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 affected offer behavior in the capacity market. Expectations about the cost and life of such investments and about future capacity and energy prices have affected retirement decisions. The markets have also provided incentives for new, lower emissions units to enter.

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 if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

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] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[2] The list of coal steam units subject to MATS, however, remains in place.[3] 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.[4]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[5] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **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.[6] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to

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 *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, 85 Fed. Reg. 31286.

3 *Id.* at 31291.

4 CAA § 110(a)(2)(D)(i)(I).

5 *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).

6 See 40 CFR § 63.6640(f).

© 2020 Monitoring Analytics, LLC

100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan[7] 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.[8] Under the ACE Rule states may permit more CO_2 emissions than under the Clean Power Plan.
- **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.[9]
- **Waters of the United States.** The EPA finalized a rule that significantly narrows the definition of the Waters of the United States. In contrast, the Supreme Court expanded the scope of the CWA when it held that discharge of pollutants from a point source into non jurisdictional groundwater "is the functional equivalent of a direct discharge" when pollutants are conveyed by groundwater into jurisdictional waters.[10]

7 *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.

8 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).

9 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).

10 *County of Maui v. Hawaii Wildlife Fund*, Slip. Op. No. 18–260 (April 23, 2020).

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[11] The EPA has proposed significant changes to the implementing regulations.

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 rejoined on January 1, 2020.[12] Virginia and Pennsylvania are preparing to join.[13] [14] The auction price in the September 2, 2020, auction for the 2018/2020 compliance period was $6.82 per ton, or $7.52 per metric tonne.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.52 per MWh or 132.5 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 130.3 percent for a new combined cycle (CC) unit and $43.15 per MWh or 158.6 percent for a new coal plant (CP) in 2020.

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, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia did not have renewable portfolio standards.

11 42 U.S.C. §§ 6901 *et seq.*

12 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019).<https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

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

14 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/>.

© 2020 Monitoring Analytics, LLC

- **RPS Cost.** The cost of complying with RPS, as reported by the states, is \$4.5 billion over the five year period from 2014 through 2018, an average annual RPS compliance cost of \$893.1 million. The compliance cost for 2018, the most recent year with complete data, was \$986.9 million.

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.** In PJM, as of September 30, 2020, 93.9 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.9 percent of coal steam MW had some type of particulate control, and 94.8 percent of fossil fuel fired capacity 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.** Wind and solar generation was 4.3 percent of total generation in PJM in the first nine months of 2020. RPS Tier I generation was 5.0 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM in the first nine months of 2020. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.

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 PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. 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 in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 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.[15] The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets

15 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.").

© 2020 Monitoring Analytics, LLC

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. FERC's recent MOPR order addressed these impacts.

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 on behalf of the states 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 provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to states in order to permit states to 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.

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 $6.33 per tonne in Washington, DC to $18.22 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $62.89 per tonne in Pennsylvania to $878.57 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2020 of $7.52 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[16] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.71 per MWh.[17] The impact of an $800 per tonne carbon price would be $267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

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

16 "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>.

17 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 the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-18.

© 2020 Monitoring Analytics, LLC

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. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. Such modeling information would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state. This would permit states to make critical decisions about carbon pricing. For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. 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 five year period from 2014 through 2018 for the nine jurisdictions that had RPS was $893.1 million, or a total of $4.5 billion over five years. The RPS compliance cost for 2018, the most recent year for which there is complete data, was $986.9 million. RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

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 $2.5 billion per year if the carbon price were $6.82 per short ton and emissions levels were five percent below 2019 emission levels. 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 $18.0 billion if the carbon price were $50 per short ton and emission levels were five percent below 2019 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $6.82 per short ton would be about $1.4 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the 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.[18]

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.[19] [20]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[21] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

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.

18 For more details, see the *2019 State of the Market Report for PJM*, Vol. 2, Appendix H: "Environmental and Renewable Energy Regulations."
19 42 U.S.C. § 7401 et seq. (2000).
20 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.
21 42 U.S.C. §§ 6901 *et seq.*

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.

On May 22, 2020, the EPA published a rule finalizing its Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.[22] The EPA determined that the estimated cost to coal and oil fired power plants of complying with the MATS rule in 2015 outweighed the estimated quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions in 2015.[23] The EPA determined 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] Removal of the appropriate and necessary finding creates the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On April 9, 2020, the EPA finalized a rule establishing a new sub category in the MATS with less stringent requirements for units fueled by eastern bituminous refuse coal, waste coal.[27] The rule allows four refuse coal plants, Grant Town Power Plant (Unit 1A and 1 B (40 MW each)) in West Virginia; and Colver Power Project (110 MW), Ebensburg Power Plant (50 MW), and Scrubgrass Generating Co. (Units 1 and 2 (42 MW each)) in Pennsylvania; to emit higher levels of acid gases and SO_2.[28] The EPA stated that it was concerned that units would close and leave coal refuse piles, which are prone to smoldering and emit uncontrolled acid gases and other HAP.[29]

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. 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. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[30]

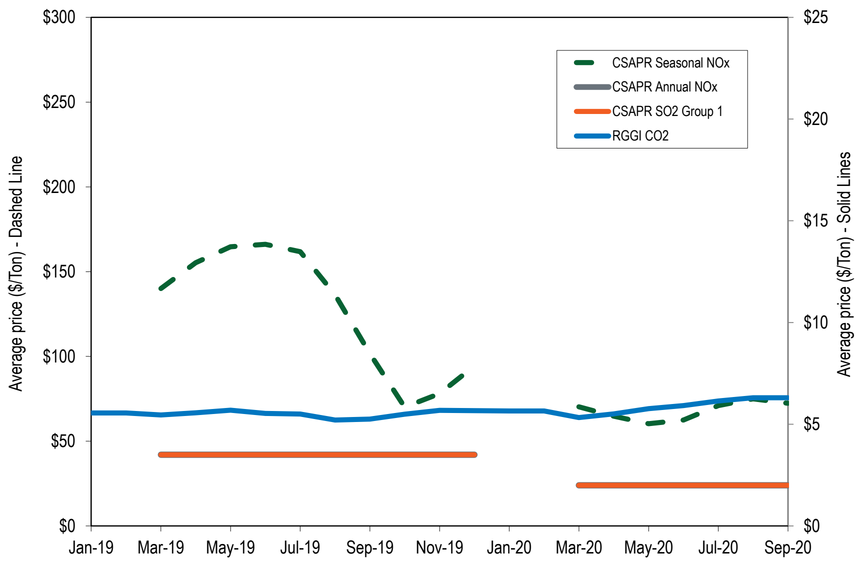
Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for January 1, 2019, through September 30, 2020. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

22 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, 85 Fed. Reg. 31286.
23 *Id.* at 31299.
24 Michigan v. EPA, 135 S.Ct. 2699 (2015) (reversed EPA determination that cost does not have to be read into the definition of "appropriate").
25 85 Fed. Reg. at 31288.
26 *Id.* at 31291. The EPA explains (*id.*): "The Court's holding in *New Jersey* [517 F.3d 574 (D.C. Cir. 2008)] plainly states that CAA section 112(c)(9) 'unambiguously limit[s] EPA's discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.' 517 F.3d 574, 583 (D.C. Cir. 2008)."
27 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Subcategory of Certain Existing Electric Utility Steam Generating Units Firing Eastern Bituminous Coal Refuse for Emissions of Acid Gas Hazardous Air Pollutants*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 20838 (April 15, 2020).
28 *Id.* at 20841.
29 *Id.* at 20847.
30 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. 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. On May 15, 2020, the Court denied an appeal of the EPA decision filed by Maryland, except that the Court agreed that EPA did not sufficiently support its rejection based on the cost effectiveness of Maryland's request that two waste coal plants, Cambria Cogeneration (Pa.) and Grant Town Cogen (W.Va.), be required to operate selective noncatalytic reduction (SNCR) controls, and remanded the decision. Maryland v. Wheeler, Case No. 18-1285 (D.C. Cir May 19, 2020).

© 2020 Monitoring Analytics, LLC

In the first nine months of 2020, CSAPR annual NO_x prices were 42.9 percent lower than in the first nine months of 2019. In the first nine months of 2020, CSAPR Seasonal NO_x prices were 53.6 percent lower than in the first nine months of 2019.

Figure 8-1 Spot monthly average emission price comparison: January 2019 through September 2020



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 from inhibiting progress in areas that do not.[31] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[32]

31 42 U.S.C § 7470 et seq.

32 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second part considers whether any identified increase is also a "significant net emission increase."

On August 1, 2019, the EPA proposed revisions to the NSR permitting program under which, both emissions increases and decreases from a major modification would be considered in the first part of the NSR applicability test.[33] Under the revised rule the need for a permit and associated investments in pollution controls would be more frequently avoided than under the current rule.

The ACE rule as proposed on August 21, 2018, also included changes to NSR regulations.[34] These proposed NSR changes have been deferred to a separate future action.[35] 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 part 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. If accepted, fewer projects would be evaluated under the NSR analysis to determine whether an NSR permit is needed.

On March 25, 2020, the EPA released a memorandum changing the EPA's longstanding interpretation of "begin actual construction" under the NSR preconstruction permitting regulations.[36] [37] EPA policy has been to preclude almost every physical onsite construction activity that is of a permanent nature prior to issuance of a permit. Under the new interpretation, which focuses on the statutory meaning of "emissions unit,"[38] the policy precludes

33 *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).

34 82 Fed. Reg. 48035.

35 84 Fed. Reg. 32520, 32521.

36 See Anne L. Idsal, Principal Deputy Assistant Administrator, Memorandum re Interpretation of "Begin Actual Construction" Under the New Source Review Preconstruction Permitting Regulations" ("March 25th Memo").

37 See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).

38 40 CFR § 52.21(b)(7) ("any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit…").

© 2020 Monitoring Analytics, LLC

only the construction of the emissions unit. The EPA clarified that the costs and consequences of pre permit construction are risks born by the owner/operators if no permit issues, or issues without the expected terms or conditions. The new interpretation significantly expands the scope of activity that an owner/operator willing to assume the risks may undertake prior to receiving an NSR permit when constructing a project that will include an emissions unit.

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.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[39] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. There are 785.9 MW of diesel RICE, 86.8 percent of registered diesel generators in demand response, that do not meet EPA emissions standards that are included in PJM DR portfolios but should not be. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate.

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[40] [41]

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."[42] 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.[43] 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.

Effective October 23, 2015, the EPA placed national limits on the amount of CO_2 that new, modified or reconstructed fossil fuel fired steam power plants

39 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

40 See CAA § 111.

41 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.

42 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).

43 *Id.*

© 2020 Monitoring Analytics, LLC

would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).[44] On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[45]

On June 19, 2019, the EPA repealed the Clean Power Plan[46] and replaced it with the Affordable Clean Energy (ACE) rule.[47]

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 allows states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard.[48] As a result, the impact on coal fired generation depends upon actions taken in their host state. Under the ACE Rule states may permit more CO_2 emissions than under the Clean Power Plan.

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).[49] [50]

On October 22, 2019, the EPA issued a final rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule. The rule prevents 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.[51] 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.[52]

On April 21, 2020, the EPA and the Department of the Army published a final rule to define WOTUS, the Navigable Waters Protection Rule ("NWPR").[53] The NWPR became effective in PJM states on June 22, 2020. The replacement rule significantly narrows the scope of federal jurisdiction. The replacement rule does not include coal ash ponds in the definition of WOTUS.[54] Environmental groups have filed complaints seeking to overturn the NWPR, including in federal district court in Maryland.[55]

The scope of the CWA has expanded and the precise definition of WOTUS has become less important as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[56] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[57] This holding invalidates the EPA's recent interpretive statement intended to establish a bright line rule excluding all releases of pollutants to groundwater from the permitting program.[58] The EPA may not interpret the CWA to require a direct discharge.[59] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[60] The existence of a functional discharge will depend on an

44 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) ("2015 GHG NSR Rule"); 40 CFR Part 60, subpart TTTT.

