Environmental and Renewable Energy Regulations

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

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The EPA has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM Energy Market.

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

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which 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] The rule established a compliance deadline of April 16, 2015.

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

  On June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[2] On April 14, 2016, the EPA issued the finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[3]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4]

  On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR).[5] [6]

1 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
2 Michigan et al. v. EPA, Slip Op. No. 14-46.
3 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
4 CAA § 110(a)(2)(D)(i)(I).
5 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
6 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.

In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[7] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 SO_2 budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia.[8] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[9] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[10] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[11]

On November 16, 2015, the EPA proposed a rule updating CSAPR to address interstate emission transport with respect to the 2008 ozone NAAQS, to respond to the July 28 remand of certain states' ozone season NO_X emissions budgets established by CSAPR, and to update the status of certain states' outstanding interstate ozone transport obligations with respect to the 1997 ozone NAAQS.[12] Issuance of a final order is pending.

On February 26, 2016, the EPA issued a rule affirming its tolling by three years CSAPR's original deadlines.[13] The rule means that compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[14]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs.[15] As a result, the national emissions standards uniformly apply to all RICE.[16] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[17] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[18] On May 3, 2016, the Court issued a mandate to implement the May 1, 2015, order.
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[19] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay on the rule that will prevent its taking effect until judicial review is completed.[20]
- **Cooling Water Intakes.** The EPA has promulgated a rule implementing Section 316(b) of the Clean Water Act (CWA), which requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[21] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.

7 134 S. Ct. at 1609.
8 EME Homer City Generation , L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).
9 *Id.* at 11–12.
10 *Id.* at 11.
11 Emissions Budget Decision at 24–25.
12 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 80 Fed. Reg. 75706 (Dec. 3, 2015).
13 *Rulemaking to Affirm Interim Amendments to Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491; *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
14 *Id.*
15 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).
16 *Id.*
17 DENREC v. EPA at 3, 20–21.
18 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.
19 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."
20 North Dakota v. EPA, et al., Order 15A793.
21 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).

- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The CCRR likely will raise the costs of disposal of CCRs to meet the EPA criteria.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** 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.[22] 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.[23]
- **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").[24] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities and facilitate trading of emissions allowances. Auction prices in the first six months of 2016, for the 2015-2017 compliance period were $4.53 per ton. The clearing price is equivalent to a price of $4.99 per metric tonne, the unit used in other carbon markets.

22 N.J.A.C. § 7:27-19.
23 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
24 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On June 30, 2016, 76.7 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.1 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of June 30, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. Kentucky and Tennessee have not enacted renewable portfolio standards. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[25] West Virginia had a voluntary standard, but the state legislature repealed the West Virginia renewable portfolio standard on January 22, 2015.

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. Attempts to extend the definition of renewable energy to include nuclear power in order to provide subsidies to nuclear power could increase this impact if successful. Renewable energy credit markets are

25 See Ohio Senate Bill 310.

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.[26]

Renewable energy credits (RECs), federal investment tax credits and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The credits provide an incentive to make negative energy offers and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices and markets are not publicly available for all PJM states. 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.

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

26 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.").

PJM markets could also provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and create very difficult market power monitoring and mitigation issues.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and certain area sources of emissions.[27 28] The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the Clean Water Act (CWA) affects generating plants that rely on water drawn from jurisdictional water bodies.[29]

Control of Mercury and Other Hazardous Air Pollutants

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

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas,

27 42 U.S.C. § 7401 et seq. (2000).

28 The EPA defines "major sources" 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.

29 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

nickel, selenium and cyanide.[30] The rule establishes a compliance deadline of April 16, 2015.

In a related EPA rule also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).[31]

On June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[32] On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[33] This action supplies the initial cost determination that the U.S. Supreme Court found lacking, and which was the sole basis for remand.

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

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[34] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and periodically revised accordingly.

Recent regulatory activity related to these emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[35]

The EPA finalized the CSAPR on July 6, 2011. 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, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[36] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[37]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[38] Group 2 does not include any states in the PJM region.[39] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[40] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Under the original timetable for implementation, Phase 1 emission reductions were expected to become effective starting January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone season NO_X reductions. CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level

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

31 NSPS are promulgated under CAA § 111.

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

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

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

35 CAA § 110(a)(2)(D)(i)(I).

36 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012) ("CSAPR II").

37 *Id.*

38 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

39 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

40 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, units in PJM states may only trade and use allowances originating in Group 1 states.

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

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR).[41]

In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]," to the EPA's 2014 emissions budgets.[42] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 SO_2 budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia.[43] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[44] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[45] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned emissions budgets, which remain effective until replaced.[46]

On November 16, 2015, the EPA proposed a rule updating the CSAPR ozone season NO_X emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 ("CSPAR Update NOPR").[47] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_X emissions level was lowered to 0.075 ppm from 0.08 in 1997.[48] The CSAPR Update NOPR would increase the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

Starting May 1, 2017, the CSPAR Update NOPR would reduce summertime NO_X from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[49] Table 8-1 shows the reduced NO_X emissions budgets for each PJM affected state. Table 8-1 also shows the assurance level, which is a hard cap on emissions, meaning that emissions above the assurance cannot be covered by emissions allowances, even if available.

41 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014). Some issues, involving what the EPA characterizes as EPA "technical and scientific judgments" continue to require resolution by the courts. See Respondents' Motion To Lift The Stay Entered On December 30, 2011, USCA for the Dist. of Columbia Circuit No. 11-1302, et al. (June 26, 2014) at 9–10 ("EPA Motion to Lift Stay). On October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion.
42 134 S. Ct. at 1609.
43 EME Homer City Generation, L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).
44 *Id.* at 11–12.
45 *Id.* at 11.
46 Emissions Budget Decision at 24–25.
47 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, NOPR, EPA-HQ-OAR-2015-0500, 80 Fed. Reg. 75706 (Dec. 3 2015) ("CSAPR Update"); *Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone*, EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 40662 (July 11, 2011) ("CSAPR Supp.").
48 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).
49 *Id.* at 75742.

