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 most recent interstate emissions rule, the Cross-State Air Pollution Rule (CSAPR), will, when implemented, also 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 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 establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date 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).

- **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.[2]

  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.[3,4]

  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.[5]

- **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

1 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
2 CAA § 110(a)(2)(D)(i)(I).
3 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).
4 Order, City Generation, L.P. EPA et al v. EME Homer et al., No. 11-1302.
5 *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).

engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[6] The Court held that "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."[7] Specifically, the Court found that 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.[8]

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, pursuant to Section 111(d) of the EPA Act, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[9] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to regulate CO_2 emissions from existing sources.[10] The EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities on June 2, 2014, the Existing Stationary Sources Notice of Proposed Rulemaking ("ESS NOPR").[11] The EPA refers to its rules directed at GHG under Section 111(d) as the "Clean Power Plan."

  The ESS NOPR established interim and final emissions goals for each state that must be met by 2020 and 2030. The EPA plans to issue final rules on both the GHG NSPS and the ESS NOPR in the summer of 2015. Individual state plans likely will be submitted in the summer of 2017, while multistate plans likely will be submitted in the summer of 2018.

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.[12] 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.[13]

- **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").[14] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.

  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 that may have impacted PJM markets.[15] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, agreed to terms with the Illinois Pollution Control Board.[16]

- **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 2015 for the 2015-2017 compliance period were $5.41 per ton. The clearing price is equivalent to a price of $5.96 per metric tonne, the unit used in other carbon markets.

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

6 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).

7 DENREC v. EPA at 3, 20–21.

8 *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.

9 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").

10 See CAA § 111(b)&(d).

11 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).

12 N.J.A.C. § 7:27–19.

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

14 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

15 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).

16 See *Id.*

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 March 31, 2015, 78.3 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 92.7 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 March 31, 2015, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. 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.[17] West Virginia had a voluntary standard, but the state Legislature repealed their renewable portfolio standard on January 22, 2015.

Renewable energy credits (RECs) 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.

17 See Ohio Senate Bill 310.

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 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 bundled with a wholesale sale of electric energy even if the transfer of the energy and the REC documented separately.[18] RECs affect prices in wholesale power markets. 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. 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 environmental permits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and 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.

PJM markets could 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 environmental dispatch rules, in contrast, poses a threat to economic dispatch and creates very difficult market power monitoring and mitigation issues.

18 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.").

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.[19,20] The EPA 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.[21]

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, nickel, selenium and cyanide.[22] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date 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).

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).[23] 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.

Much 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.[24]

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) now in effect.[25]

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.[26] The CSAPR covers 28 states,

19 42 U.S.C. § 7401 et seq. (2000).

20 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.

21 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.

22 *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).

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

24 CAA § 110(a)(2)(D)(i)(I).

25 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.

26 *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).

including all of the PJM states except Delaware, and also excluding the District of Columbia.[27]

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.[28] Group 2 does not include any states in the PJM region.[29] 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[30] 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 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.

Under the original implementation timetable, significant additional Phase 2 SO_2 emission reductions would have taken effect in 2014 from certain states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

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 November 21, 2014, 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.[31]

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).[32] 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").[33]

27 *Id.*
28 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.
29 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
30 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.
31 *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).
32 *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").
33 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.

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).[34]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[35] 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 include demand resources in RPM.[36]

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.[37] The Court held that "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."[38] Specifically, the Court found that 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.[39]

On December 24, 2013, PJM filed revisions to the rules providing for a PJM Pre-Emergency Load Response Program that allows PJM to dispatch resources participating in the program with no prerequisite for system emergency conditions.[40] PJM retained the PJM Emergency Load Response Program (ELRP), but proposed to restrict participation in the ELRP to DR based on "generation that is behind the meter and has strict environmental restrictions on when it can operate."[41] Such restrictions refer to the EPA's amended RICE NESHAP Rule. The EPA created an exception to and weakened its NESHAP RICE Rule based on arguments that markets such as PJM needed RICE for reliability. PJM created an exception to its rule, which would allow RICE to continue to use the EPA's exception. The MMU protested retention of the emergency program, particularly because it accorded discriminatory preference to resources that have negative consequences for reliability, the markets and the environment.[42]

By order issued May 9, 2014, the Commission ordered that PJM "either: (i) justify the need for, and scope of, its proposed exemption, including any necessary revisions to its Tariff to ensure that the exemption is properly tailored to the environmental restrictions imposed on these units, or (ii) remove the exemption for behind-the-meter demand response resources from its tariff."[43] In its compliance filing, PJM attempted to justify the exception.[44] An order from the Commission on PJM's compliance filing is now pending.

Regulation of Greenhouse Gas Emissions

The EPA has proposed to regulate CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS and encourage coordination between the EPA and the states.[45,46]

The EPA's first step was the development of regulations applicable to new resources, New Source Performance Standards (NSPS). On September 20,

34 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."