45 *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA–HQ–OAR–2013–0495; FRL–9987–85– OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) ("2018 Proposed Rev. GHG NSR").

46 *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.

47 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").

48 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.

49 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.").

50 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."

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

52 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).

53 See *The Navigable Waters Protection Rule: Definition of "Waters of the United States,"* EPA Docket No. EPA–HQ–OW–2018–0149, 85 Fed. Reg. 22250.

54 *Id.* at 22251–22252.

55 See Chesapeake Bay Foundation et al. v. Wheeler et al., Case 1:20-cv-01064-GLR (USDC Dist. of Md.).

56 Slip. Op. No. 18–260 (April 23, 2020).

57 *Id.*

58 *See Interpretive Statement on Application of the Clean Water Act National Pollutant Discharge Elimination System Program to Releases of Pollutants From a Point Source to Groundwater*, 84 Fed. Reg. 16810 (April 23, 2019).

59 Slip. Op. No. 18–260 at 5.

60 *Id.* at 1.

analysis including time and distance, and other factors.[61] Additional litigation or administrative action may clarify the functional discharge analysis.[62] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[63]

Discharges and Intakes

The EPA regulates discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[64]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[65] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. 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.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[66] 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.

61 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").

62 *Id.*

63 *See id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").

64 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix I: "Environmental and Renewable Energy Regulations."

65 42 U.S.C. §§ 6901 *et seq.*

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

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[67]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[68]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

67 The Water Infrastructure Improvements for the Nation Act (WIIN Act).

68 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).

© 2020 Monitoring Analytics, LLC

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[69] On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[70] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[71] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented." Utilities may obtain an automatic extension to November 30, 2020, upon certification of need for additional time. Upon receipt of required documentation satisfying certain criteria, the EPA may grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[72]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.[73] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of a coal ash permitting program.

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions.[74] In 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[75] Effective July 1, 2019, coal ash ponds at power stations in the Chesapeake Bay Watershed had to be closed by removal of coal ash. The removed coal ash either had to be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

On March 30, 2020, in response to a statutory mandate,[76] the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[77] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The proposed rules include a permitting program and are intended to meet federal standards.[78] Presumably the rules, once finalized, would be the basis for an application under RCRA allowing the Illinois EPA to also administer the federal regulatory program. The Illinois EPA has identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[79] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[80]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluents guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[81] On May

69 Utility Solid Waste Activities Group, et al. v. EPA, No. 15-1219 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).

70 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA–HQ–OLEM–2019–0172; FRL–10002– 02–OLEM, 85 Fed. Reg. 53516 (August 28, 2020).

71 *Id.* at 53516–53517, 53536.

72 *Id.*

73 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Federal CCR Permit Program*, 85 Fed. Reg. 9940 (Feb. 20, 2020).

74 The following Virginia power stations host coal ash ponds: Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, Clinch River Plant and Possum Point Power Station, owned by Dominion Energy; and Glen Lyn Plant, owned by Appalachian Power.

75 Va. Code § 10.1-1402.03.

76 Ill. Public Act 101-171 (a.k.a. SB 09).

77 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.

78 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845) ("Proposed Illinois CCR Rules").

79 Proposed Illinois Rules at 3.

80 *Id.* at 3.

81 See Potomac Riverkeeper Network, Press Release, "Maryland Proposes to Reject Effort to Delay Pollution Reductions" (Posted April 4, 2020), <https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>.

© 2020 Monitoring Analytics, LLC

15, 2020, GenOn announced its decision to start the retirement process for the Dickerson Generating Station, citing "unfavorable economic conditions and increased costs associated with environmental compliance."[82] On July 28, 2020, the MDE extended the permit to November 23, 2023.[83]

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[84]

- **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.

82 See "GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant," (May 15, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>.
83 MDE, Final Determination for GenOn Dickerson Generating Station State Discharge Permit Application 14DP0048A, NPDES Permit MD0002640 Montgomery County.
84 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix I: "Environmental and Renewable Energy Regulations."

State Regulation of Greenhouse Gas Emissions

Clean Energy Standards

In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[85] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[86] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[87]

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[88]

Delaware and Maryland are the only PJM states that were members of RGGI in 2019. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[89] Other PJM states have expressed interest in joining RGGI. The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI on January 1, 2021.[90] Virginia's RGGI rules were finalized in July 2020 and Virginia will begin participating in RGGI on January 1, 2021.[91] Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental

85 Va. HB 1526/SB 851.
86 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
87 *Id.*
88 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>.
89 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
90 See 9VAC5-140-6010-6430.
91 "RGGI States Welcome Virginia as Its CO_2 Regulation is Finalized," RGGI Inc., (July 8, 2020) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2020_07_08_VA_Announcement_Release.pdf>.

© 2020 Monitoring Analytics, LLC

Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.[92] The Pennsylvania Environmental Quality Board (EQB), on September 15, 2020, approved a draft regulation developed by the Pennsylvania Department of Environmental Protection (DEP) that governs Pennsylvania's entry into RGGI in 2022. The draft regulation will be subject to public comment and then the DEP will hold a series of hearings prior to submitting a final regulation to the EQB.[93] The order also directs DEP to "engage with PJM Interconnection to promote the integration of this program in a manner that preserves orderly and competitive economic dispatch within PJM and minimizes emissions leakage."

Table 8-1 shows the RGGI CO_2 auction clearing prices and quantities for the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of September 2, 2020, in short tons and metric tonnes.[94] Prices for auctions held September 2, 2020, were $6.82 per allowance (equal to one short ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[95] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the last auction clearing price of $5.75 in June 2020.

Table 8-1 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2015/2018 and 2018/2020 Compliance Periods[96]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
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
December 4, 2019	$5.61	13,116,444	13,116,444	$6.18	11,899,041	11,899,041
March 11, 2020	$5.65	16,208,347	16,208,347	$6.23	14,703,969	14,703,969
June 3, 2020	$5.75	16,336,298	16,336,298	$6.34	14,820,045	14,820,045
September 2, 2020	$6.82	16,192,785	16,192,785	$7.52	14,689,852	14,689,852

RGGI auctions generated $259.9 million in auction revenue in the first nine months of 2020 and have generated $3.7 billion in auction revenue since 2008.[97] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2017 reporting year, have spent approximately 58 percent of the revenue on energy efficiency, 14 percent on clean and renewable energy, 8 percent on greenhouse gas abatement and 14 percent on direct bill assistance.[98]

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

92 Executive Order No. 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor (Oct. 3, 2019), <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

93 "Environmental Quality Board Approves Proposed Climate Change Regulation," DEP Newsroom, (September 15, 2020) <https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21865&typeid=1>.

94 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.

95 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).

96 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2020).

97 See Auction Results at <https://www.rggi.org/>.

98 *The Investment of RGGI Proceeds in 2017*, The Regional Greenhouse Gas Initiative (RGGI), October 2019, <https://www.rggi.org/investments/proceeds-investments>.

2019 CO_2 emission levels and the RGGI clearing price for the September 2020 auction ranges from $1.3 billion per year to $2.5 billion per year depending on associated reductions in carbon emission levels (Table 8-2).[99] Table 8-2 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2019 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-2 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2019 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose 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.[100]

Table 8-2 Estimated CO_2 allowance revenue at September 2020 RGGI price level[101] [102]

		Estimated CO_2 allowance revenue ($ millions), carbon price $6.82 per short ton					
Jurisdiction	2019 power generation CO_2 emissions (short tons)	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
Delaware	2,007,608.3	$13.0	$12.3	$11.6	$11.0	$10.3	$6.8
Illinois	27,218,451.4	$176.3	$167.1	$157.8	$148.5	$139.2	$92.8
Indiana	39,583,687.7	$256.5	$243.0	$229.5	$216.0	$202.5	$135.0
Kentucky	27,571,710.2	$178.6	$169.2	$159.8	$150.4	$141.0	$94.0
Maryland	13,176,745.0	$85.4	$80.9	$76.4	$71.9	$67.4	$44.9
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	15,820,055.8	$102.5	$97.1	$91.7	$86.3	$80.9	$53.9
North Carolina	114,473.8	$0.7	$0.7	$0.7	$0.6	$0.6	$0.4
Ohio	79,400,173.0	$514.4	$487.4	$460.3	$433.2	$406.1	$270.8
Pennsylvania	82,719,699.4	$535.9	$507.7	$479.5	$451.3	$423.1	$282.1
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	31,030,859.6	$201.0	$190.5	$179.9	$169.3	$158.7	$105.8
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	61,130,636.7	$396.1	$375.2	$354.4	$333.5	$312.7	$208.5
Total	379,774,100.9	$2,460.6	$2,331.1	$2,201.6	$2,072.0	$1,942.5	$1,295.0

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-3 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. The 2020 compliance year is the third year of the fourth control period.

In 2014, RGGI began adjusting the emission cap to account for banked allowances from previous control periods.[103] At the end of the first control period, 57,449,495 banked allowances were held by market participants.[104] 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 budget, brings the overall cap adjustment to 8,207,664 allowances per year.[105] A second cap adjustment,

99 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.
100 "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/20190617a.shtml>.
101 The 2019 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.
102 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 8-2 do not reflect offset allowances.
103 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.
104 "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>.
105 *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.

 © 2020 Monitoring Analytics, LLC

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.[106] The RGGI clearing price since 2014 has been on average 104.5 percent higher than the prices prior to the emission cap adjustments.

Table 8-3 RGGI emissions cap history[107 108]

	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	$5.43	80,179,708	(2.5%)	58,288,301	(3.4%)
2020		$6.07	96,175,215	19.9%	74,283,807	27.4%

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-4 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 $18.0 billion if the carbon price were $50 per short ton and emission levels were five percent below 2019 levels. Allowance revenues to states would be $1.9 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2019.

106 "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>.

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

108 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

Table 8-4 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
Jurisdiction	Carbon Price ($ per short ton)				$10.00	
Delaware	$19.1	$18.1	$17.1	$16.1	$15.1	$10.0
Illinois	$258.6	$245.0	$231.4	$217.7	$204.1	$136.1
Indiana	$376.0	$356.3	$336.5	$316.7	$296.9	$197.9
Kentucky	$261.9	$248.1	$234.4	$220.6	$206.8	$137.9
Maryland	$125.2	$118.6	$112.0	$105.4	$98.8	$65.9
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$150.3	$142.4	$134.5	$126.6	$118.7	$79.1
North Carolina	$1.1	$1.0	$1.0	$0.9	$0.9	$0.6
Ohio	$754.3	$714.6	$674.9	$635.2	$595.5	$397.0
Pennsylvania	$785.8	$744.5	$703.1	$661.8	$620.4	$413.6
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$294.8	$279.3	$263.8	$248.2	$232.7	$155.2
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$580.7	$550.2	$519.6	$489.0	$458.5	$305.7
Total	$3,607.9	$3,418.0	$3,228.1	$3,038.2	$2,848.3	$1,898.9
	Carbon Price ($ per short ton)				$25.00	
Delaware	$47.7	$45.2	$42.7	$40.2	$37.6	$25.1
Illinois	$646.4	$612.4	$578.4	$544.4	$510.3	$340.2
Indiana	$940.1	$890.6	$841.2	$791.7	$742.2	$494.8
Kentucky	$654.8	$620.4	$585.9	$551.4	$517.0	$344.6
Maryland	$312.9	$296.5	$280.0	$263.5	$247.1	$164.7
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$375.7	$356.0	$336.2	$316.4	$296.6	$197.8
North Carolina	$2.7	$2.6	$2.4	$2.3	$2.1	$1.4
Ohio	$1,885.8	$1,786.5	$1,687.3	$1,588.0	$1,488.8	$992.5
Pennsylvania	$1,964.6	$1,861.2	$1,757.8	$1,654.4	$1,551.0	$1,034.0
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$737.0	$698.2	$659.4	$620.6	$581.8	$387.9
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,451.9	$1,375.4	$1,299.0	$1,222.6	$1,146.2	$764.1
Total	$9,019.6	$8,544.9	$8,070.2	$7,595.5	$7,120.8	$4,747.2
	Carbon Price ($ per short ton)				$50.00	
Delaware	$95.4	$90.3	$85.3	$80.3	$75.3	$50.2
Illinois	$1,292.9	$1,224.8	$1,156.8	$1,088.7	$1,020.7	$680.5
Indiana	$1,880.2	$1,781.3	$1,682.3	$1,583.3	$1,484.4	$989.6
Kentucky	$1,309.7	$1,240.7	$1,171.8	$1,102.9	$1,033.9	$689.3
Maryland	$625.9	$593.0	$560.0	$527.1	$494.1	$329.4
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$751.5	$711.9	$672.4	$632.8	$593.3	$395.5
North Carolina	$5.4	$5.2	$4.9	$4.6	$4.3	$2.9

