Environmental and Renewable Energy Regulations

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

Renewable energy mandates and associated incentives by state and federal governments 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 potentially significant impacts on PJM wholesale markets.[1]

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.[2] 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). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[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 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.[5]

- **National 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).[6] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided

1 For quantification of the economics of new entrant wind and solar installations, see the *2013 State of the Market Report for PJM*, Volume II, Section 7, "Net Revenue."

2 *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).

3 *Reconsideration of Certain New Source Issues: 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, 78 Fed. Reg. 24073 (April 24, 2013).

4 CAA § 110(a)(2)(D)(i)(I).

5 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

6 *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).

that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[7]

In PJM's recent filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program which would allow RICE to continue to use the EPA's exception.[8] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[9] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[10] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to take the much more significant step of regulating CO_2 emissions from existing sources.[11] In anticipation of timely issuance of a final GHG NSPS, 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").[12] The ESS NOPR established interim and final emissions goals for each state that must be met, respectively, by 2020 and 2030. States have flexibility to meet these goals, including through participation in multistate CO_2 credit trading programs.

- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best available technology for minimizing adverse environmental impacts. A final rule implementing this requirement was issued May 19, 2014.[13]

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.[14] 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.[15]

- **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. Auction prices in 2014 for the 2012-2014 compliance period were $5.02 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $5.53 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 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, 2014, 71.1 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.7 percent of coal steam MW had some type of particulate control, and 92.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

7 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia Bill 20-569.
8 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).
9 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3–6.
10 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").
11 *See* CAA § 111(b)&(d).
12 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
13 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.
14 N.J.A.C. § 7:27–19.
15 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).

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' 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, 2014, 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. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 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 when the net of marginal cost and credits is negative. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation. RECs markets are not transparent. Data on RECs 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. 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.

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.[16] [17] 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.[18]

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.[19] The rule establishes a compliance deadline of April 16, 2015.

16 42 U.S.C. § 7401 et seq. (2000).
17 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.
18 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.
19 *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*

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). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal and oil fired power plants based on new information and analysis.[20]

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

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

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.[22]

On April 29, 2014, the U.S. Supreme Court upheld 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.[23]

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.[24] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[25]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[26] Group 2 does not include any states in the PJM region.[27] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[28] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Under the original timetable for implementation, 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 SO_2 emission reductions would have taken effect in 2014 from certain states,

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).

20 *Reconsideration of Certain New Source Issues: 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, 78 Fed. Reg. 24073 (April 24, 2013).

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

22 CAA § 110(a)(2)(D)(i)(I).

23 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

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

25 *Id.*

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

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

28 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.

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.

Because of the delay resulting from judicial review, the initial timetable for implementation is not feasible and must be replaced. In the meantime, EPA advises that CAIR remains in effect and "no immediate action from States or affected sources is expected."[29]

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).[30] 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").[31]

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).[32]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[33] 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 MMU objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand resources in the PJM markets, nor for reliability.[34] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[35] Otherwise a 15-hour exception applies.[36] The exempted emergency demand response programs include demand resources in RPM.[37]

Pending initiatives in Pennsylvania and New Jersey would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[38] The MMU and PJM have stated that these state measures would not, if enacted,

29 See EPA. "Cross-State Air Pollution Rule (CSAPR)," <http://www.epa.gov/airtransport/CSAPR/>.

30 *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").

31 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.

32 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."

33 *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.

34 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA–HQ–OGC–2011–1030 (February 16, 2012).

35 Final NESHAP RICE Rule at 31–24.

36 *Id.* at 31.

37 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.

38 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

have any harmful impact on system reliability.[39] The MMU has also explained that such measures would improve markets.[40]

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.[41] 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."[42] Such restrictions refer to the EPA's amended RICE NESHAP Rule. 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 for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[43] 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."[44] In its compliance filing, PJM attempted to justify the exception.[45] An order from the Commission on PJM's compliance filing is now pending.

39 *See* Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-0708 (August 9, 2012); Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012); Market Monitor, Comments of the Independent Market Monitor for PJM, Supporting Testimony before the Pennsylvania House of Representatives Environmental and Energy Committee re House Bill 1699, An Act Providing for the Regulation of Certain Reciprocal Internal Combustion Engines (November 20, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_to_PA_CERE_1699_20131120.pdf>; Letter from Terry Boston, President & CEO, PJM to Hon. Chris Ross re Pennsylvania House Bill 1999 (November 11, 2013) ("With regards to your inquiry of potential impacts to grid reliability, PJM does not anticipate the emergence of system reliability issues, should HB 1699 become law."); Letter from Terry Boston, President & CEO, PJM to Hon. Mary M. Cheh re District of Columbia Bill 20-569 (December 19, 2013).

