2011 Joint Report on the Impact of Environmental and Renewable Technology Issues in the Northeast

ISO New England, New York ISO and PJM

Addressing issues in support of the Northeast Coordinated System Plan (NCSP)

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Contributors:

ISO-NE: Patricio Silva, Michael Henderson, Jim Platts

NYISO: John Adams, John Buechler, Peter Carney, Dawei Fan, Zach Smith

PJM: Ken Schuyler, Gary Helm

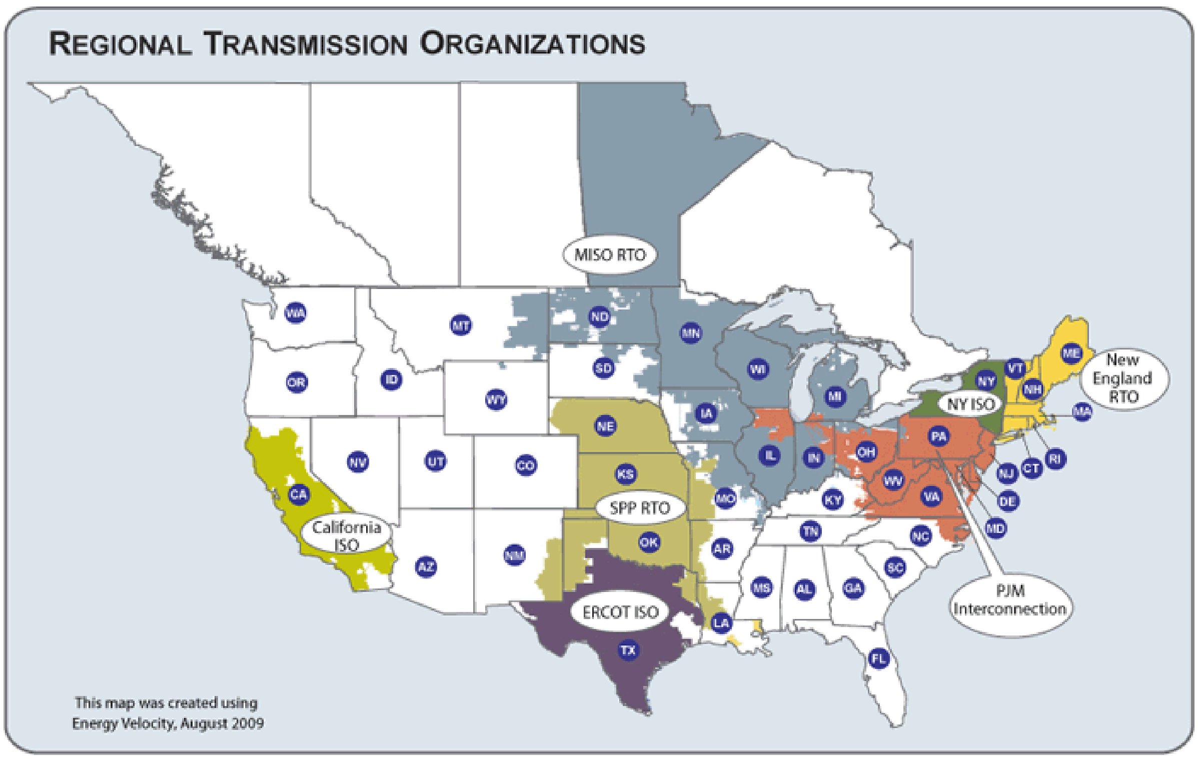
Preface

This report is written in support of the Northeast Coordinated System Plan (NCSP). This report analyzes the potential interregional impacts of pending environmental regulations and associated with the integration of variable energy resources. The report was prepared by the Joint ISO/RTO Planning Committee (JIPC). The report also includes discussion of the North American Electric Reliability Corporation's (NERC) Special Reliability Assessment of the potential impact of the EPA's proposed non-carbon environmental regulations.

1. Executive Summary

ISO New England Inc. (ISO-NE), the New York Independent System Operator (NYISO), and PJM Interconnection (PJM) each produce their own annual regional plan covering the needs of the region that each ISO/RTO serves. In addition, these ISO/RTOs work jointly under a formal protocol, the Northeastern ISO/RTO Planning Coordination Protocol, studying numerous issues related to interregional electric system problems, developments and performance. The intent of collaboration under the joint planning protocol is to ensure that the electric system is planned on a wider interregional basis and is well coordinated. This report is an interim update to the current Northeast Coordinated System Plan that focuses on the current joint activities evaluating the potential interregional impact of pending environmental regulations and renewable portfolio standards on system reliability.

Figure 1-1. Regional Transmission Organizations



Source: Federal Energy Regulatory Commission, http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

ISO-NE, NYISO, and PJM follow a planning protocol to enhance the coordination of their planning activities and address planning seams issues among the interregional balancing authority areas.[1] Hydro-Québec TransÉnergie, the Independent Electric System Operator (IESO) of Ontario and the New Brunswick System Operator (NBSO) participate on a limited basis to share data and

[1] Additional information about the Northeastern ISO/RTO Planning Coordination Protocol ("Protocol") is available online at http://www.interiso.com/public/document/Northeastern%20ISO-RTO%20Planning%20Protocol.pdf. An *RTO* is a Regional Transmission Organization that is responsible for a wide geographic area known as a balancing area. ISO New England is the RTO for Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The New York Independent System Operator (NYISO) is responsible for New York State. PJM Interconnection is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

information. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts
- Develop the Northeast Coordinated System Plan (NCSP) on a periodic basis[2]
- Allocate the costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

To implement the protocol, the Joint ISO/RTO Planning Committee (JIPC) was formed, and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) was created to discuss work conducted by the JIPC.[3] Through the open stakeholder process, the JIPC has made progress addressing several interregional planning issues over the past year, including this report on the potential effects of environmental regulations, including the integration of wind and other renewable resources.

The states served by the Northeastern ISO/RTOs are subject to many environmental regulations, including those regarding ambient air quality, greenhouse gases (such as carbon dioxide), air toxics, coal ash and cooling water. Generator capital, operation and maintenance costs are expected to increase for many affected units because of the aggregate impact of these regulations. Those increased costs will include new emission allowances, new pollutant controls, increased waste disposal, and cleaner fuels. The regulations may also affect reliability by limiting generator energy production, reducing capacity output, hastening generator retirements. Since interregional system performance could change as a result of new generation patterns, the JIPC monitors environmental regulations for potential system impacts.

Also, most of the states served by PJM, NYISO, and ISO-NE have renewable portfolio standards or related energy policies. The interconnection queues in the three ISO/RTO regions total over 59,000 MW of renewable resources, over 92% of which are wind resources, including significant offshore wind projects.

[2] Past NCSPs and related materials are available at http://www.interiso.com/documents.cfm. While "periodic" is not explicitly defined within the protocol, new analytical material has historically been provided on an annual basis.
[3] See "Inter-ISO Planning," IPSAC meeting notices; http://www.interiso.com/default.cfm.

Table 1-1. ISO-NE, NYISO, & PJM Interconnection Queues for Renewable Development

ISO/RTO	Onshore Wind	Offshore Wind	Biomass	Conventional Hydro	Landfill Gas	Fuel Cells	Solar	Total
ISO-NE[(a)]	2,359 (36)	1,027 (3)	450 (13)	35 (8)	34 (1)	9 (1)	0	3,914 (62)
NYISO[(b)]	4,610 (41)	1,961 (4)	76.6 (3)	16.1 (4)	31.2 (7)	0	31.5(1)	6,726.4 (60)
PJM[(c)]	39,518 (247)	2,369 (8)	816 (24)	1,160 (24)	417 (84)	0	4,221 (352)	48,501 (739)
Total	**46,487 (324)**	**5,357 (15)**	**1,342.6 (40)**	**1,211.4 (36)**	**452.2 (92)**	**9 (1)**	**4,252.5 (353)**	**59,141.4 (861)**

Sources: [(a)] Based on April 1, 2011 Interconnection Queue; [(b)] Based on May 2011 interconnection queue; [(c)] PJM 2010 RTEP Regional Transmission Expansion Plan dated February 28, 2011. Includes projects as of January 31, 2011

Finally, the growth of wind and other intermittent resources creates operating challenges for all the ISO/RTOs and the need for market design adjustments and system integration plans. These include transmission development to interconnect these wind projects, system operating flexibility to accommodate wind's variability, operator awareness and practices, and the need for wind generator plant performance and standards. The JIPC monitors the separate evaluations of wind issues being conducted individually by the ISO/RTOs, and the North American Electric Reliability Corporation (NERC).

2. Environmental Issues with Potential Interregional Impacts

This section discusses the status of air, water and solid waste regulations and policies that may affect the electric power generation facilities within the ISO/RTOs over the next five to ten-year planning period and the issues that these regulations and policies may have on system operations and reliability. Attainment of standards for four criteria pollutants have been or are being revised by the U.S. Environmental Protection Agency (EPA), and will likely lead to lower emission limitations for power plants. These pollutants are sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter (PM) and ozone (O_3). In addition regulations concerning regional haze, emissions of hazardous air pollutants such as mercury, emissions of greenhouse gases, cooling water technologies and coal combustion byproducts may impact these same generating facilities. These regulatory programs are affecting, and will continue to affect, the costs of operating and maintaining existing generating units, most notably coal and oil units, and collectively have the potential to affect interregional system reliability.

2.1 Impacts of Power Plants

Generating electricity using fossil fuels results in air emissions. These emissions include sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), mercury (Hg) and carbon dioxide (CO_2) and other Hazardous Air Pollutants (HAPs). SO_2 and NO_x emissions combine with cloud vapor to further acidify rain, which can negatively affect ecosystems and erodes physical structures. NO_x and volatile organic compounds (VOCs) react with sunlight—typically in the afternoon of warmer days from May through September—to form ozone (O_3).[4] Mercury is a naturally occurring element, which poses risks to human health and is found in coal, oil, air, water, and the soil. High levels of mercury concentrations in fish have led to advisories restricting its human consumption. Particulate matter (PM) contributes to acid rain, smog and haze, and carbon dioxide has the potential to contribute to global climate change.

Many power plants also use water from surrounding waterways for once-through cooling purposes, discharging the heated water back into the environment. Both the uptake and discharge processes can have negative impacts on the ecosystems and habitats of those waterways.

New, stricter federal, regional, and state air, water and solid waste regulations will be implemented over the next 10 years to reduce air emission levels from power plants and other emitting sources and to mitigate adverse impacts that power plants have on water quality. To minimize emissions and impacts on water quality, some existing thermal plants will likely need to retrofit controls, use cleaner fuels, or apply some combination of both measures. If the economics of switching to alternative fuels or adding emission controls are not favorable, some facilities may curtail operations or shut down.

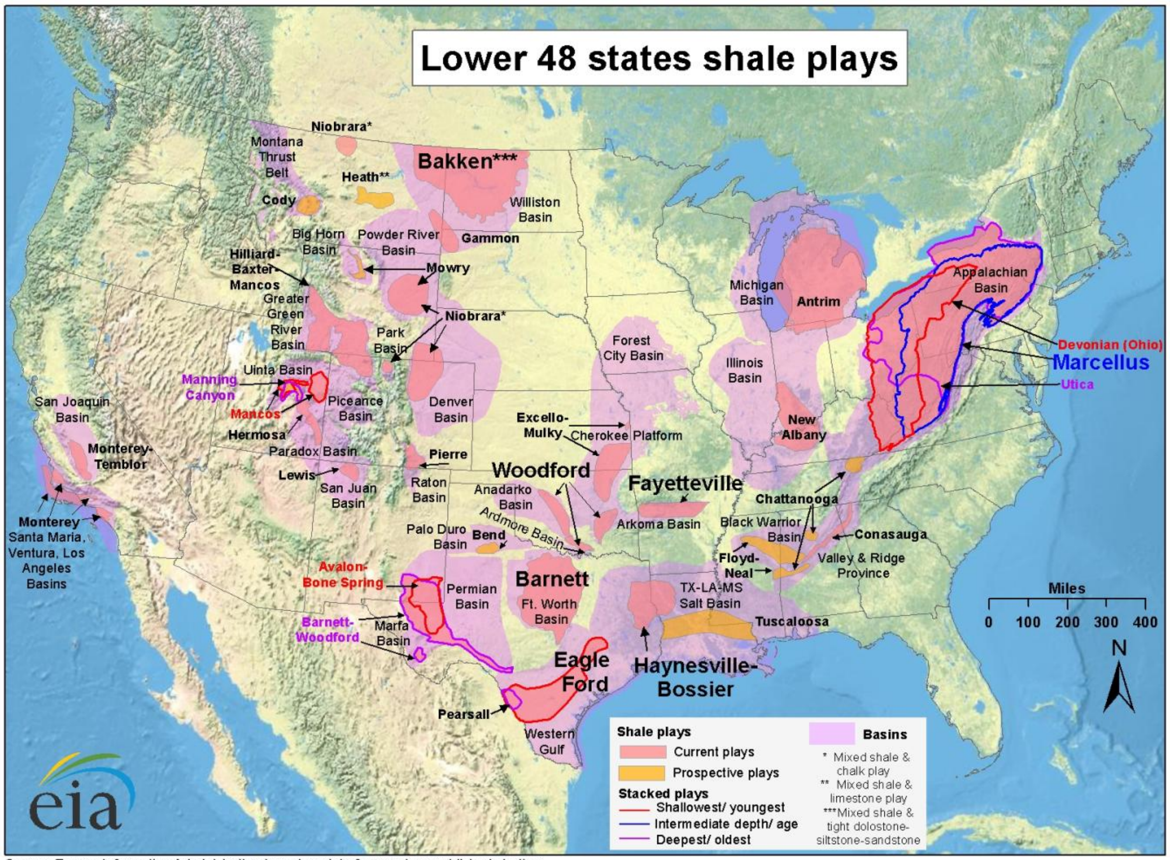
Individually or together, directly or indirectly, these pending regulations, are likely to increase the cost of production and ownership at the affected facilities. Alternatively, some generation owners may choose to retire rather than retrofitting environmental control technology that could lead to installing replacement resources that are cleaner and more efficient. The challenge directed at the JIPC is to develop plans that maintain electric system reliability.

In addition to upcoming EPA regulations, several states in the RTOs/ISOs are members of the Ozone Transport Commission (OTC). This organization develops model air pollution regulations, which

[4] VOCs come principally from the transportation sector.

several member states have adopted as part of their attainment obligations under the Clean Air Act, discussed in the following section. An example of this is the OTC model NO_x Reasonable Achievable Control Technology (RACT) requirements developed for boilers and combustion turbines at power plants.

The RTOs/ISOs are also assessing the impact of state energy efficiency and demand response programs, storage, and electric vehicle deployment on system reliability requirements. These are not addressed in this interim report. Other matters potentially impacting system reliability are the effects of increased natural gas production from Shale Plays such as Marcellus or Utica, nuclear generating relicensing, and development of more renewable energy sources than are currently planned.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1-2. Map of Shale Plays in the Lower 48 States

Planning to meet these environmental, economic and reliability requirements should be done collaboratively among the region's stakeholders, including the ISO/RTOs and their stakeholders, and state and federal environmental and energy agencies and policy makers.

2.2 EPA's Criteria Pollutants Affecting Power Plants

Under the *Clean Air Act*, EPA has established six criteria pollutants that are considered harmful to human health, property, and ecosystems. These six pollutants are sulfur dioxide, nitrogen dioxide, ozone, carbon monoxide (CO), lead (Pb), and particulate matter in two sizes—2.5 microns ($PM_{2.5}$) and 10 microns (PM_{10}). More recently, the EPA determined that greenhouse gases represent an endangerment to public health and the environment and initiated new rule-makings to limit emissions from power plants.[5] Among these pollutants are several that fossil fuel plants emit directly and others that are formed from these emissions through chemical reactions in the atmosphere.

The EPA has established *National Ambient Air Quality Standards* (NAAQS) for the six criteria pollutants, as shown in Table 2-1. Under the Clean Air Act, EPA is required to review the relevant science and public health effects, incorporate these data into a formal review on the protectiveness of existing NAAQS and issue a finding on whether an existing NAAQS should be revised, and, if so, to propose new standards that would be protective of public health and the environment. If a criteria pollutant is shown to be at a level above the NAAQS for a certain area (usually a county or state), the area is considered a *nonattainment area* for that specific criteria pollutant.

To meet the NAAQS for a specific pollutant over a designated time period, each area must develop or revise its air quality plan (i.e., a *state implementation plan*, SIP) for that pollutant.[6] A part of these plans addresses a requirement for new power plants and existing power plants undergoing certain types of modifications to use *best available control technologies* (BACT) or the generally more stringent, technically achievable *lowest achievable emission rate* (LAER).[7] Facilities sited in attainment areas require BACT, whereas facilities sited in nonattainment areas require LAER. In addition, any new plant in a nonattainment area must acquire *offsets* from existing emission sources that have reduced emissions in that same nonattainment area. Older fossil fueled plants are required to use reasonably available control technology (RACT) to control emissions.

Throughout the states served by the ISO/RTOS, as well as other states, the criteria pollutants may be in attainment in some areas and not in others; nonattainment areas are typically found in the more urban areas where transportation emissions comprise a significant contribution to the ambient levels. The three criteria pollutants that are of importance for fossil fuel power plants are SO_2, NO_x (as a precursor to ozone formation) and PM. Ozone levels in many areas of the ISO/RTOs are not in compliance with either the existing or the more stringent proposed ozone NAAQS. National and state air pollution control measures emphasize reductions of NO_x and volatile organic compounds (VOC), as these compounds are pre-cursors to the formation of ground level ozone. These pollutants are regulated are under various programs in addition to and separate from the NAAQS program. For example, power plant NO_x emissions have been a major target for reductions because of the role NO_x emissions play in ozone production and haze; while fine particulate control measures have occurred from efforts focused on reducing sulfate and nitrate precursors through post combustion controls, and fuel switching to lower sulfur fuels.

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[5] U.S. EPA, *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, Final Rule*, 74 Fed.Reg. 66496 (December 15, 2009).

[6] State environmental regulatory agencies submit SIPs to the regional EPA office for review and approval.

[7] BACTs are pollution control measures mandated by the CAA based on the maximum degree that each pollutant can be reduced with consideration of energy, environmental, and economic impacts. State and local permitting agencies typically determine BACTs on a case-by-case basis, and the technologies are implemented through the application of production processes or other available methods. LAERs are the most stringent CAA designations for the levels of control required for major emission sources in CAA nonattainment areas. LAER technologies are the most effective pollution-control measures regardless of cost.