Table 8-1 Current and Proposed CSPAR Ozone Season NO_X Budgets for Electric Generating Units (before accounting for variability)[50]

State	Current CSPAR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Proposed Updated CSPAR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Percent Change	Assurance Level (Tons)
Illinois	21,208	12,078	(43.0%)	14,614
Indiana	46,175	28,284	(38.7%)	34,224
Kentucky	32,674	21,519	(34.1%)	26,038
Maryland	7,179	4,026	(43.9%)	4,871
Michigan	24,727	19,115	(22.7%)	23,129
New Jersey	3,382	2,015	(40.4%)	2,438
North Carolina	18,455	12,275	(33.5%)	14,853
Ohio	37,792	16,660	(55.9%)	20,159
Pennsylvania	51,912	14,387	(72.3%)	17,408
Tennessee	8,016	5,481	(31.6%)	6,632
Virginia	14,452	6,818	(52.8%)	8,250
West Virginia	23,291	13,390	(42.5%)	16,202

During the delay of CSAPR implementation from 2012–2015, the EPA estimates that banked emissions allowances "could be in excess of 210,000 tons by the start of the 2017 ozone-season compliance period."[51] The EPA is concerned that "unrestricted use of the bank … could allow emissions to exceed the state budgets, up to the assurance level [an annual cap on use of allowances], year after year."[52] The EPA does not propose to address excess allowances by reducing state emissions budgets. Instead, the EPA proposes a greater than 1-to-1 surrender ratio for allowances.[53] The analysis in the CSPAR Update Rule assumes a 4-to-1 surrender ratio, but the ratio may differ in the final rule.[54]

On November 21, 2014, the EPA issued a rule tolling by three years CSAPR's original deadlines. Compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[55]

50 CSAPR at 48270; CSAPR Supp.at 40666; CSAPR Update NOPR at 75745.
51 CSAPR Update NOPR at 75746.
52 *Id.*
53 *Id.*
54 *Id.* at 75747.
55 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[56] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include 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").[57]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[58]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[59] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The exempted emergency demand response programs included demand resources in RPM.[60]

56 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("Final NESHAP RICE Rule").
57 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ.
58 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."
59 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.
60 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that use behind the meter generators will maintain emergency status and not have to curtail during pre-emergency events, unlike other demand resources. This matter remains pending.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[61] As a result, the national emissions standards uniformly apply to all RICE.[62] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[63] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[64]

On May 3, 2016, the Court issued a mandate to implement the May 1, 2015, order. The MMU is currently taking steps to ensure resource portfolios remain in compliance.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[65] [66]

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[67] [68] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("CPE Guidelines" or Clean Power Plan).[69] On February 6, 2016, the U.S. Supreme Court issued a stay on the CPE Guidelines that will prevent them from taking effect until judicial review is completed.

States have flexibility to meet the EPA's GHG goals, including through participation in multistate CO_2 credit trading programs. The CPE Guidelines provided that a state must submit an individual final compliance plan by September 6, 2016, or request a two-year extension, including for the purpose of developing a multistate plan. The EPA has begun to develop a federal plan applicable in states that do not submit plans, which the EPA plans to finalize in the summer of 2016.

The CPE Guidelines set state by state rate and mass based CO_2 emissions targets.[70] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2022 and the final goals effective 2030.[71] The EPA anticipates that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 32 percent below the level of emissions in 2005.[72]

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

62 *Id.*

63 DENREC v. EPA at 3, 20–21.

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

65 See CAA § 111.

66 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

67 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

68 79 Fed. Reg. 1352 (January 8, 2014).

69 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

70 *Id.* at 1560.

71 *Id.* at 1559.

72 *Id.* at 34839.

The EPA has calculated rate and mass-based goals based on EGU emissions rates for each state.[73] The EPA uses three building blocks to calculate state goals.[74] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[75]

To calculate state interim and final goals, the EPA assumes the following building blocks: (i) heat rate improvement of 2.1–3.4 percent (depending upon the region) at affected EGUs; (ii) displacement of generation from lower emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units; and (iii) displacement of generation from new zero emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.[76]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-2.

Table 8-2 Interim and final targets for CO_2 emissions goals for PJM states[77] (Short Tons of CO_2)

Jurisdiction	2020 Interim New Source Complements (Short Tons of CO_2)	2030 Final New Source Complements (Short Tons of CO_2)	2020 Interim Mass Goal (Short Tons CO_2)	2030 Final Final Goal (Short Tons CO_2)
Delaware	78,842	69,561	5,141,711	4,781,386
District of Columbia	NA	NA	NA	NA
Illinois	818,349	722,018	75,619,224	67,119,174
Indiana	939,343	828,769	86,556,407	76,942,604
Kentucky	752,454	663,880	72,065,256	63,790,001
Maryland	170,930	150,809	16,380,325	14,498,436
Michigan	623,651	550,239	53,680,801	48,094,302
New Jersey	313,526	276,619	17,739,906	16,876,364
North Carolina	692,091	610,623	57,678,116	51,876,856
Ohio	949,997	838,170	83,476,510	74,607,975
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Tennessee	358,838	316,598	32,143,698	28,664,994
Virginia	450,039	397,063	30,030,110	27,830,174
West Virginia	602,940	531,966	58,686,029	51,857,307
Total	8,008,336	7,065,645	689,786,255	617,871,210

73 A mass-based goal is expressed as maximum number of tons of CO_2 that may be emitted over a time period, while a rate-based goal is expressed as a number of pounds of CO_2 per MWh.
74 *Id.* at 1559.
75 *Id.* at 1559–1560.
76 *Id.* 1559.
77 The District of Columbia has no affected EGUs and is not subject to the CPE Guidelines (at 1560).

The difference in goals reflects different evaluation of state specific factors, referred to as building blocks, including heat rate improvements, dispatch among affected EGUs, expanded use of less carbon-intensive generating capacity and demand-side energy efficiency.[78] The essence of the approach is that the baseline is set by the current opportunity in a state to achieve additional CO_2 emissions reductions. No credit is given for prior steps that states have taken, some more than others, to achieve CO_2 emissions reductions.

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[79] The CPE Guidelines would not require states to implement the building blocks in their plan, but would require states to meet the goals through an approach included in an EPA-approved plan.

