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) and the Cross-State Air Pollution Rule (CSAPR) will require significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal and SO_2 and NO_x emissions. These investments may result in higher offers in the capacity market, and if units do not clear, in the retirement of some 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, as a result, had a significant impact on PJM wholesale markets.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule (MATS).**[1] 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. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources). In addition, in a related EPA rule issued on the same date regarding New Source Performance Standards (NSPS), a rule also referred to as part of MATS, the EPA requires new electric generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_x and filterable particulate matter.
- **Cross-State Air Pollution Rule (CSAPR).** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that 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 National Ambient Air Quality Standards (NAAQS). CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia. This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to a Federal Court of Appeals order directing revisions compliant with the requirements of the CAA. CSAPR was expected to become effective January 1, 2012, but a stay issued on December 30, 2011, by the Federal Court of Appeals considering petitions to review CSAPR, prevents such implementation pending a decision on the merits. CAIR will remain in effect pending such resolution.
- **National Emission Standards for Reciprocating Internal Combustion Engines (RICE).** The EPA recently issued rules regulating owners and operators of wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter and often used to provide demand side resources in the RPM. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs), and particulate matter.

  Several curtailment service providers (CSPs) reached a settlement with the EPA regarding their appeals in Federal Court, resulting in a commitment by the EPA to file revised rules that would accommodate participation by RICE in emergency demand response programs administered by Independent System Operators. The Market Monitoring Unit objected to the settlement, explaining that it did

1 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

not enhance clean air, participation by demand side resources in the organized markets nor reliability.[2] If approved, the settlement would require the EPA Administrator to take final action on the rules substantially consistent with the settlement by December 14, 2012.

- **Greenhouse Gas Tailoring Rule.** On May 13, 2010, the EPA issued a rule regulating CO_2 and other greenhouse gas emissions under the existing framework of new source review (NSR) and prevention of significant deterioration (PSD). As a result, new or modified units must install or implement the best available control technology (BACT). State environmental regulators determine BACT project by project, with guidance from the EPA.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey has 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 HEDD. New Jersey's HEDD rule,[3] 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.[4] New Jersey's HEDD rule will be implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates.

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. After December 31, 2011, the State of New Jersey will no longer participate in the RGGI program. Auction prices in 2011 for the 2009-2011 compliance period were $1.89 throughout the year, which was the price floor for 2011.

Renewables and Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. At the end of 2011, 64.5 percent of coal steam MW's had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.0 percent of coal steam MW's had some type of particulate control. NOx emission controlling technology is used by nearly all fossil fuel unit types, and 90.4 percent of fossil fuel fired capacity in PJM has NOx emission control technology in place.

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 2011, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 8.30 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out-of-market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

2 See 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).

3 N.J.A.C. § 7:27-19.

4 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).

Conclusion

Initiatives at both the Federal and state levels have an impact on the cost of energy and capacity in 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 could be used to incorporate renewable resource requirements to ensure that renewable resources have access to a broad market and are priced competitively so as to reflect their market value. PJM markets can 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. EPA issues technology based standards for major sources and certain area sources of emissions.[5,6] In recent years, the EPA has been actively defining and tightening its standards and considering potential mechanisms, such as cap and trade, to facilitate meeting those standards. EPA actions have and are expected to continue to affect the costs to build and operate generating units in PJM which in turn affect 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 CAA affects generating plants that draw water from jurisdictional water bodies.

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. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.

The CAA requires the standards to reflect the maximum degree of reduction in hazardous air pollutant emissions that is achievable taking into consideration the cost of achieving the emissions reductions, any non air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the Maximum Achievable Control Technology (MACT). The MACT floor is the minimum control level allowed for NESHAP and ensures that all major hazardous air pollutant emission sources achieve the level of control already achieved by the better-controlled and lower-emitting sources in each category. Section 112 of the CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing 5 sources for source categories with less than 30 sources).

On December 16, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which is actually two separate rules issued on the same date.[7] One rule applies the MACT requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide (MATS/MACT Rule). The rule establishes a compliance deadline of April 16, 2015, near the end of the 2014/2015 RPM Delivery Year. A source may obtain an extension for up to one additional year where necessary for the installation of controls.

