206.1	40.4%
March	2,299,037.1	42.5%	2,387,719.3	41.7%
April	2,071,212.0	39.8%	2,044,167.0	37.7%
May	1,824,269.0	34.7%	1,519,815.5	27.5%
June	1,456,609.5	28.6%	1,117,467.9	21.1%
July	809,478.9	16.9%	881,491.2	16.8%
August	689,983.0	15.0%	984,116.9	19.0%
September	908,311.6	19.0%	1,164,672.2	22.1%
October	1,916,644.9	35.6%		
November	2,197,021.1	40.2%		
December	2,149,119.8	42.0%		
Annual	20,515,967.5	33.4%	15,103,948.6	30.9%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer noncapacity related wind energy at their discretion. Figure 8-17 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Figure 8-17 Average hourly day-ahead generation of wind units in PJM: January through September, 2018



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-18 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2018. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

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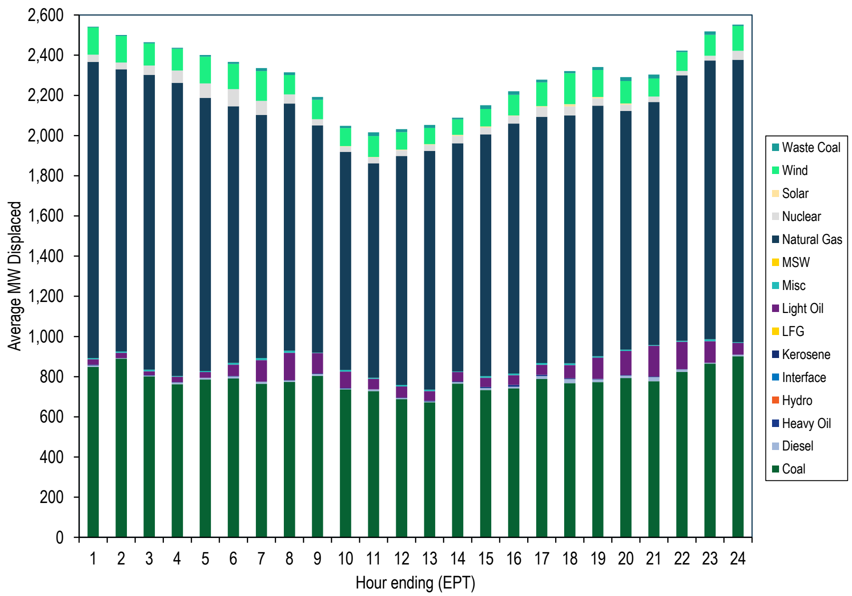
Figure 8-18 Marginal fuel at time of wind generation in PJM: January through September, 2018



Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-8, there are 1,548.5 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-9, there are 4,454.8 MW capacity of solar registered in GATS that are not PJM capacity or energy resources. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to escape their proper financial responsibility through badly designed rules, such as rules for netting.

New Jersey and Maryland recently have taken significant steps to promote solar power, including community solar.

Legislation enacted on May 24, 2018, in New Jersey included provisions promoting the development of solar power in the state.[158] The statute raised New Jersey's RPS requirement to 21 percent by 2020, 35 percent by 2025, and 50 percent by 2030. The statute requires generators to source increasing amounts of electricity from behind-the-meter solar, 4.3 percent by 2019, 4.9 percent by 2020, and 5.1 percent by 2021. The states will discontinue the SREC program in 2021. The Board of Public Utilities is directed to develop and provide an "orderly transition" to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

In 2016, Maryland legislation established a pilot program for community solar energy systems.[159] Regulations for a three year pilot program developed by the Maryland Public Service Commission became effective July 18, 2016.

Table 8-20 shows the capacity factor of solar units in PJM. In the first nine months of 2018, the capacity factor of solar units in PJM was 24.2 percent. Solar units that were capacity resources had a capacity factor of 24.5 percent and an installed capacity of 1,227 MW. Solar units that were classified as energy only had a capacity factor of 21.8 percent and an installed capacity of 132 MW. Solar capacity in RPM is derated to 38 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[160]

158 N.J. S. 2314/A. 3723.
159 Md. S.B. 1087.
160 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

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Table 8-20 Capacity factor of solar units in PJM: January through September, 2018

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.8%	132
Capacity Resource	24.5%	1,227
All Units	24.2%	1,359

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-19 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-19 Average hourly real-time generation of solar units in PJM: January through September, 2018