Table 8-4 Estimated CO_2 allowance revenue at various carbon prices (cont'd)

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
Jurisdiction	Carbon Price ($ per short ton)				$50.00	
Ohio	$3,771.5	$3,573.0	$3,374.5	$3,176.0	$2,977.5	$1,985.0
Pennsylvania	$3,929.2	$3,722.4	$3,515.6	$3,308.8	$3,102.0	$2,068.0
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,474.0	$1,396.4	$1,318.8	$1,241.2	$1,163.7	$775.8
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,903.7	$2,750.9	$2,598.1	$2,445.2	$2,292.4	$1,528.3
Total	$18,039.3	$17,089.8	$16,140.4	$15,191.0	$14,241.5	$9,494.4

Table 8-5 shows the estimated impact of five 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 2020 would have increased by 7.6 percent.[109]

Table 8-5 Estimated impact of Carbon price on LMP: January through September, 2019 and 2020

		2019 (Jan - Sep)			2020 (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	$27.60	$28.22	2.3%	$21.23	$22.85	7.6%
Scenario 2	$10.00	$27.60	$28.91	4.8%	$21.23	$24.67	16.2%
Scenario 3	$15.00	$27.60	$29.60	7.3%	$21.23	$26.49	24.8%
Scenario 4	$25.00	$27.60	$30.55	10.7%	$21.23	$30.13	41.9%
Scenario 5	$50.00	$27.60	$33.56	21.6%	$21.23	$39.23	84.8%

109 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

© 2020 Monitoring Analytics, LLC

Table 8-6 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[110] [111] 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 8-6 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 8-7 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 $183.47 per MWh for the first nine months of 2020. 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 slightly less than $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.

Applying this method to tier I and class I REC and SREC price histories yields the implied carbon prices in Table 8-7. The carbon price implied by the average REC price for the first nine months of 2020 in Washington, DC is $6.33 per tonne which is consistent with the average 2020 RGGI clearing price of $6.69 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[112] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

110 Heat rates from: *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.
111 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 March 9, 2020).
112 "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>.

Table 8-7 Implied carbon price based on REC and SREC prices: 2009 through 2020[113]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Jurisdiction with Tier I or Class I REC	Carbon Price ($ per tonne) Implied by REC Prices											
Delaware					$34.15	$35.17	$31.91	$32.91	$10.26	$11.57	$16.05	
Maryland	$2.07	$1.92	$3.06	$6.34	$17.46	$28.45	$29.18	$26.09	$23.12	$21.28	$17.73	$17.56
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.01	$19.18	$18.22
Ohio						$10.16	$8.52	$5.29	$6.27	$11.17	$13.79	$13.94
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$28.88	$26.35	$23.35	$21.47	$17.88	$17.71
Washington, D.C.							$3.19	$4.04	$4.88	$4.68	$5.50	$6.33
Jurisdiction with Solar REC	Carbon Price ($ per 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	$251.23	$183.09	$127.67	$87.00	$82.77	$79.36
New Jersey	$1,372.37	$1,352.15	$1,309.00	$537.08	$345.94	$326.21	$388.73	$424.21	$459.21	$445.00	$409.08	$374.10
Ohio						$82.32	$45.12	$36.15	$31.82			
Pennsylvania	$610.05	$590.57	$378.67	$101.80	$68.34	$75.90	$66.89	$55.06	$43.84	$28.07	$49.52	$62.89
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$840.35	$848.82	$878.57
Regional Greenhouse Gas Initiative	CO_2 Allowance Price ($ per tonne)											
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$6.69

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 must pay penalties (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).[114] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2020, Virginia and Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties.[115] Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard

113 There were no trades in 2018 and 2019 for Ohio SRECs available in the Evomarkets data.

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

115 Effective January 1, 2021 the Virginia voluntary RPS is being replaced with a mandatory RPS.

© 2020 Monitoring Analytics, LLC

was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[116]

As of September 30, 2020, Kentucky, Tennessee and West Virginia have no renewable portfolio standards.

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 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.[117]

Table 8-8 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 Renewable and alternative energy standards of PJM jurisdictions: 2020 to 2030[118 119]

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Illinois	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	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%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	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%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)		6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)		14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	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%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Virginia	7.00%										
Jurisdiction with No Standard											
Kentucky	No Renewable Portfolio Standard										
Tennessee	No Renewable Portfolio Standard										
West Virginia	No Renewable Portfolio Standard										

On April 11, 2020, the Virginia legislature passed a new law that replaces Virginia's current voluntary renewable portfolio standard (RPS) with a mandatory RPS.[120] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[121 122] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II

116 See the Indiana Utility Regulatory Commission's "2020 Annual Report," at 41 (Oct. 2020) <https://www.in.gov/iurc/2981.htm>.
117 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
118 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
119 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.
120 See "Virginia Clean Economy Act,"(April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
121 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).
122 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS

utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[123] 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. Table 8-9 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington DC.

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.[128] 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).[129] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[130] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.[131] [132]

Table 8-9 Recent changes in RPS rules[124] [125] [126] [127]

Jurisdiction	Legislation	Effective Date	Summary of changes
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermiate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
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.

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

124 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

125 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

126 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.

127 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>.

128 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.

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

130 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

131 BPU Docket No. QO18080851.

132 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

© 2020 Monitoring Analytics, LLC

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. Deepwater Wind has since been acquired by Orsted.[133] These project awards are the first under Maryland's 2010 OREC program.

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[134] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[135]

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, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[136] 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 8-10 shows the Tier I standards for PJM states.[137] All eligible technologies for the RPS standards in Table 8-10 satisfy the EIA definition of renewable energy.[138]

133 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).
134 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.
135 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.
136 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.
137 This includes New Jersey's Class I renewable standard.
138 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

Table 8-10 Tier I / Class I renewable standards of PJM jurisdictions: 2020 to 2030

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	28.00%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
New Jersey	21.00%	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	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.[139]

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.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

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, DC, but in the other states REC prices are not publicly available.

139 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.

Figure 8-2 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2020. Tier I REC prices are lower than SREC prices. For example, the average SREC price in Washington, DC in the first nine months of 2020 was $430.87 and the average Tier I price in Washington, DC in the first nine months of 2020 was $3.10.

Figure 8-2 Average Tier I REC price by jurisdiction: January 2009 through September 2020

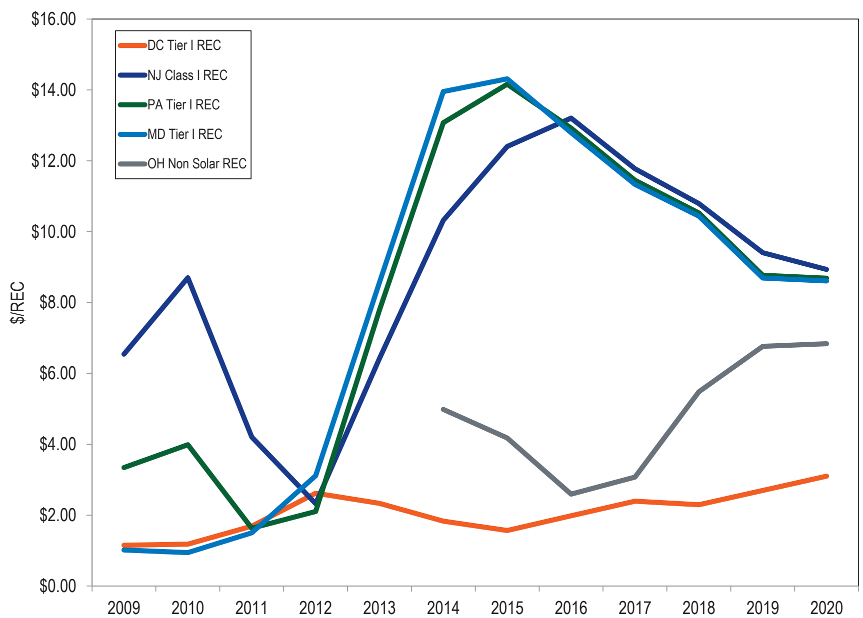
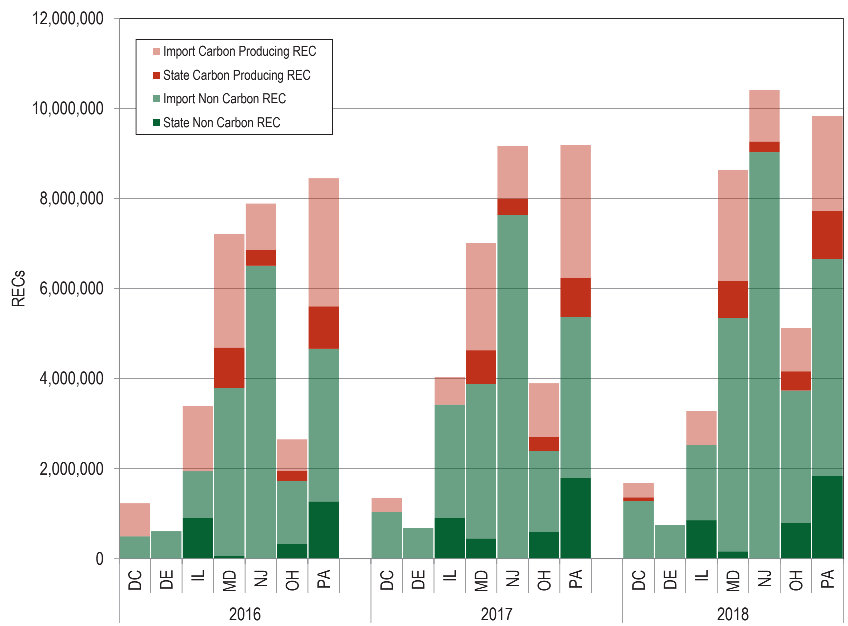


Figure 8-3 and Table 8-11 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2018 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[140] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The DC New Eligible requirement is fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-3 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-11 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, and 26.2 percent State RECs for the 2016 compliance year. Pennsylvania met its Tier I target using 55.3 percent noncarbon producing RECs, and 44.8 percent carbon producing RECs for the 2016 compliance year. Pennsylvania met its Tier I target using 70.9 percent imported RECs, and 29.0 percent State RECs for the 2017 compliance year. Pennsylvania met its Tier I target using 58.5 percent noncarbon producing RECs, and 41.4 percent carbon producing RECs for the 2017 compliance year.

Figure 8-3 State fulfillment of Tier I equivalent RPS: 2016 through 2018



140 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 21, 2020).