The MATS/MACT Rule sets emissions limits separately for each pollutant. The rule differs from the initial MACT proposal in several significant respects. Only filterable particulate matter (PM), as opposed to both filterable and condensable PM, is considered for compliance with emissions limits. Work practice standards are included for startup and shutdown periods. The rule extends the period of averaging for Hg from 30 to 90 days, but tightens the applicable standards for sources using averaging. The rule narrows the options for demonstrating continuous compliance to either continuous monitoring or periodic quarterly testing. The revised rule establishes seven categories of units covered by various requirements.

5 42 U.S.C. § 7401 et seq. (2000).

6 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.

7 Mercury Air Toxics Standards (MATS) rule, 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 Nos. EPA-HQ-OAR-2009-0234 & EPA-HQ-OAR-2011-0044.

The other MATS rule sets New Source Performance Standards (NSPS)(MATS/NSPS Rule). The MATS/NSPS Rule requires new electric generating units constructed after May 3, 2012, to comply with amended emission standards for SO_2, NO_x and filterable Particulate Matter.

Control of NO_x and SO_2 Emissions

The CAA requires States to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[8] The EPA has sought to promulgate default Federal rules to achieve this objective.

The CAA requires EPA to review and, if appropriate, revise the air quality criteria for the primary (health-based) and secondary (welfare-based) NAAQS every five years. The NAAQS are the targets to which compliance mechanisms such as the rules regulating transport are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010.[9] The EPA has initiated proceedings to review secondary NAAQS for NO_x and SO_x and primary and secondary NAAQS for Ozone (O_3). Proposed rules are expected to issue, respectively, in July, 2011 and May, 2013.[10] Additionally, on September 22, 2011, the EPA issued draft guidance regarding determining compliance with one-hour SO_2 NAAQS State Implementation Plan submissions.[11] If adopted, the approach outlined in the draft guidance could impact the attainment status of generating units within PJM, and require additional controls for SO_2.

On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), the latest in a series of rules aimed at regulating transport. 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.[12] The CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[13] This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to an order of the U.S. Court of Appeals for the District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act.

The CSAPR and its initial emissions caps were expected to become effective January 1, 2012, and to be reduced substantially two years later, on January 1, 2014. An order of the U.S. Court of Appeals for the District of Columbia has disrupted this timetable. On December 30, 2011, the Court issued a stay of the implementation of the CSAPR pending resolution of pending petitions for review.[14] The timetable for completing that review is uncertain. The Court stated that in the meantime EPA "is expected to continue administering [CAIR]." EPA has reinstated CAIR and restored 2012 CAIR allowances to accounts on January 10, 2012.[15]

It is unclear how effectively CAIR can be reestablished. The CSAPR does not recognize CAIR trading credits. EPA froze and then reinstituted CAIR trading accounts. These and other factors may influence the nature of continued participation in CAIR. The case will not be heard on the merits until a hearing convenes in April, 2012. A reasonable evaluation of whether or in what form CSAPR will survive cannot be made prior to that hearing.[16]

The discussion here assumes that CSAPR eventually becomes effective in its current form, and those assumptions were relevant to market expectations and behavior in 2011. Whether or in what form the CSAPR does take effect depends upon developments in 2012 and beyond.

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

8 CAA § 110(a)(2)(D)(i)(I).
9 See 40 CFR Parts 50, 53, and 58.
10 See EPA Docket No. EPA-HQ-OAR-2007-1145 and EPA-HQ-OAR-2008-0699.
11 EPA, Draft Guidance for 1-Hour SO_2 NAAQS SIP Submissions (Draft September 22, 2011).
12 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).
13 Id.
14 USCA Case No. 11-1302, Document #1350421.
15 See EPA website at <http://www.epa.gov/airmarkets/progsregs/cair/index.html>.
16 EPA states on its website: "The court's decision is not a decision on the merits of the rule and EPA firmly believes that when the court does weigh the merits of the rule it will ultimately be upheld" (<http://epa.gov/airtransport/faqs.html>). However, the likelihood that the party seeking the stay will prevail on the merits of the appeal is one of the factors considered in the decision to grant a stay. Cuomo v. United States Nuclear Regulatory Comm'n, 772 F.2d 972, 974 (D.C. Cir. 1985) (citing Washington Metro. Area Transit Comm'n v. Holiday Tours, Inc., 559 F.2d 841, 843 (D.C. Cir. 1977)); accord Hilton v. Braunskill, 481 U.S. 770, 776 (1987).