Table 2-1. National Ambient Air Quality Standards[8]

	Primary Standards		Secondary Standards	
Pollutant	**Level**	**Averaging Time**	**Level**	**Averaging Time**
Carbon Monoxide (CO)	9 ppm (10 mg/m³)	8-hour	None	
	35 ppm (40 mg/m³)	1-hour	Same as Primary	
Lead (Pb)	0.15 µg/m³	Rolling 3-Month Average	Same as Primary	
Nitrogen Dioxide (NO_2)	53 ppb	Annual (Arithmetic Average)	Same as Primary	
	100 ppb	1-hour	None	
Particulate Matter (PM_{10})	150 µg/m³	24-hour	Same as Primary	
Particulate Matter ($PM_{2.5}$)	15.0 µg/m³	Annual (Arithmetic Average)	Same as Primary	
	35 µg/m³ (2006 std)	24-hour	Same as Primary	
Ozone (O_3)	0.075 ppm (2008 std)	8-hour Under review	Same as Primary	
	0.08 ppm (1997 std)	8-hour	Same as Primary	
	0.12 ppm	1-hour	Same as Primary	
Sulfur Dioxide (SO_2)	0.03 ppm	Annual (Arithmetic Average)	0.5 ppm	3-hour
	0.14 ppm	24-hour		
	75 ppb	1-hour	None	

(1) Not to be exceeded more than once per year.
(2)Final rule signed October 15, 2008. The 1978 lead standard (1.5 µg/m³ as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.
(3) The official level of the annual NO_2 standard is 0.053 ppm, equal to 53 ppb, which is shown here for the purpose of clearer comparison to the 1-hour standard
(4) To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 ppb (effective January 22, 2010).
(5) Not to be exceeded more than once per year on average over 3 years.
(6) To attain this standard, the 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 15.0 µg/m³.
(7) To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m³ (effective December 17, 2006).
(8) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (effective May 27, 2008) EPA is considering revising this standard below 0.0075 ppm.
(9) (a) To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm. (being reconsidered)
(b) The 1997 standard—and the implementation rules for that standard—will remain in place for implementation purposes as EPA undertakes rulemaking to address the transition from the 1997 ozone standard to the 2008 ozone standard.
(c) EPA is in the process of reconsidering these standards (set in March 2008).
(10) (a) EPA revoked the in all areas, although some areas have continuing obligations under that standard ("anti-backsliding").
(b) The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is $\leq$ 1.
(11) (a) Final rule signed June 2, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

[8] U.S.EPA, National Ambient Air Quality Standards (Revised as of April 18, 2011) http://www.epa.gov/air/criteria.html

2.2.1 Sulfur Dioxide (SO_2)

In June 2010, EPA revised the primary SO_2 NAAQS adopting a new 75 *parts per billion* (ppb) 1-hour standard. It is based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations.[9] Under Clean Air Act § 109, EPA is also considering whether to revise the secondary SO_2 NAAQS to protect sensitive aquatic ecosystems from continuing acidic deposition, targeting. A consent decree mandated release of the proposed rule by July 12, 2011 and a final rule by May 20, 2012.[10]

2.2.2 Nitrogen Dioxide (NO_2)

The current NO_2 NAAQS is an annual standard of 53 ppb. However, the EPA adopted a new one-hour daily maximum concentration NO_2 standard of 100 ppb. [11] Additional monitoring sites will need to be added by January 1, 2013. After three years of data have been accumulated, the EPA will propose designations of non-attainment and maintenance[12] areas for this new standard.

2.2.3 Fine Particulates ($PM_{2.5}$)

In 2006 EPA revised its $PM_{2.5}$ NAAQS, which is comprised of an annual standard of 15 μg/m^3 and a 24-hour standard of 35 μg/m^3. The revised NAAQS was subject to a legal challenge and in February 2009 the D.C. Circuit Court of Appeals remanded both the primary annual and secondary $PM_{2.5}$ NAAQS finding that EPA failed to adequately explain how the primary standard provided adequate protection from both short- and long-term exposure to fine particles; and why setting secondary standards identical to the primary standard provided the required protection of the public welfare, including visibility impairment.[13] EPA is in the process of revising the primary annual and secondary $PM_{2.5}$ NAAQS and is expected to propose revised standards by mid-2011 and to promulgate new standards later in 2011, with revised state air quality plans due three years later.[14]

2.2.4 Ozone (O_3)

In March 2008, the eight-hour NAAQS ozone standard was reduced by EPA from 84 ppb to 75 ppb. This new standard was challenged in court and EPA, on September 16, 2009, announced the reconsideration of the March 2008 primary and secondary ozone NAAQS. In January 2010, EPA proposed a stricter primary standard in a range of 60 to 70 ppb.[15] EPA has an announced schedule to make a final determination in the reconsideration of the March 2008 primary and secondary ozone NAAQS by July 29, 2011.

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[9] U.S. EPA, *Primary National Ambient Air Quality Standard for Sulfur Dioxide; Final Rule*, 75 Fed.Reg. 35520 (June 22, 2010).

[10] Ctr. for Biological Diversity v. Johnson, Second Stipulation to Amend Consent Decree, No. 05-1814 (LFO) (D.C. Cir. Oct. 22, 2009); Miller Jr., Paul, Northeast States for Coordinated Air Use Management, *A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability* (March 30, 2011) pp. 8-9.

[11] U.S. EPA, *Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Final Rule*, 75 Fed.Reg. 6474 (February 9, 2010).

[12] Once a nonattainment area satisfies the applicable NAAQS and the requirements in CAA § 107(d)(3)(E) to redesignate as meeting that NAAQS, the EPA will designate the area as a maintenance area. If the air quality in a region is better than required by the NAAQS it defined as an attainment area.

[13] American Farm Bureau Federation v. EPA, 559 F.3d 512, 520-32 (D.C. Circuit 2009); U.S. EPA, *Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards*, EPA 452/R-11-003 (April 2011) pp. 1-9, 1-10.

[14] U.S. EPA, *Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards*, EPA 452/R-11003 (April 2011).

[15] U.S. EPA, *Primary National Ambient Air Quality Standards for Ozone; Proposed Rule*, 75 Fed.Reg. 2938 (January 19, 2010)

2.2.5 Ozone Attainment and SO_2 Reductions

Ozone attainment is being implemented by the states and EPA principally through reductions in NO_x emissions through its remanded Clean Air Interstate Rule (CAIR). SO_2 emission reductions are also part of CAIR as SO_2 contributes to smog.

2.3 Update of Environmental Regulations

The EPA is in the process of finalizing a suite of environmental regulations under the *Clean Air Act*, the *Clean Water Act,* and the *Resource Conservation and Recovery Act* that will impact generators across the ISO/RTOs. These regulations could materially affect various electric power generators beginning in 2012 and continuing through 2020, when all affected facilities are required to come into compliance. When finalized, based on EPA estimates, these regulations could affect over 35 GW of installed capacity across ISO-NE (15.9 GW) and NYISO (18.6 GW) and some undetermined amount in PJM. In some cases, this will entail significant capital investment for retrofitting facilities with post-combustion control devices, closed-cycle cooling systems, or fuel-switching equipment, or retiring electric generators.

Between July 2011 and May 2012, three of the proposed regulations (*Clean Air Transport Rule*, *Utility Air Toxics Rule*, and the *Cooling Water Intake § 316(b) Rule*) are required to be finalized by EPA according to various court orders and are scheduled to be implemented between January 2012 and January 2016.[16] Table 2-2 summarizes the proposed regulations, their targeted pollutants, and likely control technologies considered most suitable on the basis of available information.

Table 2-2. Proposed US EPA Environmental Regulations

Proposed EPA Regulation	Targeted Pollutant or Impact	Control Options
Clean Air Act § 112 Utility Air Toxics Rule	Hazardous air pollutants (mercury (Hg), HCI, HF, metals, organics)	Hg removal: fabric-filter baghouse (FF), activated carbon Injection (ACI) 80-90%; scrubber- selective catalytic reduction (SCR) cobenefit >90%[(a)] Wet or dry FGD, dry sorbent injection and fuel switching.
Clean Air Act § 110(a)(2)(D)(i)(I) Clean Air Transport Rule (CATR)	Reduce contribution to ozone and $PM_{2.5}$ nonattainment in downwind nonattainment areas.	NO_x removal: SCR 70-95%; selective noncatalytic reduction (SNCR) 30-75%[(b, c)]
		SO_x removal: scrubber ≥95%; dry sorbent injection <70%
Resource Conservation & Recovery Act Coal Combustion Residue Rule (Coal Ash)	Coal combustion waste disposal	Phase out wet-surface impoundments (ash ponds); composite liners; other design requirements for disposal sites or unit retirements[17]

[16] Various court orders require several upcoming EPA rulemakings: *Clean Air Transport Rule* (North Carolina v. EPA, 531 F3.d 896 (D.C. Cir. 2008) (revoking *CAIR),* North Carolina v. EPA, 550 F.3d 1176 (D.C. Cir. 2008) (remanding CAIR, ordering development of *CATR*)); *Air Toxics Rule* (New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008) (revoking *Clean Air Mercury Rule* (*CAMR*), *American Nurses Association v. Jackson*, No. 08-2198 (D.D.C. 2010) (setting rulemaking schedule)); *Cooling Water Intake Rule* (Riverkeeper, Inc. v. Jackson, 93 Civ. 0314 (S.D.N.Y 2010) (setting rulemaking schedule)..

[17] If EPA determines coal combustion byproducts should be treated as hazardous waste, the resulting required modifications in plant operations that would be required are so great that most coal units would retire.

Proposed EPA Regulation	Targeted Pollutant or Impact	Control Options
Clean Water Act § 316(b) Cooling Water and Wastewater Rule	Cooling water intake impacts	Intake design upgrades: cooling water intake structure retrofits; closed cycle cooling towers.
	Waste water toxic metals	Treatment or zero discharge

[(a)] Fabric-filter collection system, or baghouse, is a post-combustion particulate control system that traps particles in cylindrical or square filter elements, which are periodically cleaned to remove trapped particles.

[(b)] Selective catalytic reduction (SCR) is a post-combustion NO_X control technology that treats flue gas with ammonia (NH_3) as it enters a catalyst reactor. NH_3 reacts with NO_X, removing greater than 90% under optimal conditions in a temperature range between 600 and 700°F.

[(c)] Selective noncatalytic reduction (SNCR) is a post-combustion NO_X control technology that treats flue gas with ammonia or urea and can remove greater than 30% of NO_X in the flue gas under optimal conditions in a temperature range between 1,800 and 2,000°F.

The proposed *Air Toxics rule* affects coal- and oil-fired units over 25 MW, *CATR* affects all fossil fuel-fired units over 25 MW, and the proposed *Coal Ash rule* affects coal-fired units, while the proposed *Cooling Water Intake § 316(b)* rule affects cooling water intake structures at fossil fuel-fired and nuclear powered generators depending on the size and configuration of the existing cooling water intake structures in use at those facilities.

2.3.1 Clean Water Act

Changes in cooling water intake requirements for power plants under the *Clean Water Act § 316(b)* potentially could require closed-cycle cooling retrofits on some power plants in the region. The revised requirements would result in fewer aquatic organisms being impinged (trapped) against exterior portions of the cooling water intake structure (CWIS) or entrained (drawn into the cooling systems). In earlier rulemakings and various court decisions, EPA established that impingement and entrainment of aquatic life are the principal adverse impacts of CWIS at existing electric generating facilities.

On April 20, 2011, under the requirements of the *Clean Water Act* § 316(b) and in response to litigation, the EPA proposed revised national standards for minimizing adverse environmental impacts in the location, design, construction, and capacity of cooling water intake structures at existing electric generating facilities.[18] Existing facilities subject to the proposed cooling water rule are those with the following characteristics:

- Have cooling water intake structures withdrawing waters of the United States (ocean, tidal, lake or estuary)
- Have a total design intake flow of the cooling water intake structure(s) greater than 2 million gallons per day (MGD)
- Exclusively use at least 25% of the water withdrawn for cooling purposes measured on an average annual basis for each calendar year.[19]

Based on EPA analysis, approximately 22 GW of installed capacity across the ISO/RTOs may need to demonstrate compliance with the proposed *Cooling Water Intake § 316(b)* rule through studies or retrofit to closed-cycle cooling systems.

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[18] U.S. EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174 (April 20, 2011).

[19] EPA proposed *Cooling Water Rule* at 76 Fed.Reg. at 22192.

Under a consent decree, the EPA must finalize the proposed *Cooling Water Intake § 316(b)* rule by July 2012. Depending on site-specific circumstances, affected electric generating facilities would have to establish plans to demonstrate compliance with the new regulations, install closed cycle cooling systems or install effective alternative technologies. The compliance demonstration process would begin in the near term and depending upon site specific situations it may extend over a period of up to eight years to comply (i.e., to July 2020).

The existing CWA § 316(b) performance standards require reducing impingement mortality by 80% to 95% and, under certain circumstances, entrainment by 60% to 90% from an established baseline.[20] In its technical support documentation accompanying the proposed *Cooling Water Intake § 316(b)* rule, EPA estimates nationwide that 93% of affected facilities already have installed traveling screens that satisfy this requirement.

Additional assessments prepared by EPRI and NERC prior to the publication of the proposed *Cooling Water Intake § 316(b)* rule assumed more stringent impingement and entrainment controls would be required at existing electric generating facilities than those proposed by EPA in its preferred control option. EPRI estimated that 428 power generating facilities consuming more than 50 million gallons per day of once through cooling water could be required to retrofit closed cycle cooling systems at a cost of more than $95 billion with annual operating cost penalties in excess of $15 billion.[21] In contrast, the proposed *Cooling Water Intake § 316(b)* rule preferred entrainment mitigation option (Option 1) requires electric power generating facilities consuming more than 125 million gallons per day of once through cooling water to prepare and submit an entrainment characterization study, to determine whether they would be required to retrofit closed cycle cooling systems. If Option 1 is adopted by EPA in the final *Cooling Water Intake § 316(b)* rule for entrainment mitigation, total compliance costs are expected to be lower, but many power generating facilities in the ISO/RTOs may be required retrofit closed cycle cooling systems.

[20] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174, 22180 (April 20, 2011).

[21] EPRI *National Cost Estimate for Retrofit of U.S. Power Plants with Closed-Cycle Cooling*, (1022212) January 20, 2011. http://my.epri.com/portal/server.pt?Abstract_id=000000000001022212 EPRI assumed all affected electric generating facilities would retrofit with wet mechanical draft cooling towers, which are the most commonly used form of closed-cycle cooling over the past two decades."

Table 2-3. EPA Proposed Control Options and Costs for the Proposed *Cooling Water Intake § 316(b) rule* for the ISO/RTOs[(a)]

Option	Impingement and Entrainment Mitigation Control Requirements		Estimated Annual Compliance Costs ($ Millions, 2009)[(b)]
	Existing Facilities	New Units at Existing Facilities	
1	Uniform impingement mortality controls at all existing facilities Site-specific entrainment controls for existing facilities that have a design intake flow rate (DIF) (withdrawal) of over 2 MGD Site specific determination of Best Technology Available for entrainment for facilities with greater than 125 MGD actual intake flow	Uniform entrainment controls	$216
2	Impingement mortality controls at all existing facilities that withdraw over 2 MGD (DIF) Flow reduction equal to closed-cycle cooling at facilities with DIF of over 125 MGD	Flow reduction equal to closed-cycle cooling	$2,850
3	Impingement mortality controls at all existing facilities that withdraw over 2 MGD (DIF) Flow reduction commensurate with closed-cycle cooling at all existing facilities with DIF over 2 MGD	Same requirements as existing facilities	$2,959
4	Uniform impingement mortality controls at all existing facilities that withdraw 50 MGD or more (DIF) Best professional judgment permits for existing facilities with design intake flow between 2 MGD and 50 MGD (DIF)	Uniform entrainment controls	$209

(a) Source: US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174, 22204-22206 (April 20, 2011). Exhibit VII-11, Compliance Cost per Unit of Electricity Sales in 2015 by Regulatory Option and NERC Region, p. 22228, 22229.
(b) EPA estimated annual pre-tax compliance costs (2009 $) for known affected *§ 316(b) in NERC ECAR, MAAC, MAIN, NPCC regions, includes facilities in States outside the three ISO/RTOs service areas.*

Under the preferred Option 1 in the proposed *Cooling Water Intake § 316(b) rule*, existing facilities with a design intake of greater than 125 MGD would have the additional requirement to submit entrainment mortality characterization studies and detailed engineering assessments of entrainment technology control options to the local permitting authority. Using such information, the local permitting authority would make a site-specific determination of what constitutes the best technology available (BTA) for minimizing adverse environmental impacts under the *Clean Water Act § 316(b)*, if any, for entrainment mitigation, including installation of closed-cycle cooling systems equipped with natural or mechanical draft cooling towers. Local permitting authorities would determine site-specific entrainment BTA controls balancing the following mitigating factors:

- Local energy reliability concerns should be considered;
- Increased air emissions associated with construction of closed cycle CWIS at fossil fuel-fired facilities;
- Land availability, noise abatement and local setback restrictions may preclude construction of closed cycle CWIS at a minority of existing electric generating facilities;

- Given the long lead times required in planning, designing, and constructing closed cycle CWIS, EPA proposes local permitting authorities be given latitude in considering the remaining useful plant life in establishing site-specific entrainment standards.

Entrainment compliance costs, particularly retrofitting closed loop CWIS at existing electric generating facilities are expected to constitute the majority of the anticipated compliance costs.

Table 2-4. EPA Estimated Impact of Proposed *Cooling Water Intake § 316(b) rule* in 2028

NERC Region	Baseline Capacity (MW)	Capacity (MW)	% of baseline capacity	Change in Variable Cost per MWh (%)
Option 1 – IM everywhere				
NPCC	33,618	859	2.6	-1.2
RFC	138,519	-95	-0.1	0.1
Option 2 – IM Everywhere and EM for Facilities with DIF 125 MGD				
NPCC	33,618	4,415	13.1	-8.8
RFC	138,519	3,329	2.4	1.9
Option 3 – I&E Mortality Everywhere				
NPCC	33,618	4,415	13.1	-9.0
RFC	138,519	3,329	2.4	2.0
Source: EPA proposed *Cooling Water Rule* at 76 Fed.Reg. at pp. 22232-22233; Exhibit VII-13, *Impact of Market Model Analysis Options on In-Scope Facilities, At the Year 2028.* *Note: EPA analysis only evaluated impact on NERC regions and not ISO/RTOs, The Reliability First Corporation (RFC) footprint is similar to the PJM service area, and was used as a proxy.*				

Under Option 1, by 2028, EPA estimates total national capacity loss from early retirements at 1,056 MW, full closure of 20 generating units at 13 facilities (5,647 MW) and partial closure of 19 generating units at 16 facilities (4,227 MW).[22] Under the more stringent Option 2, total capacity loss in 2028 increases to 16,815 MW with the NPCC suffering the largest capacity loss, 15.2%. According to EPA, the impact for Option 3 is similar in magnitude to that estimated for Option 2.[23] Option 4 was not modeled by EPA, since it was similar in design to Option 3. In its *Cooling Water Intake § 316(b) rule* modeling analysis, EPA subtracts generating units avoiding closure from generating units retiring to determine net impacts. Compliance outages at affected facilities under preferred Option 1 would be concentrated in the 2013-2017 time period according to EPA, while under Options 2, 3 and 4 outages would stretch out over several successive five years period until 2028.

2.3.1.1 § 316(b) Cooling Water Rule Impact in New England

EPA estimates that cooling water intake structures serving 30 existing electric generating facilities in New England are subject to the proposed *Cooling Water Intake § 316(b) rule*.[24] Under the EPA preferred Option 1 in the proposed *Cooling Water Intake § 316(b) rule*, 12.1 GW of installed capacity in New England would be required to upgrade mortality impingement control technologies if they did

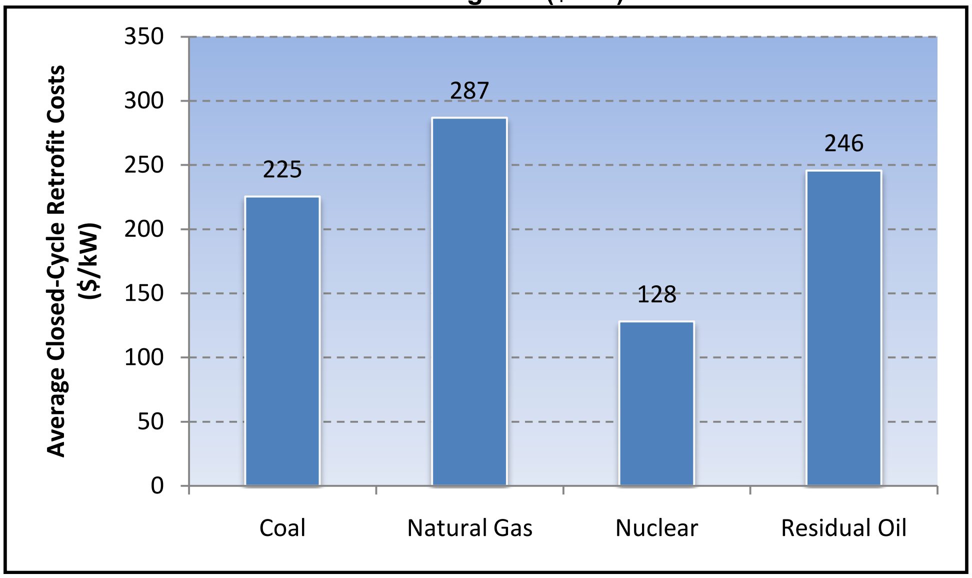
[22] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174, 22233 (April 20, 2011).