40 *Id.*

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

42 *Id.* at 8–9.

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

44 See 147 FERC ¶ 61,103 at P 41.

45 See PJM compliance filing, ER14-822-002 (June 2, 2014) at 4–8.

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.[46,47]

The EPA's first step is the development of regulations applicable to new resources, New Source Performance Standards (NSPS). On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[48,49] The standards would require advanced technologies like efficient natural gas units and efficient coal units implementing 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 take the much more significant step of regulating CO_2 emissions from existing sources.[50] 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

46 *See* CAA § 111.

47 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.

48 *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>.

49 79 Fed. Reg. 1352 (January 8, 2014).

50 See CAA § 111(b)&(d).

generation facilities ("ESS NOPR") on June 2, 2014.[51] The President requested that EPA issue a final rule by June 1, 2015.[52]

The ESS NOPR sets state by state CO_2 emissions targets, which are expressed as interim and final rate based goals.[53] 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.[54] 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.[55] 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.[56]

The EPA has calculated goals based on EGU emissions rates for each state. The EPA uses four building blocks to calculate state goals.[57] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[58]

To calculate state interim and final goals, 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 with 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.[59]

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.

51 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
52 See June 25th Presidential Memorandum.
53 *Id.* at 34894.
54 ESS NOPR at 34837.
55 *Id.* at 34894.
56 *Id.* at 34839.
57 *Id.* at 34836.
58 *Id.* at 34856-34858.
59 *Id.* at 34861

Table 8-1 Interim and final targets for CO_2 emissions goals for PJM states[60] (lbs/MWh)[61]

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

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[62] 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.[63] The EPA would impose its own plan if a state does not timely propose a plan that EPA finds satisfactory.[64]

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."[65] 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.[66]

60 The District of Columbia has no affected EGUs and is not subject to the ESS NOPR. *Id.* at 34867.
61 CO_2 targets reported in adjusted output-weighted average pounds per net MWh.
62 *Id.* at 34830.
63 *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.").
64 *Id.* at 34844.
65 *Id.* at 34901.
66 *Id.* at 34835.

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.[67] 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.[68]

The ESS NOPR permits states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[69]

The Presidential Memorandum on the Climate Action Plan charged the EPA to issue a final rule on EGU CO_2 emissions standards by June 1, 2015.[70] The ESS NOPR provides for states to submit plans implementing the rule by June 30, 2016, with a two-year extension available to states involved in the development of a multistate plan.[71]

Federal Regulation of Environmental Impacts on Water

On May 19, 2014, the EPA issued a rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the CWA.[72]

67 *Id.* at 34848–34849.
68 *Id.* at 34910.
69 *Id.* at 34834.
70 June 25th Presidential Memorandum.
71 ESS NOPR at 34915.
72 See EPA, *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667.

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.[73] 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.[74]

Table 8-2 shows the HEDD emissions limits applicable to each unit type. Emissions limits for coal units became effective December 15, 2012.[75] Emissions limits for other unit types will become effective May 1, 2015.[76]

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

Fuel and Unit Type	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

73 N.J.A.C. § 7:27-19.
74 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).
75 N.J.A.C. § 7:27-19.4.
76 N.J.A.C. § 7:27-19.5.
77 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

State Regulation of Greenhouse Gas Emissions

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.[78,79]

Table 8-3 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional auctions for the 2012-2014 compliance period held as of June 30, 2014, in short tons and metric tonnes. Prices for auctions held in 2014 for the 2012-2014 compliance period were at the highest clearing price yet at $5.02 per allowance (equal to one ton of CO_2), which is above the current price floor of $2.00 for RGGI auctions.[80] The price increased from the previous high of $4.00 in March 2014, from $3.00 in December 2013, due to a 45 percent reduction in the quantity of allowances offered in this auction. The 23,491,350 allowances sold include the original allowances offered for sale in the market of 18,491,350 as well as 5,000,000 additional cost containment reserves (CCR). This auction included the additional CCRs for the first time, due to the demand for allowances above the CCR trigger price of $4.00 per ton. There are no additional CCRs available for sale in 2014. Prices increased for the June 4, 2014, auction to $5.02 per allowance.