© 2020 Monitoring Analytics, LLC

Table 8-11 State fulfillment of Tier I equivalent RPS: 2016 through 2018

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%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%

Table 8-12 Additional renewable standards of PJM jurisdictions: 2020 to 2030

Jurisdiction	Type of Standard	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	Tier II Standard	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Maryland	Off Shore Wind		1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.94%	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%
North Carolina	Swine Waste	0.07%	0.14%	0.14%	0.14%	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
Pennsylvania	Tier II Standard	10.00%	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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 8-12 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 8-12 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-12 are included in the total RPS requirements presented in Table 8-8. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or Class 2 standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2024, 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 in 2020. 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.[141]

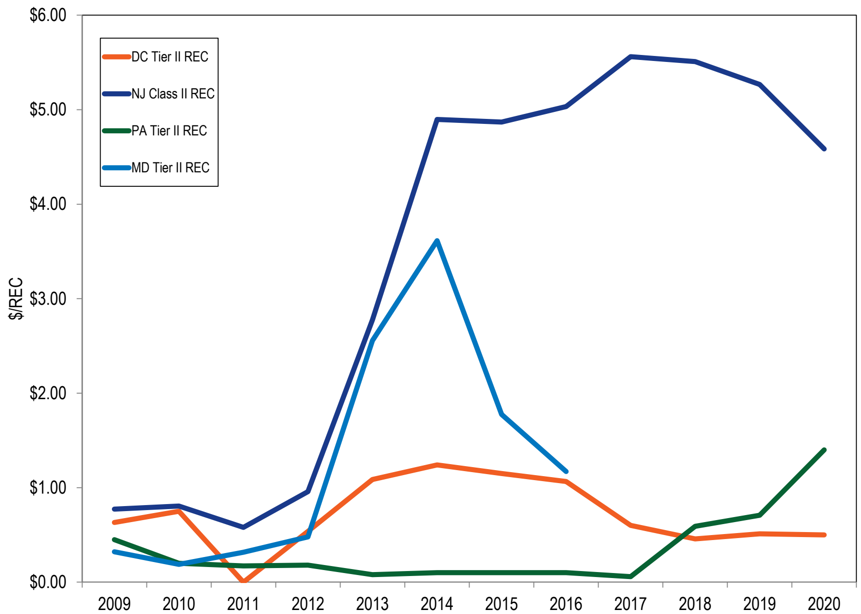
Tier II prices are lower than SREC and Tier I REC prices. Figure 8-4 shows the average Tier II REC price by jurisdiction for January 1, 2009 through September 30, 2020. Pennsylvania had the lowest average Tier II REC prices at $1.40 per REC while New Jersey had the highest average Tier II REC prices at $4.58 per REC.[142]

141 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>.

142 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed October 21, 2020). There were not any reported cleared purchases for January 1, through September 30, 2020, for MD Tier II RECs.

© 2020 Monitoring Analytics, LLC

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through September 2020



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-10 but must be met by solar RECs (SRECs) only. Table 8-13 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, DC have requirements for the proportion of load to be served by solar. New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[143] New Jersey is considering but has not finalized successor programs, such as a transitional 15 year fixed priced REC (TREC). Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. 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, 5.1 percent for 2020 through 2022 and decreases to 1.1 percent for 2032.[144] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[145]

143 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).

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

145 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

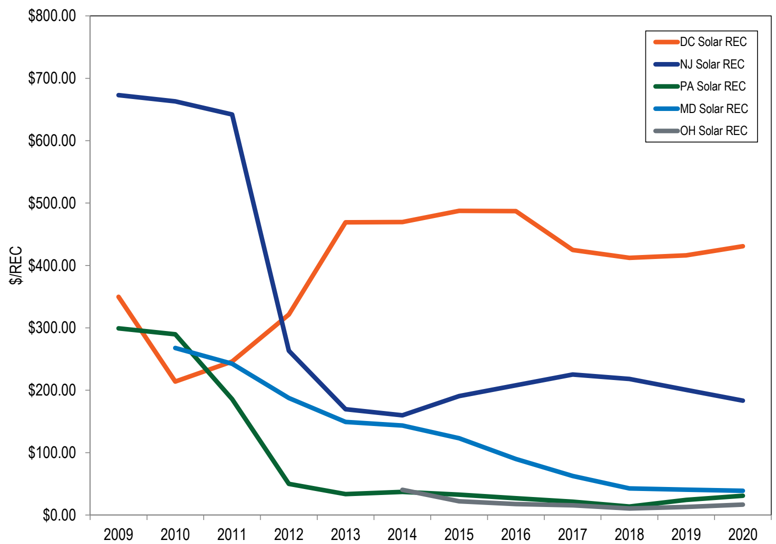
© 2020 Monitoring Analytics, LLC

Table 8-13 Solar renewable standards by percent of electric load for PJM jurisdictions: 2020 to 2030[146]

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois (RECs)	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	4,000,000
Maryland	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	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%
Ohio	No Minimum Solar Requirement										
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	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										

Figure 8-5 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2020. The average NJ SREC prices dropped from $673 per SREC in 2009 to $183 per SREC in the first nine months of 2020. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price increased from $197 per SREC in 2011 to $431 per SREC in the first nine months of 2020.[147]

Figure 8-5 Average SREC price by jurisdiction: January 2009 through September 2020



146 The Illinois solar standard currently requires 2 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 099-0906, June 1, 2017.
147 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 21, 2020).

Figure 8-6 and Table 8-14 shows where the SRECs originated that are used to satisfy the states' solar requirement by retiring RECs for 2016 through 2018.[148] 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 8-14 shows the percent of imported and local SRECs used to meet the RPS requirements. For example, Washington, DC met its solar requirement using 50.2 percent imported SRECs for the 2016 compliance year.

Figure 8-6 State fulfillment of Solar RPS: 2016 through 2018

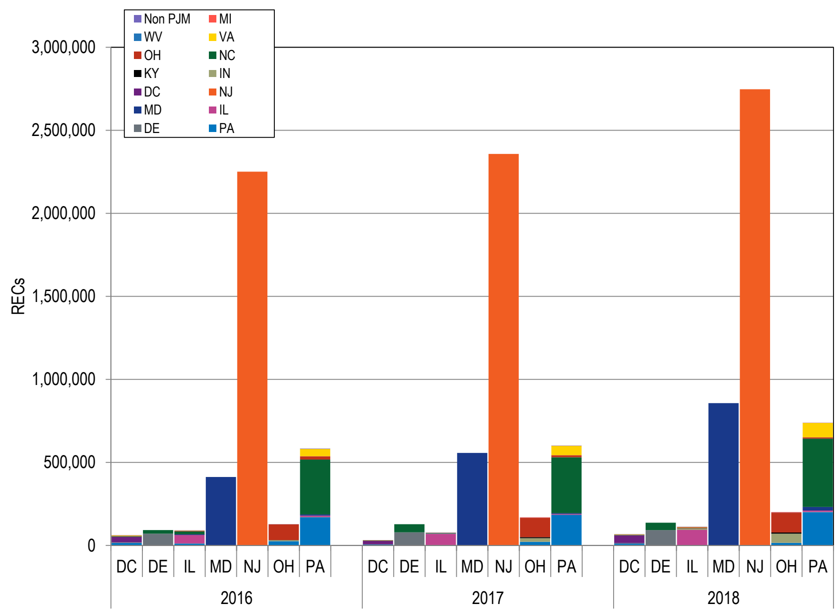


Table 8-14 State fulfillment of Solar RPS: 2016 through 2018

		State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	DE Solar Eligible	76.5%	23.5%
	IL Solar Renewable	56.1%	43.9%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	73.3%	26.7%
	PA Solar	29.1%	70.9%
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.5%	12.5%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	69.0%	31.0%
	PA Solar	30.6%	69.4%
2018	DC Solar	67.4%	32.6%
	DE Solar Eligible	67.7%	32.3%
	IL Solar Renewable	82.8%	17.2%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%
	PA Solar	27.2%	72.8%

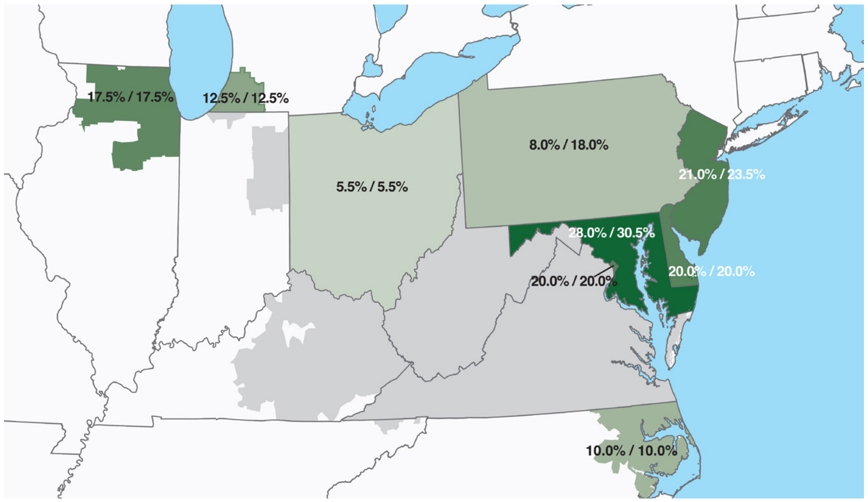
Figure 8-7 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-7, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents 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 18.0 percent number in Figure 8-7 overstates

148 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 21, 2020).

© 2020 Monitoring Analytics, LLC

the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-7 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-7 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2020[149]



Under the existing state renewable portfolio standards, 11.8 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2020. Tier I resources consist of landfill gas, run of river hydro, wind and solar resources. Tier II resources consist of pumped storage, solid waste and waste coal resources. In the first nine months of 2020, 7.0 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 8-15. 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 2030 under currently defined RPS rules. Approximately 9.5 percent of PJM load should have been served by Tier I or renewable energy resources in the first nine months of 2020. In the first nine months of 2020, 5.0 percent of PJM generation was Tier I or renewable energy, which is 4.5 percentage points less than the amount required, as shown in Table 8-15. The current REC production from PJM generation resources was not enough to meet the 2020 state renewable requirements. LSEs use RECs from generators registered in GATS to fulfill state RPS standards. Not all generators registered in GATS are PJM resources. For example, there are 2,543.8 MW of installed capacity of solar that are PJM resources (Table 8-16), and 6,799 MW of installed capacity of solar that are not PJM resources (Table 8-17). The installed solar MW that are not PJM generation consist of rooftop solar and other small projects that do not participate in the wholesale energy markets. If the installed capacity not part of PJM had the same output per ICAP MW, approximately 7.5 percent of generation would be Tier I, compared to 5.0 percent with just PJM resources, which is 2.0 percentage points less than the expected amount required. RECs typically have a lifespan of five years. This allows unused RECs in one year to be used for future RPS goals. Once an LSE retires a REC to meet a state renewable requirement, that REC is no longer eligible for trading or use elsewhere. LSEs that are unable to meet the RPS with only RECs may use alternative compliance payments for unmet goals based on each state's requirements. 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 2030 under defined RPS rules.

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 8-15 shows generation by jurisdiction and resource type for the first nine months of 2020. Wind output was 17,977.8 GWh of 30,548.4 Tier I GWh, or 42.5 percent, in the PJM footprint. As shown in Table 8-15, 42,330.6 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 72.2 percent. Total wind and solar generation (noncarbon producing) was 3.4 percent of total generation in PJM for the first nine months of 2020. Tier I generation was 5.0 percent of total generation in PJM and Tier II was 1.9 percent of total

149 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.

generation in PJM for the first nine months of 2020. Landfill gas, solid waste and waste coal (carbon producing) were 8,464.0 GWh, or 20.0 percent of the total Tier I and Tier II.