except Delaware, and also excluding the District of Columbia.[17] "Group 2" does not include any states in the PJM region.[18] 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[19] NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Table 7-1 2012 and 2014 assurance levels (Tons) for SO_2[20] NO_x and O_3 season NO_x[21] emissions

	SO_2		NO_x		O_3 Season NO_x	
	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level
Illinois	277,169	146,465	56,489	56,489	25,662	25,662
Indiana	336,800	190,111	129,477	127,940	56,720	55,872
Kentucky	274,541	125,415	100,401	91,141	43,762	39,536
Maryland	35,542	33,280	19,627	19,557	8,687	8,687
Michigan	270,578	169,914	77,197	74,387	31,160	29,920
New Jersey	9,051	6,577	9,069	8,706	4,809	4,328
North Carolina	161,520	67,992	59,693	49,033	26,823	22,331
Ohio	366,071	161,751	109,390	103,242	48,476	45,728
Pennsylvania	328,808	132,185	141,583	140,649	63,163	62,814
Tennessee	174,817	69,423	42,130	22,818	18,039	9,699
Virginia	83,568	41,367	39,226	39,226	17,487	17,487
West Virginia	172,485	89,288	70,177	64,407	30,592	28,182

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.

Significant additional SO_2 emission reductions would be required in 2014 from certain states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

The rule would implement 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. The EPA will not assess assurance level penalty provisions until January 1, 2014.[22]

Table 7-1 shows the assurance levels applicable in 2012 and 2014 for SO_2, NO_x and seasonal ozone for each PJM state.

Emission Standards for Reciprocating Internal Combustion Engines

The EPA recently issued rules regulating owners and operators of a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter and are often used to provide demand side resources in the RPM market. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal

17 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.

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

19 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 (PM2.5) measures less than 2.5 microns across.

20 Annual NO_x assurance levels for Michigan and Annual NO_x and SO_2 and Seasonal NO_x for New Jersey are as set forth in the Technical Revisions to State Budgets and New Unit Set-Asides, Docket No. EPA-HQ-2009-0491 (October 2011) at 5 (Table 1.208.b) & 38 (Table 10.h), which includes changes approved in Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone, Final Rule, DPA Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 80760 (December 27, 2011).

21 CSAPR at 48269–70 (Tables VI.F-1, F-2 & F-3); Proposed Revised CSAPR at 40666 (Table 1.C-2).

22 See CSAPR II at 10330.

Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[23]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NOX, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn upon the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition). Spark ignition facilities are further subdivided.

A number of curtailment service providers petitioned the United States Court of Appeals for the District of Columbia Circuit for review of certain aspects of the RICE Rules.[24] On December 28, 2011, the EPA released a Notice of Proposed Settlement Agreement and Request for Public Comment that would allow owners and operators of emergency stationary internal combustion engines to operate emergency stationary internal combustion engines in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 60 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. Under the settlement, the rules may also allow for more hours of operation.[25] The Market Monitoring Unit objected to the settlement, explaining that it did not enhance clean air, participation by demand side resources in the organized markets nor reliability.[26] If approved, the settlement would require the EPA Administrator to take final action on the rules by December 14, 2012, and if the EPA promulgates in final form an amendment to the RICE Rules that includes changes substantially the same as those agreed upon, then Petitioners will dismiss their appeal.

Greenhouse Gas Regulation

On April 2, 2007, the U.S. Supreme Court overruled EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[27] 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.[28]

The EPA determined that in order to regulate greenhouse gas emissions, it would need to develop a different standard for determining major sources that require permits to emit greenhouse gases as opposed to other pollutants. Application of the prevailing 100 or 250 tons per year (tpy) annual emissions rates would overwhelm the capabilities of state permitting authorities and impede the ability to construct or modify regulated facilities.[29]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[30] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011, referring to each phase as a step. Affected facilities will be required to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tpy CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[31]

On July 1, 2011, step 2 expanded the rule to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[32] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[33]

On February 3, 2012, the EPA proposed step 3.[34] This proposed rule would leave the step 2 thresholds unchanged. Step 2 allows permitting on a plant wide basis so that changes at a facility that do not violate the plant wide limits do not require additional permitting.[35]

23 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.