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

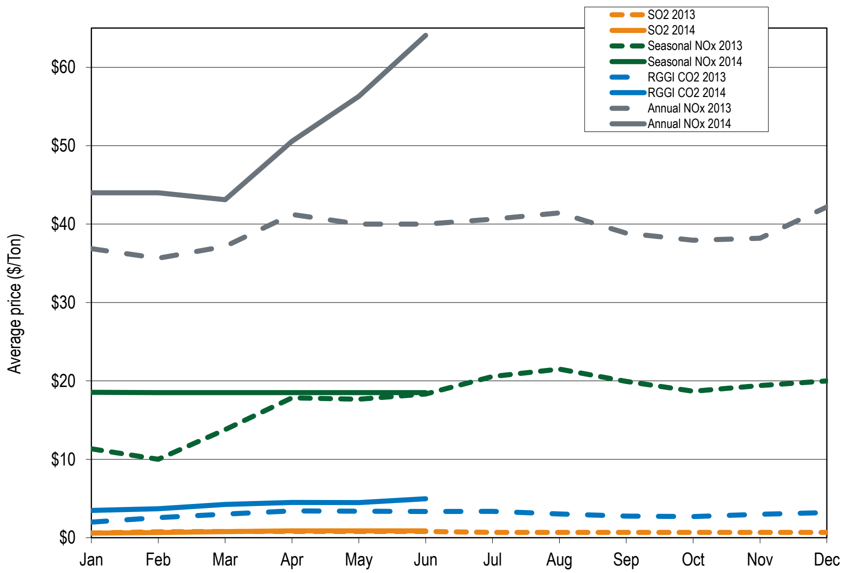
	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	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

Figure 8-1 shows average, daily settled prices for NO_x, CO_2 and SO_2 emissions.[82] In the first six months of 2014, NO_x prices were 30.8 percent higher than in the first six months of 2013. The increase of NO_x prices was at least in part due to the recent Supreme Court ruling which upheld the EPA's CSAPR program which limits the amount of NO_x emissions by power plant.[83] SO_2 prices were 2.1 percent higher in the first six months of 2014 compared to the first six months of 2013. Figure 8-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances

78 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>.
79 For more details see the *2013 State of the Market Report for PJM*, Volume 2: Section 8, "Environmental and Renewables."
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).
81 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed July 31, 2014).
82 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.
83 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

are required for generating units in participating RGGI states. This includes the PJM states of Delaware and Maryland.

Figure 8-1 Spot monthly average emission price comparison: 2013 and January through June of 2014[84]



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' 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, 2014, 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. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2024. As shown in Table 8-4, New Jersey will require 24.1 percent of load to be served by renewable resources in 2024, the most stringent standard of all PJM jurisdictions. Renewable generation earns renewable energy credits (RECs) (also known as alternative energy credits) when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction. For example, Illinois only requires utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

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. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh for generation from alternative energy resources including waste coal and pumped-storage hydroelectric, and allows two credits per MWh of electricity generated by renewable energy resources, which include wind, solar, and run of river hydroelectric. 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.

84 See *Evolution Markets*, <http://www.evomarkets.com> (Accessed July 31, 2014).

Table 8-4 Renewable standards of PJM jurisdictions to 2024[85,86]

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%
Illinois	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	12.80%	13.00%	15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%
Michigan	6.75%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	12.53%	13.76%	14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%
North Carolina	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	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%
Pennsylvania	10.72%	11.22%	13.72%	14.22%	14.72%	15.22%	15.72%	18.02%	18.02%	18.02%	18.02%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%
Washington, D.C.	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	20.00%
West Virginia		10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%	15.00%

Table 8-5 Pennsylvania weighted average AEC price and AEC price range for 2010 to 2014 Delivery Years[87]

	2010/2011 Delivery Year		2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Pennsylvania	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range
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
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
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

REC prices are required to be disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are difficult to determine. Few sources provide public REC price data. Table 8-5 has the Pennsylvania weighted average price and price range for 2010 through 2014 delivery years. The weighted average price of solar credits in Pennsylvania decreased from $325.00 in the 2010/2011 Delivery Year to $109.23 in the 2013/2014 Delivery Year. Tier I credits increased from $4.77 in the 2010/2011 Delivery year to $8.31 in the 2013/2014 Delivery Year, while Tier II resources dropped $0.10 from $0.32 in the 2010/2011 Delivery Year to $0.22 in the 2013/2014 Delivery Year.[88]

Many PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards 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 units by 2023.[89] 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 2024, New Jersey will continue to have the most stringent standard, requiring that at least 3.74 percent of load be served by solar resources.