Table 8-15 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2020

	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	31.3	0.0	0.0	0.0	31.3	0.0	0.0	0.0	0.0	31.3
Illinois	90.7	0.0	12.2	8,108.1	8,211.1	0.0	0.0	0.0	0.0	8,211.1
Indiana	15.5	27.5	12.3	3,618.4	3,673.7	0.0	0.0	0.0	0.0	3,673.7
Kentucky	0.0	266.1	0.0	0.0	266.1	0.0	0.0	0.0	0.0	266.1
Maryland	45.3	0.0	337.1	509.4	891.8	0.0	417.6	0.0	417.6	1,309.4
Michigan	44.5	48.9	4.0	0.0	97.4	0.0	0.0	0.0	0.0	97.4
New Jersey	146.2	12.0	667.8	9.1	835.1	218.8	1,020.0	0.0	1,238.8	2,073.9
North Carolina	0.0	637.9	1,077.2	420.2	2,135.3	0.0	0.0	0.0	0.0	2,135.3
Ohio	256.8	551.6	1.1	1,472.3	2,281.7	0.0	0.0	0.0	0.0	2,281.7
Pennsylvania	469.8	3,591.2	50.6	2,608.1	6,719.6	1,476.8	1,003.9	3,330.8	5,811.4	12,531.1
Tennessee	0.0	1,172.7	0.0	0.0	1,172.7	0.0	0.0	0.0	0.0	1,172.7
Virginia	396.6	1,144.8	746.7	0.0	2,288.1	3,147.0	689.9	0.0	3,836.9	6,125.0
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	27.6	657.4	27.3	1,232.2	1,944.4	0.0	0.0	477.5	477.5	2,421.9
Total	1,524.4	8,110.1	2,936.1	17,977.8	30,548.4	4,842.6	3,131.4	3,808.3	11,782.2	42,330.6
Percent of Renewable Generation	3.6%	19.2%	6.9%	42.5%	72.2%	11.4%	7.4%	9.0%	27.8%	100.0%
Percent of Total Generation	0.3%	1.3%	0.5%	3.0%	5.0%	0.8%	0.5%	0.6%	1.9%	7.0%

Figure 8-8 shows the average hourly output by fuel type for January 1 through September 30 of 2014 through 2020. 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.[150]

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

© 2020 Monitoring Analytics, LLC

Figure 8-8 Average hourly output by fuel type: January through September, 2014 through 2020

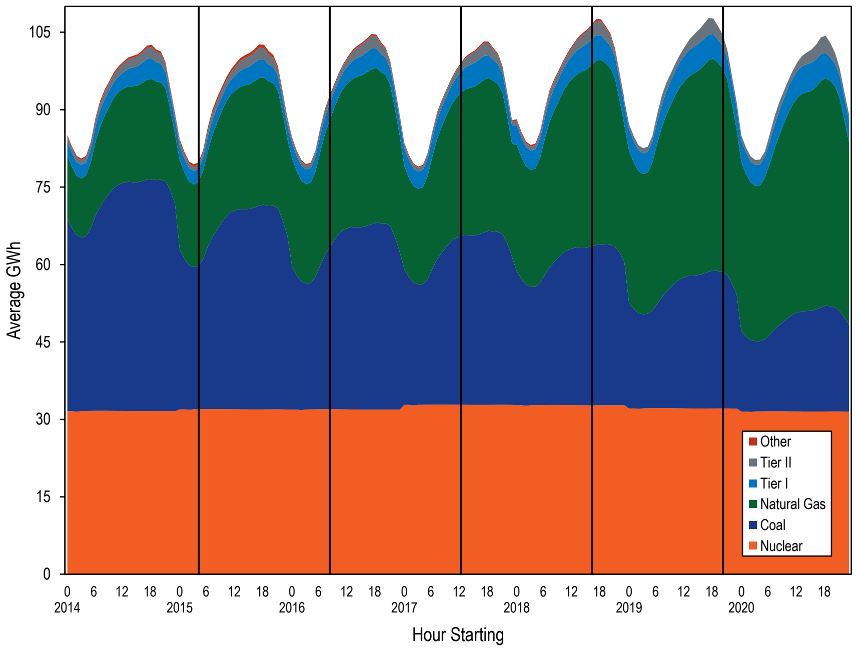


Table 8-16 shows the summer installed capacity rating of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify as Tier II because they have a renewable fuel as an alternative fuel. For example, a coal generator 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. North Carolina has the largest amount of solar capacity in PJM, 817.5 MW, or 32.1 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 6,208.2 MW, or 63.7 percent of the total wind capacity.

PJM is developing new rules for determining the capacity value of intermittent generators. The new rules are expected to rely on the effective load carrying capability (ELCC) method.[151] Under the current rules a generator's capacity value is derated from the installed capacity level by multiplying the generator's net maximum capability by a capacity factor. The capacity factor is either based on the generator's historical performance during summer peak hours or is a class average value calculated by PJM. The intent of the current method is to obtain a MW value the generator can reliably produce during the summer peak hours.[152] As of October 1, 2020, the derated capacity eligible for compensation in the PJM Capacity Market totaled 1,296.4 MW for wind generators and 946.9 MW for solar generators. This compares to installed wind capacity of 9,752.2 MW and installed solar capacity of 2,543.8 MW in Table 8-16. PJM posts class average capacity factors for wind and solar generators. There are two classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.[153]

151 PJM's Capacity Capability Senior Task Force (CCSTF) is currently reviewing ELCC proposals. See the CCSTF webpage for additional details <https://www.pjm.com/committees-and-groups/task-forces/ccstf.aspx>.
152 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
153 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017 <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

Table 8-16 PJM renewable capacity by jurisdiction (MW): September 30, 2020

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	4,185.8	4,594.0
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	223.2	128.2	0.0	190.0	1,127.1
Michigan	0.0	12.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	30.5
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	70.3	0.0	0.0	453.0	11.0	679.6	152.0	0.0	4.5	1,370.3
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	817.5	0.0	0.0	208.0	1,490.5
Ohio	4,846.0	58.2	0.0	136.0	0.0	119.1	1.1	0.0	0.0	795.8	5,956.2
Pennsylvania	0.0	196.8	2,346.0	0.0	1,269.0	893.3	77.2	261.8	1,347.0	1,457.2	7,848.3
Tennessee	0.0	0.0	0.0	0.0	0.0	156.6	0.0	0.0	0.0	0.0	156.6
Virginia	585.0	127.7	0.0	17.0	5,386.0	430.4	721.4	123.0	0.0	0.0	7,390.5
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	3.2	0.0	0.0	0.0	257.9	0.0	0.0	96.0	742.5	1,099.6
PJM Total	5,431.0	545.7	4,503.0	235.0	7,108.0	3,015.6	2,543.8	665.0	1,443.0	9,752.2	35,242.4

There are three classes of solar generators with capacity factors ranging from 39.0 percent to 60.0 percent.[154]

There are two approaches to calculating ELCC. The load approach measures, after the introduction of a class of intermittent generators, the additional load that can be added to the system while maintaining the 0.1 LOLE reliability standard. The generation approach measures the amount of 100 percent available generation that, when added to the system, results in an LOLE equivalent to the LOLE that results from the introduction of a class of intermittent generators.[155] PJM is planning to use the generation approach. Both approaches capture the interaction of intermittent generation and load. Unlike the current capacity value method that only uses data from summer peak hours, the ELCC method will consider all hours in a year. The ELCC method when properly designed will capture the changes in capacity values that result from a changing resource mix.

Once the ELCC is calculated, the impact on units' offers and market clearing needs to be defined. The correct approach is to price all intermittent MW in a class based on the marginal value of the intermittent resources as defined based on the interaction between the ELCC curve and the optimal clearing of the capacity market.[156] The marginal value of any class of intermittent resource generally declines the more resources are added. Interactions between classes can also be accounted for. Owners and developers of intermittent resources want to lock in high intermittent MW values, based on average rather than marginal values, for periods as long as, or longer than, 10 years.[157] While the goal of such owners and developers is to shift risk to customers and to other generation owners, using an average ELCC value and/or locking in an ELCC value is not required to provide the appropriate incentives for entry and it is fundamentally incompatible with competitive markets. The use of average values and lock ins arbitrarily favor older renewable technologies over newer renewable technologies, arbitrarily favor renewable technologies over thermal technologies, and overstate the actual capacity available for reliability. Such lockins distort market outcomes and impose costs on other generation technologies and on customers who bear the costs of reduced reliability or of purchasing additional capacity to offset the overstatements. Building long term distortions into the market design will lead to negative and unintended consequences. Such long term distortions are inconsistent with an efficient, competitive market. The ELCC could be an advance in the sophistication of measuring the actual reliability contribution of renewable resources, but it will be a significant regression if the implementation is designed to ignore the actual reliability implications of the ELCC impacts of increased renewables penetration.

154 Id.

155 See "Effective Load Carrying Capability (ELCC) Review - Part II," PJM, November 14, 2019 <https://pjm.com/-/media/committees-groups/committees/pc/20191114/20191114-item-15-elcc-review.ashx>.

156 "ELCC IMM Proposal," Monitoring Analytics, LLC., August 7, 2000. <http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_CCSTF_ELCC_IMM_Proposal_20200807.pdf>.

157 PJM. Agenda. Capacity Capability Senior Task Force (CCSTF) (August 7, 2020). <https://pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200807/20200807-agenda-doc.ashx>.

© 2020 Monitoring Analytics, LLC

Table 8-17 shows renewable capacity registered in the PJM generation attribute tracking system (GATS) not all of which are PJM resources.[158] For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 6,798.7 MW of which 2,560.3 MW are 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 1,505.3 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 54.0 MW of capacity registered with GATS located in Alabama.

Table 8-17 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): September 30, 2020[159]

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	54.0	0.0	54.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	127.2	0.0	2.0	131.4
Georgia	0.0	0.0	27.1	0.0	0.0	0.0	152.2	0.0	0.0	179.3
Illinois	0.0	21.4	55.4	0.0	5.2	0.0	365.6	0.0	600.7	1,048.3
Indiana	0.0	0.0	49.6	0.0	5.2	109.6	123.3	0.0	180.0	467.6
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	2.1	0.0	336.8	340.5
Kentucky	600.0	162.2	20.2	0.0	0.4	0.0	38.2	93.0	0.0	914.0
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	65.0	0.0	12.7	0.0	0.0	0.0	1,090.0	13.8	0.3	1,181.8
Michigan	0.0	1.3	12.6	0.0	0.0	0.0	4.9	31.0	80.6	130.3
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	61.2	0.0	451.0	517.8
New Jersey	0.0	0.0	45.8	0.0	11.6	0.0	2,560.3	0.0	4.7	2,622.3
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	520.4	0.0	0.0	0.0	0.0	1,197.0	151.5	0.0	1,868.9
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	19.7	52.0	10.7	33.0	235.1	92.8	50.7	500.6
Pennsylvania	109.7	31.5	45.2	97.6	13.6	0.0	430.9	8.6	3.2	740.2
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	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.6
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	0.0	29.6	11.3	0.0	2.6	0.0	208.8	287.6	0.0	539.9
Washington, D.C.	0.0	0.0	0.0	0.0	49.4	13.5	106.0	0.0	0.0	168.9
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	4.1	0.0	0.0	4.1
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.1	44.6	0.0	53.7
Total	774.7	881.6	339.7	149.6	98.6	156.1	6,798.7	776.9	2,069.9	12,045.9

158 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. 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.

159 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 24, 2020).

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.[160] 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.

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.[161] This is equivalent to providing a REC price equal to three times its stated value per MWh.

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 8-18 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

160 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).

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

Table 8-18 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 8-19 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.

© 2020 Monitoring Analytics, LLC

Table 8-19 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must 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.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance 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.[162] Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates which was $63.16 per MWh for 2019. Figure 8-9 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 discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

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

© 2020 Monitoring Analytics, LLC

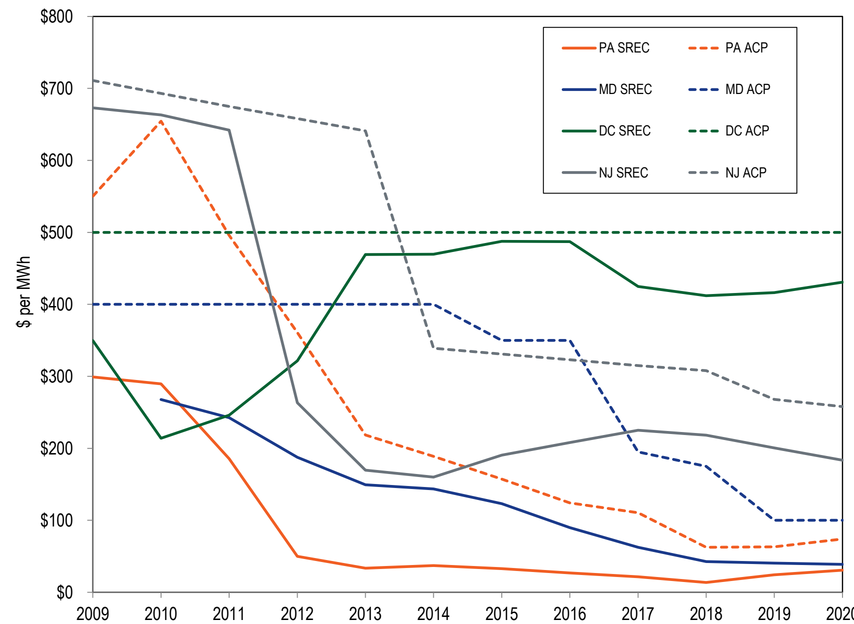
Table 8-20 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-20 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: September 30, 2020[163 164]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$0.35		
Maryland	$30.00	$15.00	$100.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$258.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$52.62		
Pennsylvania	$45.00	$45.00	$74.00
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.