[23] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174, 22234 (April 20, 2011).

[24] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 24976, 22174, 22214 (April 20, 2011). EPA concluded that modified Ristroph (or equivalent) coarse mesh traveling screens are the most appropriate basis for determining compliance costs, but this does not preclude the use of other impingement mortality control technologies or by reducing the maximum intake velocity to less than 0.5 feet per second.

not already have modified coarse mesh traveling screens installed or equivalent impingement mortality control technologies.[25] These affected facilities would be required to adopt, measures for reducing the entrapment of aquatic life against the outside surface of cooling water intake structures or screening devices.

Figure 2-1. Estimated Closed-Cycle Cooling Water Retrofit Capital Costs in New England ($/kW).



Within the larger 12.1GW inventory of installed capacity in New England of affected power generation facilities equipped with CWIS having design intake flows ranging between 3.2 and 2,059 MGD, there is approximately 5.6 GW of installed capacity located at power generation facilities equipped with CWIS with a design intake greater than 125 MGD. This latter group would have the additional requirement of submitting an entrainment characterization study to determine whether closed-cycle cooling would be required at these facilities. [26] Figure 2-1 shows the average capital costs for closed-cycle cooling water intake structures, calculated by the ISO for known affected facilities in New England.[27]

2.3.1.2 § 316(b) Cooling Water Rule Impact in NYISO

NYS DEC is currently seeking comment on its policy document "Best Technology Available (BTA) for Cooling Water Intake Structures." The proposed policy will apply to plants with design intake capacity greater than 20 million gallons/day and prescribes reductions in fish mortality. The proposed policy establishes performance goals for new and existing cooling water intake structures. The

[25] "EPA notes that in a number of areas of the country (California, Delaware, New York and New England), permitting authorities have already required or are considering requiring existing facilities to install closed-cycle cooling operations." EPA *proposed Cooling Water Rule* 76 Fed.Reg. at 22210.

[26] In New England, Connecticut, Maine, (except for facilities located in sovereign Indian nations), Rhode Island and Vermont have delegated authority to issue NPDES permits under the federal Clean Water Act. Massachusetts and New Hampshire are non-delegated states and issue joint NPDES permits to affected facilities in collaboration with EPA Region 1.

[27] Using closed-cycle cooling water intake estimated capital costs from NERC's *2010 Special Reliability Scenario Assessment: Resource Adequacy of Potential U.S. Environmental Regulations*, EPA technical support documentation for the proposed 316(b) Cooling Water Rule, and reported closed-cycle cooling water intake structure retrofits in New England, the ISO calculated expected capital costs for the most common configuration of environmental controls based on boiler size and accounting for already installed or planned controls. Individual unit costs could vary considerably from the average costs indicated in Figure X-1. EPA notes that in permitting authorities in California, Delaware, New York, and the New England States already have required or are considering requiring existing facilities to install closed-cycle cooling operations. *EPA proposed Cooling Water Rule*, 76 Fed.Reg. 22174, 22210.

performance goals call for the use of wet, closed-cycle cooling systems at existing generating facilities. The policy does provide some limited relief for plants with historical capacity factors less than 15%.

Once the NYS DEC has made a determination of what constitutes BTA for a facility, the Department will consider the cost of the technology to determine if the costs are "wholly disproportionate" to the environmental benefits to be gained with BTA. NYS DEC's BTA policy will require the use of closed cycle cooling systems at plants that currently have open cycle cooling systems. However, it will allow some limited relief from these requirements for 1) sites that cannot physically accommodate cooling towers, 2) generators with current historical capacity factors below 15%, and 3) where the expense of a closed cooling water system is "wholly disproportionate" compared to the environmental benefits to be gained. A majority of the sites evaluated may need to retrofit closed cycle cooling systems.

NYS DEC has estimated the capital and operating costs of using closed cycle cooling at electric generators in NY at $8.5 billion, without consideration for cases where limited relief is granted. NYS DEC has made twelve BTA determinations of which two determinations required the use of closed cycle cooling systems. Although the number of impacted MWs is unknown, for study purposes the NYISO shows a range from 4,410 MW to 7,376 MW. This program will require capital investments that are one to two orders of magnitude greater than the cumulative costs for the for the air emission control initiatives examined. Consequently, the BTA program has the greatest potential to lead to unplanned retirements.

2.3.1.3 § 316(b) Cooling Water Rule Impact in PJM

EPA estimates that cooling water intake structures serving 164 existing electric generating facilities in PJM are subject to the proposed *Cooling Water Intake § 316(b) rule*.[28] Under the EPA preferred Option 1 in the proposed *Cooling Water Intake § 316(b) rule*, according to EPA, none of the installed capacity in PJM would be required to upgrade mortality impingement control technologies if they did not already have modified coarse mesh traveling screens installed or equivalent impingement mortality control technologies. EPA estimates that under Option 1, the NERC RFC region, which PJM comprises, "will experience *avoided* capacity closures – i.e., one or more generating units that are otherwise projected to cease operations in the baseline become more economically attractive sources of electricity in the post-compliance case, because of relative changes in the economics of electricity production across the full market, and thus *avoid* closure. This counterintuitive result is due to the integrated nature of electricity markets."[29] [Emphasis added.]

2.3.2 Utility Air Toxics Rule

The EPA proposed national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generators under the *CAA§ 112(d)* and revised new source performance standards (NSPS) for fossil-fuel-fired electric generating units under the *CAA § 111(b)*.[30]

The proposed *Air Toxics Rule* requires existing coal- and oil-fired electric generating units to reduce

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[28] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 24976, 22174, 22214 (April 20, 2011). EPA concluded that modified Ristroph (or equivalent) coarse mesh traveling screens are the most appropriate basis for determining compliance costs, but this does not preclude the use of other impingement mortality control technologies or by reducing the maximum intake velocity to less than 0.5 feet per second.

[29] Id. at 22232.

[30] U.S. EPA, *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; Proposed Rule*, 76 Fed.Reg. 24976 (May 3, 2011).

emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). EPA is proposing numerical emission limits for Hg, particulate matter (PM), HCl, and HF as surrogates for the larger group of hazardous air pollutants that must be controlled under the CAA § 112(d). [31]

Under *Clean Air Act § 112(d),* existing coal- and oil-fired electric generating units have three years after the proposed *Air Toxics Rule* is finalized to comply with the proposed air toxics emissions limits.[32] An additional (fourth) year to comply may be granted by the local (state) permitting authority. EPA also added flexibility in the rule by allowing emissions averaging among similar units at the same facility, the ability to use surrogates to monitor emissions compliance: hydrogen chloride for acid gases and particulate matter for hazardous metals, the designation of five separate subcategories with tailored limits, and separate monitoring provisions for limited use oil-fired units.

EPA believes significant co-benefit air toxics emission reductions will be achieved at existing coal- and oil-fired generating units also subject to the proposed *CATR* with existing or planned retrofits of advanced SCR and flue-gas desulfurization (FGD) pollution control systems for NO_X and SO_2 control, lowering the compliance burden on affected facilities. SCR NO_x controls are considered an integral element in air toxics control technology options since they enhance oxidation of elemental Hg, especially from bituminous coals, as the flue gas passes through the SCR reactor, and the ionic Hg is water soluble and susceptible to capture in a downstream FGD control device.**[33]** EPA also evaluated the efficacy and capital costs for other control technology options including dry sorbent injection, as potential alternatives for scrubbers and activated carbon injection for Hg control.

Table 2-3 shows EPA calculated average retrofit capital costs for SO_2 and HCl reduction for bituminous coal-fired generating units using dry sorbent injection (DSI) in combination with a downstream particulate matter (PM) control device (electrostatic precipitator (ESP) being the most common installed PM control device on coal-fired generating units). A dry sorbent is injected into the flue gas ductwork downstream of the boiler where it reacts with the SO_2 and HCl and forms a compound, which is then captured in a downstream fabric filter or ESP and removed as waste.[34] EPA believes that DSI will be an attractive SO_2 and HCl control technology option for smaller and medium sized bituminous coal-fired generating units.

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[31] The EPA proposed Air Toxics Rule includes alternative emission standards with specific limits for: SO_2; total non-Hg metals; antimony (Sb); arsenic (As); beryllium (Be); cadmium (Cd); chromium (Cr); cobalt (Co); lead (Pb); manganese (Mn); mercury (Hg); nickel (Ni); selenium (Se).

[32] Assuming the court-required deadline for final signature by November 16, 2011, the compliance deadline would be November 16, 2014; however, EPA indicates extensions will be made, extending the time for compliance until 2016.

[33] NESCAUM, *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants* (March 31, 2011) pp. 18-19.

[34] U.S.EPA, *Documentation Supplement for EPA Base Case v.4.10_PTox – Updates for Proposed Toxics Rule (March 2011) p. 91. Table X-2 shows a representative set of generating unit capacities, heat rates and capital costs.*

Table 2-5. EPA Estimated Capital Costs for SO_2 and HCl reduction Control Options for Bituminous coal-fired Generating Units

Control Type	Heat Rate (Btu/kWh)	Capital Costs ($/kW)				
		100 MW	**300 MW**	**500 MW**	**700 MW**	**1000 MW**
Dry Sorbent Injection – Fabric Filter	9,000	122	55	38	30	28
	10,000	125	57	40	31	31
	11,000	129	59	41	34	34
Dry Sorbent Injection – ESP	9,000	141	64	47	47	47
	10,000	145	66	52	52	52
	11,000	149	68	58	58	58
Fabric Filter	9,000	188	153	139	130	122
	10,000	205	167	151	141	132
	11,000	221	180	163	153	143

Source: U.S.EPA, *Documentation Supplement for EPA Base Case v.4.10_PTox – Updates for Proposed Toxics Rule (March 2011) Tables 5-23, 5- 24 pp. 95, 98.*

Meanwhile, Table 2-6 below shows EPA calculated average retrofit capital costs for Hg reduction for bituminous coal-fired generating units using activated carbon injection (ACI) in combination with a downstream particulate matter (PM) control device (baghouse). Pulverized activated carbon is injected into the flue gas ductwork downstream of the boiler and SCR, Hg present in the flue gas reacts with the activated carbon, and the resulting compound is captured downstream in fabric filter (baghouse) PM control device. Depending on the boiler configuration and existing pollution control devices, additional flue gas conditioning may be required to optimize Hg removal efficiencies.[35]

[35] U.S. EPA, *Documentation Supplement for EPA Base Case v.4.10_PTox – Updates for Proposed Toxics Rule (March 2011) Table 5-18, p. 86.*

Table 2-6. EPA Estimated Capital Costs for Hg reduction Control Options for Bituminous coal-fired Generating Units

Control Type	Heat Rate (Btu/kWh)	Capital Costs ($/kW)				
		100 MW	**300 MW**	**500 MW**	**700 MW**	**1000 MW**
Activated Carbon Injection (ACI) – ESP[a]	9,000	32.06	12.6	8.16	6.13	4.53
	10,000	32.56	12.80	8.29	6.23	4.60
	11,000	33.04	12.99	8.41	6.32	4.67
ACI w/ Existing Baghouse[b]	9,000	27.93	10.98	7.11	5.34	3.95
	10,000	28.37	11.16	7.23	5.43	4.01
	11,000	28.80	11.32	7.33	5.51	4.07
ACI w/ Additional Baghouse[c]	9,000	240	182	162	150	139
	10,000	259	197	176	163	151
	11,000	278	212	189	176	163

[a] ACI with a sorbent injection rate of 5lbs/million actual cubic feet per minute (acfm) assuming bituminous coal

[b] ACI with a sorbent injection rate of 2lbs/million acfm assuming bituminous coal

[c] Additional Full Baghouse and ACI with a sorbent injection rate of 2lbs/million acfm assuming bituminous coal

Source: U.S.EPA, *Documentation Supplement for EPA Base Case v.4.10_PTox – Updates for Proposed Toxics Rule (March 2011) Table 5-18, p. 86.*

2.3.2.1 Air Toxics Rule Impact in New England

In New England, 7.9 GW of existing installed capacity, either coal steam or oil/gas steam units, are subject to the proposed *Air Toxics Rule*. Of that existing capacity, 1.3 GW reports some installed FGD control devices for SO_2 control, and 1 GW reports installed baghouse devices for particulate control.[36]

2.3.2.2 Air Toxics Rule Impact in NYISO

All coal-fired capacity in New York State would be subject to the proposed *Air Toxics* rule. However, a significant majority of that capacity may be able to achieve compliance with the use of existing pollution control equipment. 8,500 MW of oil- and gas-fired capacity will be subject to the rule as proposed. Options available for achieving the required reductions include, fuel switching, as well as retrofitting emission control technology.

2.3.2.3 Air Toxics Rule Impact in PJM

In PJM, approximately 11.5 GW of existing installed coal-fired capacity under 400 MW is over 40 years old, and is not equipped with FGD or a baghouse. This makes them more likely to have to make expenditures to meet the proposed *Air Toxics Rule*. Based on EPA's control cost formulas included with the proposed rule, the average capital cost to all units in PJM that may need to add activated carbon injection and a baghouse is approximately $170/kW.

2.3.3 *Clean Air Transport Rule*

Under court order, the EPA proposed the *Clean Air Transport Rule* in August 2010 to replace the

[36] U.S. EPA, *National Electric Energy Data System* (NEEDS), version 4.10, accessed April 7, 2011.

Clean Air Interstate Rule.[37] Both *CATR* and *CAIR* are designed to reduce SO_2 and NO_X emissions from fossil fuel electric generating units that contribute to the formation of ground-level ozone and fine particulates across 31 states and the District of Columbia and their downwind transport.[38] Under the CAA § 110(a)(2)(D), sources of air pollution in upwind states are prohibited from "contributing significantly" to poor air quality in downwind states.

The proposed *CATR* applies to fossil fuel electric generators with a nameplate capacity greater than 25 MW across the eastern United States. *CATR* will require greater reductions in SO_2 and NO_x emissions from *CAIR* affected fossil fuel electric generating units, requiring additional advanced pollution control devices. Since *CATR* is a federal implementation plan, it is directly administered by EPA, rather than through state regulations, as was the case with *CAIR*. Some states in the ISO/RTOs may eventually adopt state regulations allowing for delegated *CATR* implementation, but some complications may emerge during the transition from *CAIR* to *CATR*.

Beginning in 2012, emissions reductions would be governed by this rule, rather than the Clean Air Interstate Rule (CAIR). By 2014, EPA estimates this rule, along with concurrent state and other EPA actions, would reduce power plant SO_2 emissions by 71 percent and NO_x emissions by 52 percent over 2005 levels. EPA acknowledges that further reductions may be necessary to meet several eastern states' NAAQS.

For $PM_{2.5}$ attainment, EPA establishes two tiers of states reflecting the stringency of SO_2 reductions required. There would be a more stringent SO_2 tier comprised of 15 states ("Group 1") and a more moderate SO_2 tier comprised of 13 states ("Group 2") with uniform stringency within each tier. Group 1 states would face additional reduction requirements in 2014, while Group 2 states would remain at 2012 levels. (Note: States would not be grouped similarly for NO_x. NO_x would be one pool for annual emissions to address the $PM_{2.5}$ NAAQS, and another for ozone season NO_x, addressing the ozone NAAQS.)

CATR regulates emissions through state-specific emissions budgets, intrastate trading, and limited interstate trading. EPA is also considering two alternate structures: Alternative 1 – state-specific emissions budgets with intrastate trading, but prohibiting interstate trading; and Alternative 2 – state-specific emissions budgets with an emissions rate limit.

CATR creates four new allowance currencies – Annual NO_X Allowances, Ozone Season NO_X Allowances, Group 1 SO_2 Allowances, and Group 2 SO_2 Allowances. Thus, EPA's proposed state budgets do not utilize CAIR allowances, and in contrast to CAIR, the CATR would not allow Title IV SO_2 allowances to be used. Similarly, *CATR* SO_2 allowances would not be valid in the Acid Rain Program. All allowances are to be allocated to existing and new sources. There would be no auction, and limited trading would be permitted.

Covered sources would include only EGUs in the *CATR* states with capacity greater than 25 MW. While some states included some non-EGU sources and EGUs less than 25 MW in *CAIR's* ozone season NO_x program, EPA proposes that these sources would not be covered by CATR. A covered

[37] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule*, 75 Fed.Reg. 45210 (August 2, 2010); *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call; Final Rule*, 70 Fed.Reg. 25162 (May 12, 2005).

[38] In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the *Clean Air Interstate Rule (CAIR)*. North Carolina v. EPA, 531 F3.d 896 (D.C. Cir. 2008).The court later modified its decision, withdrawing its vacatur and remanding *CAIR* to EPA for further rulemaking consistent with its earlier decision. In withdrawing the vacatur, the court determined that notwithstanding *CAIR's* relative flaws, remanding was appropriate under the circumstances given environmental benefits *CAIR* was already achieving while EPA worked to correct the deficiencies in a replacement rulemaking. North Carolina v. EPA, 550 F.3d 1176 (D.C. Cir. 2008).

source would be any stationary, fossil-fuel-fired boiler or combustion turbine with nameplate capacity of more than 25 MW producing electricity for sale. "Fossil fuel" includes natural gas, petroleum, coal, or any form of fuel derived from these, the same that is used in *CAIR*.

In the *CATR* preamble, EPA notes that in the Northeast, a large number of EGUs serving generators with a nameplate capacity equal to or less than 25 MW contribute NO_x emissions to ozone problems on high electric demand days (HEDD), usually on the hottest days in the summer where meteorological conditions help convert the increased NOx emissions to ozone.[39] There is regional interest from OTC and affected state air regulators in lowering the 25 MW applicability threshold in the ozone season program to deal with this issue and/or potentially requiring these units to operate with greater controls than a trading program may necessitate. EPA has requested comments on lowering the 25 MW applicability threshold for EGUs during the ozone season, and whether a trading program offers the right approach for addressing NO_x emissions from these smaller EGUs or whether more direct controls are necessary.

Any Title IV sources subject to *CATR* provisions would still need to comply separately with all Acid Rain provisions of the Clean Air Act. EPA notes that compliance with *CATR* would reduce SO_2 emissions in covered states substantially below their share of the 2010 Title IV cap. Thus, demand, as well as prices for Title IV allowances, would decrease. EPA states that this could potentially result in emissions increases at sources covered by the Acid Rain Program, but not *CATR*, as Title IV allowances become much less costly than emissions reductions.

In *CATR*, intrastate trading would be unlimited, but interstate trading would be limited due to complex assurance provisions. Interstate trading would essentially be limited to 10 percent above each state's budget for any given year and an average of 6 percent over any rolling 3-year period.

[39] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule*, 75 Fed.Reg. 45210, 45309 (August 2, 2010).

Table 2-7. Proposed *Clean Air Transport Rule* SO_2 and NO_x State Emissions Budgets[40]

State	SO_2 Annual (Tons)				NO_X Annual, All years (Tons)	
	2012 and 2013		2014 and later			
	Option 1	Options 2 & 3	Option 1	Option 2 & 3	Option 1	Option 2 & 3
ISO-NE						
Connecticut	3,059	2,967	3,059	2,967	2,775	2,692
Massachusetts	7,902	7,665	7,902	7,665	5,960	5,781
NYISO						
New York	66,542	64,546	42,041	40,780	23,341	22,641
PJM						
Delaware	7,784	7,550	7,784	7,550	6,206	6,020
District of Columbia	337	327	337	327	170	165
Illinois	208,957	202,688	151,530	146,984	56,040	54,359
Indiana	400,378	388,367	201,412	195,370	115,687	44,686
Kentucky	219,549	212,962	113,844	110,429	74117	71,893
Maryland	39,665	38,475	39,665	38,475	17,044	16,533
Michigan	251,337	243,797	155,675	151,005	64,932	62,984
New Jersey	11,291	10,952	11,291	10,952	11,826	11,471
North Carolina	111,485	108,140	81,859	79,403	51,800	50,246
Ohio	464,964	451,015	178,307	172,958	97,313	94,394
Pennsylvania	388,612	376,953	141,693	137,442	113,903	110,486
Tennessee	100,007	97,007	100,007	97,007	28,362	27,511
Virginia	72,595	70,417	40,785	39,561	29,581	28,693
West Virginia	205,422	199,259	119,016	115,445	51,990	50,430
Total	2,559,886	2,483,089	1,396,207	1,354,321	751,047	728,515
Option 1 refers to the preferred control remedy proposed in the August 2, 2010 *CATR* rulemaking. Options 2 and 3 refer to alternative allocations proposed in the January 7, 2011 Notice of Data Availability.						

