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 in making the investments in some cases when those offers clear, and in the retirement of units in some cases when those offers do not clear.

Environmental requirements and initiatives at both the federal and state levels 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 resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and increased transparency.

Overview

Federal Environmental Regulation

- **MATS.** 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]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[3] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits under State Implementation Programs.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[4] Emergency stationary RICE participating in demand response programs are allowed to operate for up to 100 hours/calendar year providing emergency demand response during periods when there is a NERC declared Energy Emergency Alert Level 2 or there is a five percent voltage/frequency deviations, and for an unlimited time during emergency situations.
- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan[5] and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.[6] Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.

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 (Feb. 16, 2012).

2 CAA § 110(a)(2)(D)(i)(I).

3 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA–HQ–OAR–2018–0048; FRL-9997–95–OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

4 See 40 CFR § 63.6640(f).

5 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

6 See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA–HQ–OAR–2017–0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).

- **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.[7]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[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. New Jersey is rejoining.[9] Virginia and Pennsylvania are preparing to join.[10] [11] The auction price in the September 4, 2019, auction for the 2018/2020 compliance period was $5.02 per ton. The clearing price is equivalent to a price of $5.73 per metric tonne, the unit used in other carbon markets. The price decreased by $0.60 per ton, 7.5 percent, from $5.62 per ton from June 5, 2019, to $5.02 per ton for September 4, 2019.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring 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, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia did not have renewable portfolio standards.

- **RPS Cost.** The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017, or an average annual RPS compliance cost of $840.4 million.[12]

Emissions Controls in PJM Markets

- **Regulations.** 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.

- **Emissions Controls.** As of September 30, 2019, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.6 percent of coal steam MW had some type of particulate control, and 93.6 percent of fossil fuel fired capacity in PJM had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Total wind and solar generation was 3.1 percent of total generation in PJM for the first nine months of 2019. Tier I generation was 4.6 percent of total generation in PJM and Tier II generation was 2.2 percent of total generation in PJM for the first nine months of 2019. Only Tier I generation is renewable.

7 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).

8 42 U.S.C. §§ 6901 *et seq.*

9 Executive Order 7; see *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

10 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

11 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

12 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

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 the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing including the distribution of carbon revenues, and for coordination with PJM wholesale markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. First reported Q2, 2019. 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.[13] The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. 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 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 MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $5.64 per tonne in Washington, D.C. to $31.78 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $48.08 per tonne in

13 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.").

Pennsylvania to $789.17 per tonne in Washington, D.C. The effective prices for carbon compare to the RGGI clearing price in September 2019 of $5.73 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[14] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $267.30 per MWh.[15] The impact of a $50 per tonne carbon price would be $16.71 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 offers 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 ensures 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.

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. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price 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.

The annual average cost of complying with RPS over the four year period from 2014 through 2017 for the eight jurisdictions that had RPS and reported compliance costs was $840.4 million, or a total of $3.4 billion over four years.[16] The RPS compliance cost for 2016, the most recent year for which there is complete data for all jurisdictions except North Carolina, was $986 million. RPS costs are payments by customers to the sellers of qualifying resources.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $2.1 billion per year assuming a five percent reduction below 2018 emission levels and a carbon price equal to the latest RGGI auction clearing price. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be about $1.2 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

14 "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, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

15 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents an upper bound on the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-16.

16 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[17]

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.[18] [19]

The CWA 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.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[20]

The EPA's actions have affected 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.

CAA: NESHAP/MATS

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.

17 For more details, see the *2018 State of the Market Report for PJM*, Vol. II, Appendix I: "Environmental and Renewable Energy Regulations."
18 42 U.S.C. § 7401 et seq. (2000).
19 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.
20 42 U.S.C. §§ 6901 *et seq.*

On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.[21] The EPA determined the cost to coal and oil fired power plants of complying with the MATS rule ranged from $7.4 to $9.6 billion annually.[22] The EPA determined the quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions ranged from $4 to $6 million annually.[23] The EPA determined, in accordance with a decision of the U.S. Supreme Court, that based on analysis of costs versus benefits it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.[24] [25] The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.[26]

CAA: NAAQS/CSAPR

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). In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. Implementation was delayed in the courts, but CSAPR is now fully effective. 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. The CSAPR covers 28

21 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 84 Fed. Reg. 2670 (Feb. 7, 2019).
22 *Id.* at 2676.
23 *Id.*
24 Michigan v. EPA, 135 S.Ct. 2699 (2015).
25 84 Fed. Reg. at 2676–2678.
26 *Id.* at 2768. EPA explains (*id.*): "Under D.C. Circuit case law, the EPA's determination that a source category was listed in error does not by itself remove a source category from the CAA section 112(c)(1) list—even EGUs, notwithstanding their special treatment under CAA section 112(n). *New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008)."

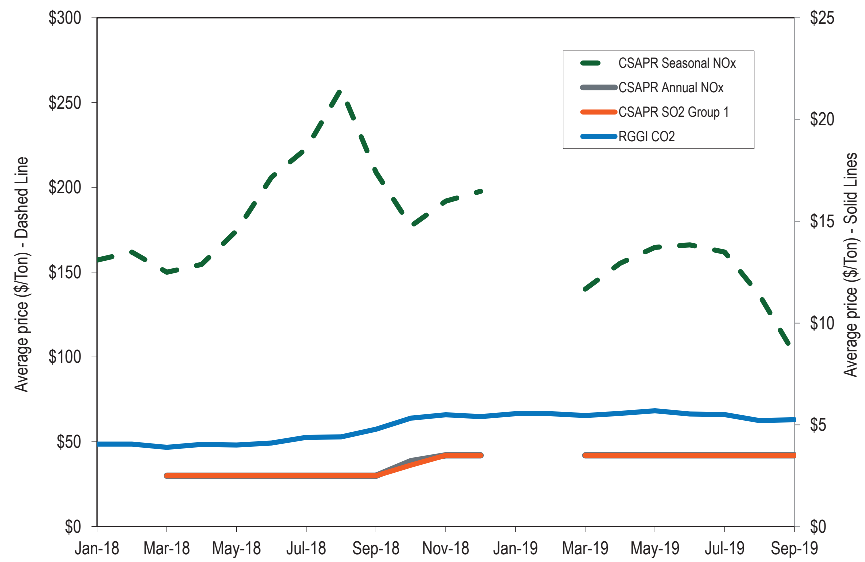
states, including all of the PJM states except Delaware, and also excluding the District of Columbia. The Cross-State Air Pollution Rule ("CSAPR") is a federal emissions trading program designed to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR emissions prices may be compared with RGGI emissions prices.

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. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland.[27]

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, 2018 through September 30, 2019. 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 2019, CSAPR annual NO_X prices were 40.0 percent higher than in the first nine months of 2018. The CSAPR Seasonal NO_X price hit a peak of $258.15 in August 2018.

Figure 8-1 Spot monthly average emission price comparison: January 2018 through September 2019



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or inhibiting progress in areas that do not.[28] NSR requires permits before construction commences.

On August 1, 2019, EPA proposed to reform the New Source Review (NSR) permitting program.[29] Under a revised NSR rule, both emissions increases and decreases from a major modification would be considered in the first prong of the NSR applicability test.

NSR review applies a two prong analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and

27 See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware 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 filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285.

28 42 U.S.C § 7470 et seq.

29 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

existing units. The first analytical prong provides for consideration of whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second prong considers whether any identified increase is also a "significant net emission increase." No permit is required if there is a negative determination under either prong.

The proposed rule changes apply to the first prong. The rule clarifies that under the first prong, a project's decreased as well as increased emissions are considered.[30] Consideration of decreased emissions makes this prong easier to satisfy and thereby avoid the need for a permit and associated investments in pollution controls.

The ACE rule as proposed on August 21, 2018, also included changes to NSR regulations.[31] These proposed NSR changes have been deferred to a separate future action.[32] As proposed, these NSR changes would apply to new units or existing units receiving major modifications. Under these proposed NSR changes, only modifications that increase a plant's hourly rate of emissions would be deemed major and require a two pronged NSR analysis. Modifications that increased a plant's annual run time and annual emissions but not the hourly emissions rate would not require an NSR analysis.

CAA: RICE

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). 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). 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). EPA regulations allow RICE to operate for only 100 hours per year, of which 50 hours must be during emergencies (Energy Emergency Alert Level 2).[33]

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[34] [35]

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."[36] 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.[37] 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.[38] [39] The proposed rule

30 See E. Scott Pruitt, EPA Memorandum re Project Emissions Accounting Under New Source Review Preconstruction Permitting Program (March 13, 2018).
31 82 Fed. Reg. 48035.
32 84 Fed. Reg. 32520, 32521.
33 See 40 CFR § 63.6640(f).
34 See CAA § 111.
35 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 (Dec. 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.
36 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).
37 *Id.*
38 *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>.
39 79 Fed. Reg. 1352 (Jan. 8, 2014).

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 June 19, 2019, the EPA repealed the prior administration's Clean Power Plan[40] and replaced it with the Affordable Clean Energy (ACE) rule.[41] The ACE rule establishes emission guidelines pursuant to which states must develop plans to address greenhouse gas emissions from existing coal fired power plants.

The ACE Rule (i) defines the "best system of emission reduction" (BSER) for existing power plants as on-site, heat-rate efficiency improvements and (ii) lists "candidate technologies" that states can use to establish standards of performance and incorporate into their plans.[42 43]

The ACE Rule replaces the Clean Power Plan's use of national greenhouse gas emissions limits with the application of emission reduction measures at the power plant. The ACE Rule allows states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard.[44] As a result, the impact on coal fired generation depends upon actions taken in their host state. Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.

The EPA finalized regulations governing implementation of ACE and any future emission guidelines issued under Section 111(d) of the CAA. The regulations clarify "that states have broad discretion in establishing and applying emissions standards consistent with the BSER." The implementing regulations also coordinate state and federal deadlines: A state must issue State Implementation Plans (SIP) by June 19, 2022; if no SIP issues, the EPA must issue a Federal Implementation Plan (FIP) by June 19, 2024. The EPA will accept or reject a state's SIP within 12 months after timely receipt, and, if a state's SIP is rejected, issue an FIP for such state within two years.

CWA: WOTUS Definition and Effluents

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).[45] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[46] 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.[47] 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.[48] The proposed 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.[49]

On December 11, 2018, the EPA and Department of the Army proposed a replacement definition of "waters of the United States."[50] The proposed definition would replace both the approaches used before and after the 2015 Rule. The proposed rule includes "waters within the ordinary meaning of the term, such as oceans, rivers, streams, lakes, ponds, and wetlands."[51] The proposed rule excludes "features that flow only in response to precipitation; groundwater, including groundwater drained through subsurface drainage systems; certain ditches; prior converted cropland; artificially irrigated areas that would revert to upland if artificial irrigation ceases; certain artificial lakes

40 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

41 See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019) ("ACE Rule").

42 See CAA § 111(d).

43 *Id.*

44 Candidate technologies include: Neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrade (steam turbine), redesign/replace economizer, and improved operating and maintenance practices.

45 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

46 80 Fed. Reg. 37054 (June 29, 2015).

47 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

48 *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).

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

50 See *Revised Definition of "Waters of the United States,"* EPA Docket No. EPA-HQ-OW-2018-0149, 84 Fed. Reg. 4154 (Feb. 14, 2019).

51 *Id.* at 4155.

and ponds constructed in upland; water-filled depressions created in upland incidental to mining or construction activity; storm water control features excavated or constructed in upland to convey, treat, infiltrate, or store storm water run-off; wastewater recycling structures constructed in upland; and waste treatment systems."[52] The new rule would specifically exclude from EPA jurisdiction waters that are now included.

The EPA issues effluent limitation guidelines ("ELGs") under the CWA, which apply a Best Available Technology Economically Available ("BAT") to identified waste streams.[53] The BAT standard requires the best technology, subject to cost considerations. On September 30, 2015, EPA issued a rule updating the standard for certain waste streams from steam power plants.[54] On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated BAT standards for two identified categories, legacy wastewater (wastewater created, as determined by the permitting authority, between November 1, 2020 and December 31, 2023) and combustion residual leachate (wastewater percolating through landfills and impoundments).[55] The Court determined that reliance on impoundments for both categories is not BAT, and remanded to the EPA the determination of BATs consistent with the CWA.[56]

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. 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. In contrast to the BAT standard, the BTA standard requires the best technology without regard to cost. 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).[57]

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.