85 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
86 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.
87 See PAPUC. Pennsylvania AEPS Alternative Energy Credit Program, "Pricing," <http://paaeps.com/credit/pricing.do> (Accessed July 31, 2014).
88 Tier I resources are solar photovoltaic and thermal energy, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, biomass and coal mine methane. Tier II resources are waste coal, distributed generation, demand-side management, large-scale hydropower, municipal solid waste and integrated combined coal gasification technology.
89 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.

Table 8-6 Solar renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%
Illinois	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%
North Carolina	0.07%	0.14%	0.14%	0.14%	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%
Pennsylvania	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.50%
West Virginia	No Solar Standard										

Table 8-7 Additional renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Illinois	Wind Requirement	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%
Illinois	Distributed Generation	0.04%	0.68%	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	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%
New Jersey	Solar Garve-Out (in GWh)	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433	3,989
North Carolina	Swint Waste	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-7 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind resources, increasing from 6.00 percent of load served in 2014 to 16.50 percent in 2024. 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.[90] North Carolina also 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).

PJM jurisdictions include various methods for complying with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $339.00 per MWh.[91] 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 methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Standard alternative compliance payments can replace solar, wind energy, organic biomass and hydro power. Table 8-8 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

90 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

91 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/Policies for Renewables & Efficiency, "Renewables Portfolio Standard," <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed July 31, 2014).

Table 8-8 Renewable alternative compliance payments in PJM jurisdictions: As of June 30, 2014[92]

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		$339.00
North Carolina	No specific penalties		
Ohio	$47.56		$350.00
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	$50.00		

Table 8-9 shows renewable generation by jurisdiction and resource type in the first six months of 2014. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 8,925.0 GWh of 15,051.3 Tier I GWh, or 59.3 percent, in the PJM footprint. As shown in Table 8-9, 29,142.1 GWh were generated by resources that were renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 51.6 percent. Landfill gas, solid waste and waste coal were 11,655.5 GWh of renewable generation or 40.0 percent of the total Tier I and Tier II.

Table 8-9 Renewable generation by jurisdiction and renewable resource type (GWh): January through June 2014

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	24.8	0.0	0.0	0.0	0.0	0.0	0.0	24.8	49.5
Illinois	85.6	0.0	0.0	7.6	0.0	0.0	3,873.4	3,966.7	3,966.7
Indiana	0.0	0.0	25.3	0.0	0.0	0.0	1,467.5	1,492.8	1,492.8
Kentucky	0.0	0.0	48.5	0.0	0.0	0.0	0.0	48.5	48.5
Maryland	50.3	0.0	1,158.7	34.9	313.4	0.0	167.4	1,411.3	1,724.7
Michigan	12.4	0.0	36.1	0.0	0.0	0.0	0.0	48.5	48.5
New Jersey	163.1	280.0	14.2	136.0	793.6	0.0	5.7	318.9	1,392.5
North Carolina	0.0	0.0	443.6	0.0	0.0	0.0	0.0	443.6	443.6
Ohio	171.5	0.0	223.2	1.4	0.0	0.0	643.6	1,039.7	1,039.7
Pennsylvania	414.3	1,265.5	1,740.3	11.2	823.2	5,324.7	1,920.3	4,086.0	11,499.3
Tennessee	0.0	0.0	0.0	0.0	169.9	0.0	0.0	0.0	169.9
Virginia	243.8	2,060.4	361.7	0.0	974.9	1,556.7	0.0	605.5	5,197.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	4.8	0.0	713.3	0.0	0.0	528.6	847.2	1,565.2	2,093.8
Total	1,170.5	3,605.9	4,764.8	191.0	3,075.0	7,410.0	8,925.0	15,051.3	29,142.1

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[93] This capacity includes coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. Coal and natural gas units are considered to generate renewable energy only when generating using a renewable fuel, like waste coal in West Virginia. West Virginia has the largest amount of renewable capacity in PJM, 10,255.4 MW, or 21.7 percent of the total renewable capacity. West Virginia allows coal technology, coal bed methane, waste coal and fuel produced by a coal gasification facility to be counted as alternative energy resources. New Jersey has the largest amount of solar capacity in PJM, 216.5 MW, or 76.4 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 2,187.4 MW, or 36.0 percent of the total wind capacity.