States could implement a state measures approach, which involves a state "adopt[ing] a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable."[80] States could choose from market-based trading programs, emissions performance standards, renewable portfolio standards (RPS), energy efficiency resource standards (EERS), and other demand-side energy efficiency programs.[81]

The CPE Guidelines recognize that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlight the Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act of 2006.[82] Each of these programs would require significant changes in order to comply with the approach in the CPE Guidelines. The trading rules could remain, but new regional goals and compliance deadlines that equal or exceed the state goals and compliance deadlines set in the CPE Guidelines would be needed. The rules would also take into account that the CPE Guidelines rely on reduced emissions from EGUs to reach state goals and does not count non-EGU offsets towards meeting those goals.[83]

78 CPE Guidelines 1559–1560.
79 *Id.*
80 *Id.* at 1560.
81 *Id.* at 898.
82 *Id.* at 1560.
83 *Id.* at 34910.

The CPE Guidelines permit states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[84]

Federal Regulation of Environmental Impacts on Water

Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from waters of the United States and has a design intake flow of greater than two million gallons per day (mgd).[85]

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

Although the rule is now generally effective, it is implemented with respect to particular facilities as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.

Federal Regulation of Waste Disposal

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[86] Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

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

On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR) under RCRA, the more lenient subtitle D, effective October 19, 2015.[87] The CCRR sets criteria for the disposal of coal combustion residues (CCRs) produced by electric utilities and independent power producers. 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. In 2012, beneficial use was made of approximately 40 percent of residues, such as in the manufacture of cement, concrete, wallboard and roadbed.[88]

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

Table 8-3 describes the criteria and anticipated implementation dates.

84 *Id.* at 1560.
85 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).
86 42 U.S.C. §§ 6901 *et seq.*
87 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
88 CCRR at 21303.

Table 8-3 Minimum Criteria for Existing CCR Ponds (Surface Impoundments) and Landfills and Date by which Implementation is Expected

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

The CCRR likely will raise the costs of disposal of CCRs for the owners of surface impoundments and landfills to meet the EPA criteria.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

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

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[89] 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.[90] NO_x emissions limits for coal units became effective December 15, 2012.[91] NO_x emissions limits for other unit types became effective May 1, 2015.[92]

Table 8-4 shows the HEDD emissions limits applicable to each unit type.

Table 8-4 HEDD maximum NO_X emission rates[93]

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

89 N.J.A.C. § 7:27-19.
90 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
91 N.J.A.C. § 7:27-19.4.
92 N.J.A.C. § 7:27-19.5.
93 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

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").[94] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[95] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[96]

State Regulation of Greenhouse Gas Emissions

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[97] RGGI generates revenues for the participating states which have spent approximately 62 percent of revenues to date on energy efficiency, 8 percent on clean and renewable energy, 9 percent on greenhouse gas abatements and 15 percent on direct bill assistance.[98]

Table 8-5 shows the RGGI CO_2 auction clearing prices and quantities for the 2009-2011 compliance period auctions, the 2012-2014 compliance period auctions and 2015-2017 compliance period auctions held as of June 30, 2016, in short tons and metric tonnes. Prices for auctions held June 1, 2016, for the 2015-2017 compliance period were at $4.53 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[99] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction of $5.25 in March 2016. 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 auction to use CRRs.

94 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

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

96 See *Id.*

97 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>.

98 *Investment of RGGI Proceeds Through 2013*, The Regional Greenhouse Gas Initiative, April 2015 <http://www.rggi.org/docs/ProceedsReport/Investment-RGGI-Proceeds-Through-2013.pdf> (Accessed July 5, 2016).

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

Table 8-5 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[100]

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

CAIR and CSAPR

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[101] [102] On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and 2016 and CSAPR's Phase 2 emissions effective January 1, 2017.[103] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR and had a corresponding impact on market prices for CAIR emissions allowances and CSAPR emissions allowances.

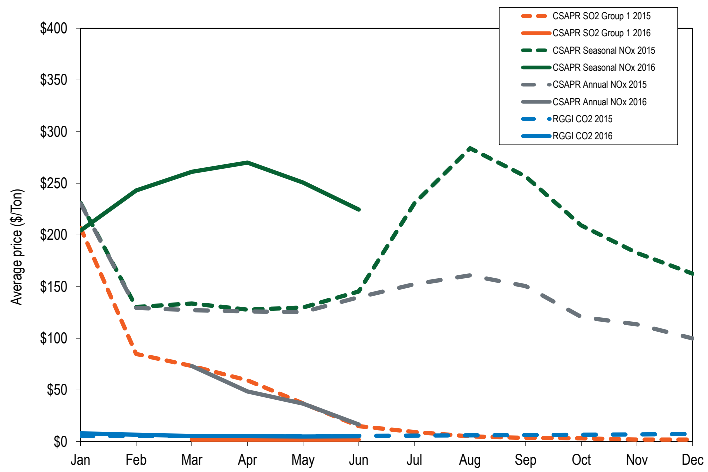
Figure 8-1 shows average, monthly settled prices for NO_x, CO_2 and SO_2 emissions allowances including CSAPR related allowances for 2015 and the first six months of 2016.[104] Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first six months of 2016, CSAPR annual NO_x prices were 70.6 percent lower than the CSAPR NO_x prices in the first six months of 2015. There were not any reported cleared purchases for January or February 2016 for CSAPR Annual NO_x. The average price of CSAPR SO_2 in the first six months of 2016 was $2.00 compared the average price of $79.36 for CSAPR SO_2 in the first six months of 2015.[105]

100 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed July 5, 2016).

101 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
102 Order, City Generation, L.P. EPA et al. v. EME Homer et al., No. 11-1302.
103 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
104 The NO_x prices result from the Clean Air Interstate Rule (CAIR) established by the EPA covering 28 states. The SO_2 prices result from the Acid Rain cap and trade program established by the EPA. The CO_2 prices are from RGGI.
105 There were not any reported cleared purchases for January or February 2016 for CSAPR SO_2 or CSAPR Annual NO_x.

Figure 8-1 Spot monthly average emission price comparison: January 2015 through June 2016[106]



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of June 30, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[107] West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[108]

Under the existing state renewable portfolio standards, approximately 7.8 percent of PJM load must be served by renewable resources in 2016 and, if the proportion of load among states remains constant, 14.2 percent of PJM load by must be served by renewable resources in 2028 under defined RPS rules. As shown in Table 8-6, Delaware and Illinois will require 25.0 percent of load to be served by renewable resources in 2028, the highest standard of PJM jurisdictions. Renewable resources earn renewable energy credits (RECs) (also known as alternative energy credits) when they generate electricity. These RECs are bought by retail suppliers to fulfill the requirements for generation from renewable resources.