35 *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.

36 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that utilize 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.

37 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).

38 DENREC v. EPA at 3, 20–21.

39 *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.

40 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2014).

41 *Id.* at 8–9.

42 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822-000 (January 14, 2014) at 3–6.

43 See 147 FERC ¶ 61,103 at P 41.

44 See PJM compliance filing, FERC Docket No. ER14-822-002 (June 2, 2014) at 4–8.

45 See CAA § 111.

46 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.

2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[47,48] The standards would require advanced technologies like efficient natural gas units and efficient coal units with partial carbon capture and storage (CCS). The proposed rule includes two limits for fossil fuel fired utility boilers and 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 (MW): 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).

Once NSPS standards for CO_2 are in place, the CAA permits the EPA to regulate CO_2 emissions from existing sources.[49] In anticipation of timely issuance of a final NSPS for CO_2, the EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities ("ESS NOPR") on June 2, 2014.[50] The EPA plans to issue a final rule in the ESS NOPR proceeding in the summer of 2015.

States have flexibility to meet the EPA's GHG goals, including through participation in multistate CO_2 credit trading programs. A state opting to submit an individual compliance plan must do so by the summer of 2017 and states opting to submit multistate plans must do so by the summer of 2018 (assuming in both cases that a one-year extension is requested). The EPA has begun to develop a federal plan applicable in states that do not submit plans which it plans to finalize in the summer of 2016.

The ESS NOPR sets state by state CO_2 emissions targets, which are expressed as interim and final rate based goals.[51] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2020 and the final goals effective 2030.[52] The ESS NOPR would allow states to translate the rate based goals into mass based goals (a cap on the tons of CO_2 emissions) when they submit their plans.[53] Mass based goals would facilitate multistate approaches to emissions reductions. The EPA anticipates that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 30 percent below the level of emissions in 2005.[54]

The EPA has calculated goals based on EGU emissions rates for each state. The EPA uses four building blocks to calculate state goals.[55] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[56]

To calculate state interim and final goals, the EPA assumes the following building blocks: (i) heat rate improvement of six percent at affected EGUs; (ii) displacement in the system dispatch of the most carbon intensive EGUs with generation from less carbon intensive EGUs (including NGCC units under construction); (iii) displacement in the system dispatch of affected EGUs by low or zero carbon generation (renewables and nuclear, including planned nuclear); and (iv) reduced emissions from affected EGUs from the use of demand side energy efficiency.[57]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-1.

47 *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>.
48 79 Fed. Reg. 1352 (January 8, 2014).
49 See CAA § 111(b)&(d).
50 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
51 *Id.* at 34894.
52 ESS NOPR at 34837.
53 *Id.* at 34894.
54 *Id.* at 34839.
55 *Id.* at 34836.
56 *Id.* at 34856–34858.
57 *Id.* at 34861.

Table 8-1 Interim and final targets for CO_2 emissions goals for PJM states[58] (lbs/MWh)[59]

PJM State	2020 Interim Rate-Based Goal (lb/MWh)	2030 Final Rate-Based Goal (lb/MWh)
Kentucky	1,844	1,763
West Virginia	1,748	1,620
Indiana	1,607	1,531
Ohio	1,452	1,338
Illinois	1,366	1,271
Maryland	1,347	1,187
Tennessee	1,254	1,163
Michigan	1,227	1,161
Pennsylvania	1,179	1,052
North Carolina	1,077	992
Delaware	913	841
Virginia	884	810
New Jersey	647	531
District of Columbia	NA	NA

The difference in goals reflects different state by state evaluation of 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.[60] 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.[61] The ESS NOPR would not require states to implement the building blocks in their plan; it would require states to meet the goals through an approach included in an EPA-approved plan.[62] The EPA would impose its own plan if a state does not timely propose a plan that EPA finds satisfactory.[63] EPA has begun to develop a federal plan, which it plans to issue in the summer of 2016 along with a final rule in the ESS NOPR proceeding.

58 The District of Columbia has no affected EGUs and is not subject to the ESS NOPR. *Id.* at 34867.
59 CO_2 targets reported in adjusted output-weighted average pounds per net MWh.
60 ESS NOPR at 34858–34877.
61 *Id.* at 34830.
62 *Id.* at 34897 ("[A] core flexibility provided under CAA section 111(d) is that while states are required to establish standards of performance that reflect the degree of emission limitation from application of the control measures that the EPA identifies as the BSER, they need not mandate the particular control measures the EPA identifies as the basis for its BSER determination.").
63 *Id.* at 34844.