52 *Id.*
53 *See* 33 U.S.C. § 1311, 1314, 1362(11).
54 *See Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,838 (Nov. 3, 2015).
55 *See Southwestern Electric Power Co., et al. v. EPA*, Slip. Op. 15-60821.
56 *Id.* at 3.
57 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).

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[58]

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 ash, produced by electric utilities and independent power producers.[59] 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.

58 42 U.S.C. §§ 6901 *et seq.*

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

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

On March 1, 2018, the EPA proposed a rule amending the CCRR.[60] Effective August 9, 2018, the EPA approved (i) revised groundwater protections standards for constituents without an established MCL, (ii) alternative performance standards and (iii) extended deadlines for placement of waste

60 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).

in CCR units closing for cause in certain situations.[61] EPA indicated that additional revisions will be considered in a future rulemaking.

State Environmental Regulation

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[62]

- **New Jersey HEDD.** 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. 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.
- **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). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

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.[63]

Delaware and Maryland are the only PJM states that are currently members of RGGI. Other PJM states have expressed interest in joining RGGI. New Jersey, a founding member of RGGI opted out in 2011. New Jersey will rejoin RGGI in 2020.[64] The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI. However subsequent budget legislation prevents Virginia's participation.[65] Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to join RGGI.[66] The order stipulates that the DEP is to present a rulemaking package to the Pennsylvania Environmental Quality Board by July 31, 2020.[67]

PJM has initiated a task force to investigate the issues associated with the introduction of a carbon price in the PJM energy market.[68]

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 2008/2011 compliance period auctions, the 2012/2014 compliance period auctions, the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of September 4, 2019, in short tons and metric tonnes.[69] Prices for auctions held September 4, 2019, were $5.20 per allowance (equal to one short ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[70] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction clearing price of $5.62 in June 2019.

61 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).
62 For more details, see the *2018 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."
63 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>.
64 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/news-releases/rggi-releases>.
65 "Statement Regarding Virginia State Budget," RGGI Inc., (May 6, 2019), <https://www.rggi.org/news-releases/rggi-releases>.
66 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>
67 *Id.*
68 PJM. Carbon Pricing Senior Task Force (CPSTF) (July 2019) <https://www.pjm.com/committees-and-groups/task-forces/cpstf.aspx>.
69 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.
70 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).

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009/2011, 2012/2014, 2015/2018, and 2018/2020 Compliance Periods[71]

	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
December 5, 2018	$5.35	13,360,649	13,360,649	$5.90	12,120,580	12,120,580
March 13, 2019	$5.27	12,883,436	12,883,436	$5.81	11,687,660	11,687,660
June 5, 2019	$5.62	13,221,453	13,221,453	$6.19	11,994,304	11,994,304
September 4, 2019	$5.20	13,116,447	13,116,447	$5.73	11,899,044	11,899,044

71 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed October 17, 2019).

RGGI auctions have generated approximately $2.8 billion in auction revenue since 2009 and almost all of the auction revenue has been returned to the participating states.[72] The RGGI states have spent approximately 55 percent of this revenue on energy efficiency, 17 percent on clean and renewable energy, 11 percent on greenhouse gas abatements and 11 percent on direct bill assistance.[73]

Table 8-3 Estimated CO_2 allowance revenue at September 2019 RGGI price level[74 75 76]

	Estimated CO_2 allowance revenue ($ millions), carbon price $5.20 per short ton						
Jurisdiction	2018 power generation CO_2 emissions (short tons)	5 percent reduction below 2018 emission levels	10 percent reduction below 2018 emission levels	15 percent reduction below 2018 emission levels	20 percent reduction below 2018 emission levels	25 percent reduction below 2018 emission levels	50 percent reduction below 2018 emission levels
Delaware	2,820,304.7	$13.9	$13.2	$12.5	$11.7	$11.0	$7.3
Illinois	34,918,315.6	$172.5	$163.4	$154.3	$145.3	$136.2	$90.8
Indiana	49,202,850.2	$243.1	$230.3	$217.5	$204.7	$191.9	$127.9
Kentucky	29,989,896.2	$148.2	$140.4	$132.6	$124.8	$117.0	$78.0
Maryland	17,167,736.9	$84.8	$80.3	$75.9	$71.4	$67.0	$44.6
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	15,521,984.9	$76.7	$72.6	$68.6	$64.6	$60.5	$40.4
North Carolina	302,169.7	$1.5	$1.4	$1.3	$1.3	$1.2	$0.8
Ohio	88,921,973.3	$439.3	$416.2	$393.0	$369.9	$346.8	$231.2
Pennsylvania	81,414,231.3	$402.2	$381.0	$359.9	$338.7	$317.5	$211.7
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	34,399,627.4	$169.9	$161.0	$152.0	$143.1	$134.2	$89.4
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	64,849,471.6	$320.4	$303.5	$286.6	$269.8	$252.9	$168.6
Total	419,508,561.7	$2,072.4	$1,963.3	$1,854.2	$1,745.2	$1,636.1	$1,090.7

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2018 CO_2 emission levels and the RGGI clearing price for the June 2019 auction ranges from $1.1 billion per year to $2.1 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[77] Table 8-3 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2018 CO_2 emission levels ranging from five to 50 percent. CO_2 emissions for the PJM states were approximately five times the total CO_2 emissions for the nine RGGI states.[78] A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-3 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2018 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey has chosen an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[79]

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-4 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. RGGI is currently in the second year of the fourth control period.

In 2014, RGGI began adjusting the emission cap to account for banked allowances from previous control periods.[80] At the end of the first control period, 57,449,495 banked allowances were held by market participants.[81] The cap adjustment for banked allowances was spread over a seven year period beginning in 2014 with the RGGI cap being reduced each year by one-seventh of the banked allowances. An additional reduction of 593 allowances per year, applying only to the Connecticut allowance

72 "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States" at 2, Analysis Group, April 17, 2018.

73 *The Investment of RGGI Proceeds in 2016*, The Regional Greenhouse Gas Initiative, September 2018, <https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2016.pdf>.

74 The 2018 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

75 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.

76 Emissions for the PJM states includes all power generators located in the state and is not limited to generators participating in the PJM energy markets.

77 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.

78 Based on 2018 CO_2 emissions data from the EPA Continuous Emission Monitoring System (CEMS).

79 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/news_archive.shtml>.

80 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

81 "First Control Period Interim Adjustment for Banked Allowances Announcements," Regional Greenhouse Gas Initiative (Jan. 13, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_01_13_FCP_Adjustment.pdf>.

budget, brings the overall cap adjustment to 8,207,664 allowances per year.[82] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13,683,744 allowances per year and will be in place through 2020.[83] The RGGI clearing price since 2014 has been on average 99.1 percent higher than the prices prior to the emission cap adjustments.

Table 8-4 RGGI emissions cap history[84 85]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009		$2.77	188,000,000		188,000,000	
2010	1st	$1.93	188,000,000	0.0%	188,000,000	0.0%
2011		$1.89	188,000,000	0.0%	188,000,000	0.0%
2012		$1.93	165,000,000	(12.2%)	165,000,000	(12.2%)
2013	2nd	$2.92	165,000,000	0.0%	165,000,000	0.0%
2014		$4.72	91,000,000	(44.8%)	82,792,336	(49.8%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	3rd	$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	$5.36	80,179,708	(2.5%)	58,288,301	(3.4%)
2020			78,175,215	(2.5%)	56,283,807	(3.4%)

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-5 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $19.9 billion if the carbon price were $50 per short ton and emission levels were five percent below 2018 levels. Allowance revenues to states would be $2.1 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2018.

82 Id at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years.

83 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.

84 See Regional Greenhouse Gas Initiative, "Elements of RGGI" and "Auction Results," <https://www.rggi.org/> (Accessed June 25, 2019).

85 The RGGI cap for 2020 does not reflect emissions for New Jersey.

Table 8-5 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2018 emission levels	10 percent reduction below 2018 emission levels	15 percent reduction below 2018 emission levels	20 percent reduction below 2018 emission levels	25 percent reduction below 2018 emission levels	50 percent reduction below 2018 emission levels
Jurisdiction	Carbon Price ($ per short ton)				$10.00	
Delaware	$26.8	$25.4	$24.0	$22.6	$21.2	$14.1
Illinois	$331.7	$314.3	$296.8	$279.3	$261.9	$174.6
Indiana	$467.4	$442.8	$418.2	$393.6	$369.0	$246.0
Kentucky	$284.9	$269.9	$254.9	$239.9	$224.9	$149.9
Maryland	$163.1	$154.5	$145.9	$137.3	$128.8	$85.8
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$147.5	$139.7	$131.9	$124.2	$116.4	$77.6
North Carolina	$2.9	$2.7	$2.6	$2.4	$2.3	$1.5
Ohio	$844.8	$800.3	$755.8	$711.4	$666.9	$444.6
Pennsylvania	$773.4	$732.7	$692.0	$651.3	$610.6	$407.1
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$326.8	$309.6	$292.4	$275.2	$258.0	$172.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$616.1	$583.6	$551.2	$518.8	$486.4	$324.2
Total	$3,985.3	$3,775.6	$3,565.8	$3,356.1	$3,146.3	$2,097.5
	Carbon Price ($ per short ton)				$25.00	
Delaware	$67.0	$63.5	$59.9	$56.4	$52.9	$35.3
Illinois	$829.3	$785.7	$742.0	$698.4	$654.7	$436.5
Indiana	$1,168.6	$1,107.1	$1,045.6	$984.1	$922.6	$615.0
Kentucky	$712.3	$674.8	$637.3	$599.8	$562.3	$374.9
Maryland	$407.7	$386.3	$364.8	$343.4	$321.9	$214.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$368.6	$349.2	$329.8	$310.4	$291.0	$194.0
North Carolina	$7.2	$6.8	$6.4	$6.0	$5.7	$3.8
Ohio	$2,111.9	$2,000.7	$1,889.6	$1,778.4	$1,667.3	$1,111.5
Pennsylvania	$1,933.6	$1,831.8	$1,730.1	$1,628.3	$1,526.5	$1,017.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$817.0	$774.0	$731.0	$688.0	$645.0	$430.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,540.2	$1,459.1	$1,378.1	$1,297.0	$1,215.9	$810.6
Total	$9,963.3	$9,438.9	$8,914.6	$8,390.2	$7,865.8	$5,243.9
	Carbon Price ($ per short ton)				$50.00	
Delaware	$134.0	$126.9	$119.9	$112.8	$105.8	$70.5
Illinois	$1,658.6	$1,571.3	$1,484.0	$1,396.7	$1,309.4	$873.0
Indiana	$2,337.1	$2,214.1	$2,091.1	$1,968.1	$1,845.1	$1,230.1
Kentucky	$1,424.5	$1,349.5	$1,274.6	$1,199.6	$1,124.6	$749.7
Maryland	$815.5	$772.5	$729.6	$686.7	$643.8	$429.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$737.3	$698.5	$659.7	$620.9	$582.1	$388.0
North Carolina	$14.4	$13.6	$12.8	$12.1	$11.3	$7.6
Ohio	$4,223.8	$4,001.5	$3,779.2	$3,556.9	$3,334.6	$2,223.0
Pennsylvania	$3,867.2	$3,663.6	$3,460.1	$3,256.6	$3,053.0	$2,035.4
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,634.0	$1,548.0	$1,462.0	$1,376.0	$1,290.0	$860.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$3,080.3	$2,918.2	$2,756.1	$2,594.0	$2,431.9	$1,621.2
Total	$19,926.7	$18,877.9	$17,829.1	$16,780.3	$15,731.6	$10,487.7

Table 8-6 shows the estimated impact of three different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $5.00 per tonne, the PJM load-weighted average LMP in the first nine months of 2019 would have increased by 5.9 percent.[86]

Table 8-6 Estimated impact of Carbon price on LMP January through September 2018 and 2019

		2018 (Jan - Sep)			2019 (Jan - Sep)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$39.43	$41.11	4.2%	$27.60	$29.24	5.9%
Scenario 2	$10.00	$39.43	$42.94	8.9%	$27.60	$31.05	12.5%
Scenario 3	$15.00	$39.43	$44.78	13.5%	$27.60	$32.85	19.0%

State Renewable Portfolio Standards

Nine of 14 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 requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are 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 are penalized with alternative compliance payments.