Table 2-7 shows the initial (preferred Option 1proposed August 2, 2010) and alternative (Options 2, and 3 proposed January 7, 2011) SO_2 and NO_x allowance allocation budgets for the affected states served by the ISO/RTOs. After *CATR* was proposed on August 2, 2010, errors and deficiencies in the methodologies EPA used in calculating the initial proposed allocations were identified in public comments. On January 7, 2011, EPA issued alternate allocations, correcting some of the errors found in the initial proposed allocations. The final *CATR* SO_2 and NO_x allocations are expected in by July

[40] U.S.EPA, *Proposed Clean Air Transport Rule*, 75 Fed.Reg. 45210, 45291 (August 2, 2010); *Table IV.E-1--SO_2 and Annual NO_X State Emissions Budgets for Electric Generating Units Before Accounting for Variability (Tons); Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone,* 75 Fed.Reg. 53613 (September 1, 2010) (NEEDS v.4.10, IPM v.4.10 model run results); *Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Revisions to Emissions Inventories*, 75 Fed.Reg. 66055 (October 27, 2010); *Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New Unit Allocations in Indian Country, and Allocations by States, 76 Fed.Reg. 1109 (January 7, 2011)*.

2011 and may vary from those shown in Table 2-8, adding uncertainty in compliance planning for generators.

2.3.3.1 Transport Rule Impact in New England

In New England, 15.9 GW of installed fossil fuel capacity is estimated to be subject to the proposed *CATR*. *CATR* has some significant design differences from *CAIR* in New England with the addition of annual NO_x and SO_2 compliance programs for Connecticut and Massachusetts, and elimination of the seasonal NO_x control program in Massachusetts. Most importantly, it is a federal implementation plan, whereby EPA is directly allocating annual NO_x and SO_2 allocations to Connecticut and Massachusetts generators without consultation with state environmental agencies, unlike *CAIR*. There is a concern that some unplanned retirements may result in New England depending on the assumptions EPA relies on in the final CATR rule allowance allocations.

Of the affected installed capacity in New England, 9.3 GW at multiple facilities already is equipped with advanced SCR, 877 MW is equipped with advanced SNCR, 631 MW is equipped with advanced FGD, and another 612 MW of advanced FGD is planned or under construction.[41] The number of existing pollution control devices already installed or planned for fossil fuel capacity in the region is, in large part, a result of state environmental regulations that predate both *CAIR* and *CATR*, as shown below in Table 2-8.

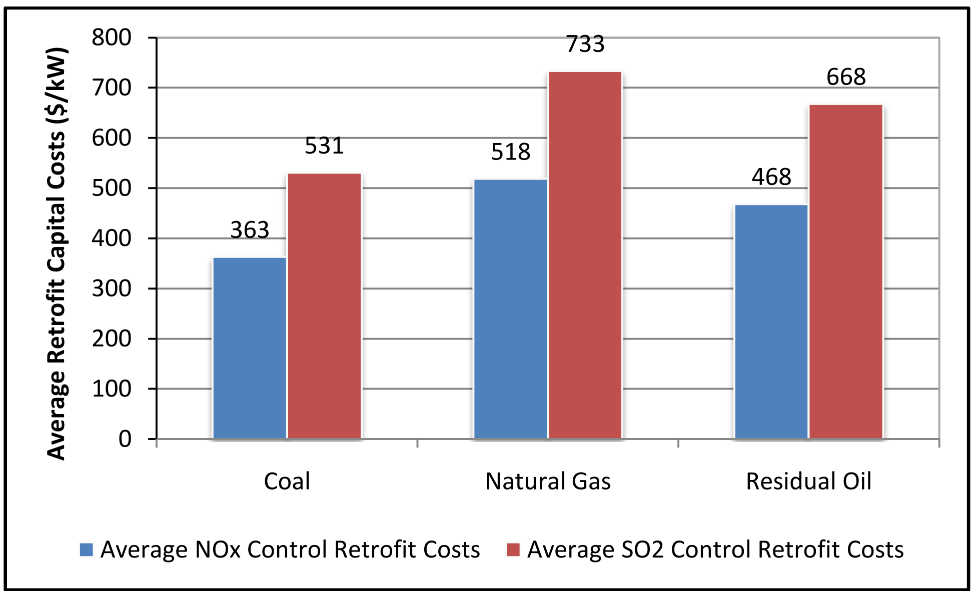

Figure 2-2. Estimated average CATR control retrofit costs for affected coal- and oil/gas-fired steam units in New England ($/kW).

Figure 2-1 shows the average retrofit capital costs ($/kW) the ISO calculated for known affected coal- and oil/gas steam units for needed *CATR* pollution control devices.[42]

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[41] U.S. EPA, *National Electric Energy Data System* (NEEDS), version 4.10, accessed April 7, 2011.

[42] Using pollution control device estimated capital costs from the North American Electric Reliability Corporation *2010 Special Reliability Scenario Assessment: Resource Adequacy of Potential U.S. Environmental Regulations* issued in October 2010, EPA technical support documentation for the proposed Clean Air Transport Rule, and reported recent environmental retrofit projects in New England, ISO calculated expected capital costs for closed-cycle cooling systems Individual unit costs could vary considerably from the average costs indicated in Figure 2-2.

2.3.3.2 Transport Rule Impact in NYISO

As noted in Table 2-8 and in the Section 2.3.3 *CATR* overview, errors identified in EPA's analytical models and databases have already obliged EPA to recalculate generator allocations. These analytical models and databases do not adequately assess the impact of *CATR* implementation on system reliability for many areas. *CATR* is a federal implementation plan and EPA is directly allocating to generators without the benefit of administration by NYS DEC.[43] There are currently three allowance allocation methodologies being considered for *CATR*. At this time, there is no basis to determine which of the three methodologies will be selected by EPA. Each appears to be problematic from a system operations perspective. For example, under EPA's revised Option 3 allocation formula, the New York system cannot be operated in compliance with NYSRC, NPCC, and NERC criterion. EPA's original option 1 has a host of challenges that will effectively make interstate trading extremely difficult.

Under the *CATR* initial preferred Option 1 intrastate trading version of the rule, and using 2008 and 2009 emissions, the NYISO estimates that up to 15 units may need to retrofit SO2 or NOx emissions control technology.

2.3.3.3 Transport Rule Impact in PJM

In PJM, approximately 11 GW of existing installed coal-fired capacity is over 40 years old, under 400 MW, and is not equipped with FGD or SCR, thus making them more likely to have to make expenditures to meet the proposed CATR. Based on EPA's control cost formulas included with the proposed rule, the average capital cost to units in PJM that may need to add SCR is approximately $370/kW and a to add an FGD is approximately $800/kW. DSI may be employed for the control of SO2 and other acid gases at certain units for approximately $115/kW; however the operating costs are significantly higher than FGD. Because of the high operating costs, DSI is considered a shorter term solution than FGD.

2.3.3.3.1 State Regulations Limiting NOx, SO2 and Hg Emissions from Select Power Generators

Table 2-8 shows state environmental regulations responsible for much of the existing or planned air toxics specific controls for existing coal-fired generating units in the ISO/RTOs. Many fossil-fuel fired generators subject to the regulations have either installed or planned pollution control devices that will satisfy some of the anticipated emission reduction requirements in the pending CATR and Air Toxics regulation, leaving those generators better positioned to acquire remaining needed pollution control devices between 2012 and 2015, which is expected to witness a burst of construction activity for control devices at affected facilities in the eastern United States.

[43] NYSDEC concurs with NYISO's analysis of the modeling and database issues identified with the proposed CATR and have commented to EPA of the need from them to revisit their analysis.

Table 2-8. Selected State Environmental Regulations on Fossil Fuel-Fired Electric Generators

State	Authority	Pollutant	Emission Limits	Year Effective
			ISO-NE	
Connecticut	Executive Order 19 & Regulations of Connecticut State Agencies (RCSA) 22a-	NO_x	0.15 lbs/MMBtu rate limit in the winter season for all fossil-fired units > 15 MW	2003
	Executive Order 19, RCSA 22a-198 & Connecticut General Statutes (CGS) 22a-198	SO_2	0.33 lbs/MMBtu annual rate limit for all federal Clean Air Act (CAA) Title IV sources > 15 MW 0.55 lbs/MMBtu annual rate limit for all non-Title IV sources > 15 MW	
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lb/GWh annual reduction for all coal-fired units	2008
Maine	Chapter 145 NOx Control Program	NO_x	0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr	2003
	Statue 585-B Title 38, Chapter 4 Protection & Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010
Massachusetts	310 CMR 7.29	NO_x	1.5 lbs/MWh annual GPS for coal-fired generating units	2006
		SO_2	3.0 lbs/MWh annual GPS for coal-fired generating units	2008
		Hg	85% Hg facility wide removal efficiency or 0.0075 lbs/GWh after January 1, 2008; 95% Hg facility wide removal efficiency or 0.0025 lbs/GWh after October 1, 2012 at Brayton Point, Mount Tom, Somerset and Salem Harbor	2008/ 2012
New Hampshire	RSA 125-O: 11-18	Hg	80% reduction of aggregated Hg content of the coal burned at select coal-fired generating units	2012
			NYISO	
New York	Part 237	NO_x	39.91 MTons non-ozone season cap for fossil fuel units > 25 MW	2004
	Part 238	SO_2	131.36 MTons annual cap for fossil fuel units > 25 MW	2005
	Mercury Reduction Program for Coal-fired Electric Utility Steam Generating Units	Hg	786 lbs annual cap through 2014 for all coal-fired boiler or CT units > 25 MW after November 15, 1990. 0.60 lbs/TBtu annual rate limit for all coal-fired units > 25 MW constructed after November 15, 1990	2010
			PJM	
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW. O.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW.	2009

State	Authority	Pollutant	Emission Limits	Year Effective
	Regulation No. 1146: Electric Generating Unit (EGU) Multipollutant Regulation	NO_x	0.125 lbs/MMBtu annual NO_x rate limit for all coal- and residual oil-fired units > 25 MW	2009
		SO_2	0.26 lbs/MMBtu annual NO_x rate limit for all coal- and residual oil-fired units > 25 MW	2009
Illinois	Title 35 Section 217.706	NO_x	0.25 lbs/MMBtu summer season NO_x rate limit for all fossil-fired units > 25 MW	2004
	Title 35, Part 225, Subpart B: Control of Hg Emissions from Coal-fired Electric Generating Units	NO_x	0.11 lbs/MMBtu annual and ozone season rate limits for all Dynegy and Ameren coal steam units > 25 MW;	2012
		SO_2	2013 & 2014: 0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW. 2015 and after: 0.25 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW.	2013
		Hg	90% Hg removal from fuel content or 0.08 lbs/GWhr annual reduction for all Dynergy and Ameren coal steam units > 25 MW.	2015
	Title 35, Part 225, Subpart F: Combined Pollutant Standards	NO_x	0.11 lbs/MMBtu annual and ozone season rate limits for all Midwest Gen coal steam units.	2012
		SO_2	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all specified Midwest Gen coal steam units.	2013
		Hg	90% Hg removal from fuel content or 0.08 lbs/GWhr annual reduction for all specified Midwest Gen coal steam units.	2015
Maryland	Maryland Healthy Air Act Annotated Code of Maryland Environment Title 2 Ambient Air Quality Control Subtitle 10 Health Air Act Sections 2-1001 - 2-1005	NO_x	3.6 MTons summer cap and 8.3 MTons annual cap for Mirant coal units. 0.5 MTons summer cap and 1.4 MTons annual cap for Allegheny coal units. 3.6 MTons summer cap and 8.03 MTons annual cap for Constellation coal units.	2009
		SO_2	2009 through 2012: 23.4 MTons annual cap for Constellation coal units, 24.2 MTons annual cap for Mirant coal units, and 4.6 MTons annual cap for Allegheny coal units. 2013 and after: 17.9 MTons annual cap for Constellation coal units, 18.5 MTons annual cap for Mirant coal units, and 4.6 MTons annual cap for Allegheny coal units.	
		Hg	2010 through 2012: 80% removal of Hg content of fuel for Mirant, Allegheny, and Constellation steam coal-fired units. 2013 and after: 90% removal of Hg content of fuel for Mirant, Allegheny, and Constellation steam coal-fired units.	
Michigan	Part 15. Emission Limitations and Prohibitions – Mercury	Hg	90% removal of Hg content of fuel annually for all coal-fired units > 25 MW.	

State	Authority	Pollutant	Emission Limits	Year Effective
New Jersey	N.J.A.C Title 7, Chapter 27, Subchapter 19, Table 1	NOx	2009-2012 annual rate limits in lbs/MMBtu for the following technologies: coal-fired boilers (wet bottom) 1.0 for tangential and wall-fired, 0.60 for cyclone-fired; coal-fired boilers (dry bottom) 0.38 for tangential, 0.45 for wall-fired, 0.55 fir cyclone-fired; Oil and/or Gas or Gas only-fired 0.20 for tangential, 0.28 for wall-fired, 0.43 fir cyclone-fired. 2013-2014 annual rate limits in lbs/MWh for the following technologies: all coal-fired boilers 1.50 for all; Oil and/or Gas 2.0 for tangential, 2.80 wall-fired, 4.30 for cyclone-fired: Gas only 2.0 for tangential, and wall-fired, 4.30 for cyclone-fired. 2015 and after annual rate limits in lbs/MWh for the following technologies: all coal-fired boilers 1.50 for all; Oil and/or Gas 2.0 for fuel heavier than No. 2 fuel oil, 1.0 for No. 2 and lighter fuel and Gas only.	2009
	N.J.A.C Title 7, Chapter 27, Subchapter 19, Table 4	NO_x	2.2 lbs/MWh annual GPS for gas-fired simple cycle combustion turbines; 3.0 lbs/MWh annual GPS for oil-fired simple cycle combustion turbines; 1.3 lbs/MWh annual GPS for gas-fired combined cycle or regenerative cycle combustion turbines; 2.0 lbs/MWh annual GPS for oil-fired combined cycle or regenerative cycle combustion turbines.	
	N.J.A.C Title 7:27-19	NO_x	2015 and after: High Electric Demand Day (HEDD) emission limits in lbs/MWh for the following technologies: coal-fired boilers 1.5; heavier than No. 2 fuel oil-fired 1.0; Gas-fired 1.0; simple cycle oil-fired combustion turbines 1.0; simple cycle oil-fired 1.60; combined cycle gas-fired 0.75; regenerative combined cycle gas-fired 0.75; regenerative combined cycle oil-fired 1.20.	2009
	N.J.A.C 7:27-27.5, 27.6 27.7 and 27.8	Hg	90% removal of Hg content of fuel annually for all coal-fired units. 95% removal of Hg content of fuel annually for all MSW incinerator units.	2007
North Carolina	North Carolina Clean Smokestacks Act Statute 143-215.107D	NO_x	25 MTons annual cap for Progress Energy coal-fired units > 25 MW; 31 MTons annual cap for Duke Energy coal-fired units > 25 MW	2007
		SO_2	2012: 100 MTons annual cap for Progress Energy coal-fired units > 25 MW; 150 MTons annual cap for Duke Energy coal-fired units > 25 MW. 2013 and after: 50 MTons annual cap for Progress Energy coal-fired units > 25 MW; 80 MTons annual cap for Duke Energy coal-fired units > 25 MW.	2009

Source: EPA IPM v.4.10 Chapter 3 Power System Operation Assumptions, *Appendix 3-2 State Power Section Regulations Included in EPA Base Case v.4.10 Toxics Rule Policy Case Run* (March 2011)

2.3.4 Coal Combustion Residuals Rule

On June 21, 2010, the EPA proposed "Disposal of Coal Combustion Residuals" regulations, which may impact nearly 600 surface impoundments and 300 landfills, as well as the coal ash recycling industry.[44] Coal-fired generating units in many jurisdictions would see increased coal ash disposal costs and lost revenue from the sale of coal combustion byproducts.

Coal combustion waste streams include fly ash and boiler slag from furnaces, electrostatic precipitators, and other particulate-matter collection devices that remove solids from the flue gas. These processes account for 57% of the estimated 136 million tons of coal combustion wastes generated annually.[45] These wastes consist of different types of inorganic residues, including antimony, arsenic, barium, beryllium, cadmium, lead, mercury, and nickel selenium. Significant risks are associated with such contaminants leaching from disposal sites.[46]

The first and more stringent option would regulate ash as "special waste" subject to hazardous waste provisions under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The second option would regulate ash under Subtitle D of RCRA, the section governing municipal and nonhazardous solid waste.

Both options have requirements for existing and new coal ash landfills and impoundments, including siting, liner, run-on and run-off control, groundwater monitoring, fugitive dust control, financial assurance, corrective action, and closure and post-closure care requirements. Each option would also allow for the beneficial use of coal ash. Under the Subtitle C option, the term *special waste* would include coal ash intended for disposal in surface impoundments and landfills, but exclude coal ash intended for beneficial use. Also, both options contain strict requirements on surface impoundments that would strongly favor the use of dry landfill disposal over surface impoundments.

The proposed Subtitle C option requires the development of state or federal permit programs, which would govern the ash life cycle, including generation, transport, storage, treatment, and disposal. It [Subtitle C] would give EPA enforcement authority. The state permit programs would require state adoption of a final rule, thus adding complexity and time to program implementation. Alternatively, the proposed Subtitle D option establishes national performance standards for ash disposal facilities, but would not cover the predisposal stages. Enforcement in the Subtitle D option is given to states through state enforcement authority and citizen suit authority. Under the Subtitle D option, regulations would go into effect approximately six months after promulgation of the final rule.

The EPA estimates, in its regulatory impact analysis, that 90 percent of operating coal capacity, or 432 plants, would be affected under the Subtitle C option versus 80 percent of operating coal capacity, or 360 plants, under the Subtitle D option.

In its proposed *Coal Combustion Residuals* rulemaking, EPA proposes two options to remedy past handling of coal combustion wastes. One way would categorize such materials as hazardous waste

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[44] U.S. EPA, *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule*, 75 Fed.Reg. 35128 (June 21, 2010).

[45] Luther, Linda, Congressional Research Service, *Regulating Coal Combustion Waste Disposal: Issues for Congress*, R41341 (September 21, 2010) pp. 8, 21. In 2008, coal-fired generators produced 136 million tons: approximately 86 million tons were disposed of in landfills (46 million tons), surface impoundments (29.4 million tons), and mines (10.5 million tons), and approximately 50 million tons were beneficially reused in building materials (gypsum) or as substitute fill materials. Id.

[46] Two closed coal combustion waste disposal sites are in New England where antimony, arsenic, and manganese have migrated off site and contaminated groundwater.

and regulate them as such under Subtitle C of RCRA.[47] The second way would regulate disposal sites under solid waste management requirements of Subtitle D of RCRA.[48] EPA also is assessing the potential increased toxicity of solid byproducts from advanced air pollution control technologies being installed at coal-fired generators.

2.4 Studies of the Impact of Proposed and Final US Environmental Regulations on Generator Retirements

In a 2010 report prepared prior to the publication of three of the four pending EPA environmental regulations, NERC evaluated the same suite of EPA's proposed environmental regulations based on available information and their potential for driving retirements of fossil generators because of the estimated impacts from these environmental initiatives[49] NERC's reliability assessment assessed the potential for individual unit retirements, comparing the total estimated costs for compliance with these potential requirements with the units' estimated wholesale energy revenues in their region. The study also evaluated the potential impact of the retirements on system reliability and potential mitigation strategies for units that appear to be uneconomic and possible candidates for retirement. Table X-3 shows NERC's modeling results for "Moderate" and "Strict" cases for ISO-NE, NYISO, and PJM. These included forecasted capacity deratings and retirements for coal- and oil-fired generators subject to the upcoming suite of EPA's proposed environmental regulations.