States could implement portfolio approaches that would "require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level."[64] 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.[65]

The ESS NOPR recognizes that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlights the Regional Greenhouse Gas Initiative (RGGI), California's Global Warming Solutions Act of 2006, and Colorado's Clean Air, Clean Jobs Act.[66] Each of these programs would require significant changes in order to comply with the approach in the ESS NOPR. 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 ESS NOPR would be needed. The rules would also take into account that the ESS NOPR relies on reduced emissions from EGUs to reach state goals and does not count non EGU offsets towards meeting those goals.[67]

The ESS NOPR permits states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[68]

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

64 *Id.* at 34901.
65 *Id.* at 34835.
66 *Id.* at 34848–34849.
67 *Id.* at 34910.
68 *Id.* at 34834.

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.[69] 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.[70]

Table 8-2 shows the HEDD emissions limits applicable to each unit type. NO_x emissions limits for coal units became effective December 15, 2012.[71] NO_x emissions limits for other unit types will become effective May 1, 2015.[72]

Table 8-2 HEDD maximum NO_x emission rates[73]

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

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NOX, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[74] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as 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 that may have impacted PJM markets.[75] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, 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.[76]

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.[77,78] RGGI generates revenues for the participating states. The states have spent approximately 65 percent of revenues to date on energy efficiency, six percent on clean and renewable energy, six percent on greenhouse gas abatements and 17 percent on direct bill assistance.[79]

Table 8-3 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 March 31, 2015, in short tons and metric tonnes. Prices for auctions held March 11, 2015, for the 2015-2017 compliance period were at the highest clearing price to date, $5.41 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[80] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the previous high of $5.21 in December 2014 as the result of a 16.1 percent reduction in the quantity of allowances offered in this auction for the 2015-2017 compliance period. This auction did not include additional

69 N.J.A.C. § 7:27-19.
70 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).
71 N.J.A.C. § 7:27-19.4.
72 N.J.A.C. § 7:27-19.5.
73 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.
74 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO_2 (CPS)).
75 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).
76 See *Id.*
77 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>.
78 For more details see the *2013 State of the Market Report for PJM*, Volume 2: Section 8, "Environmental and Renewables."
79 *Regional Investment of RGGI CO_2 Allowance Proceeds, 2012*, The Regional Greenhouse Gas Initiative, February 2014 <http://www.rggi.org/docs/Documents/2012-Investment-Report_ES.pdf> (Accessed April 1, 2015).
80 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).

Cost Containment Reserves (CCRs) since the demand for allowances was below the CCR trigger price of $6.00 per ton in 2015. The auction on March 5, 2014 was the first and only auction to use CRRs.

Table 8-3 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[81]

	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

81 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed April 1, 2015).

CAIR and CSAPR

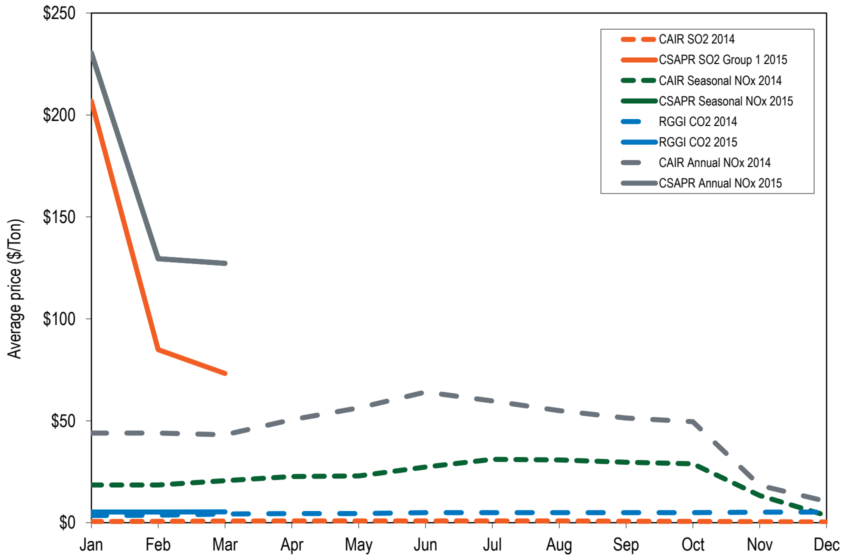
On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[82,83] On November 21, 2014, 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.[84] 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 CAIR and CSAPR related allowances for 2014 and the first three months of 2015.[85] Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

Annual and seasonal CAIR NO_x prices decreased in the last three months of 2014. In the first three months of 2015, CSAPR annual NO_x prices were 271.6 percent higher than the CAIR annual NO_x prices in the first three months of 2014. In the first three months of 2015, CSAPR SO_2 prices were 17,919 percent higher than the CAIR SO_2 prices in the first three months of 2014.

82 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).
83 Order, City Generation, L.P. EPA et al. v. EME Homer et al., No. 11-1302.
84 *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).
85 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.

Figure 8-1 Spot monthly average emission price comparison: January 2014 through March 2015[86]



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 March 31, 2015, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. 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.[87] West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[88]

Under the existing renewable portfolio standards, approximately 7.4 percent of PJM load must be served by renewable resources in 2015 and 16.2 percent of PJM load by 2028 under defined RPS rules. As shown in Table 8-4, 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.