106 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 5, 2016).

107 See Ohio Senate Bill 310.

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

Table 8-6 Renewable standards of PJM jurisdictions: 2016 to 2028[109]

Jurisdiction	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%
Illinois	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%
Indiana	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%
Kentucky	No Standard												
Maryland	15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Michigan	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%	24.21%	24.30%	24.39%	24.48%
North Carolina	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%
Pennsylvania	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Tennessee	No Standard												
Virginia	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%
Washington, D.C.	14.33%	15.98%	17.65%	19.35%	21.58%	21.85%	22.18%	22.50%	22.50%	22.50%	22.50%	22.50%	22.50%
West Virginia	No Standard												

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. 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. The FERC has found that such costs can be appropriately considered in the rates established through the operation of wholesale organized markets.[110]

Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[111] This is equivalent to providing a REC price equal to three times its stated value per MWh. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.[112]

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 8-7 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-7 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		
Indiana	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			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			

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

110 See 146 FERC ¶ 61,084 at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner.[footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition. We also find that ISO-NE's use of an inflation rate in determining the price of Renewable Energy Credits is a reasonable estimate of Renewable Energy Credits for the 2018-2019 Capacity Commitment Period.").

111 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed July 5, 2016).

112 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.

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-8 outlines these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with states' standards to be generated by in-state resources. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions.

Delaware, Pennsylvania and Virginia require that RECs largely come from within the PJM footprint though Delaware and Virginia have more nuanced rules in their standards. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

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

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
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 resources located in a control area synchronized with PJM.
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 either located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in state contiguous to Ohio has been deemed deliverable into the state of Ohio. If a renewable resource is located outside of this range, then it must demonstrate deliverabilty to the Public Utilities Commission of Ohio.
Pennsylvania	No	RECs must be purchased from resources located anywhere within PJM.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.
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.

Some PJM jurisdictions have specific RPS requirements for the purchase of solar resources. These solar requirements are included in the total requirements shown in Table 8-9 but may be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. have requirements for the proportion of load served by solar.

Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2016, New Jersey had the most stringent solar standard in PJM, requiring that 2.45 percent of retail electricity sales within the state be served by solar resources. As Table 8-9 shows, by 2028, New Jersey will continue to have the most stringent standard, requiring that at least 4.10 percent of load be served by solar.

Table 8-9 Solar renewable standards by percent of electric load for PJM jurisdictions: 2016 to 2028

Jurisdiction	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%
Illinois	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Indiana	No Minumum Solar Requirement												
Kentucky	No Renewable Portfolio Standard												
Maryland	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Minimum Solar Requirement												
New Jersey	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%	3.83%	3.92%	4.01%	4.10%
North Carolina	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%
Pennsylvania	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Tennessee	No Renewable Portfolio Standard												
Virginia	No Minimum Solar Requirement												
Washington, D.C.	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
West Virginia	No Renewable Portfolio Standard												

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-10 are also included in the total RPS requirements. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 7.50 percent of load served in 2016 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington D.C. all have "Tier II" or "Class 2" standards, which allow specific technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2020, 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 (Table 8-10).

Within the PJM footprint there have been attempts to pass low carbon portfolio standards in addition to renewable portfolio standards. An example of this is Illinois House Bill 3293, which was introduced on February 26, 2015. This legislation proposes the creation of a low carbon portfolio standard under which a defined share of all retail electricity sales in Illinois must come from generation that "does not emit any air pollution, including sulfur dioxide, nitrogen oxide, or carbon dioxide, as reported in the [PJM] Generation Attribute Tracking System."[113] Under this new legislation nuclear, certain clean coal resources, and all renewable resources would qualify as low carbon energy resources. This bill was referred again to the Rules Committee on March 27, 2015, and remains there as of June 30, 2016.

113 See Illinois House Bill 3293. <http://www.ilga.gov/legislation/99/HB/PDF/09900HB3293lv.pdf> (Accessed July 5, 2016).

Table 8-10 Additional renewable standards of PJM jurisdictions: 2016 to 2028

Jurisdiction		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available. Figure 8-2 shows the average solar REC (SREC) price by jurisdiction for 2009 through June 2016. The average NJ SREC prices dropped from $674 per SREC in 2010 to $290 per SREC in 2016. The DC SREC prices are currently the highest at $488 per SREC.[114] [115]

Figure 8-2 Average solar REC price by jurisdiction: 2009 through June 2016

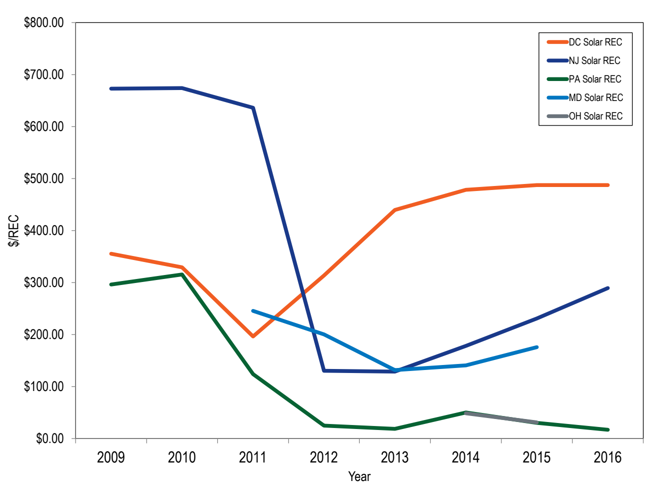
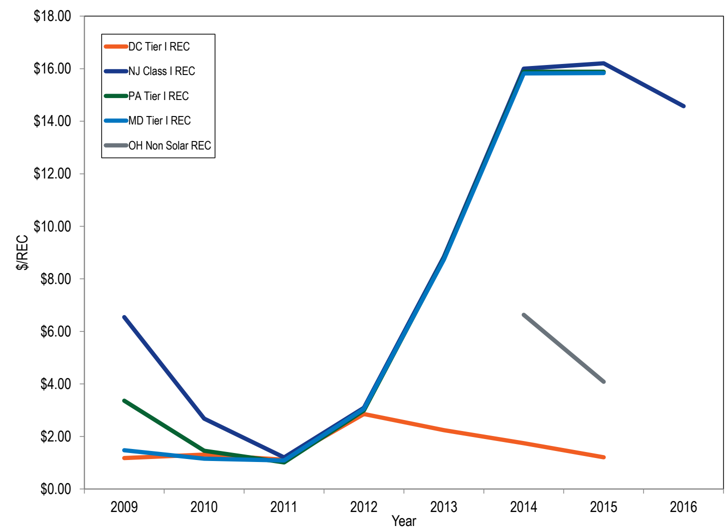