According to the NERC Special Assessment the projected 2015 moderate scenario results for the ISO/RTOs, as shown in Table 2-7 are greatest for the proposed *Cooling Water Intake § 316(b) Rule*, 1,010 MW derated, 2,182 MW retired and for the proposed *Utility Air Toxics § 112(d) Rule*, 103 MW derated and 1,061MW retired. Under the 2015 strict scenario results for the ISO/RTOs, the impacts are similar for moderate scenario results for the *Cooling Water Intake § 316(b) Rule*, but more pronounced for the proposed *Utility Air Toxics § 112(d) Rule*. Under the strict scenario results for the *Cooling Water Intake § 316(b) Rule*, 976 MW derated, 2,782 MW retired and the proposed *Utility Air Toxics § 112(d) Rule*, 1,108 MW derated and 6,803MW retired.

In the NERC 2015 moderate and strict scenario results the proposed *Cooling Water Intake § 316(b) and Utility Air Toxics § 112(d) Rules* combine to account for over 70% and 90% of the projected retirements under the moderate and strict scenarios. The impact of the proposed Clean Air Transport Rule is modest in comparison across the ISO/RTOs.

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[47] U.S. EPA, *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule*, 75 Fed.Reg. 35128 (June 21, 2010).

[48] U.S. EPA, *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule*, 75 Fed.Reg. 35128 (June 21, 2010).

[49] North American Electric Reliability Corporation *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (October 2010), http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

Table 2-9. 2015 NERC Scenario Results Impact of EPA Rules on Generators in NPCC and RFC reliability areas (MW)[50]

	Moderate Case[(a)]			Strict Case[(b)]		
	Derated	Retired	Total	Derated	Retired	Total
Cooling Water § 316(b) Rule (2015)						
NPCC-NE	0	1,061	1,061	0	1,061	1,061
NPCC-NY	22	958	980	22	958	980
RFC	988	763	1,751	954	763	1,717
Total	1,010	2,182	3,792	976	2,782	3,758
Air Toxics § 112 Rule (2015)						
NPCC-NE	0	0	0	32	616	647
NPCC-NY	0	0	0	16	694	710
RFC	103	1,061	1,164	1,060	5,493	6,553
Total	103	1,061	1,164	1,108	6,803	7,910
Clean Air Transport Rule (2013)						
NPCC-NE	0	162	162	1	0	1
NPCC-NY	0	0	0	0	0	0
RFC	1	376	377	191	781	972
Total	1	538	539	192	781	972
Combined EPA Regulations Impacts						
2013	2	914	916	383	1,562	1,945
2015	1,114	4,381	5,495	2,276	10,366	12,461

(a) NERC Moderate Case assumptions:

- Cooling Water Intake § 316(b) Rule: conversion cost curve for retrofit, $170-440/gallons per minute (GPM);
- Air Toxics § 112 Rule: assumed not fully implemented until 2018 (60% of upgraded units will receive 2015 deadline waivers), wet scrubber, activated carbon injection and fabric filters for all uncontrolled coal units, SCR for bituminous coal only; oil-fired units assumed to meet air toxics emission limits through tighter oil specifications;
- CATR: EPA preferred option, limited interstate trading, and no unit-specific rate limitations.

(b) NERC Strict Case assumes:

- Cooling Water Intake § 316(b) Rule: conversion cost $300/gpm at most locations, $400/gpm at constrained locations
- CATR - EPA direct control option, no interstate or intrastate trading, existing coal units retrofit FGDs/SCRs;
- Air Toxics § 112 Rule –25% increased cost adders to moderate case assumptions, 60% of upgraded units will receive waivers.

As shown in Table 2-8, NERC's assessment shows total retirements in 2018 ranging from 15 GW to 25 GW under the NERC moderate and strict modeling cases respectively. The proposed *Cooling Water 316(b) Rule* would result in the most retirements, and the proposed *Air Toxics Rule* and the proposed *Clean Air Transport Rule* show less impact on retirements.

[50] North American Electric Reliability Corporation *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (October 2010), pp. 17-24, Tables 3-10 http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

Table 2-10. 2018 NERC Scenario Results Impact of EPA Rules on Generators in NPCC and RFC reliability areas (MW)[51]

	Moderate Case[(a)]			Strict Case[(b)]		
	Derated	Retired	Total	Derated	Retired	Total
Cooling Water § 316(b) Rule (2018)						
NPCC-NE	194	2,504	2,698	180	2,904	3,084
NPCC-NY	347	3,011	3,357	327	3,618	3,946
RFC	1,532	5,503	7,035	1,526	5,661	7,187
Total	2,073	11,018	13,090	2,033	12,183	14,217
Air Toxics § 112 Rule (2018)						
NPCC-NE	25	0	25	32	616	647
NPCC-NY	16	58	74	16	694	710
RFC	514	2,540	3,055	1,060	5,493	6,553
Total	555	2,598	3,154	1,108	6,803	7,910
Clean Air Transport Rule (2015)						
NPCC-NE	0	162	162	14	370	384
NPCC-NY	0	0	0	22	50	73
RFC	67	1,667	1,734	552	2,192	2,744
Total	67	1,829	1,896	588	2,612	3,201
Combined EPA Regulations Impacts						
2015	1,114	4,381	5,495	2,276	10,366	12,461
2018	2,695	15,445	18,140	3,729	21,598	25,328

(a) NERC Moderate Case assumptions:

- Cooling Water Intake § 316(b) Rule: conversion cost curve for retrofit, $170-440/gallons per minute (GPM);
- Air Toxics § 112 Rule: assumed not fully implemented until 2018 (60% of upgraded units will receive 2015 deadline waivers), wet scrubber, activated carbon injection and fabric filters for all uncontrolled coal units, SCR for bituminous coal only; oil-fired units assumed to meet air toxics emission limits through tighter oil specifications;
- CATR: EPA preferred option, limited interstate trading, and no unit-specific rate limitations.

(b) NERC Strict Case assumes:

- Cooling Water Intake § 316(b) Rule: conversion cost $300/gpm at most locations, $400/gpm at constrained locations
- CATR - EPA direct control option, no interstate or intrastate trading, existing coal units retrofit FGDs/SCRs;
- Air Toxics § 112 Rule –25% increased cost adders to moderate case assumptions, 60% of upgraded units will receive waivers;

2.5 Greenhouse Gas Reduction Programs

2.6 Carbon Dioxide (CO_2) Regulation and Cap and Trade Programs

This section summarizes the Regional Greenhouse Gas Initiative (RGGI) and discusses other regional and state initiatives to reduce greenhouse gases.

2.6.1 RGGI

On January 1, 2009 RGGI took effect in the original ten participating Northeastern states. RGGI applies to carbon dioxide emissions from fossil power plants 25 MW and larger in those states. The

[51] North American Electric Reliability Corporation *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (October 2010), pp. 17-24, Tables 3-10 http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

RGGI states include those served by ISO New England, NYISO and three states in PJM (Delaware, Maryland, and New Jersey). New Jersey announced that it would withdraw from RGGI at close of the initial compliance period, which ends on December 31, 2011.[52] The annual 10-state cap is 188 million (short) tons through 2014. Each state is allocated a share of the allowances, as shown in Table 7-2 on the basis of historical emissions and negotiations.[53] Under the existing RGGI MOU, between 2015 and 2018, the cap will decrease 2.5% per year, or a total of 10% by 2018 to 169.3 million tons. At that time, the allocation for the New England states would be reduced to 50.2 million tons, New York's to 57.9 million tons the PJM RGGI states to 61.2 tons.[54]

Table 2-11: RGGI States Annual Allowance Allocations for 2009 to 2014

State	CO_2 Allocation Million (Short) Tons
Connecticut	10.70
Maine	5.95
Massachusetts	26.66
New Hampshire	8.62
Rhode Island	2.66
Vermont	1.23
New York	64.31
New Jersey*	22.89
Delaware	7.56
Maryland	37.50
Total RGGI	**188.08**

RGGI was implemented through individual state regulations. These regulations require over 685 fossil fuel generating units in RGGI states rated 25 MW or greater and administered by the three ISO/RTOs to have RGGI allowances to cover their CO_2 emissions over a three-year compliance period, the first one being 2009 to 2011. The first three-year compliance-period "true-up" deadline is March 1, 2012, for the compliance period ending December 31, 2011.[55] Plans call for quarterly auctions, and as of June 2011, RGGI, Inc. has held twelve allowance auctions. Table 2-12 shows the results of these auctions for the 10 RGGI states combined[56].

In 2010, EPA data shows CO_2 emissions from RGGI units totaled 136.9 million tons, 27 % below the current RGGI cap (188.1 million short tons of CO_2).[57] The RGGI auction prices for allowances for the initial control period (2009 to 2011) have dropped from the initial auction conducted on September 1, 2008, with a clearing price of \$3.07 per allowance, to the auction floor price of \$1.89 in the last two auctions, conducted on March 9, 2011 (Auction 11) and June 8, 2011 (Auction 12).[58]

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[52] Letter of Bob Martin, Commissioner New Jersey Department of Environmental Protection to Jonathan Schrag, Executive Director, Regional Greenhouse Gas Initiative (May 31, 2011), http://www.rggi.org/docs/New_Jersey_Letter.pdf, Mireya Navarro, Christie Pulls New Jersey from 10-State Climate Initiative, *The New York Times*, May 26, 2011, http://www.nytimes.com/2011/05/27/nyregion/christie-pulls-nj-from-greenhouse-gas-coalition.html?_r=2&ref=nyregion

[53] Under RGGI, one allowance equals the limited right to emit one ton of CO_2.

[54] The allocations for future compliance periods will have to be recalculated with the withdrawal of New Jersey from RGGI.

[55] The *true-up deadline* is the date by which RGGI-affected entities must have allowances and any offsets in their RGGI "allowance account" to cover their level of emissions from the previous three-year period.

[56] For more information, see Source: http://www.rggi.org/co2-auctions/results

[57] Office of Air and Radiation, EPA, "EPA Clean Air Markets—Data and Maps, Emissions, Preliminary Quick Reports" Web pages; http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

[58] Under RGGI, one allowance equals the limited right to emit one ton of CO_2. http://www.rggi.org/market/co2_auctions/results.

Table 2-12: RGGI Allowance Auctions through the Second Quarter of 2011

Date	2009 Allowances Sold for 2009–2011 (Tons)[b]	Clearing Price ($)	2012 Allowances Sold for 2012–2014 (Tons)[b]	Clearing Price ($)
Sep 25, 2008	12,565,387[c]	3.07	–	–
Dec 17, 2008	31,505,898	3.38	–	–
Mar 17, 2009	31,513,765	3.51	2,175,513	3.05
Jun 17, 2009	30,887,620	3.23	2,172,540	2.06
Sep 9, 2009	28,408,945	2.19	2,172,540	1.87
Dec 2, 2009	28,591,698	2.05	2,172,540	1.86
Mar 10, 2010	40,612,408	2.07	2,091,000	1.86
Jun 9, 2010	40,685,585	1.88	2,137,993	1.86
Sep 8, 2010	34,407,000	1.86	1,312,000	1.86
Dec 1, 2010	24,755,000	1.86	1,172,000	1.86
Mar 9, 2011	41,995,813	1.89	1,172,000	1.89
Jun 8, 2011	**12,537,000**	**1.89**	**943,000**	**1.89**
Total	**358,466,119**		**17,521,126**	

Source: RGGI CO2 Auction Results, http://www.rggi.org/market/co2_auctions.
[b] Any unused allowances purchased in one auction can be carried forward to the next compliance period (i.e., banked).
[c] The number of allowances sold is lower since not all states participated in this first auction.

The RGGI states auctioned varying percentages of their RGGI allocations with many states auctioning close to 100%. Legislation that authorized states to adopt regulations to reduce carbon dioxide emissions also directs how the revenue from the allowance auctions is to be dispersed. Many states have used most of the auction proceeds for energy-efficiency programs and for clean energy investments. There is a possibility that some states may use a portion of the proceeds to reduce budget shortfalls. In the twelve auctions to date a total of 358.5 million Phase 1 (2009-2011) allowances and 17.5 million Phase 2 (2012-2014) allowances have been sold. The total revenues from the twelve auctions are $886.4 million generated by over 100 bidders.[59]

The generators affected by RGGI are responsible for acquiring the allowances they need based on their projected operation and corresponding CO_2 emissions over the three-year period. Generators were the major purchasers of auction allowances. They may also use the secondary market to supplement the allowances obtained from the RGGI auctions. Secondary market prices have tracked the decline to the auction floor price, averaging below $2/ton with limited trading activity.[60] Beside the generators purchasing allowances in the RGGI auctions, they may use early-reduction allowances (i.e., reductions made in 2006 through 2008 below the RGGI historical emissions baseline), or use a combination of both measures. Generators also may use offsets created by reductions in GHG emissions in five sectors outside electricity generation, although the low allowances prices have not

[59] RGGI cumulative auction results

[60] "Market Comment," Carbon Market North America, *Point Carbon News*: Vol. 6 Issue 21 (June 3, 2011); http://www.pointcarbon.com/polopoly_fs/1.1545984!CMNA20110603.pdf.

made it cost effective to create offsets.[61]

The reduction of CO_2 emissions is achieved through a combination of the reduction of the use of electricity, improving the heat rates (Btu/kWh) of the generating units, and/or switching from higher-emitting units that are typically low in cost to lower-emitting units that are typically higher in cost. At the CO_2 prices seen in RGGI, there would be very little switching from coal or oil and gas steam to natural gas units, and as shown in the recent PJM whitepaper, it would take a CO_2 price in excess of $30/ton to induce a great deal of switching from coal to combined cycle natural gas.[62] Consequently, the reliability impacts of RGGI are currently minimal and the most visible impacts will be in terms of wholesale power prices.

For every $1/ton price of CO_2, this adds approximately $1/MWh to the cost of a typical coal unit, about $0.42/MWh to a typical combined cycle gas unit, and about $0.63/MWh to a new gas combustion turbine. Typically, the unit that sets the marginal price in wholesale markets emits CO_2. The marginal units in New York and New England are most frequently fueled by natural gas, while in PJM coal is on the margin over 70 percent of the time. As shown in PJM's whitepaper, on average in PJM an assumed $10/ton CO_2 price would translate into a $7.50-$8/MWh increase in load-weighted average LMP to its area.[63]

Under RGGI's Memorandum of Understanding, a program review is required by 2012 to evaluate various issues in the design, market performance, and achieved reductions and to improve its performance. The evaluation will assess market the reserve floor price mechanism for future allowance auctions.[64]

2.6.2 Other State and Regional GHG Initiatives

In PJM, there are a number of states that have set GHG reduction targets. New Jersey has set a target of reducing greenhouse gas emissions to 1990 levels, a reduction of 20 percent by 2020 and by 80 percent by 2050; however that program is in question while the current administration reviews the state's Energy Master Plan. Illinois set a target of 1990 levels by 2020 and 60 percent below 1990 levels by 2050. Maryland has a target of a 25 percent GHG reduction below 2006 levels by 2020 and 80 percent below 2006 levels by 2050. Pennsylvania's Climate Action Plan recommends a target of a 30 percent GHG reduction below 2000 levels by 2020. Virginia has a target of 30 percent GHG reduction below 2035 business-as-usual levels by 2025.

In New England, Connecticut has set a target of 10 percent below 1990 levels by 2020; 80 percent below 2001 levels by 2050. Maine - 1990 levels by 2010; 10 percent below 1990 levels by 2020; 75-80 percent below 2003 levels beyond 2020. Massachusetts (RGGI) - 80 percent below 1990 levels by 2050. New Hampshire - 1990 levels by 2010; 10 percent below 1990 levels by 2020; and 75-85 percent below 2001 levels in the long term. Rhode Island (RGGI) - 1990 levels by 2010; 10 percent below 1990 levels by 2020; and 75-85 percent below 2001 levels beyond 2020. Vermont (RGGI) - 1990 levels by 2010; 10 percent below 1990 levels by 2020; 75-85 percent below 2001 levels beyond.

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[61] The allowable offsets include 1) capturing and combusting methane from landfill gas; 2) reducing sulfur hexafluoride (SF_6) leaks from electricity transmission and distribution equipment and recycling the SF_6; 3) improving propane, oil, and gas end-use efficiency; 4) avoided methane emissions from agricultural manure management operations; and 5) taking up CO_2 through afforestation.

[62] "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," available at http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx.

[63] Id.

[64] RGGI Program Review; http://www.rggi.org/design/program_review

New York State has a GHG reduction target of 5 percent below 1990 levels by 2010; 10 percent below 1990 levels by 2020.[65] These rules taken together and when considered with environmental regulations at the federal level may influence the makeup of the generation fleet going forward, putting an emphasis on generating technologies with less environmental impact.

65 U.S. State-Level Greenhouse Gas Reduction Targets, Reuters January 23, 2009, http://www.reuters.com/article/2009/01/23/us-state-co2-sb-idUSTRE50M54B20090123; Power Center on Global Climate Change, http://www.pewclimate.org/what_s_being_done/in_the_states/emissionstargets_map.cfm;

3. Variable Output Renewable Technology Issues with Potential Interregional Impacts

This section covers studies related to the development of large wind and other variable output renewable resources in the ISO/RTOs region. The integration of these resources presents operational challenges to each ISO/RTO, individually and collectively The JIPC is a venue through which ISO-NE, NYISO, and PJM communicate planning efforts to avoid duplication of work and to expedite solutions that will successfully integrate wind resources into the overall system. The ISO/RTOs are participating in several group efforts related to wind integration. The following section outlines some of the major study groups investigating wind issues at an interregional level

3.1 Integration of Variable-Output Generation

Two of the main types of variable-output generation resources are wind and solar technologies. The large-scale use of wind power is becoming a norm in many parts of the world. The perceived benefits of wind power include the emissions-free electricity; the speed with which wind power plants can be constructed; the generation diversity it adds to the resource mix; the long-term certainty of its near zero fuel costs; and, the cost-competitiveness of modern utility-scale wind power with other conventional fossil sources. This emissions-free generation helps meet environmental goals, including greenhouse gas reduction objectives, and the 17 states in the combined region that have renewable portfolio standards.

While permitting can consume a considerable amount of time, once that phase has been completed, wind power plants can be constructed in as little as three to six months in the Northeast, which facilitates financing and quick responses to market signals. With a fuel cost fixed at essentially zero, wind power's long-term fuel costs are known. If the costs of fossil fuels and environmental emission-allowance prices rise, wind power may become more attractive as a resource.

Grid-connected solar photovoltaic (PV) installations are continuing to be viewed as an attractive developing technology in the Northeast, particularly in New Jersey, Connecticut and Massachusetts where state incentives are fostering growth of the market. As installed PV capacity increases in the states within the ISO/RTOs service areas, solar PV may begin to have a measurable impact on the power system load and operation.

Studies have been completed and others are continuing to determine how to successfully integrate variable-output resources into the power generation system and plan for this integration. Issues being addressed include:

- projecting and modeling energy production and the capacity values for use in analyses;
- coordinating generation and transmission planning approaches;
- studying the effects of distributed resources;
- determining the need for changes in operating practices, such as changes in the amounts of operating reserves and regulation requirements;

- identifying possible needs for integrating large amounts of storage and demand response and successfully integrating those technologies; and resolving other planning and operating aspects of the development of large-scale variable-output resources.[66]

The rest of this section summarizes results of several studies, factors about integrating these resources and their growth in the Northeast and adjacent areas, and state incentives and costs for using solar technologies.