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[87] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2019, 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 noncompliance.

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, 2019, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance. A voluntary standard including target shares was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[88]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but it was repealed.[89]

How each state satisfies its renewable portfolio standard 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 provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as

86 The impact calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost.

87 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).

88 See the Indiana Utility Regulatory Commission’s “2019 Annual Report,” at 35 (Oct. 2019) <https://www.in.gov/iurc/2981.htm>.

89 See Enr. Com. Sub. For H. B. No. 2001.

a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[90]

Table 8-7 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. Table 8-8 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, D. C.

Table 8-7 Renewable and alternative energy standards of PJM jurisdictions: 2019 to 2030[91]

Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	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	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	23.20%	30.50%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
Michigan	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	18.53%	23.50%	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	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	5.50%	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	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.	18.00%	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard												
Indiana	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%	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											

The recent New Jersey legislation also included provisions promoting the development of solar power in the state.[92] 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.

90 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
91 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
92 N.J. S. 2314/A. 3723.

Table 8-8 Recent changes in RPS rules[93] [94] [95] [96]

Jurisdiction	Legislation	Effective Date	Summary of changes
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.
New Jersey	Clean Energy Act	May 24, 2018	Established a 50.0 percent Class I renewable standard for the 2029/2030 compliance year, and an intermediate target of 35.0 percent Class I renewable standard for the 2024/2025 compliance year. Prior to this legislation, the target percent for Class I renewable was 17.9 percent for the 2020/2021 compliance year. The legislation also included an increase in the solar standard for 2018/2019 compliance year from 3.29 percent to 4.3 percent, and an increase to 5.1 percent for the 2020/2021 compliance year. The solar standard decreases to 4.9 percent in the 2023/2024 compliance year, and gradually decreases to 1.1 percent for the 2032/2033 compliance year.

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.[97] 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 of generation from qualified offshore wind projects by 2030 (plus 2,000 MW of energy storage capacity).[98] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issue Executive Order No. 8, which call for full implementation of the statute. The BPU has initiated a proceeding considering the opening of an application window for qualified offshore wind projects.[99]

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.

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 jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, D.C. group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Although 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. Table 8-9 shows the Tier I standards for PJM states.[100] All eligible technologies for the RPS standards in Table 8-9 satisfy the EIA definition of renewable energy.[101]

93 See Ohio Legislature House, 133rd Assembly, Bill 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
94 See Maryland State Legislature, Senate Bill 516, "Clean Energy Jobs" Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
95 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
96 See New Jersey CleanEnergy Program, RPS Background Info, <http://njcleanenergy.com/renewable-energy/program-activity-and-background-information/rps-background-info>.
97 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
98 N.J. S. 2314/A. 3723.
99 BPU Docket No. QO18080851.
100 This includes New Jersey's Class I renewable standard.
101 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

Table 8-9 Tier I renewable standards of PJM jurisdictions: 2019 to 2030

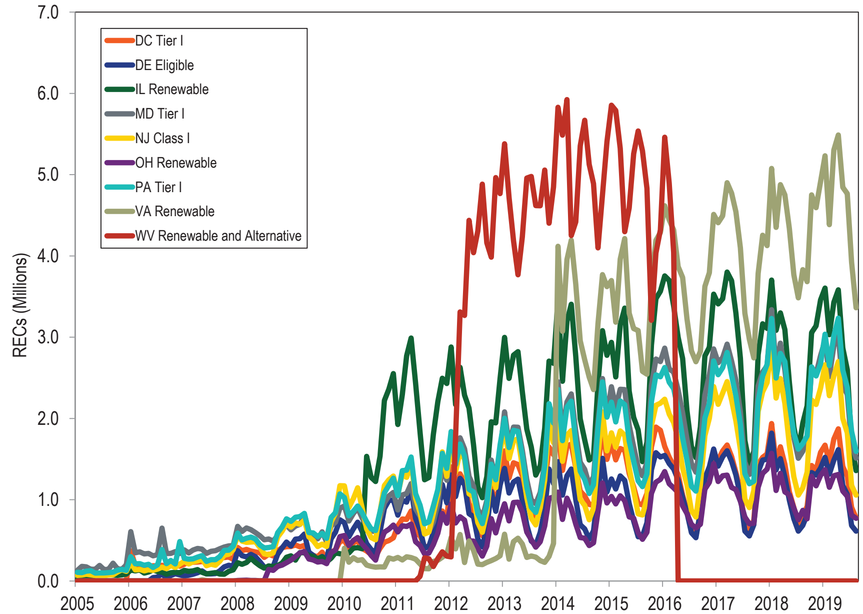
Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	20.70%	28.00%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
New Jersey	16.03%	21.00%	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	7.00%	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	17.50%	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[102]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

Figure 8-2 shows the number of RECs eligible monthly by state for January 1, 2005, through August 31, 2019.[103] REC eligibility by state is the number of RECs created in a month that the state could use to fulfil a state's RPS goal. One REC created during a month could be eligible for multiple states based on the RPS requirements. Table 8-18 describes the state's renewable portfolio standard's geographical restrictions governing the source of RECs to satisfy each state's standards. The figure includes Tier I or the equivalent REC type available in each state. Washington, D.C., Maryland, and Pennsylvania classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and West Virginia classify these RECs as renewable or eligible. West Virginia repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard.

Figure 8-2 Number of RECs eligible monthly by state: January 2005 through August 2019[104]



The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, D.C., but in the other states REC prices are not publicly available.

102 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

103 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

104 West Virginia eligible MW drop to 0 in 2016 with the repeal of the state's renewable portfolio standard.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2019. Tier I REC prices are lower than SREC prices.

Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through September 2019

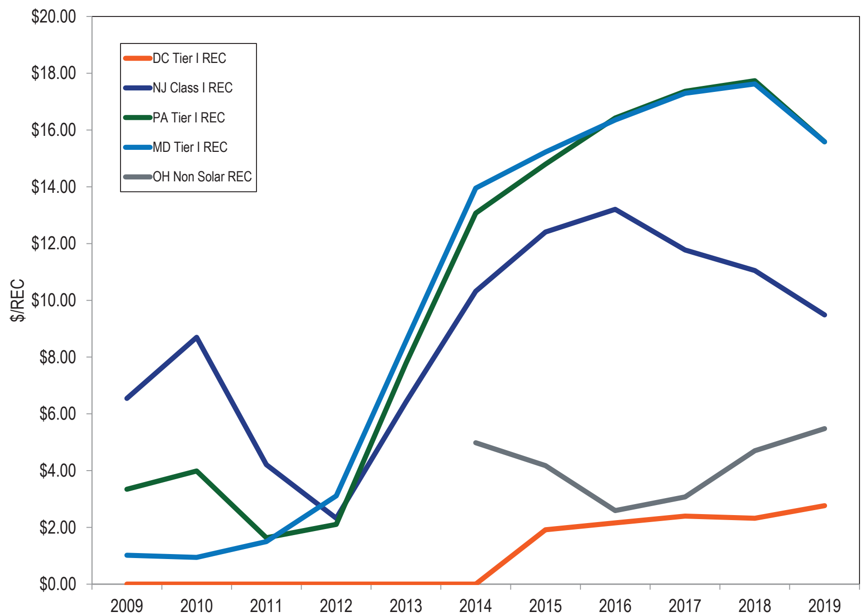
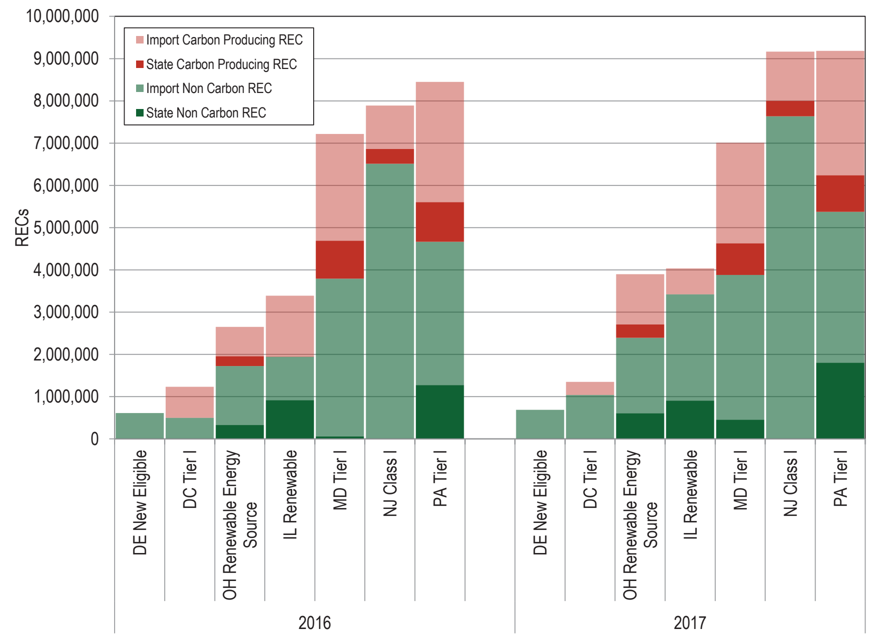


Figure 8-4 and Table 8-10 shows the fulfillment of Tier I equivalent RPS requirement for 2016 and 2017 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[105] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Non Carbon REC") or with landfill gas, captured methane, wood, black liquor, etc. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The DC New Eligible requirement is fulfilled by Non Carbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local non carbon RECs by state to meet the RPS requirements. Table 8-10 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Pennsylvania met its Tier I target using 73.9 percent imported RECs for the 2016 compliance year, and using 44.8 percent carbon producing RECs for the 2016 compliance year.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2016 and 2017



105 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 23, 2019).

Table 8-10 State fulfillment of Tier I equivalent RPS: 2016 and 2017

Year	REC Type	State Non Carbon REC	Import Non Carbon REC	State Carbon Producing REC	Import Carbon Producing REC
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%

Class 2 standards, which allow specific nonrenewable 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. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[106]

Figure 8-5 shows the number of Tier II RECs eligible monthly by state for January 1, 2005, through August 31, 2019.[107] The figure includes Tier II or the equivalent REC type available in each state. Washington, D.C., Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

Table 8-11 Additional renewable standards of PJM jurisdictions: 2019 to 2030

Jurisdiction	Type of Standard	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Illinois	Distributed Generation	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%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Maryland	Off Shore Wind			1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.96%	1.94%
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%
North Carolina	Swine Waste	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
Pennsylvania	Tier II Standard	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	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 8-11 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-11 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. Except for the Maryland offshore wind and the North Carolina poultry waste standards, the standards shown in Table 8-11 are included in the total RPS requirements presented in Table 8-7. 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, D.C. all have Tier II or

106 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2, <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

107 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

Figure 8-5 Number of Tier II RECs eligible monthly by state: January 2005 through August 2019