Figure 8-3 shows the average Tier I REC price by jurisdiction from 2009 through June 2016. Tier I REC prices are lower than SREC prices. Ohio and Pennsylvania had the lowest SREC prices at $31 per SREC and $17 per SREC while New Jersey had the highest Tier I REC prices at $14 per REC.[116] [117]

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through June 2016

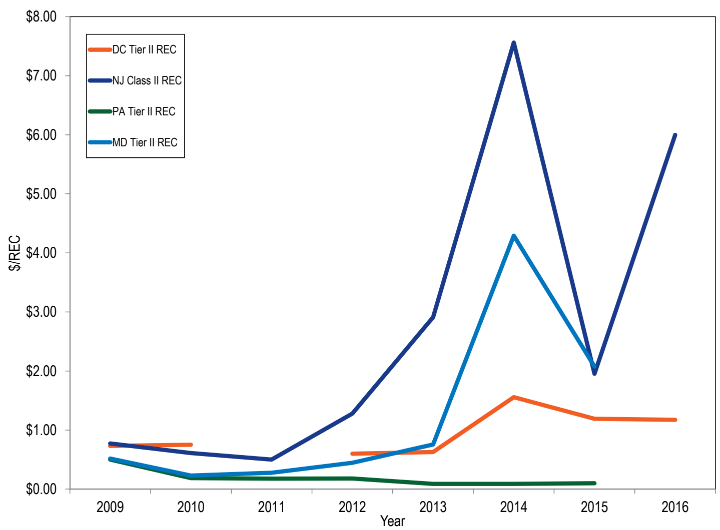


114 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 5, 2016).
115 There were not any reported purchases of MD Solar REC for the first six months of 2016.

116 Tier I REC price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 5, 2016).
117 There were not any reported purchases of DC Tier I REC, MD Tier I REC, PA Tier I REC or OH non-Solar REC for the first six months of 2016.

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 2009 through June 2016. DC had the lowest Tier II REC prices at $1.34 per REC while New Jersey had the highest Tier II REC prices at $5.06 per REC.[118]

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through June 2016



PJM jurisdictions include various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $323.00 per MWh.[119] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. For all states with an alternative compliance payment, it is cheaper to buy the REC than pay the for the alternative compliance payment.

Compliance is defined in different ways by different jurisdictions. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Table 8-11 shows the alternative compliance standards in PJM jurisdictions, where such standards exist.

Table 8-11 Renewable alternative compliance payments in PJM jurisdictions: As of June 30, 2016[120]

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$350.00
Michigan	No specific penalties		
New Jersey	$50.00		$323.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commision		
Ohio	$45.00		$300.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	No standard		

Table 8-12 shows renewable resource generation by jurisdiction and resource type for the first eight months of 2016. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, all of which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind output was 8,606.7 GWh of 14,512.9 Tier I GWh, or 59.3 percent, in the PJM footprint. As shown in Table 8-12 , 24,724.3 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 58.7 percent. Total renewable generation was 6.5 percent of

118 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed July 5, 2016). There is no data reported by Evomarkets for DC in 2011 or PA Tier II REC or MD Tier II REC for the first six months of 2016.

119 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/ Policies for Renewables & Efficiency, "Solar Renewables Energy Certificates (SRECs)," <http://programs.dsireusa.org/system/program/detail/5687> (Accessed July 5, 2016).

120 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed July 5, 2016).

total generation in PJM for the first six months of 2016. Landfill gas, solid waste and waste coal were 8,696.0 GWh of renewable resource generation or 35.2 percent of the total Tier I and Tier II.

Table 8-12 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through June, 2016

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	18.8	0.0	0.0	0.0	0.0	0.0	0.0	18.8	37.5
Illinois	52.2	0.0	0.0	7.5	0.0	0.0	3,619.1	3,678.9	3,678.9
Indiana	28.9	0.0	22.1	0.0	0.0	0.0	2,335.6	2,386.7	2,386.7
Kentucky	0.0	0.0	217.1	0.0	0.0	0.0	0.0	217.1	217.1
Maryland	48.1	0.0	1,017.5	35.0	322.8	0.0	231.9	1,332.4	1,655.3
Michigan	11.5	0.0	34.6	0.0	0.0	0.0	0.0	46.1	46.1
New Jersey	143.6	229.6	8.6	223.3	701.1	0.0	5.4	381.0	1,311.6
North Carolina	0.0	0.0	534.4	23.7	0.0	0.0	0.0	558.1	558.1
Ohio	159.3	0.0	225.7	0.7	0.0	0.0	660.2	1,045.9	1,045.9
Pennsylvania	417.6	768.3	1,501.0	13.9	661.8	3,726.3	1,754.4	3,686.8	8,843.1
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	254.1	1,651.7	287.4	0.0	370.8	1,779.2	0.0	541.5	4,343.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	619.5	0.0	0.0	0.0	0.0	619.5	619.5
Total	1,134.1	2,649.5	4,468.0	304.1	2,056.5	5,505.5	8,606.7	14,512.9	24,724.3
Percent Total	4.6%	10.7%	18.1%	1.2%	8.3%	22.3%	34.8%	58.7%	100.0%