3.1.1 Wind Generation Technology and Integration

While wind can provide many system benefits, the variability of wind resources and the uncertainty with which the amount of power produced can be accurately forecast pose challenges for the reliable operation and planning of the power system. Many favorable sites for wind development in the Northeast are remote from load centers. Development of these distant sites would likely require significant transmission development, which may not be economical and would further complicate the operations and planning of the system. The geographical diversity of wind power development throughout the Northeast could mitigate some of the adverse impacts of wind-resource variability on the overall system if the infrastructure and operational processes for operating wind are available. Several Elective and Merchant Transmission Upgrades are in various stages of development to access this wind power as well as other renewable resources

3.2 Wind Development and Integration Issues in New York, New England and PJM

This section presents the current status of wind development in the ISO/RTOs and discusses the common issues among them on wind integration. While much work has been done to address the integration of wind projects into the systems by the three ISO/RTOs, this work is ongoing as number of new wind resources continues to grow. The current issues being addressed are assuring adequate transmission development for integrating wind, wind forecasting, automatic generation control, reserve and contingency requirements, low-voltage ride through, power factor and other issues. As the quantity of wind resources increase in these systems, these issues will become more critical for system reliability.

3.2.1 New York

The NYISO, in conjunction with the New York State Energy Research and Development Authority (NYSERDA), conducted its first wind study in 2004, which concluded that up to 3,500 MW of wind could be integrated without any adverse reliability impacts. The study was conducted in response to New York State adopting a renewable portfolio standard (RPS) where 25% of electrical energy would be supplied by renewables by 2013. Since that initial study, NYS has increased its RPS to 30% by 2015 and the NYISO interconnection queue significantly exceeds the 3,500 MW evaluated in the 2004 study. Installed nameplate wind capacity in New York now totals 1,348 MW. As a result, the NYISO updated its 2004 findings by studying the integration of installed wind plants with nameplate ratings that ranged between a total installed base of 3,500 MW up to 8,000 MW for multiple years in the future. An update of the initial study was begun in 2008 and concluded in 2010 with final report issued in October 2010.[67]

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[66] See the *2009 Northeast Coordinated System Plan*, Chapter 8 (May 24, 2010) for a summary of wind integration studies and issues; http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2010/ncsp09final.pdf.

[67] NYISO, Growing Wind Final Report of the NYISO 2010 Wind Generation Study (September 2010), http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/GROWING_WIND_-_Final_Report_of_the_NYISO_2010_Wind_Generation_Study.pdf

The primary finding of the study is that wind generation can supply reliable clean energy at a very low cost of production to the New York power grid. This energy results in significant savings in overall system production costs, reductions in "greenhouse" gases such as CO_2 and other emissions such as NO_x and SO_2 as well an overall reduction in wholesale electricity prices. However, wind plants require a significant upfront capital investment. In addition, wind plants, because of their variable nature and the uncertainty of their output, provide a greater challenge to power system operation than conventional power plants. This study determined that the NYISO's systems and procedures (which include the security constrained economic dispatch and the practices that have been adopted to accommodate wind resources) will allow for the integration of up to 8 GW of installed wind plants without any adverse reliability impacts.

This conclusion is predicated on the assumption that a sufficient resource base is maintained to support the wind. The study determined that 8 GW of wind would reduce the need for conventional or dispatchable fossil fired generation on the order of 1.6 to 2 GW or an amount equivalent to 20-25% of the installed nameplate wind. This is the result of the much lower overall availability of wind-produced energy, when compared to conventional generation. This means an amount of fossil generation equivalent to 75-80% of the nameplate installed wind needs to be available for those times when the wind isn't blowing or the wind plant output is at very low levels. Non-wind generation is needed to respond to the higher magnitude ramps that will result because of the wind's variable nature.

As wind resources are added to the resource mix, their lower availability could result in an increase in the installed reserve margin and a decline in spot market prices. The impact of these changing conditions has not been analyzed in this report.

The fluctuating nature and the uncertainty associated with predicting wind plant output levels manifests itself as an increase in overall system variability as measured by the net load (load minus wind). In response to these increased operational challenges the NYISO has implemented changes to its operational practices such as being the first ISO to incorporate variable generation resources into security constrained economic dispatch (SCED) and to implement a centralized forecasting process for wind resources. The study concluded that at higher levels of installed wind generation, the system will experience higher magnitude ramping events and will require additional regulation resources to respond to increased variability during the five-minute dispatch cycle. The analysis determined that the average regulation requirement will need to increase by approximately 9% for every 1,000 MW increase in wind generation between the 4,250 MW and 8,000 MW installed base.

Although the addition of wind to the resource mix resulted in significant reduction in production costs, the reduction would have been even greater if transmission constraints between upstate and downstate were eliminated. These transmission constraints prevent lower cost generation in upstate New York from displacing higher costs generation in southeast New York. This report did not analyze the potential financial impact of an increase in transfer capability from upstate into southeast New York.

Finally, the study determined that almost 9% of the potential upstate wind energy production will be "bottled" or undeliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades to eliminate the transmission limitations. These upgrades were evaluated to determine how much of the wind energy that was undeliverable would be deliverable if the transmission limitations were removed. Additional alternatives were suggested and evaluated to address the significant levels of resource bottling that occurs in the Watertown vicinity. The suggested transmission upgrades and alternatives require a detailed physical review and economic evaluation before a final set of recommendations can be determined.

3.2.2 New England

As of April 2011, approximately 280.56 MW of utility-scale wind generation are on line in the ISO New England system, of which approximately 238.5 MW are biddable assets. New England has approximately 3,386 MW of larger-scale wind projects in the queue, of which over 1,027 MW represent offshore projects and 2,359 MW represent onshore projects.[68] A study determined that New England has the theoretical potential for developing over 215 gigawatts (GW) of wind generation.[69]

The ISO is focusing on implementing recommendations from a study of large-scale wind integration operational effects—the New England Wind Integration Study (NEWIS) that was recently completed.

3.2.2.1 Wind Generator Interconnection Facilitation

Developers of wind generation interested in interconnecting facilities to the ISO system face particular challenges because of the differences between wind power and conventional resources caused by the variability of wind power production. In recognition of this and because wind generation is a relatively new type of technology for the New England system, the ISO has developed a set of procedures to facilitate wind generator interconnection. ISO staff assist wind project developers through the interconnection process, which includes the following tasks:

- Meeting all phases of the ISO's specific commissioning protocol
- Complying with voice, data, and telemetry requirements, depending on the type of markets in which the resource will be participating
- Designating an entity that has complete control over the wind generation resource and that can be contacted at all times during both normal and emergency conditions
- Submitting real-time self-scheduling information so that the ISO can account for this information when operating the system and conducting resource adequacy analyses.
- Understanding operating requirements, which includes the provision of training, for how the ISO manages congestion, should it occur

Additionally, wind generators are notified that, because the interconnection requirements are under review based on the NEWIS (see below), the requirements are interim and may change once the recommendations for interconnection requirements have completed the ISO stakeholder review process.

3.2.2.2 New England Wind Integration Study

Figure 3-1 shows areas in New England where the development of wind resources could potentially avoid environmentally sensitive and highly populated regions. The figure shows possible locations of up to 115 GW of onshore wind resources and 100 GW of offshore wind resources, but it is not a

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[68] The 3,100 MW of wind includes wind projects in the queue, including affected non-FERC queue projects, as of April 1, 2010.

[69] *2009 Northeast Coordinated System Plan* (May 24, 2010); http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html.

projection of wind development. Most likely, only a small fraction of this potential actually will be developed. Distributed wind development, which interconnects directly with the distribution system, also is possible, such as projects in local communities.

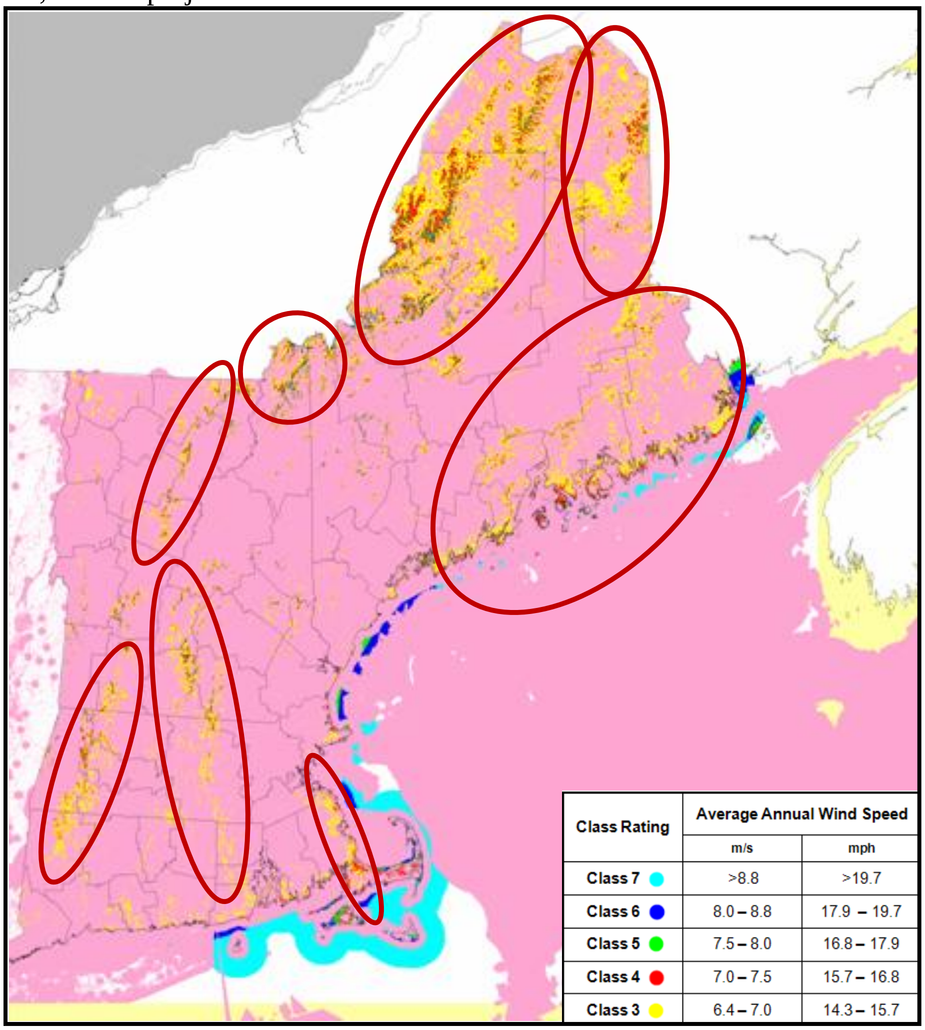

Figure 3-1: Areas in New England with the greatest wind potential.

Note: The pink indicates areas where the development of wind generation is less likely because of siting concerns and low annual wind speeds. The other colored areas are favorable for potential wind development .The ellipses show favorable clusters of the potential development of onshore wind generation. On the key, "m/s" refers to meters per second, and "mph" refers to miles per hour.

In December of 2010, the ISO-NE completed the comprehensive New England Wind Integration Study that highlights the operational effects of large-scale wind integration in New England, including the effects of wind forecasting and large-scale wind power on the rest of the generation fleet.

NEWIS captured the unique characteristics of New England's electrical power system and wind resource—including historical load and ramping profiles, geography, topology, supply- and demand-side resource characteristics, and wind profiles—and the unique impacts that these characteristics can have on system operations and planning with increasing wind power penetration.[70]

[70] The NEWIS methodology is discussed in more detail in RSP09; http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf.

The results of the complete NEWIS ultimately will form some of the basis for the ISO's policies and practices that may result in changes to the ISO tariff, operating procedures, and manuals. The ISO has presented to stakeholders the NEWIS results and recommendations. ISO will continue to work with stakeholders (in the usual ISO stakeholder processes) in implementing the study's findings which may require modifications to market and reliability rules necessary to facilitate the large-scale integration of wind resources.

The NEWIS was issued December 17, 2010 and the ISO-NE Participant Advisory Committee questions were addressed in February 2011.[71] The primary recommendations of NEWIS were based on a number of analyzed scenarios and show that given the study assumptions:

- The large scale integration of wind resources is feasible in the New England region
- Wind generation would likely displace older oil-fired generating units and require use of natural gas-fired units to provide operating reserve, regulation, and other ancillary services
- Increased system flexibility facilitates wind generation integration with the system, but the market design may need to evolve to incent resources to provide the flexibility required to balance net load and dispatchable resources, especially if fossil-unit energy revenues decrease due to large amounts of wind generation depressing energy prices.
- The need for operating reserve and regulation increases with increasing penetration of wind generation
- The existing methods for calculating capacity values are adequate, but should be monitored and possibly modified for large increases in wind generation.
- Transmission development will be required to access locations where wind generation is likely to develop
- Accurate means of forecasting wind generation outputs is required
- Implement interconnection requirements for wind generators as recommended by the NEWIS Task 2 report

The majority of actions to be implemented in the near term were derived from the NEWIS-identified technical requirements for interconnection.[72]

3.2.3 PJM Wind Integration

As of April 2011, over 4,600 MW of utility-scale wind generation are on line in the PJM region. Figure 3-2 shows the increase in wind generation in the PJM region since 2005. By 2026, PJM is expected to need 42,000 MW of installed wind generation in order to meet state RPS mandates.

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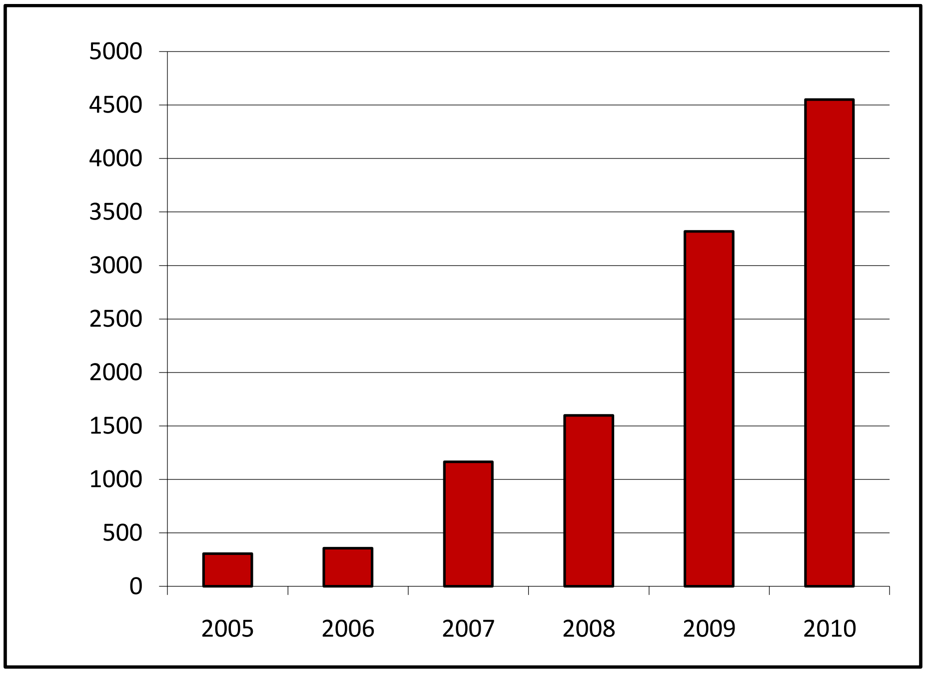
71 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/feb172011/index.html]

72 GE Energy Application and Systems Engineering, et al, *Technical Requirements for Wind Generation Interconnection and Integration* (November 3, 2009); http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf.

Figure 3-2: PJM Wind Installed Capability, 2005-2010



As the amount of wind generation continues to increase, PJM has taken several steps to evaluate and address potential impacts:

- Formed the Intermittent Resource Working Group (IRWG) to address market, operational, and reliability issues specific to variable resources.
- Implemented a centralized wind power forecasting service in April 2009 for use in PJM reliability assessments:
    - Day Ahead (Medium-Term Wind Power Forecast)
        - predict day-ahead congestion and mitigating strategies
        - ensure sufficient generation resources are scheduled to meet reserve requirements
    - Real-Time (Short-Term Wind Power Forecast)
        - evaluate current day congestion
        - ensure that sufficient generation resources are available to respond to real-time or projected fluctuations in Wind Power Output.
- Implemented changes to improve wind resource management in June 2009. Generating resources are now able to submit negative price offers, enabling wind resources to submit flexible offers that better reflect the price at which they will reduce output.
- Implemented tariff changes to allow Energy Storage Resources to participate in PJM ancillary services markets
- Implemented changes to:
    - Improve communication/coordination when a wind farm has multiple owners/operators
    - Improve dispatch and control by ensuring that economic minimums are not set too high.
- Launched a PJM Renewable Integration Study (PRIS) to assess the operational, planning, and market effects of large-scale integration of wind and solar power, evaluate

mitigation/facilitation measures available to PJM, and develop recommendations for the implementation of such mitigation/facilitation measures. The final PRIS report is expected by the end of 2012.

- Modifications to the PJM Regional Transmission Expansion Planning (RTEP) process are being considered due to the increasing requirements for renewable generation:
  - A new light load planning criterion is under development to address operational performance issues related to increased output of renewable generation during the overnight hours. The scope, procedure, potential results, and proposed PJM Manual language is currently being reviewed through the stakeholder process.
  - PJM is also considering the expansion of transmission planning criteria and/or existing scenario planning procedures to include a broader range of assumptions needed to plan for public policy initiatives such as renewable resource integration, demand response programs, or other environmental initiatives, as well as modification or expansion of PJM criteria or procedures related to "at-risk" generation in the RTEP process. In the event additional planning criteria are proposed, the impact of these proposed criteria on the current interconnection queuing processes and procedures will be assessed and recommendations made.

3.3 Solar Energy Technologies and Integration

Solar technologies include solar thermal and water heating, photovoltaic systems, and solar concentrator systems, photovoltaic systems being the most widely used in grid connected systems. In 2009, about 77% of the market consisted of crystalline silicon PV cell/modules, which average a conversion efficiency of 20%; thin film PV cell/modules comprised 21% of the PV module market and had an average conversion efficiency of 11%, while concentrator PV cell/modules had a 2% market share and an average conversion efficiency of 38%.[73]

Table 3-1 PV Module/Cell Manufacturing Survey

Type	Shipments (Peak Kilowatts)			Percent of Total		
	2007	2008	2009	2007	2008	2009
Crystalline Silicon:						
Single-Crystal	128,542	359,259	580,629	25	36	45
Cast and Ribbon	181,788	306,537	403,531	35	31	31
Subtotal	310,330	665,795	984,161	60	67	77
Thin-Film	202,519	293,182	266,547	39	30	21
Concentrator	4,835	27,527	31,852	1	3	2

Solar resource production is variable during the day and unavailable at night. Under ideal (i.e. clear-sky) conditions, it peaks at noon or thereabouts and overlaps somewhat with the summer peak electricity load hours of 2:00 p.m. to 4:00 p.m. Figure 3-3 shows representative monthly estimated outputs of a PV system for New England, based on a composite of solar data from Hartford and Boston and assuming a mix of various solar technologies.[74] The profile is suitable for ISO economic

[73] Energy Information Administration, Photovoltaic Module/Cell Manufacturers Survey (January 2011), Figure 3.8 and Table 3.8 http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solarpv.html

[74] *New England Electricity Scenario Analysis Report* (August 2, 2007); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

studies and has an estimated annual capacity factor of about 15%.

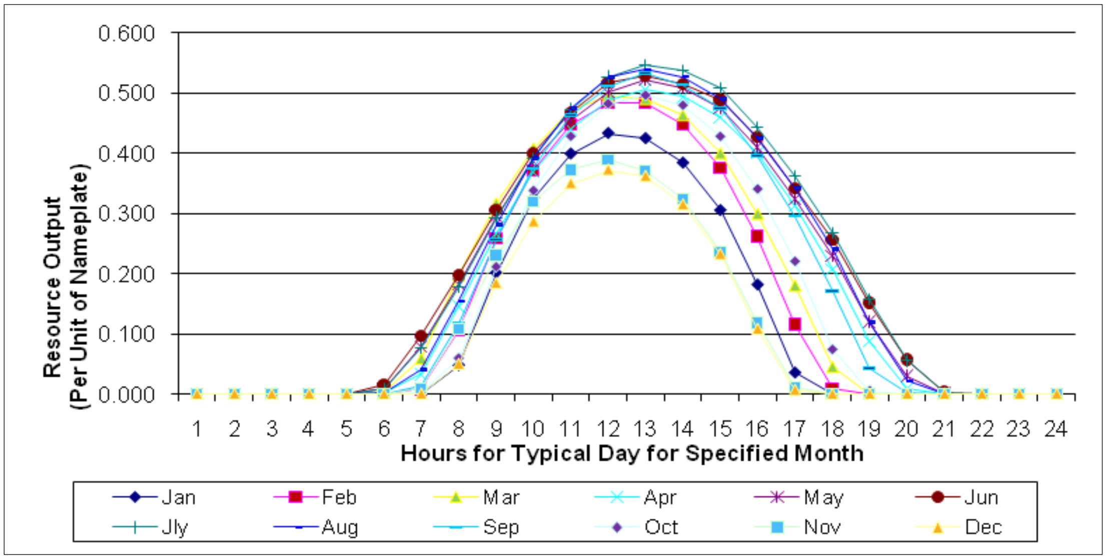


Figure 3-3: Estimated monthly output of a PV system based on a composite of solar data for Boston and Hartford.