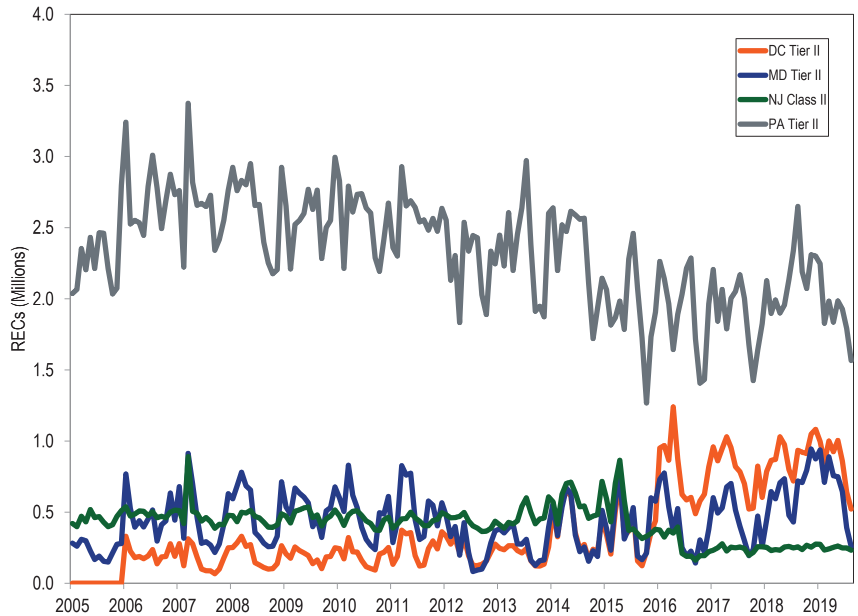
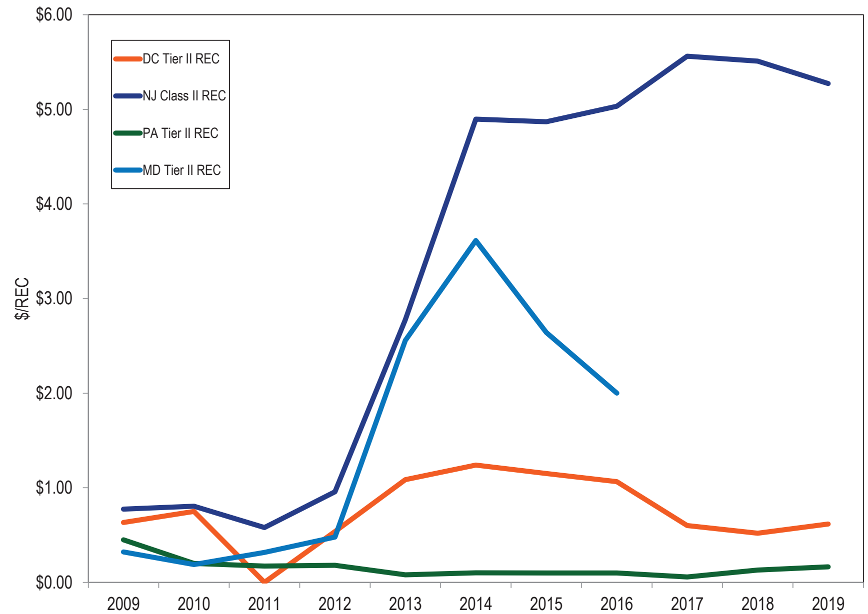


Figure 8-6 Average Tier II REC price by jurisdiction: January 2009 through September 2019



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-6 shows the average Tier II REC price by jurisdiction for January 1, 2009 through September 30, 2019. Pennsylvania had the lowest average Tier II REC prices at $0.13 per REC while New Jersey had the highest average Tier II REC prices at $5.39 per REC.[108]

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-9 but must be met by solar RECs (SRECs) only. Table 8-12 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. 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 2018. The new solar standard is 5.1 percent for energy years 2020 through

108 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed October, 2019). There were not any reported cleared purchases for January 1, through September 30, 2019, for MD Tier II RECs.

2022 and the standard gradually decreases to 1.1 percent for 2032.[109] Maryland legislation in 2019 increased the solar carve out percentages. The new Maryland RPS solar carve out target, to be reached in 2030, increased from 2.5 percent to 14.5 percent. Ohio HB 6 removed the solar carve out from the Ohio RPS.

Table 8-12 Solar renewable standards by percent of electric load for PJM jurisdictions: 2019 to 2030

Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	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	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	5.50%	6.00%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	13.50%	14.50%	14.50%	14.50%
Michigan	No Minimum Solar Requirement											
New Jersey	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%
Ohio	0.22%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	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.	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
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											

109 "Assembly, No. 3723" State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

Figure 8-7 shows the number of SRECs eligible monthly by state for January 1, 2005, through August 31, 2019.[110]

Figure 8-7 Number of SRECs eligible monthly by state: January 2005 through August 2019

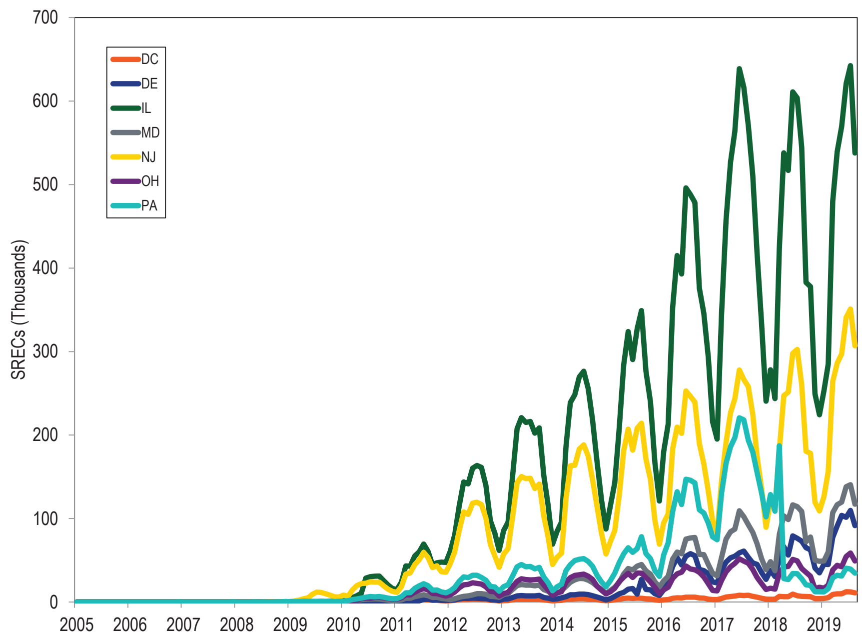


Figure 8-8 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2019. The average NJ SREC prices dropped from $673 per SREC in 2009 to $194 per SREC in 2019. The limited supply of solar facilities in Washington, D.C. compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $387 per SREC in 2019.[111]

Figure 8-8 Average SREC price by jurisdiction: January 2009 through September 2019

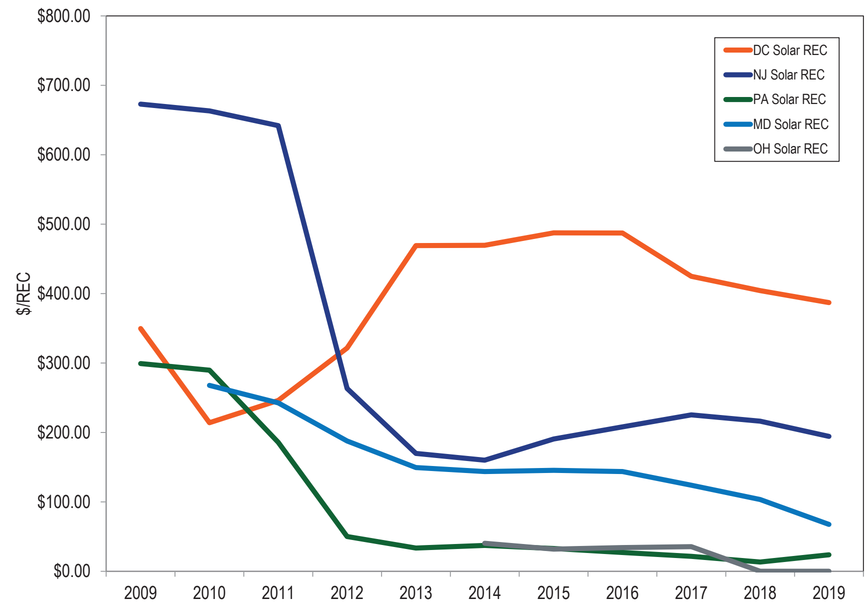


Figure 8-9 and Table 8-13 shows each the fulfillment of a solar requirement by state for 2016 and 2017, by source of SREC.[112] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-13 shows the percent of imported and local SRECs used to meet the RPS requirements. For example, Washington D.C. met its solar requirement using 50.2 percent imported SRECs for the 2016 compliance year.

110 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

111 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 17, 2019).

112 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 23, 2019).

Figure 8-9 State fulfillment of Solar RPS: 2016 and 2017

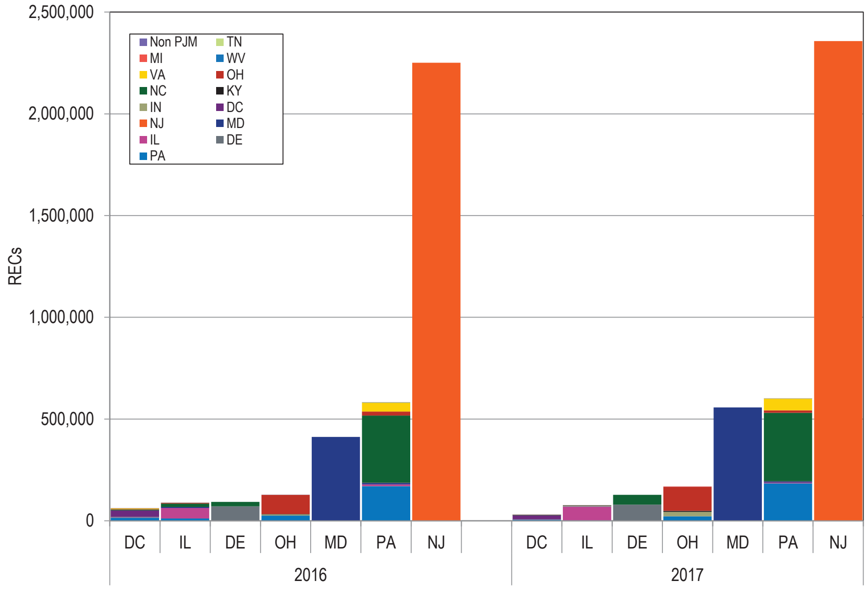
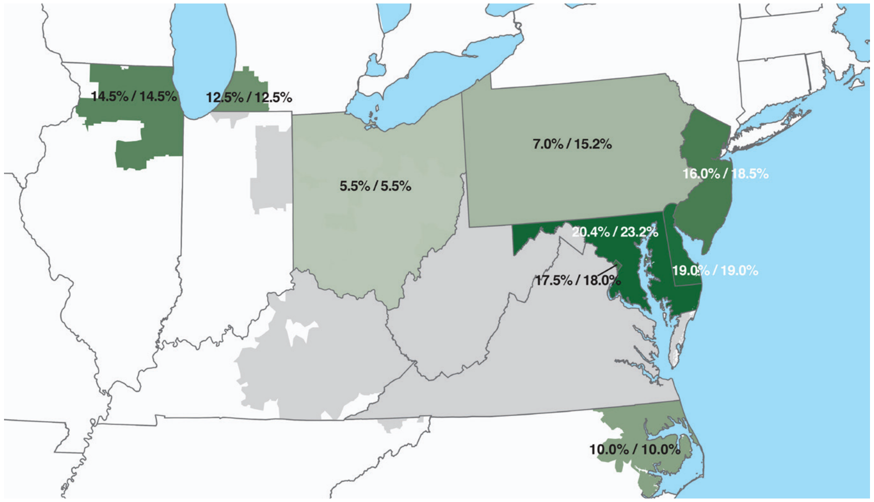


Table 8-13 State fulfillment of Solar RPS: 2016 and 2017

		State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	IL Solar Renewable	56.5%	43.5%
	DE Solar Eligible	76.5%	23.5%
	OH Solar Renewable Energy Source	73.3%	26.7%
	MD Solar	100.0%	0.0%
	PA Solar	29.1%	70.9%
	NJ Solar	100.0%	0.0%
2017	DC Solar	17.2%	82.8%
	IL Solar Renewable	87.6%	12.4%
	DE Solar Eligible	61.9%	38.1%
	OH Solar Renewable Energy Source	69.0%	31.0%
	MD Solar	100.0%	0.0%
	PA Solar	30.6%	69.4%
	NJ Solar	100.0%	0.0%

Figure 8-10 shows 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. For each state in Figure 8-10, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, 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. As a result, the 15.2 percent number in Figure 8-10 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 7.0 percent number in Figure 8-10 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-10 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2019[113]



Under the existing state renewable portfolio standards, approximately 10.3 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2019. In the first nine months of 2019, 6.8 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-14. If the proportion of load among states remains constant, 17.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2029 under currently defined RPS rules. Approximately 8.2 percent of PJM load must be served by Tier I or renewable energy resources in 2019. In the first nine months of 2019, 4.6 percent of PJM generation was Tier I or renewable energy as shown in Table 8-14. If the proportion of load among states remains constant, 15.3 percent of PJM load must be served by Tier I or renewable energy resources in 2029 under defined RPS rules.