Table 8-13 PJM renewable capacity by jurisdiction (MW): July 1, 2016

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	43.1	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,662.4	2,714.5
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,602.4	1,618.6
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
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	25.1	0.0	69.0	0.0	494.4	78.3	128.2	0.0	190.0	985.0
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.5	356.1	162.0	0.0	4.5	1,064.8
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	207.1	0.0	0.0	0.0	559.6
Ohio	11,080.0	63.4	0.0	156.0	0.0	119.1	1.1	0.0	0.0	403.0	11,822.6
Pennsylvania	0.0	208.0	2,346.0	0.0	1,269.0	888.3	19.5	345.8	1,611.0	1,337.7	8,025.3
Tennessee	0.0	0.0	0.0	0.0	0.0	52.0	0.0	50.0	0.0	0.0	102.0
Virginia	0.0	222.1	0.0	17.0	5,166.2	350.5	0.0	444.9	585.0	0.0	6,785.7
West Virginia	0.0	2.2	0.0	0.0	0.0	257.9	0.0	0.0	165.0	583.3	1,008.4
PJM Total	11,080.0	665.6	4,143.0	255.0	6,888.2	2,714.2	671.1	1,130.9	2,361.0	7,114.2	37,023.3

Table 8-13 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. New Jersey has the largest amount of solar capacity in PJM, 356.1 MW, or 53.1 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2010 at $674 per REC, and in the first six months of 2016 are at $290 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,264.7 MW, or 59.9 percent of the total wind capacity.

Table 8-14 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 2,620.5 MW of which 1,284.7 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions. This includes both solar generation located inside PJM but not PJM units, and generation connected to other RTOs outside PJM.

Table 8-14 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on July 1, 2016[121]

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	87.5	0.0	87.5
Arkansas	0.0	135.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	153.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	74.7	0.0	2.1	79.0
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	38.7	258.9	0.0	297.6
Illinois	0.0	6.6	91.9	0.0	0.6	0.0	30.9	0.0	300.5	430.5
Indiana	0.0	0.0	43.2	0.0	6.2	234.6	14.1	0.0	180.0	478.1
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	476.7	479.8
Kentucky	600.0	86.2	18.6	0.0	0.4	0.0	16.1	93.0	0.0	814.3
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	0.0	63.0
Maryland	65.0	0.0	11.7	129.0	0.0	0.0	472.9	15.0	0.3	693.9
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	2.3	0.0	0.0	61.8
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	446.0	446.2
New Jersey	0.0	0.0	53.1	0.0	8.3	0.0	1,284.7	0.0	5.0	1,351.1
New York	0.0	158.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	159.1
North Carolina	0.0	242.5	12.0	0.0	0.0	0.0	299.9	151.5	0.0	705.9
North Dakota	0.0	0.0	360.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0
Ohio	0.0	1.0	33.6	92.6	16.4	32.4	123.6	109.3	35.2	444.2
Pennsylvania	109.7	37.0	43.6	91.0	12.6	5.0	221.1	68.6	3.3	591.7
Tennessee	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	18.2	12.1	0.0	0.5	0.0	14.4	287.6	0.0	332.8
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	3.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	20.0
Total	829.7	747.4	685.2	312.6	62.9	272.0	2,620.5	1,236.7	1,449.2	8,216.2

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[122] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[123] Of the current 60,829.1 MW of coal capacity in PJM, 53,561.0 MW of capacity, 88.1 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[124] [125]

Table 8-15 SO_2 emission controls by fuel type (MW): as of June 30, 2016[126]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	53,561.0	7,268.1	60,829.1	88.1%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	0.0	50,622.2	50,622.2	0.0%
Other	325.0	4,920.7	5,245.7	6.2%
Total	53,886.0	68,811.6	122,697.6	43.9%

NO_x emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 114,291.9 MW, 93.1 percent, of 122,697.6 MW of capacity in PJM, have emission controls for NO_x. Table 8-16 shows NO_x emission controls by unit type in PJM. While most units in PJM have NO_x emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_x compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[127]

Table 8-16 NO_x emission controls by fuel type (MW), as of June 30, 2016

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	59,889.8	939.3	60,829.1	98.5%
Diesel Oil	2,207.6	3,793.0	6,000.6	36.8%
Natural Gas	49,394.8	1,227.4	50,622.2	97.6%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	114,291.9	8,405.7	122,697.6	93.1%

121 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed July 5, 2016).

122 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 5, 2016).

123 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A Section 72.2" <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed July 6, 2016).

124 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 6, 2016. Data last updated March 11, 2016).

125 The total MW for each fuel type are less than the 177,682.8 MW reported in Section 5: Capacity, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed July 6, 2016).

126 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil.

127 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants" <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed July 6, 2016).

Most coal units in PJM have particulate controls due to the NAAQS and CSAPR. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[128] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 60,495.1 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of June 30, 2016. 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 to meet the state and federal emissions limits established by the MATS EPA regulations.[129] Currently, 131 of the 158 coal steam units have baghouse or FGD technology installed, representing 52,646 MW out of the 60,829.1 MW total coal capacity, or 86.5 percent.

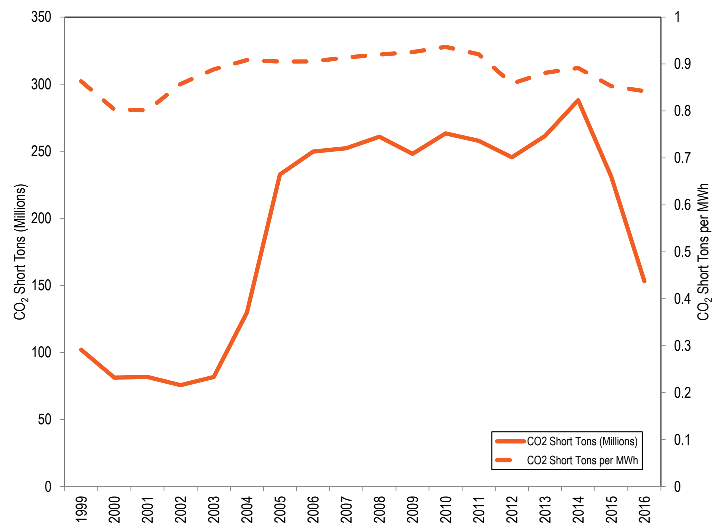
Table 8-17 Particulate emission controls by fuel type (MW), as of June 30, 2016

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	60,495.1	334.0	60,829.1	99.5%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	260.0	50,362.2	50,622.2	0.5%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	63,857.1	58,840.5	122,697.6	52.0%

Figure 8-5 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM for the first six months of each year.[130] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.80 short tons per MWh in the first six months of 2001, and a maximum of 0.94 short tons per MWh in the first six months of 2010. In the first six months of 2016, CO_2 short tons emissions were 0.84 per MWh.