Figure 8-9 Comparison of SREC Price and Solar ACP: 2009 through 2020



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 2019 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in September of 2020.[165] Pennsylvania reported that the 555,396 SRECs, 10,016,752 Tier I RECs and 11,645,974 Tier II RECs were retired during the 2019 reporting year (June 1, 2018 through May 31, 2019). Supplier obligations

163 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 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

164 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).

165 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2020," (September 2019), <https://www.pennaeps.com/wp-content/uploads/2020/09/2019-AEPS-Annual-Report.pdf>.

© 2020 Monitoring Analytics, LLC

for 2,219 SRECs, 65,662 Tier I RECs and 78,162 Tier II RECs were resolved through ACPs.

The Public Service Commission of the District of Columbia reported that 67,892 SRECs, 1,684,797 Tier I RECs and 112,484 Tier II RECs were retired during the 2018 compliance year. ACPs decreased from $26,571,010 for 2017 to $18,744,020 for 2018.[166]

The Public Service Commission of Maryland reported that 857,232 SRECs, 8,627,737 Tier 1 RECs and 1,599,819 Tier 2 RECs were retired in 2018.[167] ACPs totaled $67,796 for 2018 with the majority of payments "made in lieu of purchasing Tier 1 RECs to satisfy Industrial Load Process ("IPL") obligations."[168]

The Public Utilities Commission of Ohio reported that 5,373,438 nonsolar RECs were retired in the 2018 compliance year, exceeding the REC obligation of 5,372,094 RECs; and 224,593 SRECs were retired in the 2018 compliance year, exceeding the SREC obligation of 224,481 SRECs.[169]

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 ACPs.[170] 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 ACPs. This requirement was removed for 2017/2018 Delivery Year and ACPs for ComEd decreased to $74,148. The 2016-2017 ACPs for ComEd totaled $40,575,311.[171]

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).[172] Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.[173]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2019.[174] Electric power suppliers retired 10,408,717 class I RECs and 1,835,664 class II RECs. There were no deficiencies for class I credits; 99 ACPs were submitted for class II. Electric power suppliers retired 2,747,676 solar RECs and there were no deficiencies requiring solar ACPs.

Table 8-21 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[175] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-21 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 $4.5 billion over the five year period from 2014 through 2018 for the nine jurisdictions that had RPS and reported compliance costs.[176] The average RPS compliance cost per year

166 "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>.

167 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Dec. 2019) at 8, <https://www.psc.state.md.us/commission-reports/>.

168 *Id.* at 9.

169 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2018," Public Utilities Commission of Ohio (January 16, 2020), <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.

170 "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/>

171 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

172 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2019) at 38, <https://www.ncuc.net/Reps/reps.html>.

173 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.

174 See RPS Report Summary 2005-2019, New Jersey's Clean Energy Program (Feb. 12, 2020), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

175 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

176 The actual PJM RPS compliance cost exceeds the reported $4.4 billion since this total does not include a value for Delaware in 2014 and a value for Pennsylvania in 2018.

© 2020 Monitoring Analytics, LLC

based on the reported compliance cost for the five year period from 2014 through 2019 was $893.1 million. The compliance cost for 2018, the most recent year with complete data, was $986.9 million.

Table 8-21 RPS Compliance Cost[177 178 179 180 181 182 183 184 185 186]

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	$84,806,928
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	$27,351,388
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	$56,406,247
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	$1,049,293
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	$3,264,504
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203
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	$678,387,871	$888,389,738	$986,186,949	$925,417,144	$986,947,843

177 "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.

178 "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.

179 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Dec. 2019) at 8, <https://www.psc.state.md.us/commission-reports/>.

180 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <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.

181 "RPS Report Summary 2005-2019," New Jersey's Clean Energy Program, February 12, 2020, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

182 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2018," Public Utilities Commission of Ohio, January 16, 2020, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.

183 "2019 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, September 2020 <https://www.pennaeps.com/wp-content/uploads/2020/09/2019-AEPS-Annual-Report.pdf>.

184 "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>.

185 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.

186 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.

© 2020 Monitoring Analytics, LLC

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.[187] 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.[188] [189]

Table 8-22 shows SO_2 emission controls by fossil fuel fired units in PJM.[190] [191] [192] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[193] Of the current 59,153.1 MW of coal capacity in PJM, 55,544.8 MW of capacity, 93.9 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-22 SO_2 emission controls by fuel type (MW): September 30, 2020[194]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	55,544.8	3,608.3	59,153.1	93.9%
Diesel Oil	0.0	5,259.6	5,259.6	0.0%
Natural Gas	0.0	73,102.4	73,102.4	0.0%
Other	325.0	4,745.7	5,070.7	6.4%
Total	55,869.8	86,716.0	142,585.8	39.2%

Table 8-23 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 59,153.1 MW of coal capacity in PJM, 58,941.6 MW of capacity, 99.6 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls 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.[195]

Table 8-23 NO_X emission controls by fuel type (MW): As of September 30, 2020

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	58,941.6	211.5	59,153.1	99.6%
Diesel Oil	1,573.6	3,686.0	5,259.6	29.9%
Natural Gas	72,102.8	999.6	73,102.4	98.6%
Other	2,591.7	2,479.0	5,070.7	51.1%
Total	135,209.7	7,376.1	142,585.8	94.8%

Table 8-24 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.9 percent) in PJM have particulate controls, as well as a few natural gas units (3.8 percent) and units with other fuel sources (58.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[196] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 59,153.1 MW of coal capacity in PJM, 59,068.1 MW of capacity, 99.9 percent, have some type of particulate emissions control technology. 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, 121 of the 135 coal steam units have baghouse or FGD technology installed, representing 52,944.8 MW out of the 59,153.1 MW total coal capacity, or 89.5 percent.

187 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 7, 2020).
188 On April 16, 2020, the EPA issued a revised 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 May 7, 2020).
189 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards,"<https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)
190 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed May 7, 2020).
191 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.
192 The total MW are less than the 184,575.7 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 May 7, 2020).
193 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 May 7, 2020).
194 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.
195 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
196 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 7, 2020).

Table 8-24 Particulate emission controls by fuel type (MW): As of September 30, 2020

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	59,068.1	85.0	59,153.1	99.9%
Diesel Oil	0.0	5,259.6	5,259.6	0.0%
Natural Gas	2,786.0	70,316.4	73,102.4	3.8%
Other	2,970.5	2,100.2	5,070.7	58.6%
Total	64,824.6	77,761.2	142,585.8	45.5%

Emissions

Figure 8-10 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 third quarter of 2020. Figure 8-10 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2020.[197] [198] For the period from the first quarter of 1999 through the third quarter of 2020, the minimum CO_2 produced per MWh was 0.66 short tons per MWh in the first quarter of 2020, and the maximum was 0.96 short tons per MWh in the first quarter of 2010. Total PJM generation decreased from 231,293.0 GWh in the third quarter of 2019 to 229,848.9 GWh in the third quarter of 2020, while CO_2 produced decreased from 112.9 million short tons in the third quarter of 2019 to 108.7 million short tons in the third quarter of 2020.[199] 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.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: 1999 through September, 2020[200 201]

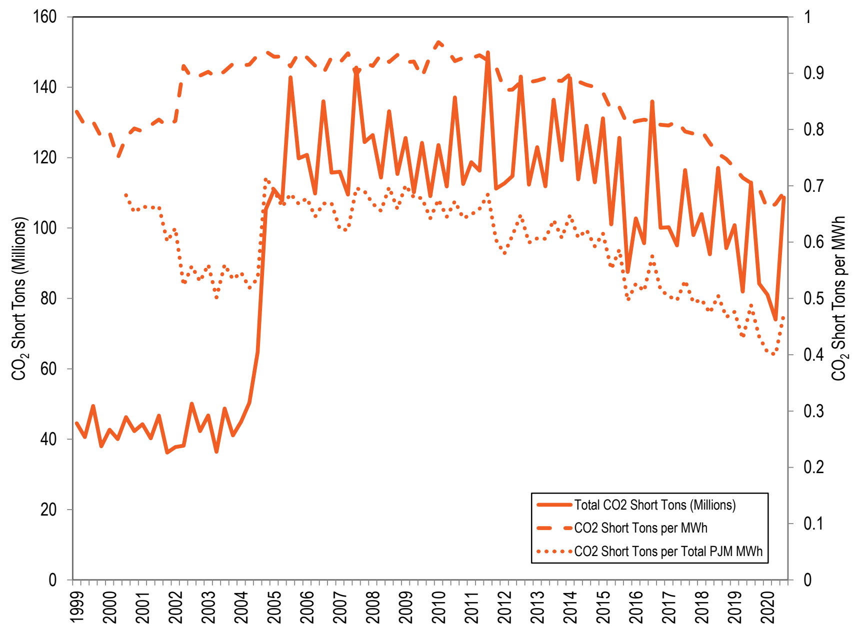


Figure 8-11 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since the first quarter of 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since the first quarter of 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.94 short tons per MWh in the first quarter of 2010.

197 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
198 Emissions data for the second quarter of 2020 was not yet finalized at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.
199 See the *2019 Quarterly State of the Market Report for PJM: January through March*: Section 3: Energy Market, Table 3-10.
200 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
201 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).

© 2020 Monitoring Analytics, LLC

In the third quarter of 2020, CO_2 emissions were 0.69 short tons per MWh for off peak hours and 0.69 for on peak hours.