113 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-14 shows generation by jurisdiction and resource type for the first nine months of 2019. Wind output was 16,974.1 GWh of 29,029.2 Tier I GWh, or 58.5 percent, in the PJM footprint. As shown in Table 8-14, 42,695.1 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 68.0 percent. Total wind and solar generation was 3.1 percent of total generation in PJM for the first nine months of 2019. Tier I generation was 4.6 percent of total generation in PJM and Tier II was 2.2 percent of total generation in PJM for the first nine months of 2019. Landfill gas, solid waste and waste coal were 10,682.5 GWh, or 25.0 percent of the total Tier I and Tier II.

Table 8-14 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2019

	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	29.9	0.0	0.0	0.0	29.9	0.0	0.0	0.0	0.0	29.9
Illinois	82.5	0.0	11.7	7,517.5	7,611.7	0.0	0.0	0.0	0.0	7,611.7
Indiana	14.7	36.5	10.9	3,872.3	3,934.5	0.0	0.0	0.0	0.0	3,934.5
Kentucky	0.0	265.6	0.0	0.0	265.6	0.0	0.0	0.0	0.0	265.6
Maryland	46.2	0.0	358.4	464.9	869.5	0.0	444.3	0.0	444.3	1,313.8
Michigan	16.1	51.4	5.3	0.0	72.8	0.0	0.0	0.0	0.0	72.8
New Jersey	191.0	23.9	578.4	10.7	804.1	231.6	987.6	0.0	1,219.2	2,023.3
North Carolina	0.0	609.0	676.9	372.2	1,658.0	0.0	0.0	0.0	0.0	1,658.0
Ohio	260.0	608.2	1.0	1,378.9	2,248.1	0.0	0.0	0.0	0.0	2,248.1
Pennsylvania	540.5	4,470.1	20.4	2,318.2	7,349.2	1,420.3	1,055.9	4,062.8	6,539.0	13,888.2
Tennessee	0.0	1,091.3	0.0	0.0	1,091.3	0.0	0.0	0.0	0.0	1,091.3
Virginia	400.8	466.3	527.7	0.0	1,394.8	2,945.3	688.8	1,132.6	4,766.6	6,161.4
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	32.0	628.4	0.0	1,039.3	1,699.6	0.0	0.0	696.7	696.7	2,396.3
Total	1,613.7	8,250.7	2,190.7	16,974.1	29,029.2	4,597.2	3,176.7	5,892.0	13,665.9	42,695.1
Percent of Renewable Generation	3.8%	19.3%	5.1%	39.8%	68.0%	10.8%	7.4%	13.8%	32.0%	100.0%
Percent of Total Generation	0.3%	1.3%	0.3%	2.7%	4.6%	0.7%	0.5%	0.9%	2.2%	6.8%

Figure 8-11 shows the average hourly output by fuel type for January 1 through September 30 of 2014 through 2019. 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.[114]

114 See the *2019 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, Table 3-9.

Figure 8-11 Average hourly output by fuel type: January through September, 2014 through 2019

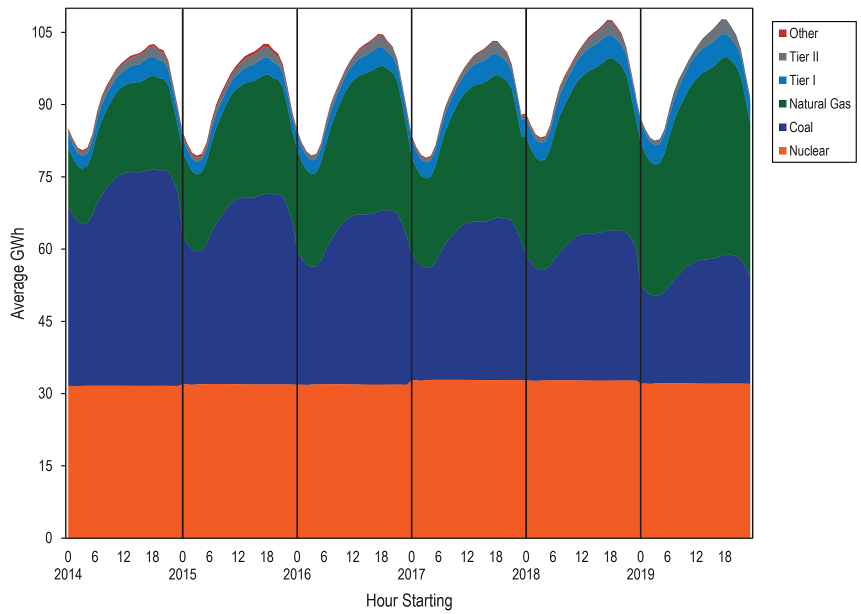


Table 8-15 shows the capacity of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify because they have a renewable fuel as an alternative fuel. For example, a coal generator that can also burn waste coal 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, 560.8 MW, or 28.6 percent of the total solar capacity. New Jersey's SREC prices were the highest in PJM at $673 per REC in 2009, and at $194 per REC in 2019. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 5,571.6 MW, or 63.0 percent of the total wind capacity.

Table 8-15 PJM renewable capacity by jurisdiction (MW): September 30, 2019

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	39.2	360.0	0.0	0.0	0.0	9.0	0.0	0.0	3,549.2	3,957.4
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	2,022.5	2,048.8
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	22.3	0.0	69.0	0.0	494.4	204.3	128.2	0.0	190.0	1,108.2
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	560.8	162.0	0.0	4.5	1,268.9
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	655.6	0.0	0.0	208.0	1,328.6
Ohio	5,734.0	68.2	0.0	136.0	0.0	119.1	1.1	0.0	0.0	669.8	6,728.2
Pennsylvania	0.0	201.8	2,346.0	0.0	1,269.0	893.3	19.5	261.8	1,561.0	1,367.2	7,919.6
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	499.0	123.0	585.0	0.0	6,874.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	5,734.0	572.7	4,503.0	235.0	7,069.5	2,754.5	1,964.0	675.0	2,311.0	8,843.4	34,662.1

Table 8-16 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 5,862.0 MW of which 2,280.2 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. There are 2,058.2 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 141.5 MW of capacity registered with GATS located in Alabama.

Table 8-16 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on September 30, 2019[115]

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	116.1	0.0	2.1	120.4
Georgia	0.0	0.0	27.1	0.0	0.0	0.0	152.2	258.9	0.0	438.2
Illinois	0.0	21.4	93.8	0.0	5.5	0.0	142.7	0.0	300.3	563.7
Indiana	0.0	0.0	49.6	0.0	5.2	109.6	114.8	0.0	180.0	459.2
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	3.2	0.0	336.8	341.6
Kentucky	600.0	162.2	18.6	0.0	0.4	0.0	37.0	93.0	0.0	911.2
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	0.0	0.0	0.0	952.8	15.0	0.3	1,045.8
Michigan	55.0	1.3	4.8	0.0	0.0	0.0	5.0	31.0	29.4	126.5
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	61.5	0.0	451.0	518.1
New Jersey	0.0	0.0	48.3	0.0	11.6	0.0	2,280.2	0.0	4.8	2,344.9
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	1,068.5	151.5	0.0	1,650.4
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	6.6	30.8	52.0	14.2	32.4	219.7	92.8	47.4	496.0
Pennsylvania	109.7	31.7	45.2	93.0	16.6	5.0	374.8	8.6	3.3	687.8
South Carolina	0.0	0.0	30.8	0.0	0.0	0.0	91.3	0.0	0.0	122.1
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	28.6	11.3	0.0	3.1	0.0	166.7	287.6	0.0	497.3
Washington, D.C.	0.0	0.0	0.0	0.0	49.4	13.5	70.7	0.0	0.0	133.6
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	4.2
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.3	44.6	0.0	53.9
Total	829.7	691.2	382.4	145.0	123.9	160.5	5,862.0	1,311.4	1,715.5	11,221.6

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.[116] 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. FERC has found that such revenues can be appropriately considered in the rates established through the operation of wholesale organized markets.[117] 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 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.[118] 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.[119]

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 8-17 shows the REC tracking systems used by each state within the PJM footprint.

115 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 17, 2019).

116 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).

117 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.").

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

119 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.

Table 8-17 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 8-18 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 each state's 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 to 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 8-18 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 be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria.
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. 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.

Carbon Pricing

Table 8-19 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[120] [121] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-19 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	$2.45	$4.90	$7.36	$24.52	$49.04	$98.08	$196.17
CC	$1.67	$3.34	$5.01	$16.71	$33.41	$66.83	$133.65
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-19 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $194.32 per MWh through the third quarter of 2019. 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 $24.52 per MWh.

120 Heat rates from: *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.
121 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).

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-20. The carbon price implied by the 2019 average REC price in Washington, D.C. is $5.64 per tonne which is consistent with the most recent RGGI clearing price of $5.73 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and the carbon prices implied by REC prices in Maryland and Pennsylvania are more consistent with the social cost of carbon which is estimated to be in the range of $50 per tonne.[122] 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 and in most cases significantly higher than the social price of carbon.

Table 8-20 Implied carbon price based on REC and SREC prices: 2009 through 2019[123]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per Metric Tonne) Implied by REC Prices**										
Delaware					$34.15	$35.17	$31.91	$32.91	$10.26	$10.29	$13.34
Maryland	$2.07	$1.92	$3.06	$6.34	$17.46	$28.45	$31.04	$33.35	$35.26	$35.94	$31.78
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.53	$19.35
Ohio						$10.16	$8.52	$5.29	$6.27	$9.59	$11.17
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$30.17	$33.49	$35.40	$36.17	$31.78
Washington, D.C.							$3.91	$4.40	$4.88	$4.73	$5.64
Jurisdiction with Solar REC	**Carbon Price ($ per Metric Tonne) Implied by Solar REC Prices**										
Delaware						$117.25	$85.40	$86.48	$35.70	$17.33	
Maryland		$546.11	$494.54	$382.57	$304.54	$292.70	$296.62	$292.64	$252.59	$210.76	$137.64
New Jersey	$1,372.37	$1,352.15	$1,309.00	$537.08	$345.94	$326.21	$388.73	$424.21	$459.21	$440.92	$396.23
Ohio						$82.32	$64.86	$69.53	$72.40		
Pennsylvania	$610.05	$590.57	$378.67	$101.80	$68.34	$75.90	$66.89	$55.06	$43.84	$27.09	$48.08
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$824.43	$789.17
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per Metric Tonne)**										
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.91

Alternative Compliance Payments

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 (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $258.00 per MWh.[124] Pennsylvania requires that solar ACPs be 200 percent of the average market value of solar RECs sold in the RTO plus the value of any solar rebates. Figure 8-12 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. 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.