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 out of market revenues for PJM resources and are in addition to revenues earned from the sale of the same MWh in PJM markets. Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MW REC for each MW produced by in state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[89] 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.[90]

86 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed May 12, 2015).
87 See Ohio Senate Bill 310.
88 See Enr. Com. Sub. For H. B. No. 2001.
89 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed April 1, 2015).
90 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.

Table 8-4 Renewable standards of PJM jurisdictions to 2028[91]

Jurisdiction	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%
Illinois	9.00%	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%	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	13.00%	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%	10.00%
New Jersey	13.76%	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%	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%	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	11.20%	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	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Washington, D.C.	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
West Virginia	No Standard													

Table 8-5 Solar renewable standards by percent of electric load for PJM jurisdictions: 2015 to 2028

Jurisdiction	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	1.00%	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	0.27%	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 Solar Standard													
Kentucky	No Standard													
Maryland	0.50%	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 Solar Standard													
New Jersey	2.45%	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%	0.14%	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%	0.12%	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	0.14%	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 Standard													
Virginia	No Solar Standard													
Washington, D.C.	0.70%	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 Solar Standard													

Some PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the total requirements shown in Table 8-4 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all 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 2014, New Jersey had the most stringent standard in PJM, requiring that 2.05 percent of load be served by solar resources. As Table 8-6 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.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-7 are also included in the total RPS requirements. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 6.75 percent of load served in 2015 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 in Pennsylvania, to qualify for renewable energy credits. North Carolina requires that 0.2 percent of power be generated using swine waste and poultry waste to fulfill their renewable portfolio standards by 2018 (Table 8-7).

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

Table 8-6 Additional renewable standards of PJM jurisdictions 2015 to 2028

Jurisdiction		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	6.75%	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	0.68%	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%	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%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	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	2.50%	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%

Table 8-7 Pennsylvania weighted average AEC price per MWh and AEC price per MWh for 2010 to 2014 Delivery Years[92]

	2010/2011 Delivery Year		2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 Delivery Year	
Pennsylvania	Weighted Average Price per MWh	Price Range per MWh	Weighted Average Price per MWh	Price Range per MWh	Weighted Average Price per MWh	Price Range per MWh	Weighted Average Price per MWh	Price Range per MWh	Weighted Average Price per MWh	Price Range per MWh
Solar AEC	$325.00	$235.00-$415.00	$247.82	$25.00-$653.00	$180.39	$10.00-$675.00	$109.23	$5.50-$600.00	$94.39	$10.00-$350.00
Tier I	$4.77	$0.50-$24.15	$3.94	$0.14-$50.00	$5.23	$0.20-$23.00	$8.31	$0.13-$100.00	$9.78	$1.25-$41.25
Tier II	$0.32	$0.01-$1.75	$0.22	$0.01-$20.00	$0.17	$0.01-$5.00	$0.22	$0.01-$20.00	$0.13	$0.01-$18.87

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. Table 8-5 has the Pennsylvania weighted average REC price and price range for 2010 through 2014 delivery years. The weighted average price of solar credits in Pennsylvania decreased from $109.23 per MWh in the 2013/2014 Delivery Year to $94.39 in the 2014/2015 Delivery Year. Tier I credits increased from $8.31 in the 2013/2014 Delivery year to $9.78 in the 2014/2015 Delivery Year, while Tier II resources dropped $0.09 from $0.22 in the 2013/2014 Delivery Year to $0.13 in the 2014/2015 Delivery Year.[93]

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 $331.00 per MWh.[94] 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.

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 8-8 shows the alternative compliance standards in PJM jurisdictions, where such standards exist.

92 See PAPUC. Pennsylvania AEPS Alternative Energy Credit Program "Pricing," <http://paaeps.com/credit/pricing.do> (Accessed April 1, 2015).

93 Tier I resources are defined by each jurisdiction. See *State RPS Comparison*, PJM EIS <http://www.pjm-eis.com/~/media/pjm-eis/documents/rps-comparison.ashx> (Accessed May 7, 2015).

94 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 April 1, 2015).

