Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast

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NESCAUM

Members of Northeast States for Coordinated Air Use Management

About NESCAUM

NESCAUM is a 501(c)(3) nonprofit association of air quality agencies in the Northeast. Our Board of Directors consists of the air directors of the six New England states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), New Jersey, and New York. Our purpose is to provide scientific, technical, analytical, and policy support to the air quality and climate programs of the eight Northeast states. A fundamental component of our efforts is to assist our member states in implementing national environmental programs required under the Clean Air Act and other federal legislation. This report was a joint effort between staff at NESCAUM and M.J. Bradley & Associates, LLC (MJB&A). Principal NESCAUM contributors to this report were Dr. Paul Miller, George Allen, Leiran Biton, and Dr. Laura Shields. Principal MJB&A contributors to this report were Chris Van Atten, Brian Jones, and Kathleen Robertson.

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Executive Summary

As the largest stationary pollution sources become better controlled to meet tighter national air quality standards, air quality planners' attention is shifting to smaller sources that are relatively uncontrolled and that represent an increasing share of harmful air emissions. In this report, we attempt to evaluate the expanding use of internal combustion engines (often diesel powered) that have historically been dedicated for backup generation when the facility lost service from the electric grid or required emergency power for tasks such as fire suppression. However, as a result of the recent development of capacity markets for electricity procurement in many parts of the U.S., these engines are now also directly and indirectly providing electricity to the grid through participation in demand response programs. In addition, traditional integrated utilities may use these engines for voltage or frequency regulation outside of market-based demand response programs.[i]

This report focuses on engines classified as emergency, thus avoiding emission limits, while operating during non-emergency periods through participation in a demand response program.

As discussed in this report, demand response may involve actual reductions in electricity consumption (curtailment), but it can also involve the use of on-site backup generators in place of grid-delivered power. These engines are generally diesel-fired but may be natural gas-fired. State environmental agencies have raised concerns that demand response programs, by allowing the use of uncontrolled backup diesel generators, may aggravate air pollution problems.[ii] The electricity markets deploy all eligible supply- and demand-side resources without consideration of respective environmental performance. In particular, concerns have been raised that demand response programs provide financial incentives for the use of uncontrolled backup generators on the hottest summer days, creating a spike in air emissions, including nitrogen oxides (NOx), when conditions would be most conducive to the formation of ground-level ozone.[iii] In addition, diesel exhaust contains a mix of toxic substances and is classified as a known human carcinogen by the World Health Organization.[iv] Because emergency diesel generators are often located in densely populated areas near ground-level, their increased use for electricity generation will also increase the public's exposure to their harmful emissions.

Estimates of installed diesel generator capacity suggest that the total population of diesel generators in the Northeast could include well over 30,000 units with a combined capacity exceeding 10 gigawatts (GW).[v] The increasing attractiveness of backup diesel engines' use in demand response programs has the potential to undermine successful efforts to date in reducing

[i] Under EPA's existing and proposed rules, engines not seeking classification as "emergency" engines would be required to meet the applicable emissions standards, but in exchange, would not be bound by any operational limitations.

[ii] See, for example, New Jersey Department of Environmental Protection comments to U.S. EPA, re: Proposed Settlement Agreement on RICE NESHAP, EPA Docket EPA-HQ-OGC-2011-1030. February 3, 2012; Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration, EPA Docket EPA-HQ-OAR-2008-0708-0400. April 30, 2010.

[iii] *Ibid*.

[iv] World Health Organization – International Agency for Research on Cancer. *IARC: Diesel Engine Exhaust Carcinogenic (*Press Release No. 213). June 12, 2012. Available at http://press.iarc.fr/pr213_E.pdf. Accessed June 2012.

[v] NESCAUM. *Stationary Diesel Engines in the Northeast: An Initial Assessment of the Regional Population, Control Technology Options and Air Quality Policy Issues*. 2003. Available at http://www.nescaum.org/documents/rpt030612dieselgenerators.pdf.

air pollution and impede states from achieving increasingly more health-protective air quality standards in the future.

Due to the number of sites, diversity of demand response resource configurations, evolving market rules, and confidentiality concerns of market participants, an inventory of diesel generators enrolled in demand response programs is not readily accessible to policymakers or the public. However, available data suggest these engines could represent 10 percent to 50 percent or more of total demand response capacity.