24 See EnerNOC, et al v. EPA, No. 10-1090 and No. 10-1336.

25 Proposed Settlement Agreement, EPA Docket No. RL-9615-8, 77 Fed. Reg. 282 (January 4, 2012).

26 See 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).

27 Massachusetts v. EPA, 549 U.S. 497.

28 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).

29 EPA, Proposed Rule, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations, Docket No. EPA-HQ-2009-0517 (February 24, 2012) at 6-7 (Step 3 Tailoring Rule).

30 EPA, Final Rule, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Docket No. EPA-HQ-OAR-2009-0517, 75 Fed. Reg. 31514.

31 Id. at 31516.

32 Id.

33 Id. at 31520.

34 Step 3 Tailoring Rule.

35 Id. at 8.

Step 2 also allows for sources to obtain status as "synthetic minor sources," and avoid status as a regulated major source, on the basis of its voluntary acceptance of enforceable emissions limits.[36] For example, a generating unit that would be a major resource if it operated every hour of the year could become a synthetic minor resource by accepting enforceable emissions limits based on its practical physical and operational limitations.[37]

On December 23, 2010, the EPA entered a settlement agreement to resolve the States and other litigants request for performance standards and emission guidelines for GHG emissions for new and significantly modified sources, as provided under Sections 111(b) and (d) of the CAA. The EPA has missed both its original and extended agreed upon deadlines to issue a proposed rule, July 26, 2011, and September 30, 2001, respectively. The EPA has not released a revised schedule. A proposed rule is expected to amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.[38]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed 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 Clean Water Act (CWA).[39] A settlement in a Federal Court obligates the EPA to issue a final rule no later than July 27, 2012.[40]

This rule seeks to protect aquatic life from from being trapped on the screens that cover water intake structures over the cooling system at a generating facility (impingement) or drawn into the cooling system (entrainment).

The EPA would study facilities that draw 125 MGD or more to evaluate, in a process open to the public, the need for site specific controls to prevent entrainment, and if there is a need, determine those controls.

The rule would require new or upgraded units to include or add technology equivalent to closed cycle cooling.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules, which apply to annual and seasonal emissions, affect units based on total annual or seasonal emissions. Units with relatively low capacity factors have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules. The New Jersey Department of Environmental Protection estimates that regulations targeting such units have the potential for region wide emission reductions of 1–2 ppb and greater localized reductions.[41]

New Jersey has 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 HEDD. New Jersey's HEDD rule,[42] 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.[43]

New Jersey's HEDD rule will be implemented in two phases. For the first and currently effective phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol) and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include the following measures: installation of emissions controls at the HEDD unit or a non-HEDD unit; run-time limitations; commitment to use natural gas on HEDD units if dual fueled;

36 Id.
37 See Id.
38 See 40 CFR Part 60.
39 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, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).
40 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, Et Al. V. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010.
41 See Tonalee Carlson Key, New Jersey Department of Environmental Protection, "Electric Generation on High Electric Demand Days," presentation at annual public hearing (April 1, 2009) at 11–12. This document may be accessed at: <http://www.state.nj.us/dep/cleanair/hearings/powerpoint/09_electric_gen.ppt>.
42 N.J.A.C. § 7:27–19.
43 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).

implementation of energy efficiency, demand response or renewable energy measures; or other approved measures. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports. The second phase involves performance standards applicable after May 1, 2015. New, reconstructed or modified turbines must comply with State of the Art (SOTA), Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT) standards, as applicable. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates. On February 8, 2012, the Governor of New Jersey announced that no extension beyond the 2015 deadline would be granted.

Table 7-2 shows the HEDD emissions limits applicable to each unit type.

Table 7-2 HEDD maximum NOx emission rates[44]

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

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 Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[45] After December 31, 2011, the State of New Jersey will no longer participate in the RGGI program.

Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

Since September 25, 2008, a total of 14 auctions have been held for 2009–2011 compliance period allowances, and 12 auctions have been held for 2012–2014 compliance period allowances.

Table 7-3 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period[46]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000

Table 7-3 shows the RGGI CO_2 auction clearing prices and quantities for the ten 2009-2011 compliance period auctions held as of the end of calendar year 2011. The

44 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.