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through September, 2020[202]

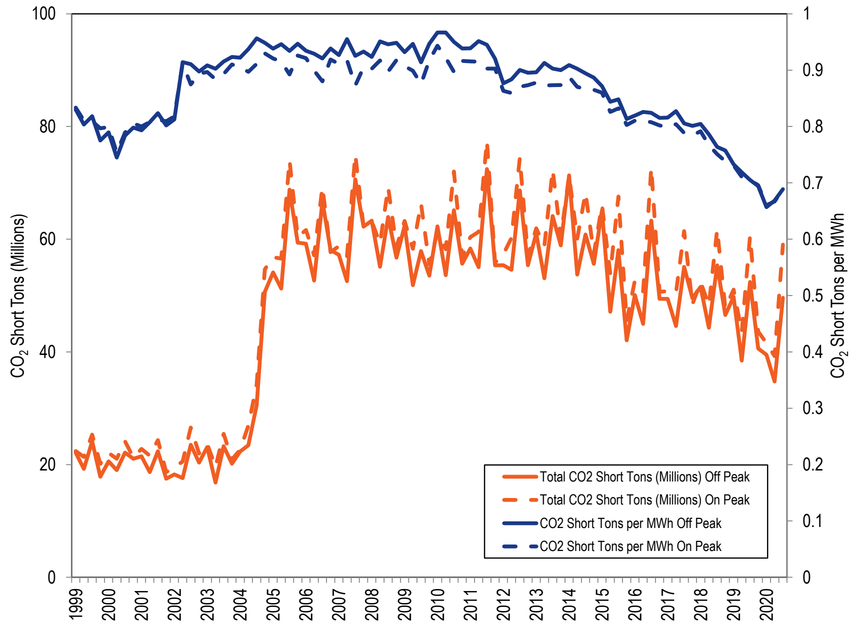


Figure 8-12 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO_2 produced per MWh was 0.000378 short tons per MWh in the first quarter of 2020, and the maximum was 0.008141 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the second quarter of 2020, the minimum NO_X produced per MWh was at a 0.000274 short tons per MWh in the third quarter of 2020, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the third quarter of 2020, SO_2 emissions were 0.00090 short tons per MWh and NO_X emissions were 0.000274 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 2020.[203] [204]

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through September, 2020[205]

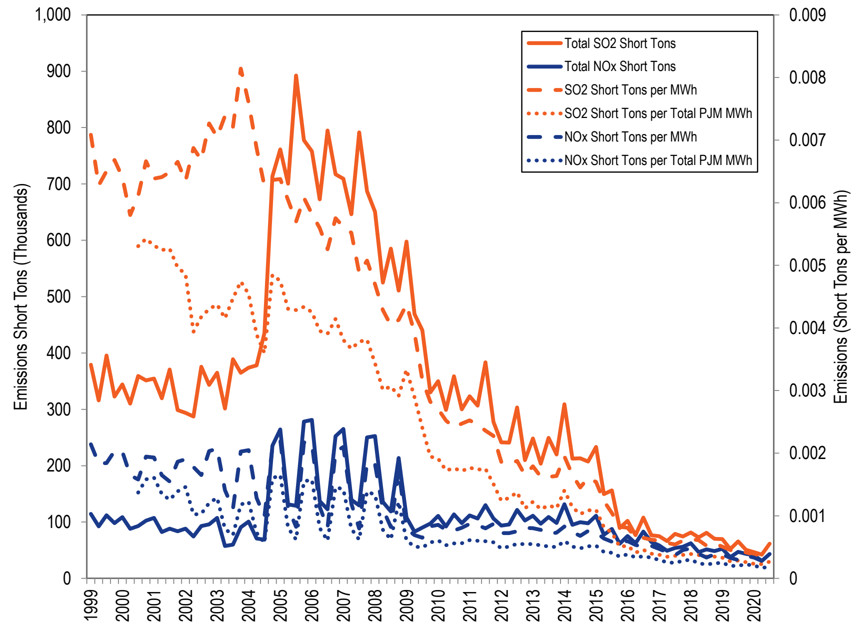


Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO_2 produced per MWh during off

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

203 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).

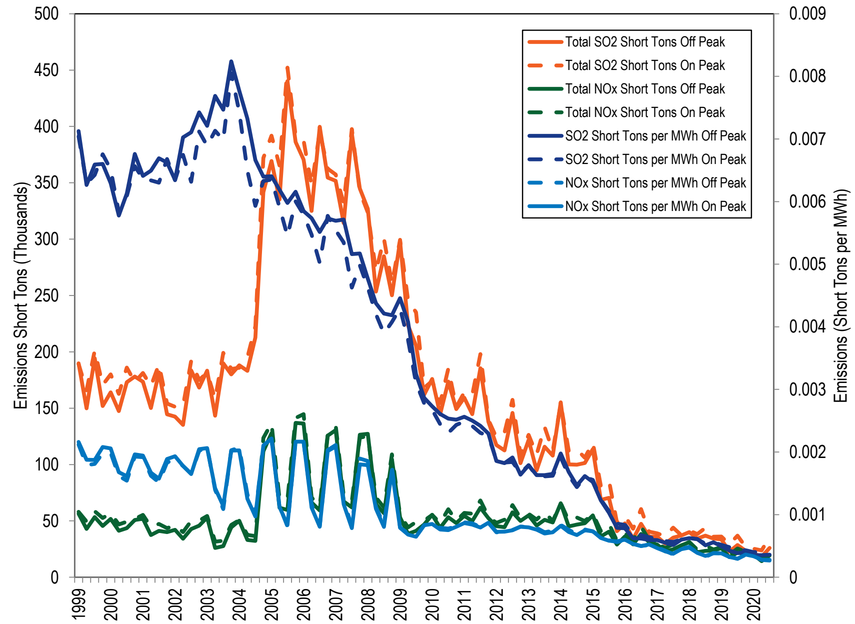
204 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

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

© 2020 Monitoring Analytics, LLC

peak hours was 0.000352 short tons per MWh in the second quarter of 2020, and the maximum was 0.008239 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO_2 produced per MWh during on peak hours was 0.000402 short tons per MWh in the first quarter of 2020, and the maximum was 0.008048 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum NO_X produced per MWh during off peak hours was 0.000268 short tons per MWh in the third quarter of 2020, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum NO_X produced per MWh during on peak hours was 0.000279 short tons per MWh in the third quarter of 2020 and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the third quarter of 2020, SO_2 emissions were 0.000360 short tons per MWh and 0.000415 short tons per MWh for off and on peak hours. In the third quarter of 2020, NO_X emissions were 0.000268 short tons per MWh and 0.000279 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through September, 2020[206]



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

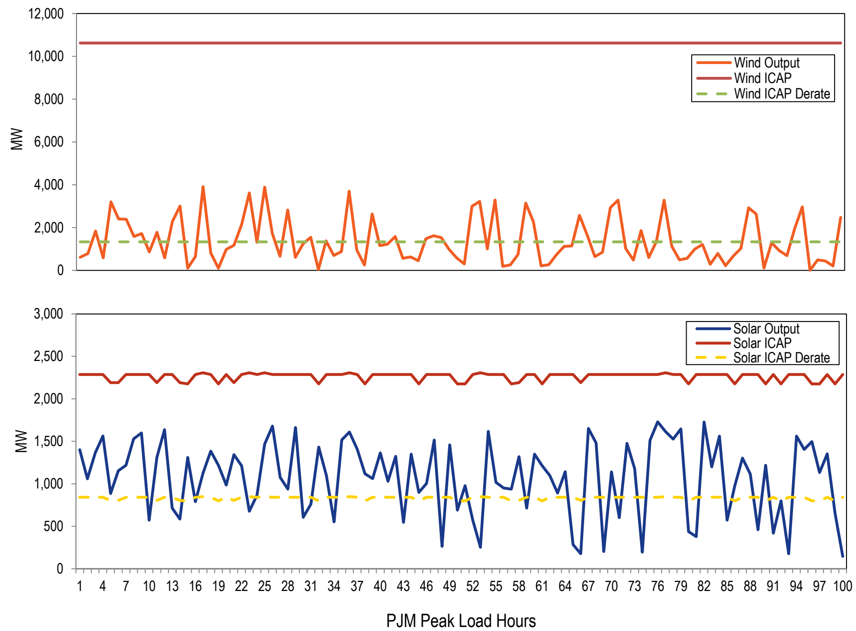
© 2020 Monitoring Analytics, LLC

Renewable Energy Output

Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in the first nine months of 2020. Of the top 100 load hours in PJM in the first nine months of 2020, 90 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.[207] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 40 hours and below the derated ICAP for 60 hours of the top 100 load hours in the first nine months of 2020. The wind capacity factor for the top 100 load hours in the first nine months of 2020 was 13.1 percent. Wind output was above the derated ICAP for 4,273 hours and below the derated ICAP for 2,302 hours in the first nine months of 2020. The wind capacity factor in the first nine months of 2020 was 25.8 percent. Solar output was above the derated ICAP for 73 hours and below the derated ICAP for 27 hours of the top 100 load hours in the first nine months of 2020. The solar capacity factor for the top 100 load hours in the first nine months of 2020 was 47.5 percent. Solar output was above the derated ICAP for 1,709 hours and below the derated ICAP for 4,866 hours in the first nine months of 2020. The solar capacity factor in the first nine months of 2020 was 23.8 percent.

Figure 8-14 Wind and solar output during the top 100 load hours in PJM: January through September, 2020



Wind Units

Table 8-25 shows the capacity factors of wind units in PJM. In the first nine months of 2020, the capacity factor of wind units in PJM was 25.8 percent. Wind units that were capacity resources had a capacity factor of 26.6 percent and an installed capacity of 8,599 MW. Wind units that were energy only had a capacity factor of 22.6 percent and an installed capacity of 2,178 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.[208]

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

208 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 8-25 Capacity factor of wind units in PJM: January through September, 2020[209]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	22.6%	2,178
Capacity Resource	26.6%	8,599
All Units	25.8%	10,777

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through September 30, 2020. The hour with the highest average output, 4,463 MW, occurred in April, and the hour with the lowest average output, 753 MW, occurred in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units in PJM: January through September, 2020

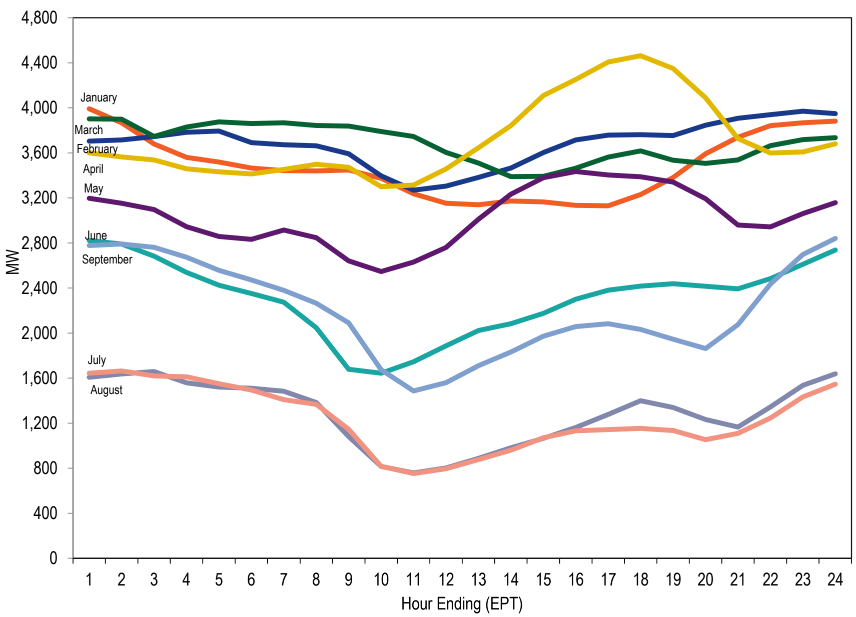


Table 8-26 shows the generation and capacity factor of wind units by month from January 1, 2019, through September 30, 2020.