122 "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, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

123 There were no trades in 2018 for Ohio SRECs available in the Evomarkets data.

124 N.J. S. 2314/A. 3723.

Table 8-21 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-21 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: September 30, 2019[125 126 127]

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	$30.00	$15.00	$100.00
Michigan	No specific penalties		
New Jersey	$50.00		$258.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$52.62		$200.00
Pennsylvania	$45.00	$45.00	$62.62
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		

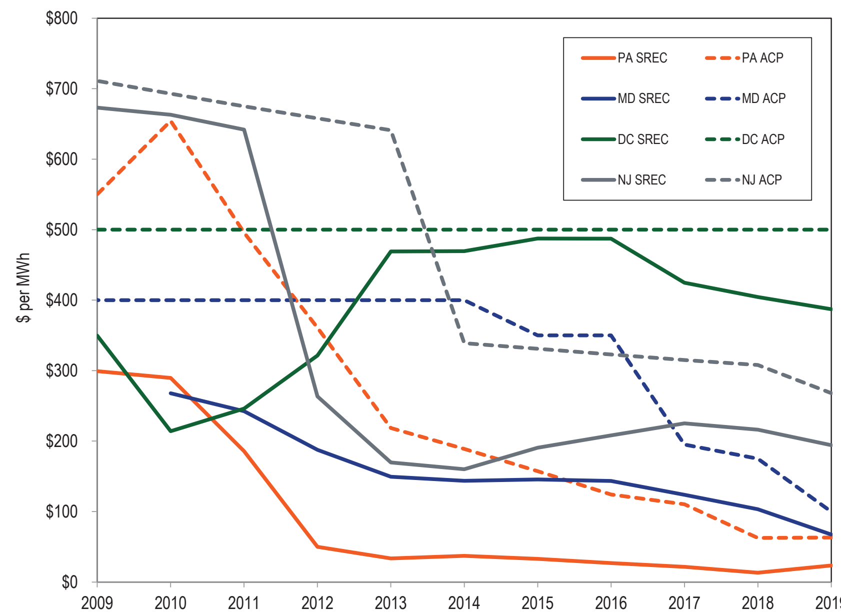
Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

125 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2017 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

126 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 21, 2019).

127 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2018. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed July 16, 2019).

Figure 8-12 Comparison of SREC Price and Solar ACP: 2009 through 2019



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 Pennsylvania Public Utility Commission issued their 2017 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 during the first quarter of 2018.[128] 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.

128 "2017 Annual Report – Alternative Energy Portfolio Standards Act of 2004," (March 2018), <http://www.pennaeps.com/reports/>.

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.[129] 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 were 50.5 percent lower than solar REC retirements in 2016, with 30,765 solar RECs retired in 2017 and 62,173 retired in 2016.

The Public Service Commission of Maryland reported that "suppliers retired over 9.0 million RECs in 2017, slightly less than both the calculated obligation for the year and the 9.1 million RECs retired for compliance in 2016."[130] Alternative compliance payments totaled $55,032 for 2017 with the majority of payments "made in lieu of purchasing Tier 1 RECs to satisfy Industrial Load Process ("IPL") obligations."[131]

The Public Utilities Commission of Ohio reported that 3,919,366 nonsolar credits were retired in the 2017 compliance year, exceeding the credit obligation of 3,912,562 credits; and 175,829 solar credits were retired in the 2017 compliance year, exceeding the solar credit obligation of 175,185.[132] Retired non solar credits for 2017 exceeded the 2016 level by 46.1 percent, and retired solar credits for 2017 exceeded the 2016 level by 29.9 percent.

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 670,488 credits for the compliance year ending May 31, 2019, with zero alternative compliance payments.[133] Delmarva Power satisfied their solar REC obligation of 124,073 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through alternative compliance payments. This requirement was removed for 2017/2018 Delivery Year and alternative compliance payments decreased to $151,027, a 99.8 percent reduction from the 2016-2017 level of alternative compliance payments.[134]

The North Carolina Utilities Commission reported that all electric power suppliers met or appear to have met the 2017 renewable energy portfolio standard, solar energy requirement, and poultry waste energy requirement.[135] [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 2017.

The Michigan Public Service Commission reported that electric power suppliers met the 2017 renewable energy standards by retiring 10,218,115 RECs.[137]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2018.[138] Electric power suppliers retired 9,166,102 class I RECs and 1,758,180 class II RECs. Alternative compliance payments were submitted for deficiencies of 24 class I credits and 9 class II credits. Electric power suppliers retired 2,357,814 solar RECs and there were no deficiencies requiring alternative compliance payments.

129 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia (May 1, 2019), <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.
130 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2018) at 7, <https://www.psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf>.
131 Id. at 8.
132 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2017," Public Utilities Commission of Ohio (March 20, 2019), <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.
133 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2018–May 31, 2019," Delmarva Power, (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>
134 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
135 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission, (Oct. 1, 2018), <https://www.ncuc.net/Reps/reps.html>.
136 Id. at 53. Compliance plan approvals are pending for one municipally-owned electric utility and one electric membership corporation (EMC).
137 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 15, 2019), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.
138 See RPS Report Summary 2005-2018, New Jersey's Clean Energy Program (Dec. 31, 2018), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

Table 8-22 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions. The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-22 is an estimate based on average REC prices and assigning the reported alternative compliance payments to the solar standard. The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017 for the eight jurisdictions that had RPS and reported compliance costs.[139] The average RPS compliance cost per year based on the reported compliance cost for the four year period from 2014 through 2017 was $840.4 million.

Table 8-22 RPS Compliance Cost[140 141 142 143 144 145 146 147 148 149]

Jurisdiction with RPS		2014	2015	2016	2017	2018
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523
Maryland	Total RPS	$103,990,914	$126,727,632	$135,198,524	$72,009,070	
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911		
	Solar	$14,163,543	$19,227,690	$21,876,876		
	Tier I	$70,922,431	$94,339,032	$101,700,328		
	Tier II	$1,098,503	$1,020,210	$1,464,707		
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583
PJM	Total RPS	$678,090,358	$888,031,302	$985,869,304	$809,597,668	$94,727,139

139 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.
140 "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
141 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.
142 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2017," Public Service Commission of Maryland, November 2018, <https://www.psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf>.
143 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2019, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
144 "RPS Report Summary 2005-2018," New Jersey's Clean Energy Program, December 31, 2018, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
145 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2017,"Public Utilities Commission of Ohio, March 20, 2019, <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.
146 "2017 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, March 2018, <https://www.pennaeps.com/annual-reports/>.
147 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2019, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
148 RPS compliance cost information for North Carolina is not available in the North Carolina Utilities Commission annual report on RPS compliance.
149 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[150] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Table 8-23 shows SO_2 emission controls by fossil fuel fired units in PJM.[151] [152] [153] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[154] Of the current 61,780.8 MW of coal capacity in PJM, 57,753.5 MW of capacity, 93.5 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-23 SO_2 emission controls by fuel type (MW): September 30, 2019[155]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	57,753.5	4,027.3	61,780.8	93.5%
Diesel Oil	0.0	4,976.6	4,976.6	0.0%
Natural Gas	0.0	57,390.0	57,390.0	0.0%
Other	136.0	3,219.7	3,355.7	4.1%
Total	57,889.5	69,613.6	127,503.1	45.4%

Table 8-24 shows NO_X emission controls by unit type in PJM. NO_X emission control technology is used by all fossil fuel fired unit types. Of the current fossil fuel fired units in PJM, 119,399.2 MW, 93.6 percent, of 127,503.1 MW of capacity in PJM, have emission controls for NO_X. 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 a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[156]

Table 8-24 NO_X emission controls by fuel type (MW): As of September 30, 2019

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	61,249.3	531.5	61,780.8	99.1%
Diesel Oil	1,298.6	3,678.0	4,976.6	26.1%
Natural Gas	55,974.6	1,415.4	57,390.0	97.5%
Other	876.7	2,479.0	3,355.7	26.1%
Total	119,399.2	8,103.9	127,503.1	93.6%

Table 8-25 shows particulate emission controls by unit type in PJM. Almost all coal units (99.6 percent) in PJM have particulate controls, as well as a few natural gas units (4.9 percent) and units with other fuel sources (35.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[157] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. In PJM, 61,535.8 MW out of 61,780.8 MW, 99.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of September 30, 2019. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[158] 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, 136 of the 151 coal steam units have baghouse or FGD technology installed, representing 55,437.5 MW out of the 61,780.8 MW total coal capacity, or 89.7 percent.

150 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 25, 2019).
151 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed October 17, 2019).
152 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. The most recent complete set of emissions data is from the second quarter of 2019.
153 The total MW are less than the 186,502.9 reported in Section 5: Capacity Market, 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 17, 2019).
154 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 October 28, 2019).
155 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.
156 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed October 23, 2019).
157 See EPA. "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed October 23, 2019).
158 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 23, 2019).

Table 8-25 Particulate emission controls by fuel type (MW): As of September 30, 2019

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	61,535.8	245.0	61,780.8	99.6%
Diesel Oil	0.0	4,976.6	4,976.6	0.0%
Natural Gas	2,786.0	54,604.0	57,390.0	4.9%
Other	1,195.5	2,160.2	3,355.7	35.6%
Total	65,517.3	61,985.8	127,503.1	51.4%

Emissions

Figure 8-13 shows the total CO_2 emissions and the CO_2 emissions per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the second quarter of 2019. Figure 8-13 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the second quarter of 2019.[159] [160] For the period from 1999 through the second quarter of 2019, the minimum CO_2 produced per MWh was 0.72 short tons per MWh in the second quarter of 2019, and the maximum was 0.95 short tons per MWh in the first quarter of 2010. Total PJM generation decreased from 195,055.4 GWh in the second quarter of 2018 to 191,169.9 GWh in the second quarter of 2019, while CO_2 produced decreased from 95.6 million short tons in the second quarter of 2018 to 81.9 million short tons in the second quarter of 2019.[161] The reduction in total CO_2 emissions was primarily the result of a decrease in the use of coal and an increase in the use of natural gas for generation.

159 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
160 Emissions data for the third quarter of 2019 was not yet available at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.
161 See the *2019 Quarterly State of the Market Report for PJM: January through June*. Section 3: Energy Market, Table 3-10.

Figure 8-13 CO_2 emissions by quarter (millions of short tons), by PJM units: 1999 through 2019[162] [163]

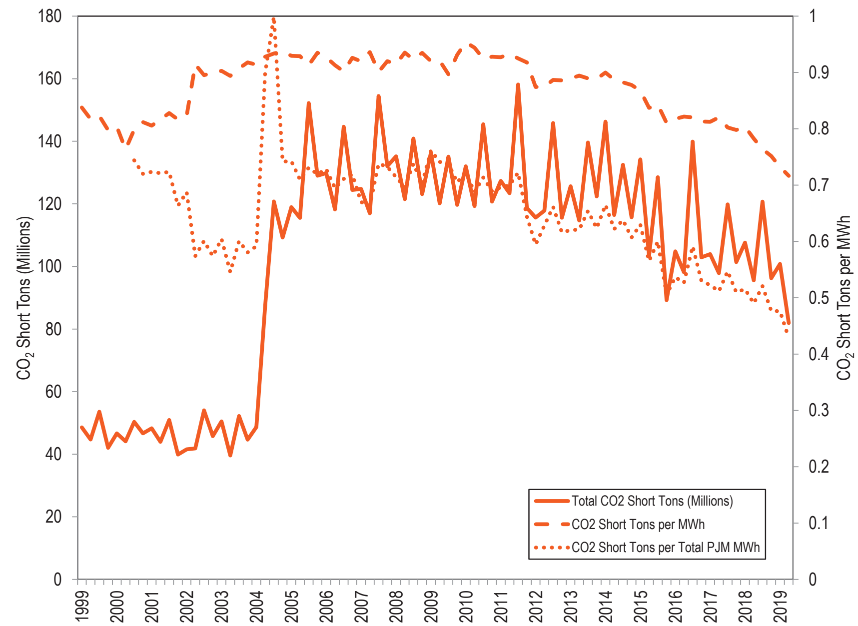


Figure 8-14 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.72 short tons per MWh in the second quarter of 2019, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.71 short tons per MWh in the second quarter of 2019, and a maximum of 0.94 short tons per MWh in the first quarter of 2010. In the second quarter of 2019, CO_2

162 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
163 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).

emissions were 0.72 short tons per MWh for off peak hours and 0.71 for on peak hours.