Table 8-8 Renewable alternative compliance payments in PJM jurisdictions: As of March 31, 2015[95]

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	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$331.00
North Carolina	No specific penalties		
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

Table 8-9 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through March 2015

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	9.6	0.0	0.0	0.0	0.0	0.0	0.0	9.6	19.2
Illinois	32.9	0.0	0.0	2.6	0.0	0.0	1,734.6	1,770.1	1,770.1
Indiana	0.0	0.0	9.8	0.0	0.0	0.0	981.1	990.9	990.9
Kentucky	0.0	0.0	37.0	0.0	0.0	0.0	0.0	37.0	37.0
Maryland	21.7	0.0	381.5	11.2	131.8	0.0	100.0	514.5	646.4
Michigan	6.0	0.0	13.8	0.0	0.0	0.0	0.0	19.8	19.8
New Jersey	73.7	124.3	4.0	56.4	324.7	0.0	2.9	137.1	586.1
North Carolina	0.0	0.0	148.7	0.0	0.0	0.0	0.0	148.7	148.7
Ohio	86.3	0.0	51.9	0.3	0.0	0.0	327.3	465.8	465.8
Pennsylvania	215.8	404.2	554.2	5.2	311.6	2,296.3	1,086.5	1,861.8	4,873.9
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	137.4	554.5	153.5	0.0	187.3	1,120.6	0.0	290.9	2,153.3
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	583.5	1,083.0	1,354.6	75.7	955.5	3,416.9	4,232.5	6,246.3	11,701.6
Percent Total	5.0%	9.3%	11.6%	0.6%	8.2%	29.2%	36.2%	53.4%	100.0%

95 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed April 1, 2015).

Table 8-9 shows renewable resource generation by jurisdiction and resource type in the first three months of 2015.[96] 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 4,232.5 GWh of 6,246.3 Tier I GWh, or 67.8 percent, in the PJM footprint. As shown in Table 8-9, 11,701.6 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 53.4 percent. Total renewable generation was 5.5 percent of total generation in PJM for the first three months of 2015. Landfill gas, solid waste and waste coal were 4,955.9 GWh of renewable resource generation or 42.3 percent of the total Tier I and Tier II.

Table 8-10 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, 228.5 MW, or 43.9 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,639.7 MW, or 64.0 percent of the total wind capacity.

96 PJM units do not need to declare what fuel they are using to generate power. Table 8-9 is calculated based on a unit's primary fuel source and settled generation MWh.

Table 8-10 PJM renewable capacity by jurisdiction (MW), on March 31, 2015

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	49.5	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,187.4	2,245.9
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,452.4	1,460.6
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	61.0	0.0	0.0	0.0	0.0	61.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.4	48.8	128.2	0.0	120.0	885.5
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	81.7	0.0	0.0	453.0	11.5	228.5	162.0	0.0	4.5	941.1
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	0.0	0.0	0.0	0.0	352.5
Ohio	13,864.0	64.7	580.0	156.0	0.0	47.4	1.1	0.0	0.0	403.0	15,116.2
Pennsylvania	0.0	222.0	2,346.0	0.0	1,269.0	888.3	19.5	345.8	1,611.0	1,337.7	8,039.3
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	218.1	0.0	17.0	5,166.2	350.5	0.0	444.9	585.0	0.0	6,781.7
West Virginia	8,772.0	2.2	519.0	0.0	0.0	213.9	0.0	0.0	165.0	583.3	10,255.4
PJM Total	22,636.0	679.4	5,242.0	255.0	6,888.2	2,493.5	306.9	1,130.9	2,361.0	6,273.2	48,266.1

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on March 31, 2015[97]

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	0.0	0.0	0.0	0.0	0.0	135.0	0.0	18.0	153.0
Delaware	0.0	60.6	2.1	0.0	0.0	0.0	0.0	0.0	0.0	62.7
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	258.9	0.0	258.9
Illinois	0.0	26.5	600.5	0.0	86.8	0.0	6.6	0.0	0.6	721.0
Indiana	0.0	2.6	180.0	0.0	43.2	94.6	0.0	0.0	6.2	326.6
Iowa	0.0	0.0	185.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0
Kentucky	600.0	1.4	0.0	0.0	17.6	0.0	2.2	93.0	0.0	714.2
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	0.0	63.0
Maryland	65.0	200.6	0.3	129.0	13.7	0.0	0.0	0.0	0.0	408.6
Michigan	55.0	1.3	0.0	0.0	3.2	0.0	1.3	0.0	0.0	60.8
Missouri	0.0	0.0	446.0	0.0	0.0	0.0	0.0	0.0	0.0	446.0
New Jersey	0.0	1,167.0	4.9	0.0	55.0	0.0	0.0	0.0	8.3	1,235.3
New York	0.0	0.4	0.0	0.0	0.0	0.0	158.7	0.0	0.0	159.1
North Carolina	0.0	100.1	0.0	0.0	0.0	0.0	242.5	30.0	0.0	372.6
Ohio	0.0	109.3	23.1	92.6	33.6	32.4	1.0	109.3	12.6	413.9
Pennsylvania	109.7	193.4	3.3	91.0	44.2	5.0	37.0	38.6	12.4	534.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	52.0	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	8.3	0.0	0.0	14.5	0.0	18.2	287.6	0.0	328.6
West Virginia	0.0	2.3	0.0	0.0	0.0	0.0	42.0	0.0	0.0	44.3
Wisconsin	0.0	0.4	0.0	0.0	0.0	0.0	9.0	44.6	0.0	54.0
District of Columbia	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.8
Total	829.7	1,888.2	1,445.3	312.6	311.8	132.0	705.4	1,070.2	58.0	6,753.2

97 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <http://www.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed April 1, 2015).