Table 8-26 Capacity factor of wind units in PJM by month: January 2019 through September 2020

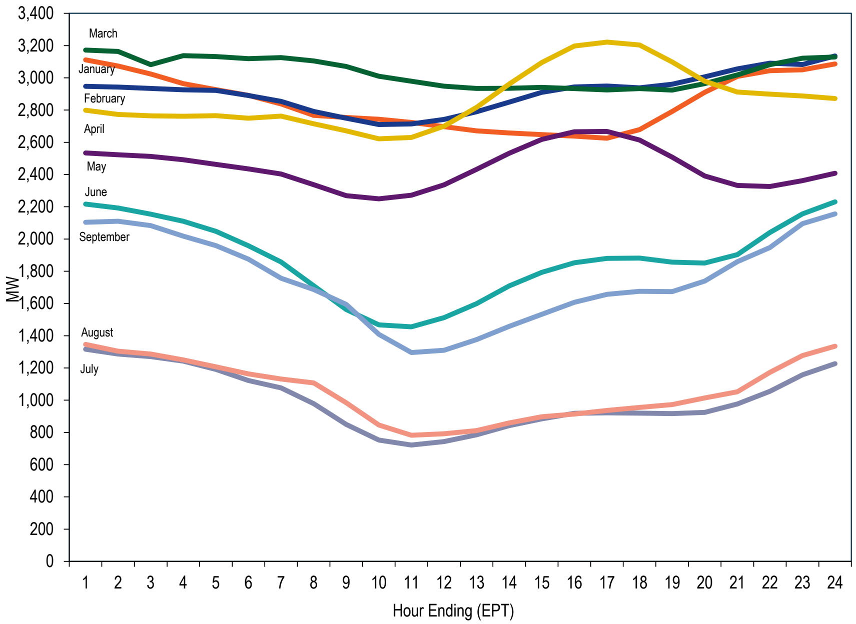
	2019		2020	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,611,714.5	36.9%	2,588,895.7	33.3%
February	2,228,415.9	34.9%	2,564,467.7	35.1%
March	2,467,063.3	34.9%	2,739,005.2	34.8%
April	2,665,719.5	38.9%	2,679,800.9	35.0%
May	1,925,357.2	27.2%	2,261,803.9	28.6%
June	1,746,607.4	25.5%	1,662,419.6	21.7%
July	1,056,020.4	14.9%	959,774.9	12.1%
August	930,466.2	13.1%	925,896.4	11.7%
September	1,342,423.1	19.6%	1,604,108.9	20.8%
October	2,179,433.7	30.8%		
November	2,157,505.1	30.6%		
December	2,855,933.5	37.7%		
Annual	24,166,659.8	28.8%	17,986,173.1	25.8%

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 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

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

© 2020 Monitoring Analytics, LLC

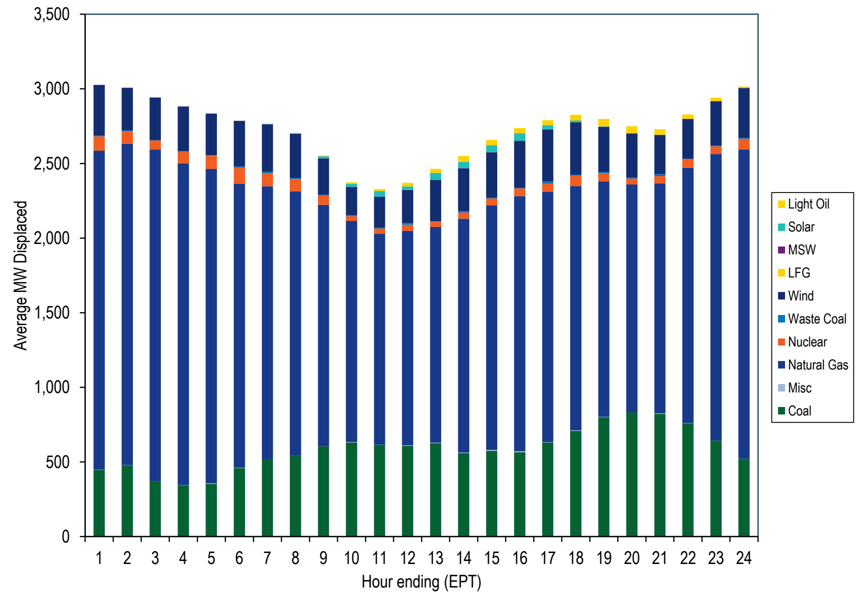
Figure 8-16 Average hourly day-ahead generation of wind units in PJM: January through September, 2020



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. 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 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.[210] Figure 8-17 and Table 8-27 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 2020. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2020, the dispatch instruction for marginal wind resources was to reduce output for 7270.6 percent of the unit intervals. 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, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

210 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Figure 8-17 Marginal fuel at time of wind generation in PJM: January through September, 2020



© 2020 Monitoring Analytics, LLC

Table 8-27 Marginal fuel MW at time of wind generation in PJM: January through September, 2020

Hour	Coal	Misc	Natural Gas	Nuclear	Waste Coal	Wind	LFG	MSW	Solar	Light Oil	Total
0	448.1	0.5	2,137.3	95.6	4.8	340.1	0.0	0.0	0.0	0.0	3,026.4
1	479.2	1.2	2,150.0	86.2	5.1	285.9	0.0	0.0	0.0	0.0	3,007.6
2	371.9	0.4	2,221.1	59.9	2.1	286.2	1.0	0.0	0.0	0.0	2,942.7
3	344.2	0.5	2,155.9	77.3	4.9	298.5	0.0	0.5	0.0	0.0	2,881.8
4	354.6	2.4	2,106.0	88.9	3.0	279.3	0.0	0.9	0.0	0.0	2,835.1
5	458.6	2.6	1,901.5	108.9	9.0	304.3	0.7	1.1	0.0	0.0	2,786.7
6	516.1	0.0	1,830.1	90.0	10.4	315.5	0.6	1.0	1.5	0.0	2,765.1
7	543.1	0.0	1,771.3	80.1	6.4	297.7	1.7	1.4	2.7	0.0	2,704.4
8	605.4	0.0	1,616.7	64.0	4.3	243.0	0.0	1.7	14.1	4.1	2,553.4
9	630.7	3.9	1,479.7	32.5	6.7	189.4	0.0	0.0	19.7	11.5	2,374.1
10	615.9	0.6	1,414.0	33.8	7.2	206.3	0.0	0.0	37.2	13.4	2,328.3
11	608.2	3.4	1,436.5	41.1	10.6	222.1	1.4	0.0	23.1	23.9	2,370.3
12	625.9	3.2	1,444.7	36.0	4.4	275.4	0.0	0.0	47.2	27.4	2,465.3
13	560.3	3.3	1,566.1	41.6	8.9	288.0	0.0	0.0	42.5	39.0	2,550.3
14	574.5	5.9	1,637.9	47.0	4.4	305.7	0.0	0.5	46.5	35.2	2,657.6
15	565.9	5.5	1,709.1	52.4	3.3	315.5	0.0	0.5	50.7	34.1	2,737.0
16	630.7	2.3	1,678.3	54.6	14.0	349.4	0.0	0.0	27.3	33.2	2,790.5
17	707.8	4.3	1,636.3	70.1	7.7	350.6	0.0	0.0	11.3	37.6	2,826.6
18	800.9	1.3	1,579.0	53.6	8.4	303.3	3.0	0.0	2.1	46.5	2,798.6
19	831.4	0.0	1,528.1	39.4	6.1	295.8	0.7	0.0	0.0	47.9	2,750.0
20	821.4	4.5	1,541.2	48.7	12.2	263.1	0.4	0.0	0.4	37.3	2,730.4
21	758.8	2.0	1,710.5	57.3	2.4	268.3	0.0	0.0	0.0	29.0	2,829.1
22	643.4	0.3	1,919.5	52.1	4.9	297.5	0.7	0.0	0.0	22.6	2,941.0
23	521.3	0.0	2,071.9	71.5	5.2	335.6	0.0	0.0	0.0	10.2	3,015.7
Average	584.1	2.0	1,760.1	61.8	6.5	288.2	0.4	0.3	13.6	18.9	2,736.2

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 8-16, there are 2,353.3 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-17, there are 6,311.7 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 avoid 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 8-28 shows the capacity factor of solar units in PJM. In the first six months of 2020, the capacity factor of solar units in PJM was 23.8 percent. Solar units that were capacity resources had a capacity factor of 24.6 percent and an installed capacity of 1,867 MW. Solar units that were energy only had a capacity factor of 19.2 percent and an installed capacity of 1,227 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.[211]

Table 8-28 Capacity factor of solar units in PJM: January through September, 2020

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	19.2%	1,227
Capacity Resource	24.6%	1,867
All Units	23.8%	3,094

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 1,444 MW, occurred in June, and the hour with the lowest peak average output, 905 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

211 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).

© 2020 Monitoring Analytics, LLC

Figure 8-18 Average hourly real-time generation of solar units in PJM: January through September, 2020

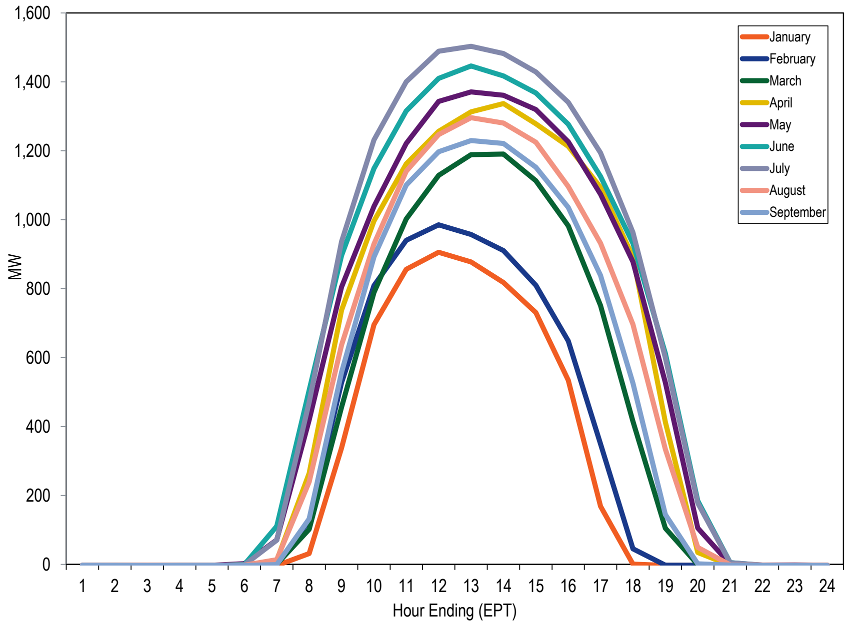


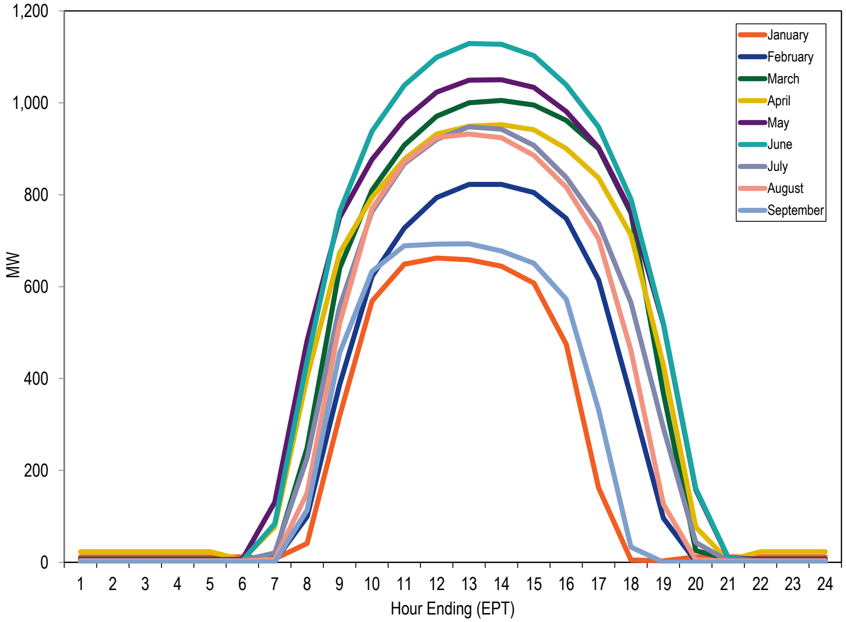
Table 8-29 shows the generation and capacity factor of solar units by month from January 1, 2019, through September 30, 2020.

Table 8-29 Capacity factor of solar units in PJM by month: January 2019 through September 2020

	2019		2020	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	120,957.1	14.4%	164,119.3	14.4%
February	130,178.1	16.5%	182,571.5	17.0%
March	209,107.5	23.4%	255,439.6	21.7%
April	234,395.2	26.8%	322,403.6	27.8%
May	270,502.0	28.8%	352,414.5	28.9%
June	270,516.0	29.2%	367,919.0	30.8%
July	319,914.9	31.7%	392,839.8	31.8%
August	276,196.9	27.5%	301,937.3	25.3%
September	242,606.8	25.4%	258,011.5	22.2%
October	183,319.8	18.5%		
November	157,567.3	15.8%		
December	127,723.7	11.6%		
Annual	2,542,985.4	22.5%	2,597,655.9	24.6%

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 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[212]

Figure 8-19 Average hourly day-ahead generation of solar units in PJM: January through September, 2020



212 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.

© 2020 Monitoring Analytics, LLC