Figure 8-14 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2019[164]

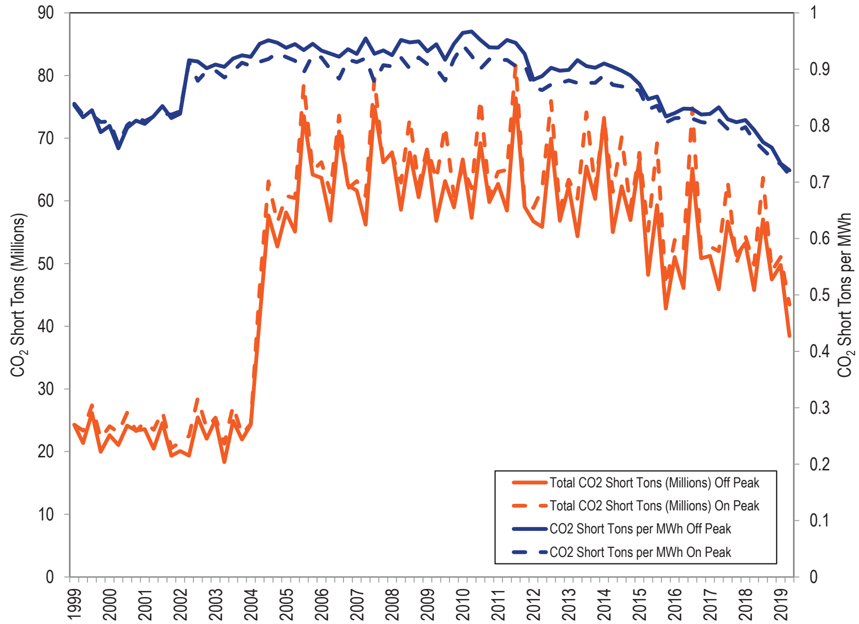


Figure 8-15 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh was 0.000455 short tons per MWh in the second quarter of 2019, and the maximum was 0.008109 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh was at a 0.000329 short tons per MWh in the second quarter of 2019, and the maximum was 0.002290 short tons per MWh in the first quarter of 1999. In the second quarter of 2019, SO_2 emissions were 0.000455 short tons per MWh and NO_X emissions were 0.000329 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, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2019.[165] [166]

Figure 8-15 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through 2019[167]

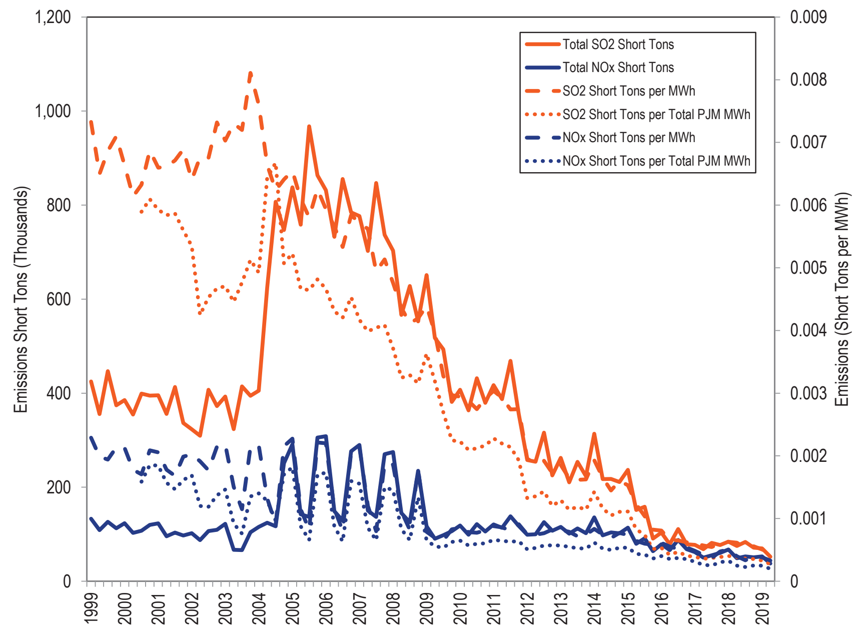


Figure 8-16 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh during off peak hours was 0.000427 short tons per MWh in the second quarter of 2019, and the

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

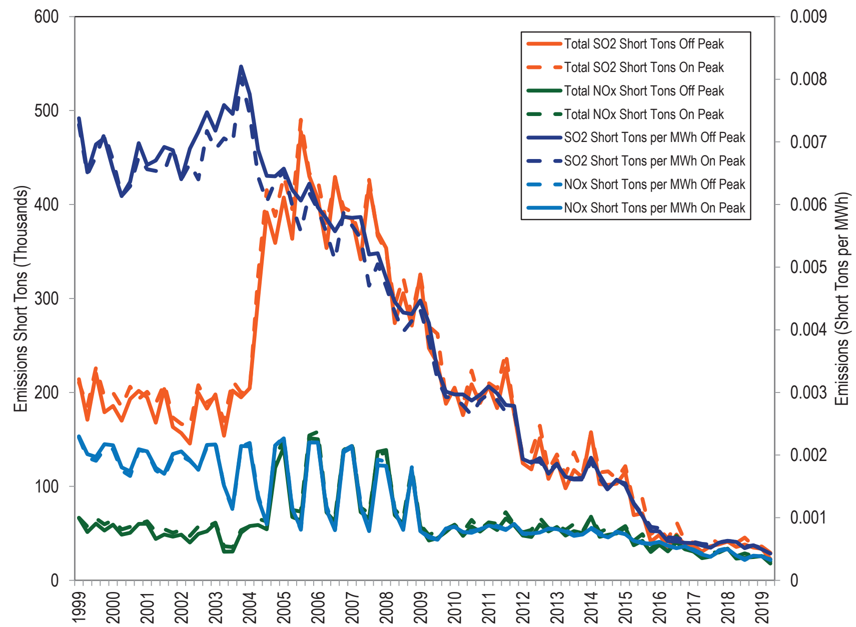
165 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

166 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

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

maximum was 0.008202 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh during on peak hours was 0.000481 short tons per MWh in the second quarter of 2019, and the maximum was 0.008020 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh during off peak hours was 0.000326 short tons per MWh in the third quarter of 2018, and the maximum was 0.002284 short tons per MWh in the first quarter of 2005. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh during on peak hours was 0.000325 short tons per MWh in the second quarter of 2019 and the maximum was 0.002298 short tons per MWh in the first quarter of 1999. In the second quarter of 2019, SO_2 emissions were 0.000427 short tons per MWh and 0.000481 short tons per MWh for off and on peak hours. In the second quarter of 2019, NO_X emissions were 0.000334 short tons per MWh and 0.000325 short tons per MWh for off and on peak hours.

Figure 8-16 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through 2019[168]



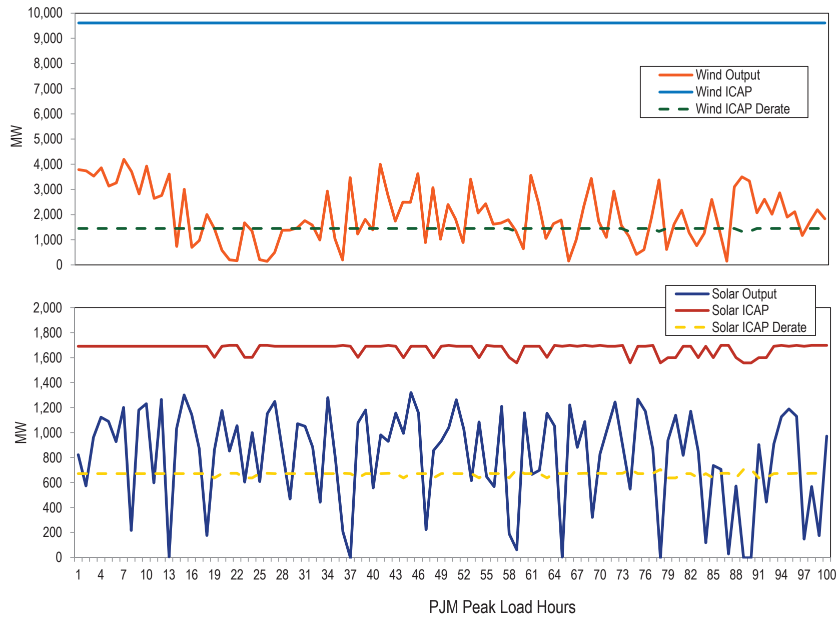
168 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Renewable Energy Output

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 8-17 shows the wind and solar output during the top 100 load hours in PJM for the first nine months of 2019. Of the top 100 load hours in PJM during the first nine months of 2019, 85 are PJM defined peak load hours. 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 capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.[169] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity (ICAP) values. Wind output was above the derated ICAP for 64 hours and below the derated ICAP for 36 hours of the top 100 load hours of the first nine months of 2019. The wind capacity factor for the top 100 load hours of 2018 was 20.4 percent. Wind output was above the derated ICAP for 4,323 hours and below the derated ICAP for 2,228 hours in the first nine months of 2019. The wind capacity factor for the first nine months of 2019 was 30.8 percent. Solar output was above the derated ICAP for 68 hours and below the derated ICAP for 32 hours of the top 100 load hours of the first nine months of 2019. The solar capacity factor for the top 100 load hours of the first nine months of 2019 was 48.6 percent. Solar output was above the derated ICAP for 1,665 hours and below the derated ICAP for 4,886 hours for the first nine months of 2019. The solar capacity factor for the first nine months of 2019 was 25.1 percent.

Figure 8-17 Wind and solar output during the top 100 load hours in PJM: January through September, 2019



Wind Units

Table 8-26 shows the capacity factors of wind units in PJM. In the first nine months of 2019, the capacity factor of wind units in PJM was 31.5 percent. Wind units that were capacity resources had a capacity factor of 30.8 percent and an installed capacity of 8,075 MW. Wind units that were energy only had a capacity factor of 36.5 percent and an installed capacity of 1,547 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[170]

169 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors depend on installation type. PJM. Class Average Capacity Factors Wind and Solar Resources,, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

170 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

Table 8-26 Capacity factor of wind units in PJM: January through September, 2019[171]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	36.5%	1,547
Capacity Resource	30.8%	8,075
All Units	31.5%	9,622

Figure 8-18 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through September 30, 2019. The hour with the highest average output, 4,021 MW, occurred in April, and the hour with the lowest average output, 789 MW, occurred in July. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-18 Average hourly real-time generation of wind units in PJM: January through September, 2019

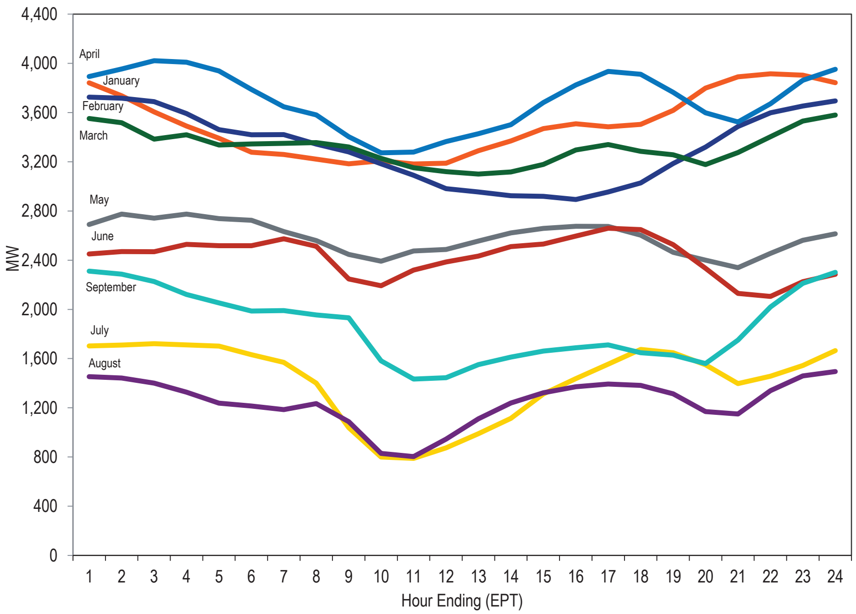


Table 8-27 shows the generation and capacity factor of wind units by month from January 1, 2018, through September 30, 2019.