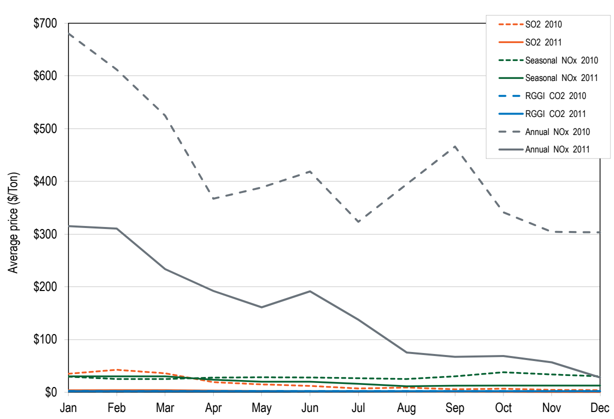
45 A similar regional initiative has organized under the Western Climate Initiative, Inc. (WCI). The first mover is the California Air Resources Board (ARB), which has organized a cap and trade program that it will implement starting in 2012. That program will be coordinated with other U.S. states and Canadian provinces participating in WCI. One such participant, Quebec, adopted cap and trade rules on December 15, 2011. British Columbia, Manitoba and Ontario are also expected to coordinate cap and trade policies through WCI.

46 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed January 3, 2012).

weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2011 calendar year was $2.56. Auction prices within the 2011 calendar year for the 2009-2011 compliance period were $1.89 throughout the year. This price, $1.89 per allowance, is the current price floor for RGGI auctions, as determined in the first RGGI auction. The average 2011 spot price for a 2009-2011 compliance period allowance was $1.91 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in March at $1.96 per ton and declining to $1.89 per ton during September through November, a price equal to the the auction's price floor of $1.89.

Figure 7-1 shows average, daily settled prices for NOx and SO_2 emissions within PJM. In 2011, seasonal NOx prices were 50.8 percent lower than in 2010. SO_2 prices were 87.3 percent lower in 2011 than in 2010. Figure 7-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

Figure 7-1 Spot monthly average emission price comparison: 2010 and 2011



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 2011, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 8.30 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2021. As shown in Table 7-4, New Jersey will require 22.5 percent of load to be served by renewable resources, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, 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 requires only 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 recognized as part of PJM markets. Revenues from RECs markets 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 each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources", which includes resources such as 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. The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of wholesale energy markets.

Table 7-4 Renewable standards of PJM jurisdictions to 2021[47,48]

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana			4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

Table 7-5 Solar renewable standards of PJM jurisdictions to 2021

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Solar Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 7-4 but must be met by solar RECs only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2021.[49] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2011, the most stringent standard in PJM was New Jersey's, requiring 0.31 percent of load to be served by solar resources. As Table 7-5 shows, by 2021, the most stringent standard will be Delaware's which requires at least 2.5 percent of load to 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 7-6 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 4.50 percent in 2011 and escalating to 14.25 percent in 2021. Maryland, New Jersey, Pennsylvania[50], and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits. North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards, while New Jersey requires 2,518 GWh of solar generation by 2021 (Table 7-6).

PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an

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

48 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.

49 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

50 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.

Table 7-6 Additional renewable standards of PJM jurisdictions to 2021

Jurisdiction		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	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 Carve-Out (in GWh)	306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste		0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)		170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

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 $675 per MWh. 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 renewable portfolio standard be met through alternative compliance payments. Table 7-7 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.

Table 7-8 shows generation by jurisdiction and renewable resource type in 2011. This includes only units that would

Table 7-7 Renewable alternative compliance payments in PJM jurisdictions: 2011

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	Voluntary standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
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 7-8 Renewable generation by jurisdiction and renewable resource type (GWh): Calendar year 2011