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 1,723.7 MW of which 1,134.3 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.

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. Many PJM units burning fossil fuels have installed emission control technology.

Coal, number 5 and number 6 fuel oil have the highest SO_2 emission rates, while natural gas and light oil have lower SO_2 emission rates.[98] Of the current 70,850.8 MW of coal capacity in PJM, 55,485.0 MW of capacity, 78.3 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-12 shows SO_2 emission controls by fossil fuel fired units in PJM.[99,100]

Table 8-12 SO_2 emission controls (FGD) by fuel type (MW), as of March 31, 2015

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	55,485.0	15,365.8	70,850.8	78.3%
Diesel Oil	0.0	6,619.8	6,619.8	0.0%
Natural Gas	0.0	53,110.9	53,110.9	0.0%
Other	325.0	4,763.5	5,088.5	6.4%
Total	55,810.0	79,860.0	135,670.0	41.1%

NO_x emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 125,751.0 MW, 92.7 percent, of 135,670.0 MW of capacity in PJM, have emission controls for NO_x. Table 8-13 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.[101]

Table 8-13 NO_x emission controls by fuel type (MW), as of March 31, 2015

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	69,624.2	1,226.6	70,850.8	98.3%
Diesel Oil	2,192.8	4,427.0	6,619.8	33.1%
Natural Gas	51,134.3	1,819.4	52,953.7	96.6%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	125,751.0	9,919.0	135,670.0	92.7%

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.[102] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-14 shows particulate emission controls by unit type in PJM. In PJM, 70,516.8 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of March 31, 2015. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet state and federal emission compliance standards. Future particulate compliance standards will require baghouse technology or ESPs, or a combination of an FGD and SCR to meet EPA regulations.[103] Currently, 49 of the 211 coal steam units have baghouse or

98 Light oil includes diesel, number 2 fuel oil and light crudes.
99 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed April 1, 2015).
100 The total MW for each fuel type are less than the 141,758.9 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 April 1, 2015).

101 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed April 1, 2015).
102 See EPA, "Air Pollution Control Technology Fact Sheet," <http://www.epa.gov/ttnchie1/mkb/documents/ff-pulse.pdf> (Accessed April 1, 2015).
103 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed April 1, 2015).

FGD technology installed, representing 53,937.0 MW out of the 70,850.8 MW total coal capacity, or 76.1 percent.

Table 8-14 Particulate emission controls by fuel type (MW), as of March 31, 2015

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	70,516.8	334.0	70,850.8	99.5%
Diesel Oil	0.0	6,619.8	6,619.8	0.0%
Natural Gas	260.0	52,693.7	52,953.7	0.5%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	73,878.8	61,791.2	135,670.0	54.5%

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-15 shows the emissions from units in the PJM footprint for 2012 through the first three months of 2015. PJM CO_2 emissions decreased by 16.5 percent from 148 million tons of CO_2 in the first three months of 2014 to 123 million tons of CO_2 in the first three months of 2015. PJM SO_2 emissions decreased by 34.5 percent from 357 thousand tons of SO_2 in the first three months of 2014 to 220 thousand tons of SO_2 in the first three months of 2015. PJM NO_x emissions decreased by 22.0 percent from 136 thousand tons of NO_x in the first three months of 2014 to 106 thousand tons of NO_x in the first three months of 2015 by PJM units.

Table 8-15 CO_2, SO_2 and NO_x emissions by month (short tons), by PJM units: January 2012 through March 2015[104]

	Short Tons											
	2012			2013			2014			2015		
	CO_2	SO_2	NO_x	CO_2	SO_2	NO_xx	CO_2	SO_2	NO_x	CO_2	SO_2	NO_x
January	42,184,331	97,935	32,761	44,149,311	87,880	37,194	53,343,342	121,741	49,412	42,963,944	75,087	36,364
February	37,061,691	78,185	28,184	40,847,569	80,971	35,589	47,071,173	107,227	43,960	44,372,829	82,285	39,279
March	33,526,901	63,176	24,712	40,927,564	90,434	34,885	47,331,266	106,699	42,872	36,032,444	62,649	30,652
April	32,670,018	70,444	24,648	33,864,020	70,628	27,017	36,220,205	79,474	32,592			
May	37,509,471	70,185	28,830	37,261,120	60,893	30,033	33,937,074	60,172	28,879			
June	43,278,529	90,376	32,199	42,185,172	78,067	34,477	43,002,722	76,733	34,030			
July	55,944,634	120,256	45,683	49,342,754	103,522	39,448	48,174,787	88,401	36,853			
August	50,622,632	104,590	39,666	46,306,760	86,744	34,161	45,074,885	79,827	35,949			
September	38,655,748	71,785	30,502	41,326,649	73,373	31,555	38,923,359	60,507	31,280			
October	34,630,973	57,200	29,031	38,321,257	66,528	29,953	34,291,532	61,146	30,866			
November	38,238,507	66,965	32,624	39,314,409	80,159	32,704	39,580,803	77,146	36,121			
December	41,606,237	82,321	35,709	44,944,175	88,764	38,514	40,496,686	71,679	34,700			
Total	485,929,672	973,418	384,548	498,790,759	967,963	405,529	507,447,832	990,750	437,511	123,369,217	220,022	106,296