Table 8-27 Capacity factor of wind units in PJM by month: January 2018 through September 2019

	2018		2019	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,599,270.5	48.0%	2,223,142.4	41.2%
February	1,948,008.3	40.1%	1,882,076.3	38.7%
March	2,146,698.1	41.1%	2,076,120.4	38.0%
April	1,840,728.2	37.2%	2,244,185.1	42.6%
May	1,370,215.9	27.3%	1,635,756.1	30.6%
June	1,010,945.4	21.0%	1,480,459.1	29.0%
July	790,461.6	16.6%	883,538.1	17.0%
August	884,856.3	19.0%	776,254.7	15.9%
September	1,047,738.1	22.0%	1,108,140.3	22.2%
October	1,870,676.4	35.6%		
November	1,835,280.5	36.3%		
December	2,003,254.1	37.0%		
Annual	19,348,133.6	32.2%	14,309,672.5	30.8%

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. Figure 8-19 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

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

Figure 8-19 Average hourly day-ahead generation of wind units in PJM: January through September, 2019

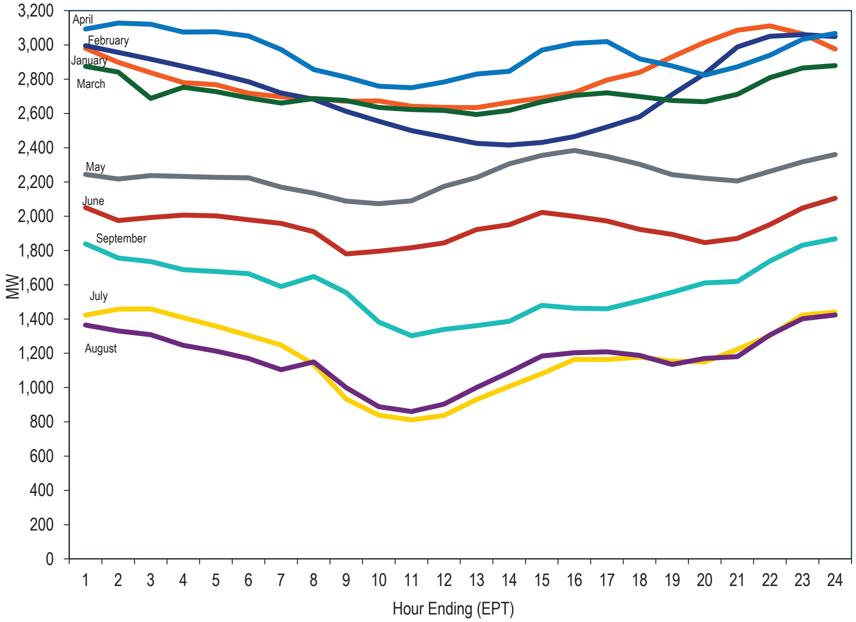
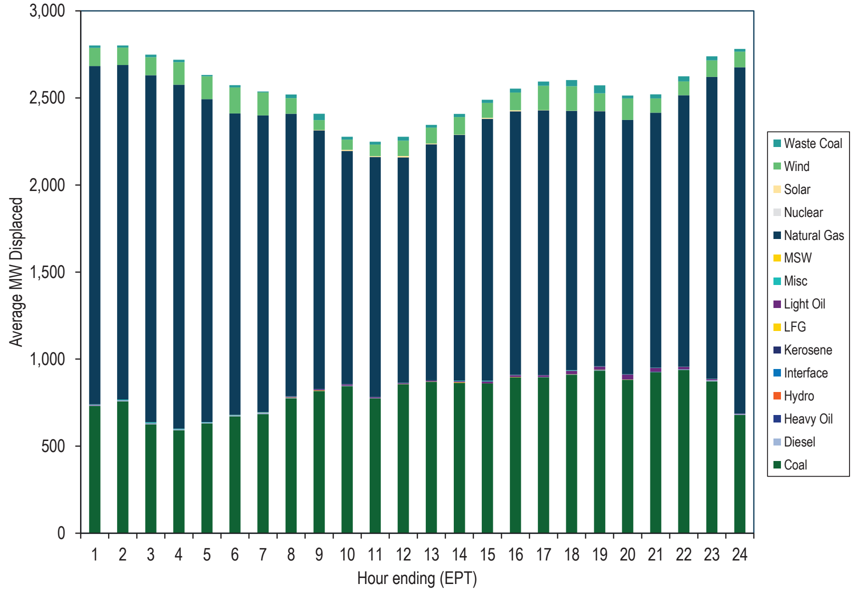


Figure 8-20 Marginal fuel at time of wind generation in PJM: January through September, 2019



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 8-20 and Table 8-28 show 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 2019. 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.

Table 8-28 Marginal fuel MW at time of wind generation in PJM: January through September, 2019

Hour	Coal	Diesel	Heavy Oil	Hydro	Interface	Kerosene	Landfill Gas	Light Oil	Miscellaneous	Solid Waste	Natural Gas	Nuclear	Solar	Wind	Waste Coal	Total
0	730.7	3.3	0.0	0.0	0.0	0.0	0.0	3.6	3.0	0.0	1,942.3	0.0	0.0	104.9	13.6	2,801.5
1	757.3	4.7	0.0	0.0	0.0	0.0	0.0	2.0	3.5	0.0	1,921.9	0.0	0.0	99.7	12.7	2,801.8
2	625.3	3.8	0.0	0.0	0.0	0.8	0.0	1.4	5.9	0.0	1,992.9	0.0	0.0	104.4	14.3	2,748.7
3	591.5	4.8	0.0	0.0	0.0	0.9	0.0	0.0	3.2	0.0	1,975.4	0.0	0.0	129.3	14.4	2,719.6
4	630.2	5.4	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	1,854.5	0.0	0.0	131.6	7.1	2,631.9
5	671.4	4.6	0.0	0.0	0.0	1.0	0.3	0.0	2.8	0.0	1,731.1	0.0	0.0	149.5	12.3	2,573.1
6	684.4	6.3	0.0	0.0	0.0	0.0	0.8	1.4	2.6	0.0	1,704.1	0.0	0.0	132.3	4.9	2,536.8
7	774.8	1.4	0.0	0.0	0.0	1.7	1.6	5.1	1.2	0.0	1,623.6	0.0	0.0	89.3	20.9	2,519.6
8	816.4	0.5	0.0	0.0	0.0	0.0	2.8	7.9	0.9	0.0	1,484.7	0.0	2.6	57.2	36.2	2,409.2
9	844.5	2.8	0.0	0.0	0.0	0.0	0.0	7.6	1.4	0.0	1,338.9	0.0	6.7	58.7	17.0	2,277.5
10	774.0	1.8	0.0	0.0	0.0	0.0	0.0	6.4	0.6	0.0	1,378.0	0.0	5.1	66.0	16.8	2,248.7
11	854.9	0.5	0.2	0.0	0.0	0.0	1.0	5.7	1.5	0.0	1,294.2	0.0	8.7	88.3	22.3	2,277.4
12	869.9	1.1	0.0	0.0	0.0	0.0	0.9	5.7	0.4	0.0	1,355.9	0.0	4.3	91.5	16.0	2,345.7
13	862.7	0.0	0.0	0.0	0.0	0.0	3.5	7.2	2.9	0.0	1,411.4	0.0	1.1	101.3	18.1	2,408.3
14	859.9	0.0	0.0	0.0	0.0	0.0	0.4	11.0	4.5	0.0	1,504.3	0.0	6.0	85.1	18.5	2,489.7
15	894.7	0.0	0.0	0.0	0.0	0.0	1.8	11.3	1.7	0.0	1,513.2	0.0	6.4	102.1	22.8	2,553.9
16	895.6	1.0	0.0	0.0	0.0	0.5	0.0	11.1	0.3	0.0	1,520.0	0.0	1.0	140.0	24.7	2,594.3
17	910.3	1.3	0.0	0.0	0.0	1.2	1.4	19.0	2.9	0.0	1,489.8	0.0	0.3	141.5	34.9	2,602.5
18	933.7	2.7	0.0	0.0	0.0	2.4	0.9	17.4	2.0	0.0	1,464.4	0.0	1.1	102.5	45.5	2,572.7
19	880.8	1.5	0.0	0.0	0.0	0.0	0.7	28.0	1.8	0.0	1,460.8	0.0	0.0	124.0	15.7	2,513.3
20	924.7	0.5	2.4	0.0	0.0	0.5	0.0	21.0	1.5	0.0	1,464.8	0.0	0.0	81.9	23.2	2,520.6
21	937.0	4.0	1.2	0.0	0.0	0.4	0.0	13.1	0.5	0.0	1,559.4	0.0	0.0	79.6	29.2	2,624.4
22	872.4	6.1	0.0	0.0	0.0	0.0	0.0	6.9	1.4	0.0	1,734.1	0.0	0.0	95.2	23.5	2,739.6
23	679.3	3.8	0.0	0.0	0.0	0.0	0.0	3.7	0.6	0.0	1,988.8	0.0	0.0	89.9	15.2	2,781.3
Average	803.2	2.6	0.2	0.0	0.0	0.4	0.7	8.2	2.1	0.0	1,612.8	0.0	1.8	101.9	20.0	2,553.8

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 8-15, there are 1,964.0 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-16, there are 5,862.0 MW capacity of solar registered in GATS that are not PJM units. 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. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-29 shows the capacity factor of solar units in PJM. In the first nine months of 2019, the capacity factor of solar units in PJM was 25.1 percent. Solar units that were capacity resources had a capacity factor of 25.1 percent and an installed capacity of 1,457 MW. Solar units that were energy only had a capacity factor of 25.6 percent and an installed capacity of 253 MW. Solar capacity in RPM is derated to 42.0, 60.0 or 38.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[172]

Table 8-29 Capacity factor of solar units in PJM: January through September, 2019

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	25.6%	253
Capacity Resource	25.1%	1,457
All Units	25.1%	1,711

Figure 8-21 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 1,148 MW, occurred in July, and the hour with the lowest peak average output, 624 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-21 Average hourly real-time generation of solar units in PJM: January through September, 2019

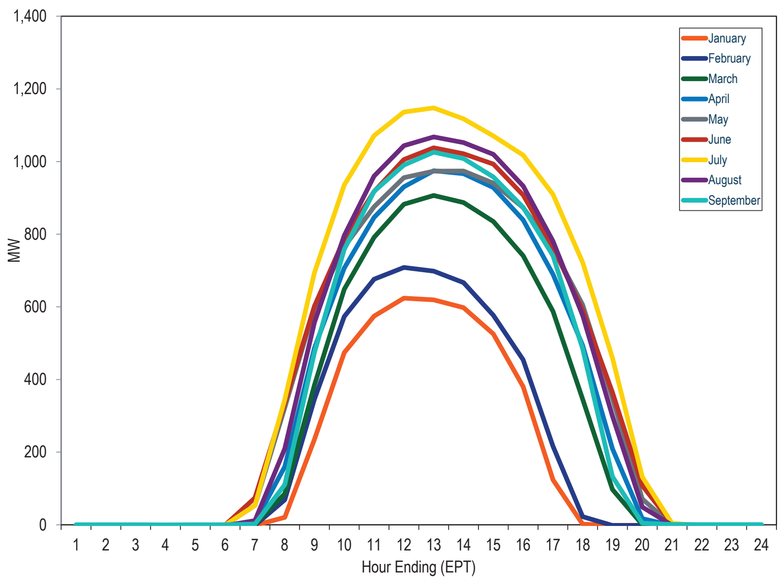


Table 8-30 shows the generation and capacity factor of solar units by month from January 1, 2018, through September 30, 2019.

Table 8-30 Capacity factor of solar units in PJM by month: January 2018 through September 2019

	2018		2019	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	102,186.2	15.4%	119,064.3	14.4%
February	90,326.9	14.2%	127,466.5	16.4%
March	159,409.4	22.4%	205,113.4	23.3%
April	201,417.3	28.2%	229,624.5	26.8%
May	203,063.6	27.3%	265,474.8	28.9%
June	222,228.7	30.6%	264,942.6	29.2%
July	220,650.2	29.4%	299,008.8	31.5%
August	217,755.2	28.9%	250,827.5	27.3%
September	142,705.9	21.0%	220,408.0	25.1%
October	156,045.7	21.4%		
November	113,801.1	15.3%		
December	96,445.7	12.6%		
Annual	1,926,036.0	22.3%	1,981,930.4	25.1%

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. Figure 8-22 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[173]

172 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

173 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 8-22 Average hourly day-ahead generation of solar units in PJM: January through September, 2019