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	61.2	0.0	0.0	0.0	0.0	0.0	0.0	61.2	122.4
Indiana	0.0	0.0	41.8	0.0	0.0	0.0	2,640.6	2,682.4	2,682.4
Illinois	148.9	0.0	0.0	0.0	7.6	0.0	5,450.5	5,599.4	5,607.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	104.6	0.0	2,553.5	0.0	913.5	0.0	311.8	2,969.9	3,883.4
Michigan	29.0	0.0	63.3	0.0	0.0	0.0	0.0	92.4	92.4
New Jersey	347.9	541.0	24.4	50.9	1,403.5	0.0	9.7	432.9	2,377.4
North Carolina	0.0	0.0	383.9	0.0	0.0	0.0	0.0	383.9	383.9
Ohio	120.0	0.0	120.9	1.3	0.0	0.0	225.0	467.2	467.2
Pennsylvania	887.6	1,650.8	3,416.7	3.4	1,715.9	11,047.7	1,784.9	6,092.6	20,507.0
Tennessee	0.0	0.0	0.0	0.0	329.0	0.0	0.0	0.0	329.0
Virginia	183.1	4,693.9	709.7	0.1	1,190.1	0.0	0.0	892.9	6,776.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	6.1	0.0	1,078.2	0.0	0.0	1,062.2	1,138.7	2,222.9	3,285.1
Total	1,888.6	6,885.7	8,392.3	55.7	5,559.6	12,109.9	11,561.1	21,897.6	46,452.8

Table 7-9 PJM renewable capacity by jurisdiction (MW), on December 31, 2011[51]

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	1,835.3	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	60.0	24.5	129.0	31.9	0.0	590.0	0.0	109.0	0.0	120.0	1,064.4
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	119.7	191.1	0.0	7.5	808.8
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	3,939.7	25.8	25.0	209.0	0.0	178.0	1.1	0.0	0.0	500.0	4,878.6
Pennsylvania	35.0	222.3	2,370.7	0.0	1,505.0	672.6	3.0	263.0	1,473.9	865.0	7,410.4
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	114.9	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,471.9
West Virginia	500.0	2.0	0.0	0.0	0.0	244.0	0.0	0.0	130.0	663.5	1,539.5
PJM Total	4,534.7	552.8	4,440.0	272.8	5,493.0	2,481.7	123.9	943.1	1,603.9	5,339.1	25,784.9

Table 7-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS[52,53] (MW), on December 31, 2011

Jurisdiction	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	25.8	0.0	0.1	25.9
Illinois	4.0	99.2	0.0	0.0	0.0	10.7	0.0	302.5	416.4
Indiana	0.0	38.6	0.0	679.1	0.0	0.7	0.0	0.0	718.4
Kentucky	2.0	16.0	0.0	0.0	0.0	0.4	88.0	0.0	106.4
Maryland	0.0	7.0	0.0	0.0	0.0	38.1	0.0	0.0	45.1
Michigan	0.0	1.6	0.0	0.0	0.0	0.2	28.0	0.0	29.8
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	39.9	0.0	0.0	23.3	414.1	0.0	0.2	477.5
New York	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	225.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	227.1
Ohio	1.0	37.3	52.6	45.0	0.0	28.0	109.3	10.4	283.6
Pennsylvania	0.2	8.4	4.8	85.5	0.3	115.2	0.0	49.2	263.6
Virginia	12.5	14.8	0.0	0.0	0.0	4.3	318.1	0.0	349.7
West Virginia	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.5
District of Columbia	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	3.1
Total	357.5	262.8	57.4	809.6	23.6	644.0	588.0	508.4	3,251.3

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 11,561.1 GWh of 21,897.6 Tier I GWh, or 53.0 percent, in the PJM footprint. As shown in Table 7-8, 46,452.8 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 47.1 percent.

Table 7-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[54] This analysis includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. Pennsylvania has the largest amount of renewable capacity in PJM, 7,410.4 MW, or 28.7 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 119.7 MW, or 96.7 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 2,998.1 MW, or 56.2 percent of the total wind capacity.

Table 7-10 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not PJM units. This includes solar capacity of 644.1 MW of which

51 The correct value as of December 31, 2010 for Pumped Storage Hydro capacity in Pennsylvania was 1,505 MW, rather than the listed 2,575 MW.

52 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.

53 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 01, 2012).

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

414.1 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 7-10 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 that 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.

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 82,039.8 MW of coal steam capacity in PJM, 52,953.2 MW of capacity, 64.5 percent, has some form of FGD technology. Table 7-11 shows emission controls by unit type, of fossil fuel units in PJM.