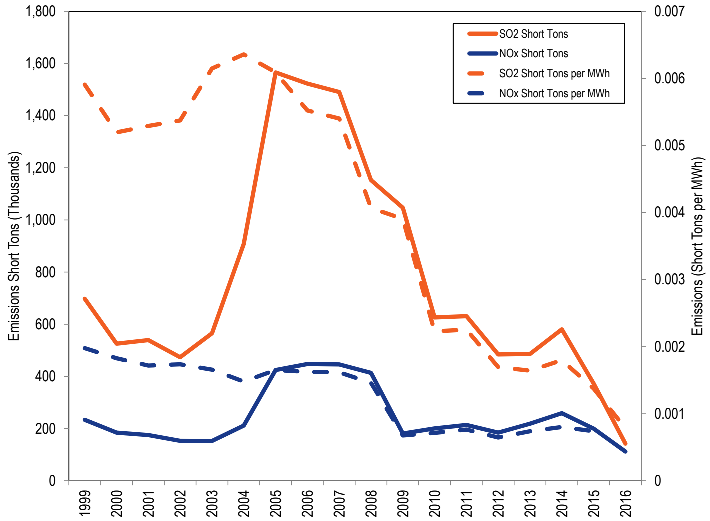
Figure 8-6 shows the total SO_2 and NO_x short ton emissions (in thousands) and the short ton emissions per MWh within PJM for the first six months of each year. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000783 short tons per MWh in the first six months of 2016, and a maximum of 0.006356 short tons per MWh in the first six months of 2004. Since 1999, the amount of NO_x produced per MWh was at a minimum of 0.000616 short tons per MWh in the first six months of 2016, and a maximum of 0.001977 short tons per MWh in the first six months of 1999. In the first six months of 2016, SO_2 short ton emissions were 0.000783 per MWh and NO_x short ton emissions were 0.000616 per MWh.

Figure 8-5 CO_2 emissions by year (millions of short tons), by PJM units: January 1999 through June 2016[131]



128 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed July 6, 2016).
129 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants l> (Accessed July 6, 2016).
130 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
131 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-6 SO_2 and NO_x emissions by year (thousands of short tons), by PJM units: January 1999 through June 2016[132]



Wind Units

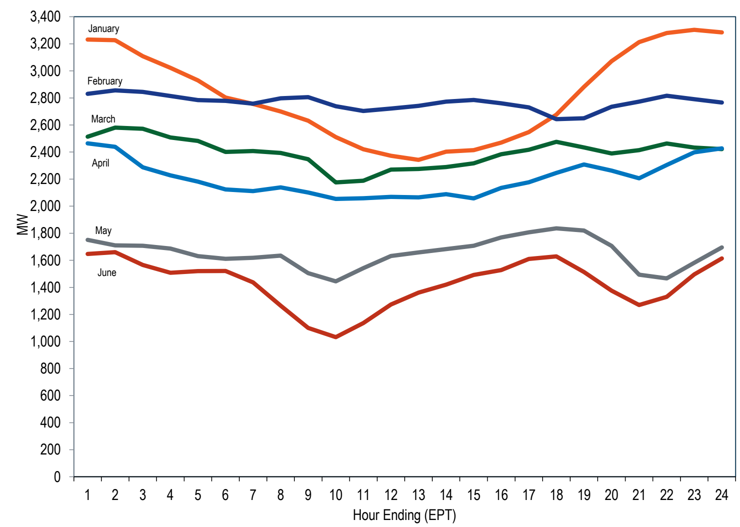
Table 8-18 shows the capacity factor of wind units in PJM. In the first six months of 2016, the capacity factor of wind units in PJM was 31.5 percent. Wind units that were capacity resources had a capacity factor of 32.4 percent and an installed capacity of 6,368 MW. Wind units that were classified as energy only had a capacity factor of 22.6 percent and an installed capacity of 889 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[133]

Table 8-18 Capacity factor of wind units in PJM: January through June 2016[134]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	22.6%	889
Capacity Resource	32.4%	6,368
All Units	31.5%	7,257

Figure 8-7 shows the average hourly real-time generation of wind units in PJM, by month. The highest average hour, 3,303.5 MW, occurred in January, and the lowest average hour, 1,032.3 MW, occurred in June. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-7 Average hourly real-time generation of wind units in PJM: January through June 2016



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

133 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

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

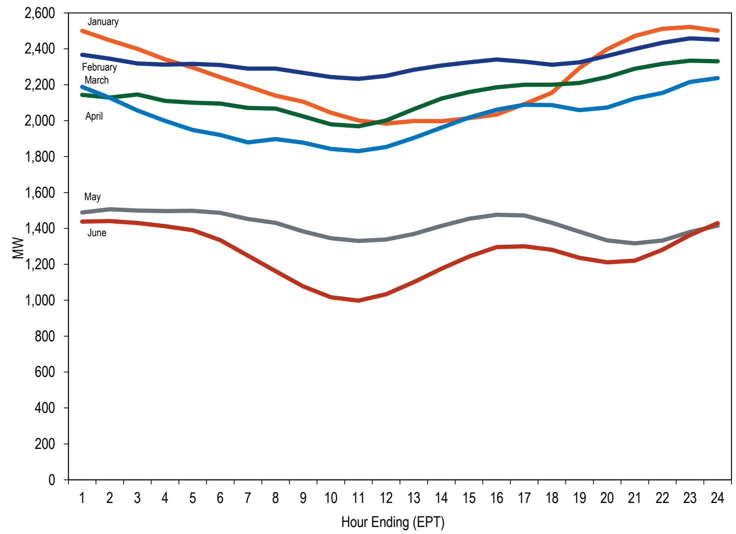
Table 8-19 shows the generation and capacity factor of wind units in each month of 2015 through June 2016.