92 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis/program-information.aspx>. (Accessed July 31, 2014)

93 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 8-10 PJM renewable capacity by jurisdiction (MW), on June 30, 2014

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	79.5	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,187.4	2,275.9
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,252.4	1,260.6
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	494.0	48.8	0.0	0.0	120.0	757.0
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	86.5	0.0	0.0	453.0	3.5	216.5	0.0	0.0	4.5	764.0
North Carolina	0.0	0.0	0.0	0.0	0.0	325.0	0.0	0.0	0.0	0.0	325.0
Ohio	13,933.0	64.7	580.0	156.0	0.0	47.4	1.1	0.0	0.0	403.0	15,185.2
Pennsylvania	0.0	222.0	2,346.0	0.0	1,269.0	888.3	8.0	103.0	1,647.0	1,337.7	7,821.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	130.1	0.0	20.0	5,166.2	350.5	0.0	321.9	585.0	0.0	6,573.7
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	22,705.0	626.2	5,242.0	258.0	6,888.2	2,405.7	283.5	474.9	2,397.0	6,073.2	47,353.7

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS), a system operated by PJM EIS. This includes solar capacity of 1,596.1 MW of which 1,063.9 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. All capacity shown in Table 8-11 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some jurisdictions. This includes both behind the meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS[94] (MW), on June 30, 2014

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
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	58.4	0.0	2.1	60.5
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	258.9	0.0	258.9
Illinois	0.0	6.6	92.4	0.0	0.3	0.0	25.0	0.0	502.5	626.8
Indiana	0.0	0.0	44.0	0.0	6.0	94.6	1.7	0.0	180.0	326.3
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	600.0	2.2	16.0	0.0	0.0	0.0	0.7	88.0	0.0	706.9
Maryland	65.0	0.4	13.7	129.0	0.0	0.0	134.7	0.0	0.3	343.1
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	59.9	0.0	8.3	23.3	1,063.9	0.0	5.0	1,160.4
New York	0.0	146.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	147.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.6	0.0	0.0	8.6
Ohio	0.0	1.0	30.4	119.6	11.1	0.0	96.7	109.3	21.9	390.0
Pennsylvania	109.7	37.0	44.2	91.0	10.8	1.0	184.8	60.6	3.3	542.3
Tennessee	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.3
Virginia	0.0	17.4	17.5	0.0	0.0	0.0	7.1	287.6	0.0	329.7
West Virginia	0.0	42.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	44.0
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	11.4	0.0	0.0	11.4
Total	829.7	262.2	319.7	339.6	36.5	119.2	1,596.1	849.0	1,046.1	5,398.1

94 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed July 31, 2014).

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 and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low SO_2 emission rates. Of the current 70,067.8 MW of coal capacity in PJM, 49,788.0 MW of capacity, 71.1 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.[95,96]

Table 8-12 SO_2 emission controls (FGD) by fuel type (MW), as of June 30, 2014

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,788.0	20,279.8	70,067.8	71.1%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	0.0	51,548.0	51,548.0	0.0%
Other	368.0	7,412.5	7,780.5	4.7%
Total	50,156.0	85,334.1	135,490.1	37.0%

NO_x emission control technology is used by all fossil fuel fired unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel fired units in PJM, 124,855.4 MW, 92.2 percent, of 135,447.1 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 will likely need to be upgraded in order to meet each state's emission compliance standards. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.[97]

Table 8-13 NO_x emission controls by fuel type (MW), as of June 30, 2014

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	68,653.2	1,414.6	70,067.8	98.0%
Diesel Oil	1,432.8	4,661.0	6,093.8	23.5%
Natural Gas	49,988.6	1,559.4	51,548.0	97.0%
Other	4,780.8	2,956.7	7,737.5	61.8%
Total	124,855.4	10,591.7	135,447.1	92.2%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (also referred to as baghouses) are used to reduce particulate matter from coal steam units.[98] In PJM, 69,133.8 MW, 98.7 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 8-14 shows particulate emission controls by unit type in PJM. 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 each state's 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.[99] Currently 52 of the 228 coal steam units have baghouse technology installed, representing 49,540.0 MW out of the 70,067.8 MW total coal capacity, or 70.7 percent.