Table 7-11 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2011

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	52,953.2	29,086.6	82,039.8	64.5%
Combined Cycle	0.0	26,905.7	26,905.7	0.0%
Combustion Turbine	0.0	30,620.8	30,620.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	0.0	9,478.0	9,478.0	0.0%
Total	52,953.2	96,457.6	149,410.8	35.4%

NOx emission controlling technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NOx controls. Of current fossil fuel units in PJM, 135,029.6 MW, or 90.4 percent, of 149,410.8 MW of capacity in PJM, have emission controls for NOx. Table 7-12 shows NOx emission controls by unit type of fossil fuel units in PJM. While most units in PJM have NOx emission controls, many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future NOx compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 7-12 NOx emission controls by unit type (MW), as of December 31, 2011

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	79,417.0	2,622.8	82,039.8	96.8%
Combined Cycle	26,169.6	736.1	26,905.7	97.3%
Combustion Turbine	24,952.8	5,668.0	30,620.8	81.5%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	4,490.2	4,987.8	9,478.0	47.4%
Total	135,029.6	14,381.2	149,410.8	90.4%

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 80,405.8 MW, 98.0 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-13 shows particulate emission controls by unit type of fossil fuel units 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 forthcoming emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which many coal steam units have not installed.

Table 7-13 Particulate emission controls by unit type (MW), as of December 31, 2011

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	80,405.8	1,634.0	82,039.8	98.0%
Combined Cycle	0.0	26,905.7	26,905.7	0.0%
Combustion Turbine	0.0	30,620.8	30,620.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	3,047.0	6,431.0	9,478.0	32.1%
Total	83,452.8	65,958.0	149,410.8	55.9%

Wind Units

Table 7-14 shows the capacity factor of wind units in PJM. In 2011, the capacity factor of wind units in PJM was 28.9 percent. Wind units that were capacity resources had a capacity factor of 29.7 percent and an installed capacity of 3,930 MW. Wind units that were classified as energy only had a capacity factor of 23.9 percent and an installed capacity of 1,410 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 7-14 Capacity[55] factor[56] of wind units in PJM: Calendar year 2011

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.9%	NA	120,242	1,410
Capacity Resource	29.7%	169.2%	355,369	3,930
All Units	28.9%	169.2%	475,611	5,339

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-15 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 935.5 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 1,973 separate five minute intervals, or 1.88 percent of all intervals. On average, 2,270.9 MW of wind were offered daily. Overall, wind units were marginal in 8,848 separate five minute intervals, or 8.42 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out-of-market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-15 Wind resources in real time offering at a negative price in PJM: Calendar year 2011

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	935.5	1,973	1.88%
All Wind	2,270.9	8,848	8.42%

Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in November, February and April, and lowest in June and July. The highest average hour, 2,350.4 MW, occurred in December, and the lowest average hour, 354.9 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 7-2 Average hourly real-time generation of wind units in PJM: Calendar year 2011

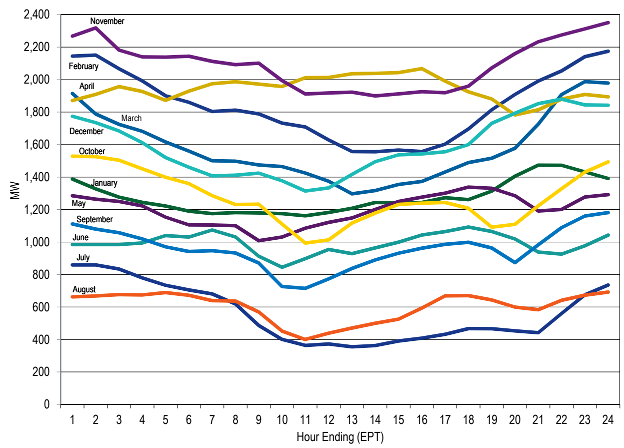


Table 7-16 shows the generation and capacity factor of wind units in each month of 2011. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 42.4 percent in February, and the lowest capacity factor was 12.2 percent in July, a difference of 30.2 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2011, and are included in this analysis as they were added.