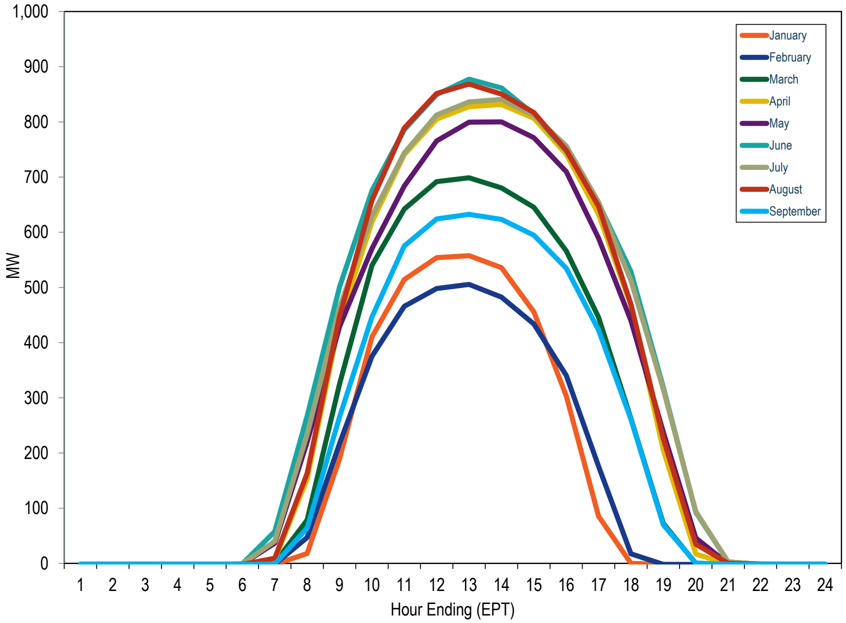


Table 8-21 shows the generation and capacity factor of solar units in each month of January 1, 2017 through September 30, 2018.

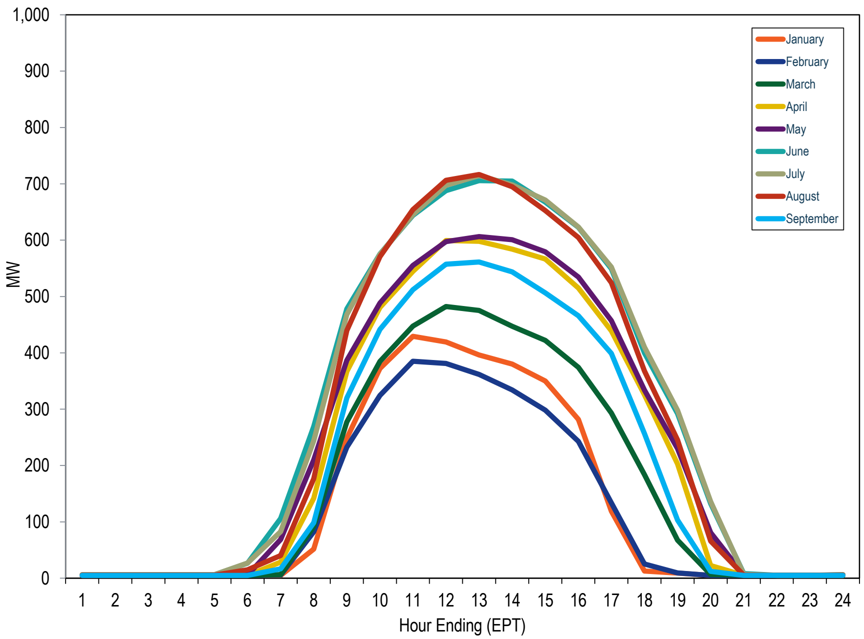
Table 8-21 Capacity factor of solar units in PJM by month: January, 2017 through September, 2018

	2017		2018	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	47,456.3	11.6%	102,161.8	15.4%
February	84,111.1	21.7%	90,296.5	14.2%
March	109,498.1	25.0%	159,360.7	22.4%
April	121,835.3	27.5%	201,333.0	28.2%
May	127,944.3	26.9%	202,986.0	27.4%
June	146,226.0	30.5%	222,134.5	30.6%
July	144,300.0	28.6%	220,548.3	29.5%
August	133,780.1	26.3%	216,827.5	28.9%
September	125,731.7	25.4%	141,575.2	21.0%
October	104,658.9	19.1%		
November	90,442.5	16.3%		
December	61,707.8	12.0%		
Annual	1,297,692.0	22.5%	1,557,223.5	24.5%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Solar units may offer noncapacity related solar energy at their discretion. Figure 8-20 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[161]

161 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

Figure 8-20 Average hourly day-ahead generation of solar units in PJM: January through September, 2018



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