Table 8-14 Particulate emission controls by fuel type (MW), as of June 30, 2014

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	69,133.8	934.0	70,067.8	98.7%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	260.0	51,288.0	51,548.0	0.5%
Other	3,159.0	4,578.5	7,737.5	40.8%
Total	72,552.8	62,894.3	135,447.1	53.6%

95 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 31, 2014).
96 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 July 1, 2014).
97 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed August 4, 2014).
98 See EPA, "Air Pollution Control Technology Fact Sheet," <http://www.epa.gov/ttnchie1/mkb/documents/ff-pulse.pdf> (Accessed August 4, 2014).
99 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed August 4, 2014).

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 PJM in the first six months of 2014. It is estimated that over 203 million metric tons of CO_2, 470 thousand metric tons of SO_2, and 364 thousand tons of NO_x were emitted in the first six months of 2014 by PJM units.

Table 8-15 CO_2, SO_2 and NO_x emissions by month (short and metric tons), by PJM units, January through June, 2014[100]

	Tons of CO_2	Tons of SO_2	Tons of NO_x
January	41,616,621.0	101,191.6	76,717.8
February	36,982,668.1	91,597.5	67,764.3
March	36,791,698.2	86,653.0	66,196.4
April	27,301,883.5	63,059.5	48,502.4
May	27,079,243.5	55,877.0	45,936.2
June	33,694,096.3	72,110.2	59,403.2
Total	203,466,210.5	470,488.7	364,520.2

Wind Units

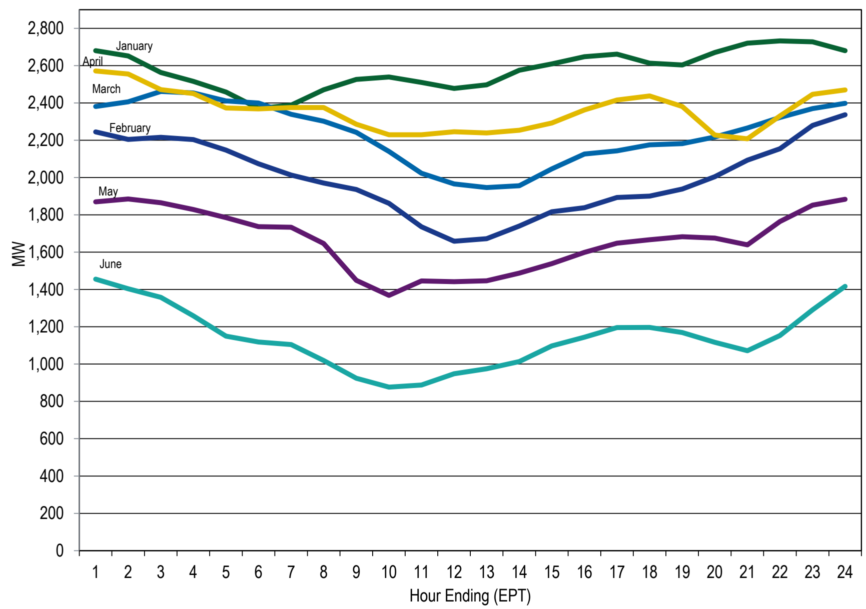
Table 8-16 shows the capacity factor of wind units in PJM. In the first six months of 2014, the capacity factor of wind units in PJM was 31.4 percent. Wind units that were capacity resources had a capacity factor of 32.4 percent and an installed capacity of 5,821 MW. Wind units that were classified as energy only had a capacity factor of 20.5 percent and an installed capacity of 544 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.[101]

Table 8-16 Capacity factor of wind units in PJM: January through June 2014[102]

Type of Resource	Capacity Factor	Capacity Factor by Cleared MW	Installed Capacity (MW)
Energy-Only Resource	31.3%	NA	1,476
Capacity Resource	33.7%	179.5%	4,888
All Units	33.1%	179.5%	6,364

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,732.2 MW, occurred in January, and the lowest average hour, 888.1 MW, occurred in June. 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 June, 2014



100 The emissions are calculated by multiplying the amount of generated MWh at a power plant times the heat rate of the plant times the emissions rate by fuel source, accounting for the controls a generator has installed to date.
101 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
102 Capacity factor is calculated based on online date of the resource.