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

Wind Units

Table 8-16 shows the capacity factor of wind units in PJM. In the first three months of 2015 the capacity factor of wind units in PJM was 34.2 percent. Wind units that were capacity resources had a capacity factor of 35.4 percent and an installed capacity of 5,998 MW. Wind units that were classified as energy only had a capacity factor of 22.7 percent and an installed capacity of 604 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.[105]

Table 8-16 Capacity factor of wind units in PJM: January through March 2015[106]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	22.7%	604
Capacity Resource	35.4%	5,998
All Units	34.2%	6,602

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,550.4 MW, occurred in February, and the lowest average hour, 1,940.7 MW, occurred in February. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-2 Average hourly real-time generation of wind units in PJM: January through March 2015

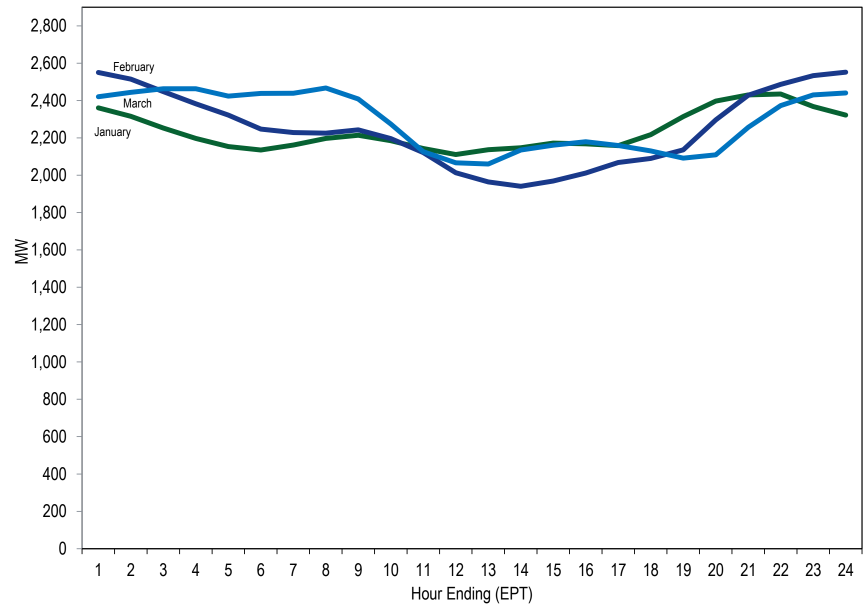


Table 8-17 shows the generation and capacity factor of wind units in each month of January 2014 through March 2015.

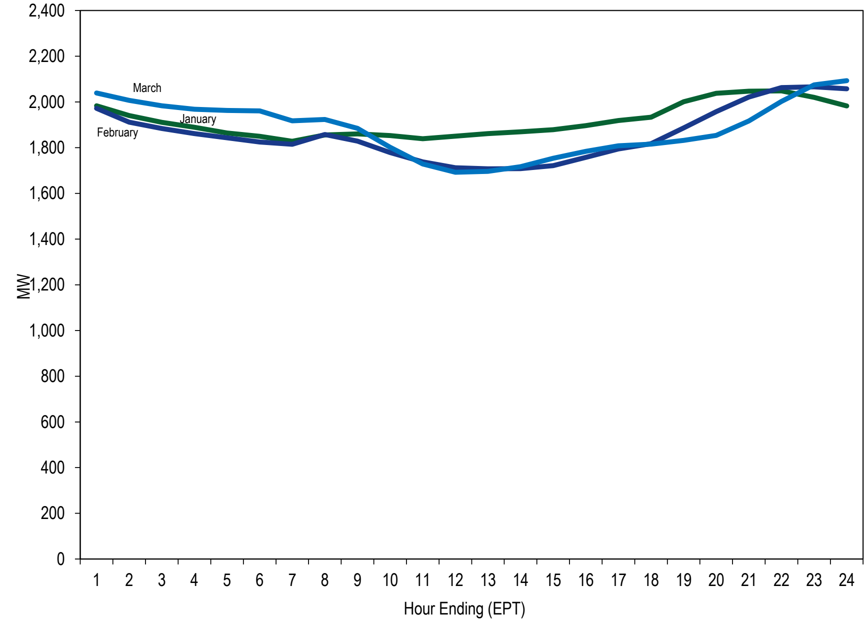
105 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
106 Capacity factor is calculated based on online date of the resource.