Source: *New England Electricity Scenario Analysis Report* (August 2, 2007); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

NERC's report on integrating variable-output resources notes that on partially cloudy days, operating PV systems have demonstrated the potential for substantial ramps in output of +/- 50% in a 30- to 90-second timeframe and +/- 70% in a five- to 10-minute timeframe. This suggests more variability with these systems than for wind turbines, which have less variation due to the inertia of their rotating mass.[75]

3.3.1.1 Photovoltaic Development

In 2009, grid connected photovoltaic installations in the United States grew by 435 MW to reach a cumulative installed capacity of 1,250 MW. The total PV capacity installed in Arizona, Florida, Massachusetts, New Jersey and Texas in 2009 was at least twice the amount installed in each state in 2008.[76]

[75] NERC, *Special Report: Accommodating High Levels of Variable Generation* (April 2009), 27; http://www.nerc.com/files/IVGTF_Report_041609.pdf.

[76] Larry Sherwood, *U. S. Solar Market Trends 2009* (Interstate Renewable Energy Council, July 2009); http://irecusa.org/wp-content/uploads/IREC-Solar-Market-Trends-Report/-2010_7-27-10_web1.pdf.

Table 3-2 Grid Connected Photovoltaic Installations in the ISO/RTOs Service Areas (2008-2009)[77]

State ISO/RTO	Installed Capacity (MW)		Cumulative Installed Capacity (MW)
	2008	2009	
ISO-NE			
Connecticut	7.5	8.7	19.7
Massachusetts	3.5	9.5	17.7
Maine	-	-	0.3
New Hampshire	0.1	0.5	0.7
Rhode Island	-	-	0.6
Vermont	0.4	0.6	1.7
NYISO			
New York	0.0	12.1	33.9
PJM			
New Jersey	22.5	57.3	127.5
Pennsylvania	3.0	3.4	7.3
Delaware	0.6	1.4	3.2
Maryland	1.9	2.8	5.6
District of Columbia	0.2	0.3	1.0
Virginia	0.2	0.3	0.8
West Virginia	-	-	-
Kentucky	-	-	-
North Carolina	4.0	7.8	12.5
Tennessee			
Ohio	0.4	0.6	2.0
Indiana	-	0.3	0.3
Illinois	0.4	1.7	4.5
Michigan	-	0.3	0.7
Total	44.7	108.4	240

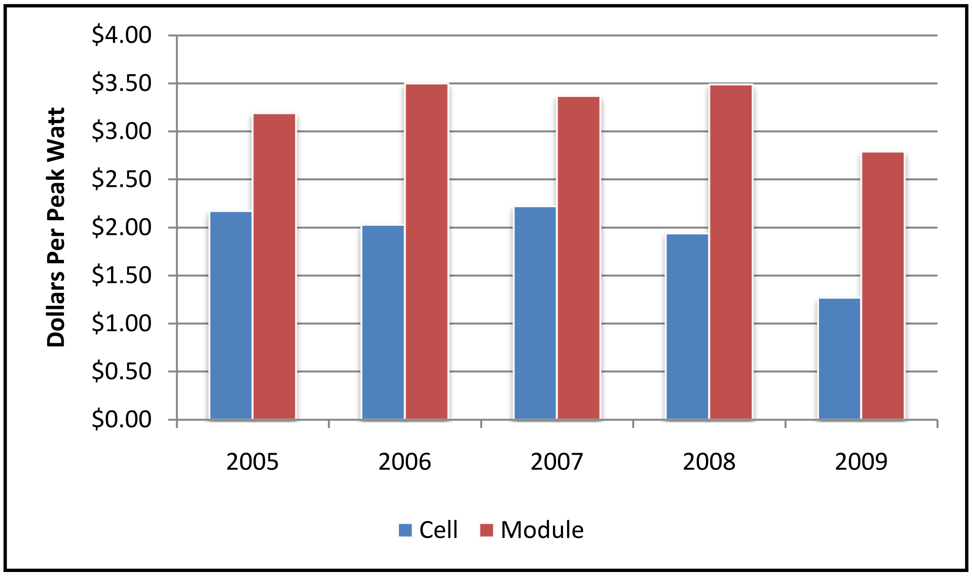
3.3.1.2 Costs of PV Systems

Materials and manufacturing costs are not the only factors affecting PV system costs. In its assessment of photovoltaic installation market trends between 1998 and 2009, the Lawrence Berkeley National Laboratory noted that average installed PV costs vary widely across states suggesting that in addition to market size, permitting requirements, labor rates and sales tax exemptions may strongly influence installed costs. During the same period, LBNL researchers found wholesale module costs fell by $1.9/W (40%) while capacity weighted average installed PV costs declined by $0.3/W (3.2%)

77 Larry Sherwood, *U. S. Solar Market Trends 2009* (Interstate Renewable Energy Council, July 2009); http://irecusa.org/wp-content/uploads/IREC-Solar-Market-Trends-Report/-2010_7-27-10_web1.pdf.

per year during the same period.[78]

Figure 3-4 Photovoltaic Cell and Module Average Prices 2005-2009



The Energy Information Administration also noted a decline in both PV cell/module costs between 2005 and 2009 as shown in Figure 3-3.[79] And preliminary 2010 cost data indicate significant further declines in average installed PV costs of an additional $1/W.[80] Thin film PV cell/modules had higher installed costs than comparable crystalline PV cell/modules in 2009, $0.8/W or higher for ≤10 kW systems and $0.4/W higher among 10-100 kW systems.[81] According to EIA, for model 7 MW and 150 MW PV facilities used to estimate production costs, the base capital costs are $6.05/W and $4.75/W respectively for such projects and total project development costs would be additional depending on other factors[82]

3.3.1.2.1 PV Integration in New England

In New England, Connecticut and Massachusetts installed 8.7 and 9.5 MW of grid-connected photovoltaic capacity, respectively in 2009. The total cumulative grid-connected photovoltaic capacity in the six New England states in 2009 was 40.7 MW.[83]

All the New England states have incentives for solar installations. These incentives typically are in the form of rebates or grants covering part of the cost of PV installations. In addition, federal incentives of investment tax credits are in effect until 2016. Two types of revenue programs for

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[78] Barbose, Galen et. al., *Tracking the Sun III: The Installed Cost of Photovoltaics in the U.S. from 1998-2009, Lawrence Berkeley National Laboratory* (December 2010) pp. 1.

[79] Energy Information Administration, *Annual Photovoltaic Module/Cell Manufacturers Survey* (January 2011), Figure 3.4. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarreport/solarpv.html

[80] Barbose, Galen, op. cit., pp. 2-3.

[81] Id., at p. 24.

[82] Energy Information Administration, *Updated Capital Cost Estimates for Electricity Generation Plants*, (November 2010), Tables 24-1, 24-2, Base Plant Site Capital Cost Estimate for PV 7,000 kW, 150,000 kW. Other factors include technology selection, power plant configuration, location adjustments depending on urban or remote locations.

[83] Larry Sherwood, *U. S. Solar Market Trends 2009* (Interstate Renewable Energy Council, July 2009); http://irecusa.org/wp-content/uploads/IREC-Solar-Market-Trends-Report/-2010_7-27-10_web1.pdf.

encouraging solar and renewable resources in general are long-term purchase contracts (10 to 20 years) and feed-in tariffs (FITs), which pay a stated price for the electricity produced. In 2009, the average combined after-tax value of state/utility cash incentives together with state and federal investment tax credits was $3.9/W, a 37% increase in the average residential PV incentive while the average commercial PV incentive remained unchanged from the prior year.[84]

Table 3-3: Grid Connected Photovoltaic Installations in New England 2008-2009

State	PV Incentive Program	No. of Systems	Total MW_{DC}	Size Range (kW_{DC})	Year Range
CT	CCEF Onsite Renewable DG Program	117	13.6	1.6 - 570	2003 – 2009
	CCEF Solar PV Program	829	4.9	0.8 - 19	2005 – 2009
MA	MassCEC Small Renewables Initiative*	1,990	20.3	0.2 - 502	2002 – 2009
NH	NHPUC Renewable Energy Rebate Program	189	0.5	0.4 - 5.0	2008 – 2009
VT	RERC Small Scale Renewable Energy Incentive	365	1.3	0.2 - 38	2004 – 2009

Since the inception of many of these solar incentive programs, a number of grid-connected, as shown in Table 3-3, and distributed generation PV system have been installed in New England.[85]

In Massachusetts, the *Green Communities Act* allows electric utilities to own up to 50 MW of solar PV installations and Massachusetts has a target of 400 MW PV installed capacity by 2020.[86] NGRID, WMECO, and NSTAR combined have solar installations in their interconnection queues approaching a total of 100 MW and Massachusetts increased maximum project size from 2 to 6 MW. NGRID has four installed PV projects with a capacity of 3.3 MW, and WMECO has installed a single project rated at 1.8 MW.[87]

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84 Barbose, Galen et. Al., *Tracking the Sun III: The Installed Cost of Photovoltaics in the U.S. from 1998-2009*, Lawrence Berkeley National Laboratory (December 2010) pp. 2-3.

85 Barbose, Galen et. Al., *Tracking the Sun III: The Installed Cost of Photovoltaics in the U.S. from 1998-2009*, Lawrence Berkeley National Laboratory (December 2010) pp. 2-3.

86 Commonwealth of Massachusetts, *An Act Relative to Green Communities*, Chapter 169 of the Acts of 2008 (July 2, 2008); http://www.mass.gov/legis/laws/seslaw08/sl080169.htm.

87 Massachusetts DOER, Renewable 225 CMR 14.05, Eligibility Criteria for RPS Class I and Solar Carve-Out Renewable Generation Units; RPS Solar Carve-Out Program: Growing the PV Market (February 28, 2011) presentation. www.mass.gov/Eoeea/docs/doer/.../basic-srec-presentation-22811.pps; *RPS Solar Carve Out Qualified Units (updated April 13, 2011)*

Table 3-4: Solar Policies in New England and Neighboring Areas[(a)]

State	Goal	Renewable Portfolio Standard	Request for Proposal (RFP)/Feed-In Tariff (FIT)	Net Metering (Size Range)[(b)]	Other
CT[(c)]		Class I	DPUC RFP and considering FIT	2 MW max	CT Clean Energy Fund rebates and loans
MA[(d)]	400 MW by 2020	Class I solar carve-out ends when 400 MW are installed. Solar auction Renewable Energy Certificates (RECs) = $300/credit. Solar Alternative Compliance Payment is $550/MWh.		60 kW to 6 MW	23.5 MW awarded in rebates last 2 years
ME[(e)]		Class I	FIT and periodic RFP for 10 contracts	0.66 max	Bill LD 336, passed in 2009, amended FIT.
NH		Class 3 0.3% by 2014		1 MW max	Proposal in the legislature
RI		Class 1	RFP for 15-year contract. 3 MW solar. FIT bill introduced in 2008.	1.65 to 3.5 MW; varies with entity	
VT	50 MW cap		175 MW of solar for RFP of 12.5 MW. FIT= 30¢/kWh.	2.2 MW max	
NY[(f)]	82 MW	NYSERDA RFP for RECs 10-year fixed-price contracts		25 kW max residential; 2 MW max nonresidential	
Ontario[(g)]			FIT (2009)	500 kW max	Small projects (<10 kW) receive 80.2¢/kWh or lower; larger projects (>10 kW) receive 44¢/kWh.

(a) Sources: North Carolina State University, *Database of State Incentives for Renewables and Efficiency* (DSIRE) (DOE, NREL contract); http://www.dsireusa.org/. Also, Robert C. Grace, *Long-Term Contracting Policies for Renewable Energy in the Northeast*, and Wilson RIckerson, *Feed-In Tariffs in the Northeast* presentations at the Northeast Energy and Commerce Association's Renewable Energy Conference, Boston (March 3, 2010); http://www.necanews.org/dev/documents/100303_grace_bob_1.pdf and http://www.necanews.org/dev/documents/100303_rickerson_wilson_1.pdf.

(b) *Net metering* is when a renewable resource generator, such as solar PV, generates more energy than is needed and sells the excess energy back to the electric power grid at some agreed to price.

(c) Connecticut Energy Information Line, Connecticut Energy Efficiency Fund, "Net Metering—Class I Renewable Energy" Web site (2010); http://www.ctenergyinfo.com/dpuc_net_metering.htm. Also, Connecticut Clean Energy Fund, "Clean Energy Incentives" Web site (n.d.); http://www.ctcleanenergy.com/CleanEnergyIncentives/tabid/57/Default.aspx.

(d) M.G.L. ch. 25A, § 11F(2002); 225 CMR 14.00(2011); 225 CMR 15.00(2009).Refer to http://www.mass.gov/energy/rps for more information on Massachusetts.

(e) 35-A M.R.S. §3210 (1999); 35-A M.R.S. §3210 (2006); CMR 65-407-311 (2007). *Resolve, Regarding Legislative Review of Chapter 313: Net Energy Billing Rule to Allow Shared Ownership, a Major Substantive Rule of the Public Utilities Commission,* Maine State Legislature. LD 336 (September 30, 2009); http://www.mainelegislature.org/legis/bills/bills_124th/chappdfs/RESOLVE20.pdf.

(f) NY PSC Order, Case 03-E-0188 (2004, 2005, 2010); Refer to http://www.dps.state.ny.us/03e0188.htm for more information. See also http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId=%7BCD4D2813-2334-431A-B7F1-77DA10455C18%7D

(g) Ontario Power Authority (OPA), *Feed-in Tariff Program: Program Overview* (July 2010); http://fit.powerauthority.on.ca/Storage/101/11057_FIT_Program_Overview_July_6_10_version_1.3.1_final_for_posting.pdf. Also, Ontario Ministry of Energy and Energy Safety Authority, *Net Metering in* Ontario (n.d.); http://www.mei.gov.on.ca/en/pdf/renewable/NetMeteringBrochure.pdf.

3.3.1.2.2 PV Integration in New York

The New York State Energy Research Development Authority (NYSERDA) administers the Renewable Portfolio Standard program authorized by the NYS Public Service Commission (NYSPSC). The program is funded through the collection of surcharges on retail bills for customers of investor owned utilities. The program periodically solicits competitive bids for subsidies for new renewable generation. To be eligible for program consideration the energy must be delivered to the New York state grid. The NYSPSC directed NYSERDA to provide ratepayer-funded subsidies in the annual amounts of $24 million to PV customer-sited installations. The program has requirements for interconnection and net metering and the use of eligible installers only.

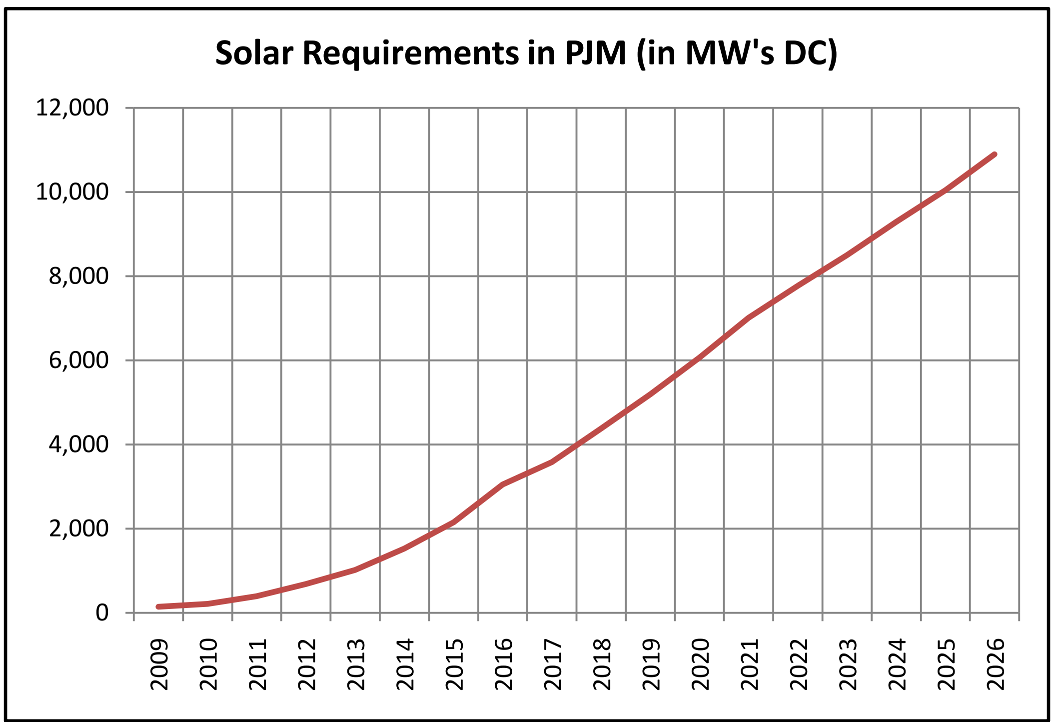
3.3.1.2.3 PV Integration in Ontario

In Ontario, the Ontario Power Authority has the responsibility for what they consider to be North America's first comprehensive FIT.[88] Recently, OPA awarded 184 renewable projects, 76 of which are ground-mounted PV under its FIT program.[89]

3.3.1.2.4 PV Integration in PJM

In the PJM region, seven states and the District of Columbia have a specific solar energy requirement included in their Renewable Portfolio Standard. These solar requirements are described in Table 3-6. When these state solar energy requirements are combined with the PJM load forecast through 2026, it is estimated that 11 GW of installed solar capacity will be needed in PJM by 2026 (see Figure 3-4).

Figure 3-4 Solar Installed Capacity Needed to Meet PJM State Targets



[88] OPA, "Renewable Energy Fee-In Tariff Program" Web page (2010); http://fit.powerauthority.on.ca/Page.asp?PageID=1115&SiteNodeID=1052.

[89] OPA, "Ontario Announces 184 Large-Scale Energy Projects," news release (April 8, 2010); http://fit.powerauthority.on.ca/Storage/100/10986_Apr_8_News_Release_FINAL.pdf.