What is sorely lacking is an inventory of the resources that are enrolled in or operate under demand response programs, including characteristics such as generator size, installation year, fuel type, emissions rates or controls, and run time. Without this information, air quality planners cannot reasonably assess the air quality impacts of these resources' participation in demand response programs. Older diesel generators, installed prior to national engine emission standards, could have emission rates of NOx as high as 40 pounds per megawatt-hour (lb/MWh), greater than ten times the NOx emission rates of well-controlled coal-fired power plants.

For air quality planners, this is most immediately a concern on high electricity demand days (HEDD). These days may be few in number over the course of a summer or several summers, but, in the NESCAUM region,[vi] high electricity demand days typically correlate with the highest temperature days as a result of air conditioner usage. This is a concern because these hot, stagnant, sunny days are also the most meteorologically-conducive for ozone (smog) formation. Therefore, even if diesel engines operate relatively rarely and on only the highest electricity demand days, their emissions on those specific days can be relatively significant and occur at the worst possible times for air pollution.

For example, electric loads soared in the NESCAUM region on July 21 to 22, 2011, when high temperatures were recorded throughout the Northeast. All three Independent System Operators (ISOs)[vii] in the NESCAUM region dispatched demand resources on July 22, 2011, and NYISO also activated these resources on July 21, 2011.

- In NYISO, 666 MW of demand response resources responded during the four-hour event on July 21 and 1,417 MW of demand response resources responded during the five-hour event on July 22. According to NYISO data, approximately 10 percent of demand response capacity is backup generators.[viii]
- In PJM, responding demand response resources achieved a reduction of approximately 2,000 MW combined on July 22.[ix] According to PJM, at least 15 percent of demand response capacity is made up of backup generators, and an additional 60 percent is unclassified and likely includes some amount of backup generators.

[vi] The NESCAUM region encompasses the states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.
[vii] The Regional Transmission Organizations/Independent System Operators (RTOs/ISOs) in the NESCAUM region are ISO-New England (ISO-NE), New York ISO (NYISO), and PJM Interconnection (PJM).
[viii] NYISO Semi-Annual Report on Demand Response Programs; Docket No. ER01-3001- June 3, 2011.
[ix] PJM. Load Management Performance Report 2011/2012. Available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/load-management-performance-report-2011-2012.ashx. Accessed June 2012.

- In ISO-NE, 643 MW of demand response resources were called on July 22 and actual reductions totaled approximately 663 MW.[x] According to ISO-NE, backup generators were not directly dispatched on July 22.[xi]

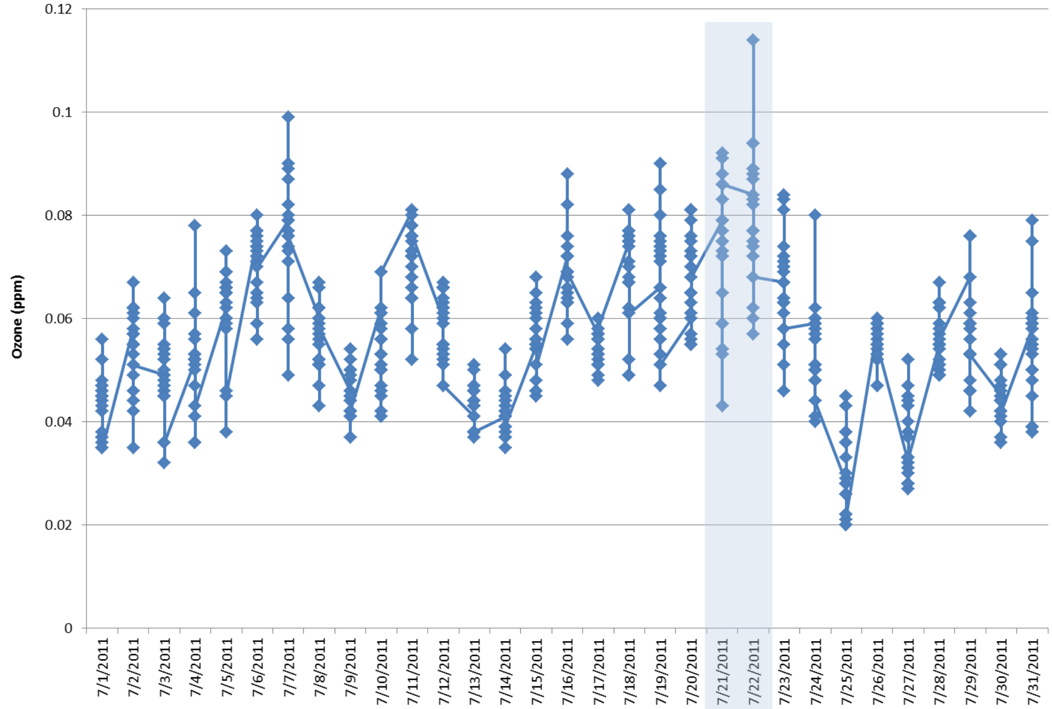
Given the paucity of data available from ISOs and demand response providers, to estimate the air quality impact of operating backup generators as part of demand response programs, particularly on poor air quality days, we obtained information from ISO demand response reports and estimated emissions associated with assumed backup generation participation in these events on July 21 and 22, 2011. For NYISO events, we utilized NYISO reported data on generator enrollment in their demand response programs. For PJM events, we created three scenarios based on levels of engine participation ranging from 15 to 50 percent. We did not estimate emissions associated with ISO-NE's dispatch of demand response resources given that the ISO did not dispatch its Real Time Emergency Generation resources.