Table 8-19 Capacity factor of wind units in PJM by month: 2015 through June 2016

	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,664,426.8	33.9%	2,095,618.0	40.5%
February	1,511,093.1	34.1%	1,925,470.3	39.8%
March	1,701,249.6	34.7%	1,781,561.4	34.5%
April	1,641,965.0	34.5%	1,587,976.6	31.7%
May	1,209,088.5	24.6%	1,230,631.9	23.6%
June	955,156.7	20.1%	1,029,071.2	19.7%
July	639,381.7	13.0%		
August	623,873.6	12.4%		
September	846,505.6	17.3%		
October	1,756,221.4	34.8%		
November	2,023,340.0	41.3%		
December	2,037,436.4	39.8%		
Annual	16,609,738.2	28.3%	9,650,329.4	31.5%

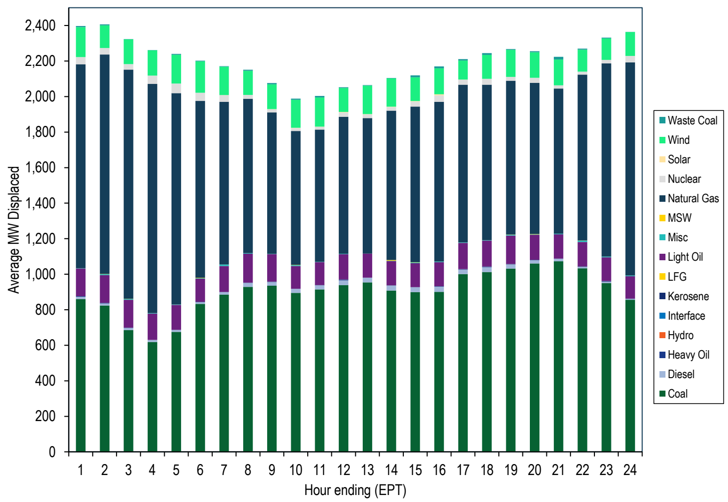
Wind units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer noncapacity related wind energy at their discretion.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

Figure 8-8 Average hourly day-ahead generation of wind units in PJM: January through June 2016



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-9 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first six months of 2016. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 8-9 Marginal fuel at time of wind generation in PJM: January through June 2016



Solar Units

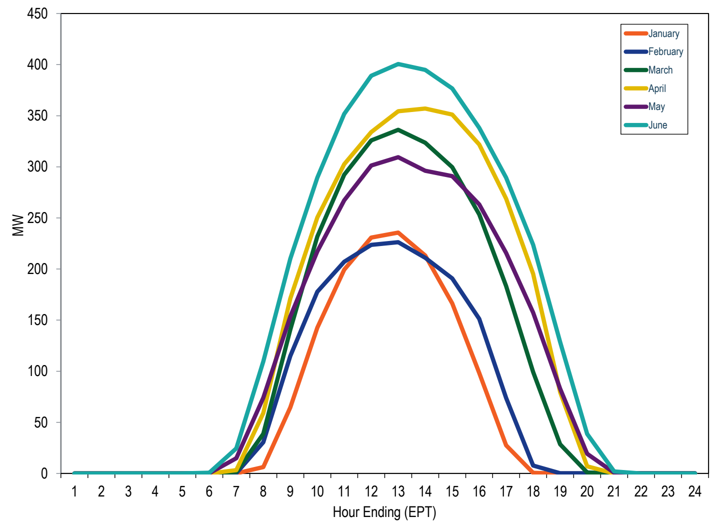
Table 8-20 shows the capacity factor of solar units in PJM. In the first six months of 2016, the capacity factor of solar units in PJM was 19.0 percent. Solar units that were capacity resources had a capacity factor of 16.8 percent and an installed capacity of 323 MW. Solar units that were classified as energy only had a capacity factor of 21.8 percent and an installed capacity of 254 MW. Solar capacity in RPM is derated to 38 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[135]

Table 8-20 Capacity factor of wind units in PJM: January through June 2016

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.8%	254
Capacity Resource	16.8%	323
All Units	19.0%	577

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-10 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation was highest in June, the month with the highest average hour, 400.6 MW, compared to 577 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-10 Average hourly real-time generation of solar units in PJM: January through June, 2016



135 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

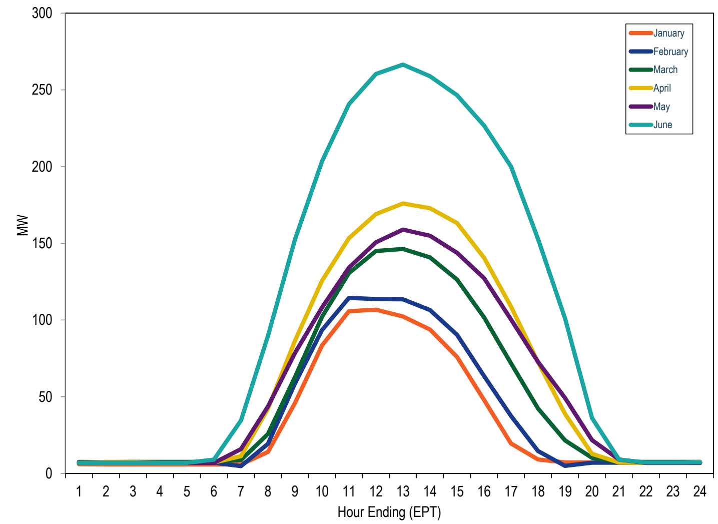
Table 8-21 shows the generation and capacity factor of wind units in each month of 2015 through June 2016.

Table 8-21 Capacity factor of solar units in PJM by month: 2015 through June 2016

	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	19,935.6	8.8%	25,967.1	10.8%
February	27,609.2	13.3%	26,416.5	11.8%
March	32,677.1	13.7%	41,467.3	17.3%
April	45,376.5	19.5%	47,114.8	20.3%
May	53,368.8	22.2%	42,139.5	17.6%
June	45,158.2	19.4%	53,874.8	23.2%
July	52,125.7	21.7%		
August	52,751.5	22.0%		
September	42,099.8	18.1%		
October	37,085.5	15.4%		
November	25,881.6	11.1%		
December	17,067.0	7.1%		
Annual	451,136.5	16.1%	236,979.9	16.8%

Solar units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Solar units may offer non-capacity related solar energy at their discretion. Figure 8-11 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[136]

Figure 8-11 Average hourly day-ahead generation of solar units in PJM: January through June, 2016



136 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.