Table 3-4: Solar Requirements in PJM States[90]

	NJ	MD	DC	PA	DE	OH	IL	NC
Geographic Requirement	In New Jersey	Must be in MD after 2011	Must be in PJM or an adjacent state	Located in PJM	Customer-sited resources must be in DE	Must be in Ohio or a contiguous state	Preference to cost-effective resources in IL	Up to 25% from out-of-state resources
Solar Percentages	08-09: 0.16% 09-10: 0.221% 10-11: 306 GWh 11-12: 442 GWh 12-13: 596 GWh 13-14: 772 GWh 14-15: 965 GWh 15-16: 1150 GWh 16-17: 1357 GWh 17-18: 1591 GWh 18-19: 1858 GWh 19-20: 2164 GWh 20-21: 2518 GWh 21-22: 2928 GWh 22-23: 3433 GWh 23-24: 3989 GWh 24-25: 4610 GWh 25-26: 5316 GWh	2008: 0.005% 2009: 0.01% 2010: 0.025% 2011: 0.05% 2012: 0.10% 2013: 0.20% 2014: 0.30% 2015: 0.40% 2016: 0.50% 2017: 0.55% 2018: 0.90% 2019: 1.20% 2020: 1.50% 2021: 1.85% 2022: 2.00%	2008: 0.011% 2009: 0.019% 2010: 0.028% 2011: 0.04% 2012: 0.07% 2013: 0.10% 2014: 0.13% 2015: 0.17% 2016: 0.21% 2017: 0.25% 2018: 0.30% 2019: 0.35% 2020: 0.4%	08-09: 0.0063% 09-10: 0.0120% 10-11: 0.0203% 11-12: 0.0325% 12-13: 0.0510% 13-14: 0.0840% 14-15: 0.1440% 15-16: 0.2500% 16-17: 0.2933% 17-18: 0.3400% 18-19: 0.3900% 19-20: 0.4333% 20-21: 0.5000%	08-09: 0.011% 09-10: 0.014% 10-11: 0.018% 11-12: 0.20% 12-13: 0.40% 13-14: 0.60% 14-15: 0.80% 15-16: 1.00% 16-17: 1.25% 17-18: 1.50% 18-19: 1.75% 19-20: 2.00% 20-21: 2.25% 21-22: 2.50% 22-23: 2.75% 23-24: 3.00% 24-25: 3.25% 25-26: 3.50%	2008: n/a 2009: 0.004% 2010: 0.010% 2011: 0.030% 2012: 0.060% 2013: 0.090% 2014: 0.12% 2015: 0.15% 2016: 0.18% 2017: 0.22% 2018: 0.26% 2019: 0.30% 2020: 0.34% 2021: 0.38% 2022: 0.42% 2023: 0.46% 2024: 0.50%	08-09: n/a 09-10: n/a 10-11: n/a 11-12: n/a 12-13: 0.0035 13-14: 0.12% 14-15: 0.27% 15-16: 0.60% 16-17: 0.69% 17-18: 0.78% 18-19: 0.87% 19-20: 0.96% 20-21: 1.05% 21-22: 1.14% 22-23: 1.23% 23-24: 1.32% 24-25: 1.41% 25-26: 1.50%	2008: n/a 2009: n/a 2010: 0.02% 2011: 0.02% 2012: 0.07% 2013: 0.07% 2014: 0.07% 2015: 0.14% 2016: 0.14% 2017: 0.14% 2018: 0.20%

90 North Carolina State University, *Database of State Incentives for Renewables and Efficiency (DSIRE)* (DOE, NREL contract); http://www.dsireusa.org/.

3.4 Imports from Eastern Canada

The eastern Canadian premiers and Canadian utilities have a strategy to build over 13,000 MW of non-emitting hydro, wind, and nuclear-powered resources and intend to sell any excess power to Ontario and New England, typically outside eastern Canada's winter-peaking season.[91]

Taking into consideration the seasonal load diversity previously referenced, some of the Canadian provinces also would expect to purchase power from the northeastern United States during their winter-peaking season. This is consistent with the goals of the Northeast International Committee on Energy (NICE), which has sought to reduce the overall emissions of greenhouse gases in the region and eastern Canada and to facilitate increased transfers of electrical energy between New England and the eastern Canadian provinces.[92] This plan also would diversify electric energy supplies for New England, provide additional sources of renewable energy, and potentially reduce costs to New England electric energy customers.

The overall strategy of increased transfers between New England and Canada requires the coordination of the respective transmission expansion plans in the Atlantic Provinces, Québec, and New England. The NICE currently is reviewing these transmission expansion plans and renewable resource development plans across the entire region to identify synergies between these system developments on either side of the international border.[93] For all projects that could have an interregional impact, ISO New England also will closely coordinate with all neighboring systems to study and implement these projects and ensure reliable system performance among the balancing authority areas. This has been the case with the Merchant and Elective Transmission Upgrades between the Canadian Provinces and New England, which are in various stages of development.

In December 2010, the New England States Committee on Electricity (NESCOE) issued a request for information (RFI).[94] The objective of the RFI is to gather information that can be used in developing a future RFP for coordinated renewable energy procurement among the states. NESCOE notes that preliminary RFI responses confirm that the region can develop or import sufficient renewable energy to meet the region's renewable energy goals, and it identifies transmission projects in various stages of development that, subject to further analysis, could facilitate the delivery of renewable energy to New England loads.[95]

At the request of the New England Governors the ISO also conducted a study of the potential for renewable resources development of up to 12,000 MW in New England, onshore and offshore, plus 3,000 MW from Canada.[96] This study showed that the development and integration of this much

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[91] The Canadian premiers and New England governors have adopted a resolution in September 2009 aimed at establishing a forum for renewable transactions. The text of this is available at http://www.negc.org/documents/Res_33-2.pdf

[92] NICE includes representatives from the New England Governors and the Eastern Canadian Premiers (NEG/ECP). Additional information about NICE is available online as follows: 1) the NEG Conference Inc. Web site, "New England Governors' Conference Programs, NEGC Energy Programs," http://www.negc.org/energy.html; and 2) NEG/ECP Resolution 31-1 of the 31st Conference of New England Governors and Eastern Canadian Premiers, Resolution Concerning Energy and the Environment (Brudenell, Prince Edward Island: NEG/ECP, June 26, 2007),http://www.negc.org/documents/NEG-ECP_31-1.pdf.

[93] See http://newenglandgovernors.org/documents/Res_33-2.pdf

[94] http://www.nescoe.com/Coordinated_Procurement.html

[95] http://www.nescoe.com/uploads/Summary_of_SIF_Responses_final.pdf.

[96] "New England 2030 Power System Study", Draft Report, ISO New England, September 8, 2009. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/eco_study_report_draft.pdf

renewable (wind) capacity appears feasible if the necessary transmission can be developed. Conceptual designs of the transmission additions were developed along with their cost estimates. No detailed transmission system analysis was conducted in this study.

3.5 Summary

With almost 52,000 MW of wind resources in the respective ISO/RTO Interconnection Queues, and with several study efforts underway in the regions, the ISO/RTO's planning for the integration of these new resources is well underway. As results emerge, the ISO/RTOs will need to keep each other advised of potential operating concerns discovered through their analyses.

4. Renewable Portfolio Standards

Most all states served by the ISO/RTOs have renewable portfolio standards or related energy policies. In some cases, the states also include energy efficiency goals. Table 4-1 below summarizes the goals of these renewable portfolio standards and related policies, including any special features for the 20 states plus the District of Columbia served by of the three ISO/RTOs. Two of the states have no RPS (Kentucky and Tennessee), and three have a state goal for renewable energy supply (Indiana, Virginia, and Vermont).

Table 4-1: State Renewable Portfolio Standards/Policies Requirements for New Renewable Resources in the ISO/RTOs Service Areas

State	New or Total Renewable Classes – %	Target Year	Comments
ISO-NE			
Maine	10	2017	New renewables, 30% existing
New Hampshire	11	2020	0.3% Solar target by 2014, existing hydro and biomass
Vermont	25*	2025	Not a RPS but a state goal for energy from forest and farms renewable sources
Massachusetts	15	2020	Existing Class for hydro and waste-to-energy
Rhode Island	14	2019	Additional 2% for existing or new Class II
Connecticut	20	2020	Class II for existing, Class III for combined heat and power and energy efficiency
NYISO			
New York	30	2015	Includes existing large hydro
PJM			
New Jersey	22.5	2020-2021	5,316 GWh must be from solar
Pennsylvania	18	2021	Includes new and existing in 2 tiers defined by technologies. 0.5% must be from solar.
Delaware	25	2025-2026	3.5% must be from solar
Maryland	20	2022	2% must be from solar
District of Columbia	20	2020	0.4% minimum for solar
Virginia	15	2025	Voluntary. Percent based on recent year sales
West Virginia	25	2025	
Kentucky			Has no RPS
North Carolina	12.5	2021	0.2% must be from solar by 2018
Tennessee			Has no RPS
Ohio	25	2024	Alternative technology standard with 12.5% from renewables, solar minimum of 0.5%

State	New or Total Renewable Classes – %	Target Year	Comments
Indiana[97]	10	2025	Voluntary RPS. Percent based on 2010 sales
Illinois	25	2025-2026	18.75% from wind, 1.5% from solar by 2026
Michigan	10	2015	Additional MW targets for larger utilities
Source: North Carolina State University, *Database of State Incentives for Renewables and Efficiency* (DSIRE) (DOE, NREL contract); http://www.dsireusa.org/.			

These renewable portfolio standards and related policies require meeting energy needs with a specific percent target. The RPSs specify different types of eligible renewable energy technologies. These typically encompass solar, wind, landfill gas, biomass and other special types of energy technologies that vary among the states. Most of the states also have one or more classes for existing renewable resources that typically cover small hydro, biomass energy and refuse plants. The load serving entities that must comply with the standard do so by buying Renewable Energy Credits (RECs) from projects within the states or nearby ones. The states may also have an alternative compliance payment feature that may be used in place of meeting the RPS by buying RECs. This serves as a price cap on the price of RECs.

4.1 New England States

Five of the New England states have RPSs that focus on developing new renewable resources. They also include existing resources and, in some states, special categories for combined heat and power (CHP) and energy efficiency (EE). Vermont has a renewable resource development goal but no RPS. Considering all of these programs, the New England goal for 2020 is to have about 32.5% of its energy derived from renewable resources and energy efficiency measures. New renewables should make up 11.4% of New England's energy in that year. In 2010, renewable resources contributed 11.8% of the annual energy produced by the generators in ISO-NE's fooprint. The net new requirement is projected to be 10,987 GWh by 2020.[98]

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[97] Indiana enacted SB 251 on May 10, 2011, creating a voluntary Clean Energy Portfolio Standard (CPS). See http://www.in.gov/legislative/bills/2011/SE/SE0251.1.html

[98] RPS calculations assume energy reductions will be achieved by meeting long-term energy efficiency goals in Connecticut, Massachusetts, and Maine and implementing passive demand response resources in New Hampshire, Vermont and Rhode Island through the ISO-NE Forward Capacity Auction 4.

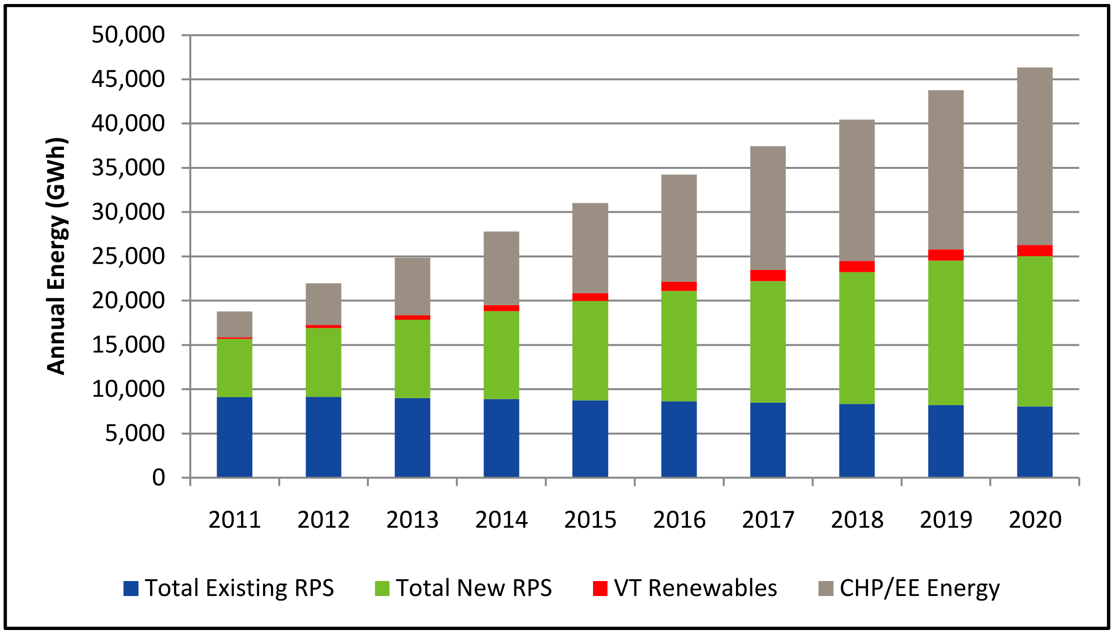

Figure 4-1: New England States projected cumulative targets and goals for renewables and energy efficiency based on RPSs and related policies.[99]

4.2 New York

The New York State Renewable Portfolio Standard (RPS), established by the New York State Public Service Commission (NYSPSC) in 2004, seeks to enlarge the proportion of renewable electricity used by retail customers. In December 2009, the NYSPSC expanded the RPS goal to increase the proportion of renewable electricity consumed by New Yorkers from 25 percent to 30 percent by 2015. The new 30 percent goal equates to a target of 10.4 million megawatt hours in 2015.

The Renewable Energy Assessment of *New York State Energy Plan 2009* reports[100], "New York produced 28,067 gigawatt hours (GWh) from renewable resources in 2007, representing 16.8 percent of the State's total electricity generation. Of that, conventional hydropower provided 90.0 percent of the State's renewable electricity, followed by biomass (5.6 percent), wind (3.1 percent) and biogas (1.3 percent)." As reported in the NYISO 2011 Load & Capacity Data report, in 2010, New York produced 29,265 GWh from renewables, which represented 21% of the State's total electricity generation. Conventional hydropower provided 81% of that total, with wind providing 9.5% and the balance (9.5%) provided by biomass, biogas and solar.

In New York State, the RPS program is funded through a surcharge on the customer bills from investor-owned utilities. The New York State Energy Research and Development Authority (NYSERDA) conducts annual auctions for the purchase of Renewable Energy Credits (RECs) which are proposed to be produced from new qualified renewable generation facilities.

4.3 PJM States

In PJM, Pennsylvania, New Jersey, Delaware, Maryland, Illinois, Indiana, Ohio, North Carolina,

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[99] These categories are defined on page 89 of the RSP09, at http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf

[100] The *New York State Energy Plan 2009* is available online at http://www.nysenergyplan.com/

Michigan, West Virginia, Virginia and the District of Columbia have RPS requirements or goals. Indiana passed a voluntary clean energy standard in May 2011, leaving Tennessee and Kentucky as the only states in the PJM region without a renewable energy requirement or goal. Figure 4-2 below shows the projected amount of renewable energy that will be needed in PJM to achieve these renewable energy mandates and goals. In 2026, PJM states are projected to require 135 million MWh of renewable energy, which equates to nearly 14% of the PJM forecasted load. This excludes energy efficiency, CHP, and alternative technologies that are not generally considered renewable resources within the PJM footprint.

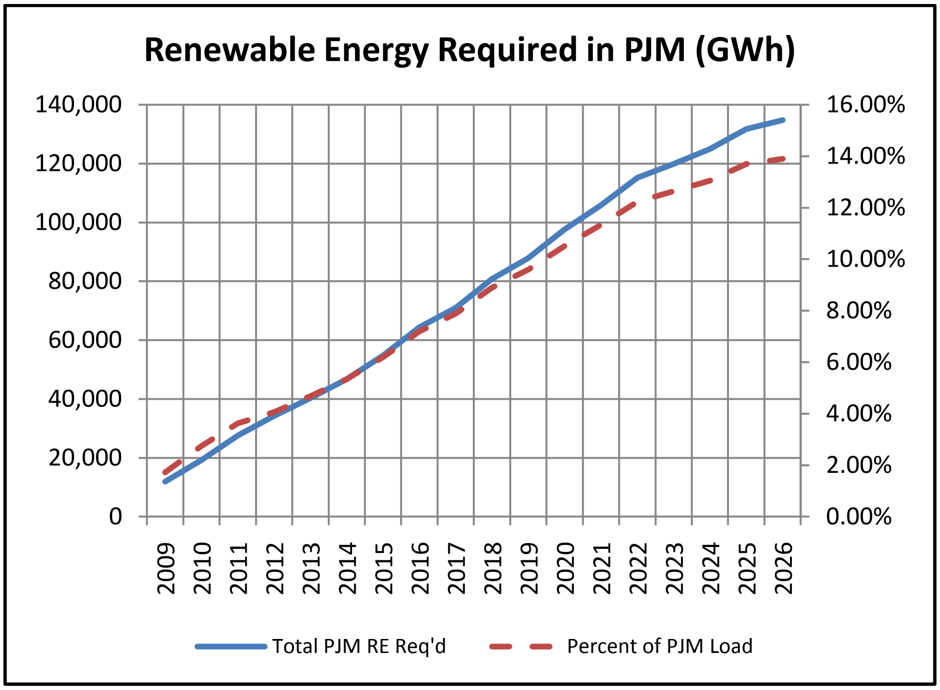

Figure 4-2: PJM States projected cumulative targets for renewables based on RPSs and related policies.

4.4 Interconnection Queues

Renewable resource development is being driven in part by renewable portfolio standards (RPS) that most states throughout the ISO/RTOs region have established. Table 4–2 shows that most of this development consists of wind resources and, currently, there is over 51,000 MW of wind projects in the ISO/RTO queues, mostly in PJM. Much is being done to analyze and develop ways to smoothly integrate wind into the operation of each ISO/RTO.

The ISO-NE Interconnection Queue of April 1, 2011 shows a total of 3,914 MW from 62 new renewable resource projects in various stages of planning.[101] Approximately 87% of the MW total is wind generation with most of it onshore.

The NYISO Interconnection Queue of May 31, 2011 shows 45 wind projects in the interconnection process with a total capacity of 6,571 MW. The report also shows 7 LFG projects with a combined

[101] The total renewable resource project for New England includes both ISO New England FERC Active and FERC Non Active Queues to accurately reflect all renewable projects physically located in the New England States.

capacity of 31.2 MW, and 3 biomass projects (wood included) with a total capacity of 76.6 MW.

The PJM 2010 RTEP Regional Transmission Expansion Plan dated February 28, 2011 summarizes renewable projects in the PJM interconnection Queues as of January 31, 2011. PJM interconnection requests (excluding projects already withdrawn) total over 48,500 MW of renewable generation, including nearly 42,000 MW of wind generation and over 4,200 MW of solar.

Table 4–2: Renewable Resource Projects in the ISO-NE, NYISO and PJM Queues – MW (# of Projects)

ISO/RTO	Onshore Wind	Offshore Wind	Biomass	Conventional Hydro	Landfill Gas	Fuel Cells	Solar	Total
ISO-NE[(a)]	2,359 (36)	1,027 (3)	450 (13)	35 (8)	34 (1)	9 (1)	0	3,914 (62)
NYISO[(b)]	4,610 (41)	1,961 (4)	76.6 (3)	16.1 (4)	31.2 (7)	0	31.5(1)	6,726.4 (60)
PJM[(c)]	39,518 (247)	2,369 (8)	816 (24)	1,160 (24)	417 (84)	0	4,221 (352)	48,501 (739)
Total	**46,487 (324)**	**5,357 (15)**	**1,342.6 (40)**	**1,211.4 (36)**	**452.2 (92)**	**9 (1)**	**4,252.5 (353)**	**59,141.4 (861)**

Sources: [(a)] Based on April 1, 2011 Interconnection Queue;
[(b)] Based on May 2011 interconnection queue;
[(c)] PJM 2010 RTEP Regional Transmission Expansion Plan dated February 28, 2011. Includes projects as of January 31, 2011

4.5 Conclusions

Any analysis of future compliance with RPS goals requires an examination of current projects and a recognition that additional projects and load reduction efforts over the next ten years will contribute to the ability to meet RPS targets. Current projects in the ISO/RTOs Generator Interconnection Queues could make significant contributions towards, and in many cases meet, state RPS goals. However, additional projects, not currently reflected in the queues of the ISO/RTOs, will likely be developed over the next decade. Many projects will have shorter development timelines than the ten year study horizon and, accordingly, will likely be in-service and generating additional renewable energy in the coming years. The queues of ISO-NE, NYISO, and PJM similarly do not capture small and behind the meter renewables. Alternatively, there may be reduced energy consumption due to demand response resources and energy efficiency efforts that have the potential to reduce load growth, and hence the RPS requirement.

The RPSs are different for each of the states. For several states, renewable resources may also be imported from neighboring regions, including Canada. Additionally, in some states the load serving entities are eligible to make alternative compliance payments to meet RPS obligations during periods of high market prices for renewable resources. These payments not only serve as a cap on the price that loads would need to pay for renewable resources to meet RPSs, but, in some states, this revenue is earmarked for renewable research and development that could spur further renewable resource supply over the next ten years.