- Based on our analysis, backup diesel generator participation during the NYISO events are estimated to have emitted approximately 11 tons of NOx and one-third of a ton of PM over the duration of the four-hour event on July 21 and over 15 tons of NOx and nearly half a ton of PM over the duration of the five-hour event on July 22.
- Backup diesel generator participation during the PJM event is estimated to have emitted between 33 and 109 tons of NOx and between one and three tons of PM during the seven-hour event on July 22.

As shown in Figure ES-1, these days also coincided with the highest ozone readings that month. In fact, the highest ozone level recorded in the New York City metropolitan area in 2011 occurred on July 22, 2011.[xii]

[x] ISO-NE. Semi-Annual Status Report on Load Response Programs of ISO New England Inc. December 30, 2011. Available at http://www.iso-ne.com/regulatory/ferc/filings/2011/dec/er03-345-000_-12-30-11_semi-annual_load_resp_rprt.pdf.
[xi] *Ibid*.
[xii] EPA AirData. Available at http://www.epa/gov/airdata. Accessed June 2012.

Figure ES-1. Daily Maximum 8-Hour Ozone Concentrations (NYC Area)



Source: U.S. EPA AirData. Available at http://www.epa/gov/airdata. Accessed June 2012.

In addition to the immediate air quality impact of the operation of these engines during peak electricity demand days, there are also longer-term concerns. These units' participation in competitive markets may be one factor, among other changing market signals, discouraging the development of new generating facilities with advanced pollution control systems. They may also discourage cleaner demand reduction measures that could meet the region's resource needs while reducing air pollution emissions, including criteria air pollutants, air toxics, and greenhouse gases.

In the following report, we provide an introduction to competitive electricity markets in the NESCAUM region and then to regulation of these generators, which we believe is essential to understanding these engines' increasing prominence.

Observations

- Air quality planners are challenged in addressing emissions from uncontrolled engines due to the lack of information on the locations of these sources, the times at which these sources may operate, the public's exposure to increased levels of diesel exhaust from these sources, and the resulting public health harms from the increased exposure.

- Preliminary screening analyses indicate that uncontrolled diesel backup generators operating under the exemption included in EPA's recent proposal could by themselves create hotspots exceeding the national health-based 1-hour NO_2 air standard.

- Increased utilization of uncontrolled diesel backup engines in economic demand response programs such as peak shaving may hinder areas from maintaining or achieving national air quality standards. Even though the proposed exemption for such use may be temporary, if usage over the next five years causes an area to violate or fail to attain a standard, that area will face additional years of planning and control requirements as a result of the interim increase in emissions from use of backup generators in non-emergency situations.

- In addition to the short-term emissions impacts, there may also be longer term impacts with regard to future resource mixes in the electricity markets. An economic dispatch model to simulate the operations of the current grid mix versus a scenario where backup generators were limited in the market and/or required to install pollution control equipment would aid air quality planners to understand the potential for broader impacts and emission trends over time.