Table 8-17 Capacity factor of wind units in PJM by month, January 2014 through March 2015

	2014		2015	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,918,441.4	40.7%	1,664,426.8	33.9%
February	1,342,055.5	31.5%	1,511,093.1	34.1%
March	1,661,382.1	35.3%	1,701,249.6	34.7%
April	1,697,703.3	37.2%		
May	1,238,061.3	26.2%		
June	820,312.2	18.0%		
July	757,166.8	16.0%		
August	566,425.3	12.0%		
September	721,411.2	15.8%		
October	1,416,878.2	30.0%		
November	1,949,112.9	41.5%		
December	1,451,542.0	29.7%		
Annual	15,540,492.0	27.8%	4,876,769.4	34.5%

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 non-capacity related wind energy at their discretion. Figure 8-3 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 8-3 Average hourly day-ahead generation of wind units in PJM: January through March 2015



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 8-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation through the first three months of 2015. Figure 8-4 shows potentially displaced marginal unit MW by fuel type in the first three months of 2015. 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 8-4 Marginal fuel at time of wind generation in PJM: January through March 2015

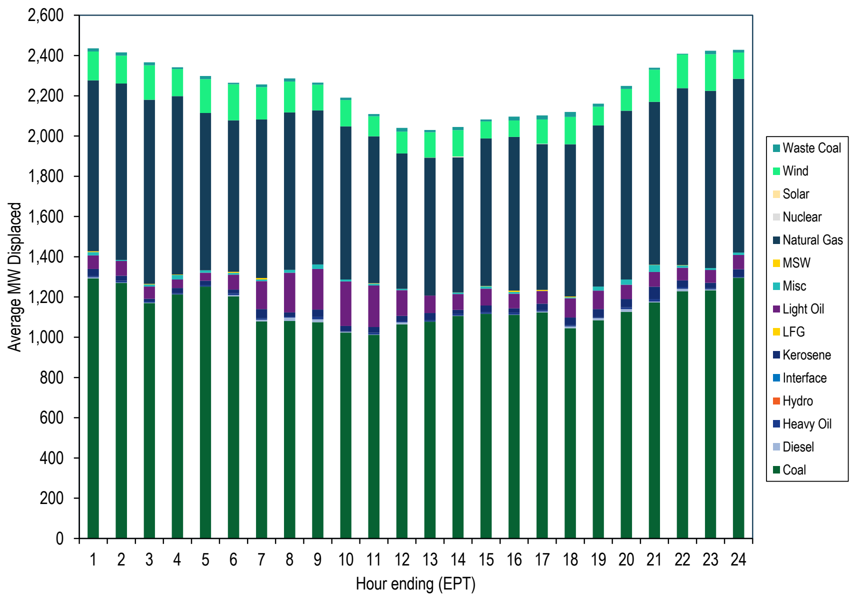
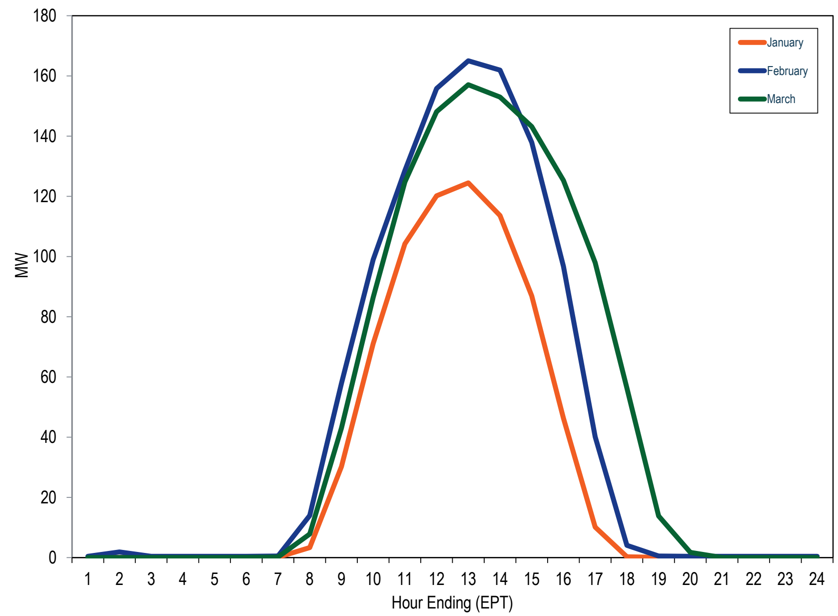


Figure 8-5 Average hourly real-time generation of solar units in PJM: January through March 2015



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-5 shows the average hourly real time generation of solar units in PJM, by month. Solar generation was highest in February, the month with the highest average hour, 165.0 MW, compared to 306.9 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.