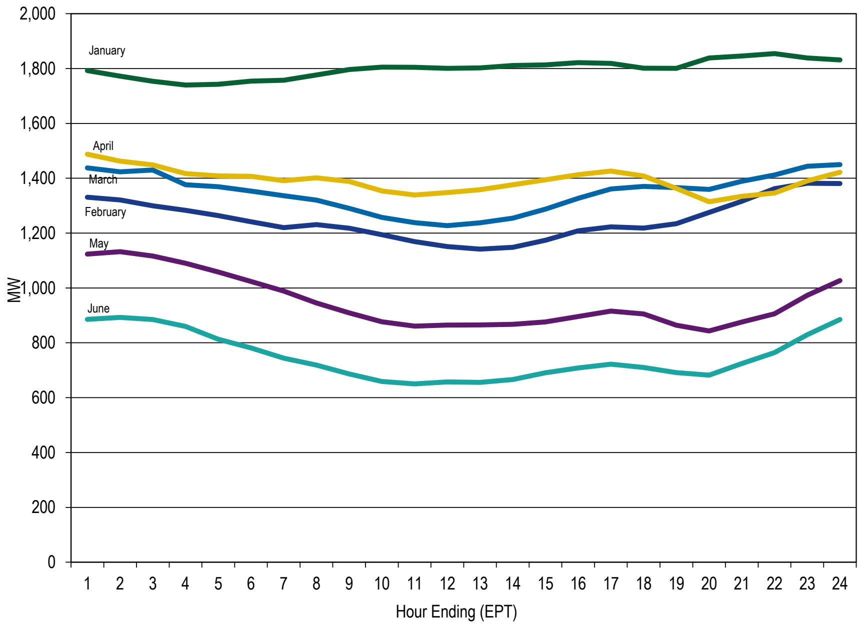
Table 8-17 shows the generation and capacity factor of wind units in each month of the first six months of 2013 and the first six months of 2014.

Table 8-17 Capacity factor of wind units in PJM by month, 2013 and January through June, 2014

	2013		2014	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,784,359.3	40.3%	1,918,441.4	42.7%
February	1,397,468.3	35.4%	1,342,055.5	33.4%
March	1,606,248.3	36.5%	1,661,382.1	37.3%
April	1,639,590.9	37.8%	1,697,703.3	38.3%
May	1,271,272.4	28.5%	1,238,061.3	27.4%
June	862,532.2	19.8%	820,312.2	19.3%
July	588,174.8	13.4%		
August	510,448.5	12.0%		
September	719,196.4	16.7%		
October	1,070,829.4	23.5%		
November	1,833,051.6	41.2%		
December	1,543,685.2	34.2%		
Annual	14,826,857.3	28.3%	8,677,955.7	33.1%

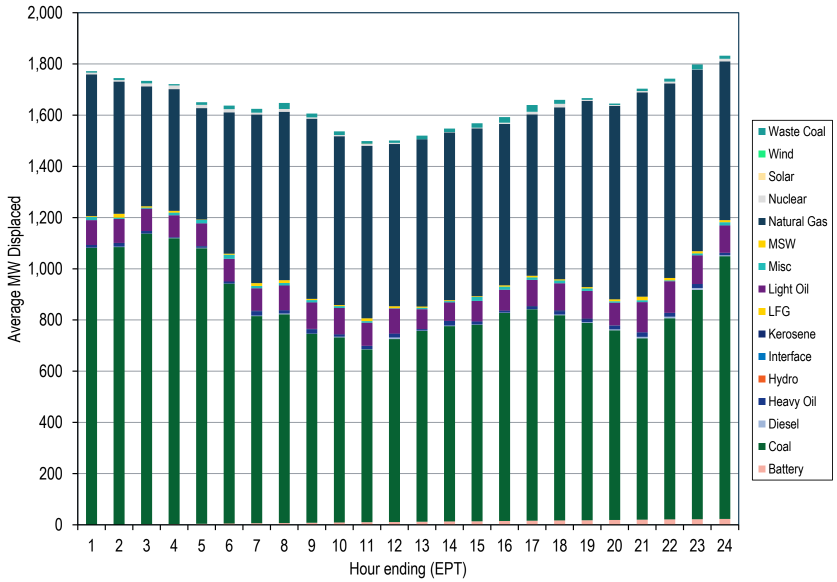
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer non-capacity related wind energy at their discretion. 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 June, 2014



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 six months of 2014. Figure 8-4 shows potentially displaced marginal unit MW by fuel type in the first six months of 2014. 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 June, 2014



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 June, the month with the highest average hour, 174.3 MW, compared to 283.5 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-5 Average hourly real-time generation of solar units in PJM: January through June, 2014