Table 7-16 Capacity factor of wind units in PJM by month, 2010 and 2011[57]

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	971,942.0	35.9%	950,441.9	29.7%
February	736,663.6	28.9%	1,237,813.0	42.4%
March	853,590.0	30.3%	1,175,567.0	36.4%
April	1,001,447.6	36.6%	1,399,217.0	44.7%
May	730,087.9	25.9%	893,485.1	27.6%
June	492,344.0	17.7%	713,713.8	22.0%
July	396,754.7	13.7%	416,695.8	12.2%
August	344,015.5	11.6%	447,575.2	13.1%
September	733,193.7	23.0%	689,962.6	20.9%
October	1,042,735.7	31.1%	946,406.3	26.3%
November	1,127,306.0	34.0%	1,507,766.4	41.8%
December	1,159,478.3	33.8%	1,182,421.6	31.5%
Annual	9,589,559.0	27.4%	11,561,065.8	28.9%

55 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource.

56 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

57 Capacity factor shown in Table 716 is based on all hours in January through September, 2011.

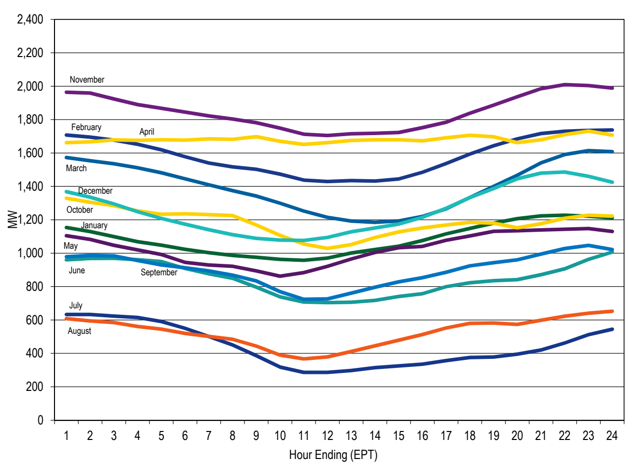
Table 7-17 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load for on peak and off peak periods. The on peak winter capacity factor was 32.4 percent while the on peak summer capacity factor was 18.7 percent. The off peak winter capacity factor was 3.6 percentage points higher than during the on peak period, while the off peak summer capacity factor was 0.4 percentage points lower than during the on peak period.

Table 7-17 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): Calendar year 2011

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.4%	42.1%	18.7%	32.3%	27.3%
	Average Wind Generation	1,475.0	2,003.5	869.3	1,551.6	1,266.4
	Average Load	86,939.1	75,551.5	99,674.0	83,896.3	91,190.4
Off-Peak	Capacity Factor	36.0%	44.9%	18.3%	37.1%	29.4%
	Average Wind Generation	1,646.3	1,874.6	853.7	1,782.2	1,366.6
	Average Load	75,243.8	62,156.7	78,079.9	69,313.3	74,626.6

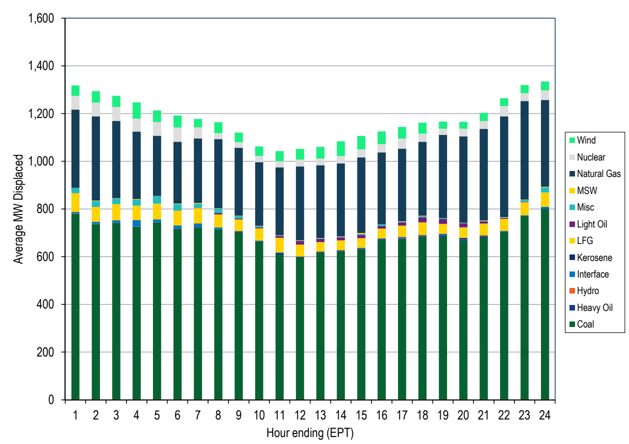
Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 7-3 shows the average hourly day-ahead time generation of wind units in PJM, by month.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: Calendar year 2011



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 will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 7-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2011. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2011. Wind output varies daily, and on average is about 292 MW lower from peak average output (2300 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the displaced fuel at times when wind resources were on the margin. In effect this means that there was no displacement for those hours.

Figure 7-4 Marginal fuel at time of wind generation in PJM: Calendar year 2011



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 7-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in July, the month with the most daylight hours. The highest average hour, 35.5 MW, occurred in December, primarily due to increases in solar capacity throughout calendar year 2011. In general, solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: Calendar year 2011