- Several NESCAUM states have been seeking to address emissions on high electric demand days, including regulation of peaking units. These regulations are resulting in the installation of pollution controls as well as unit shutdowns. Policies that permit the use of uncontrolled diesel-fired backup generators in economic or price-responsive demand response programs impede the progress that states are making to address electric sector emissions.

Recommendations

- ISOs should have the authority to collect information on the source of demand response resources from aggregators and other market participants. To improve transparency, ISOs should provide a breakdown of the resources in their demand response programs by zone similar to NYISO's approach. In addition to being necessary to accurately determine their impact, it would be important for the system operator to know what comprises system resources in order to ensure a reliable system.

- ISOs should consider separating backup generation resources into a stand-alone demand response program category similar to ISO-NE to better track their utilization for peak shaving and emergency demand response.

- The Environmental Protection Agency (EPA) should require the use of ultra-low sulfur diesel for all backup diesel engines that participate in demand response programs, similar to the existing requirements in most NESCAUM states.

- States and EPA should identify a reasonable timeframe for phasing out the participation of the oldest, dirtiest diesel engines in demand response programs.

- Operators and aggregators of engines seeking to participate in economic or price-responsive demand response programs while remaining classified as emergency engines and thereby avoiding air pollution emissions standards should register and enroll engines directly with the relevant ISO and air quality agency; other indirect operation should be considered peak shaving and subject to air pollution emissions standards.

- Owners of backup diesel generators earning capacity revenue as electric generators in non-emergency demand response programs should be required to install appropriate pollution controls, taking into account population exposure, revenues received, control costs, and any other relevant factors.

Introduction and Context

In 2003, the Northeast States for Coordinated Air Use Management (NESCAUM; see Figure 1) issued a report in response to early concerns regarding the potential air quality impacts of on-site generators. This report sought to develop a more complete inventory of the numbers and types of backup diesel generators that exist in the NESCAUM region. To that end, the report reviewed state policies concerning the permitting and operation of diesel generators, provided preliminary estimates of emissions impacts associated with diesel generator operation, reviewed control technology options, and provided specific policy recommendations.[1]

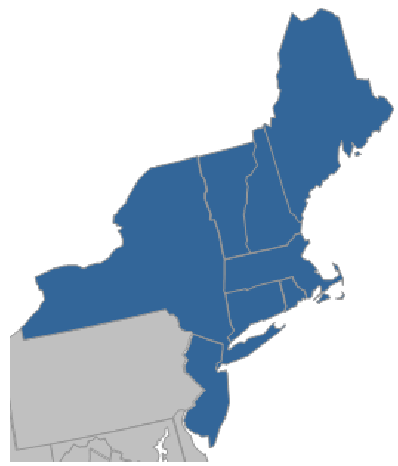


Figure 1. NESCAUM States

Since 2003, there has been considerable growth in the demand response programs managed by Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) in the NESCAUM region. During this time, demand response resources have grown from a small share (approximately 1 to 2 percent) of total capacity to greater than 5 percent currently. They are slated to grow to upwards of 10 percent of capacity by 2015.[2] This growth has prompted concerns ranging from environmental and public health impacts, system reliability, and implications for the long-term fuel mix of the region's electricity markets.

Recently, the U.S. Environmental Protection Agency (EPA) proposed regulations that would allow backup diesel engines to participate in demand response programs without meeting otherwise-applicable emissions limitations under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

This report is a follow-up to our earlier analysis with updated information on the role of demand response programs in the power markets of the Northeast, their incentives for on-site generators, and a preliminary assessment of the impact of backup diesel generators on air quality in the northeastern states.

The Regional Electricity System

The electric power system in the Northeast[3] serves more than 17 million customers and spans three major power markets managed by ISOs/RTOs: ISO New England (ISO-NE), the New York Independent System Operator (NYISO), and the PJM Interconnection (PJM) (see Figure 2).[4] The Federal Energy Regulatory Commission (FERC)—which oversees the U.S. electricity industry—encouraged the formation of the ISOs/RTOs as part of its efforts to restructure the

[1] NESCAUM. *Stationary Diesel Engines in the Northeast: An Initial Assessment of the Regional Population, Control Technology Options and Air Quality Policy Issues*. 2003. Available at http://www.nescaum.org/documents/rpt030612dieselgenerators.pdf.

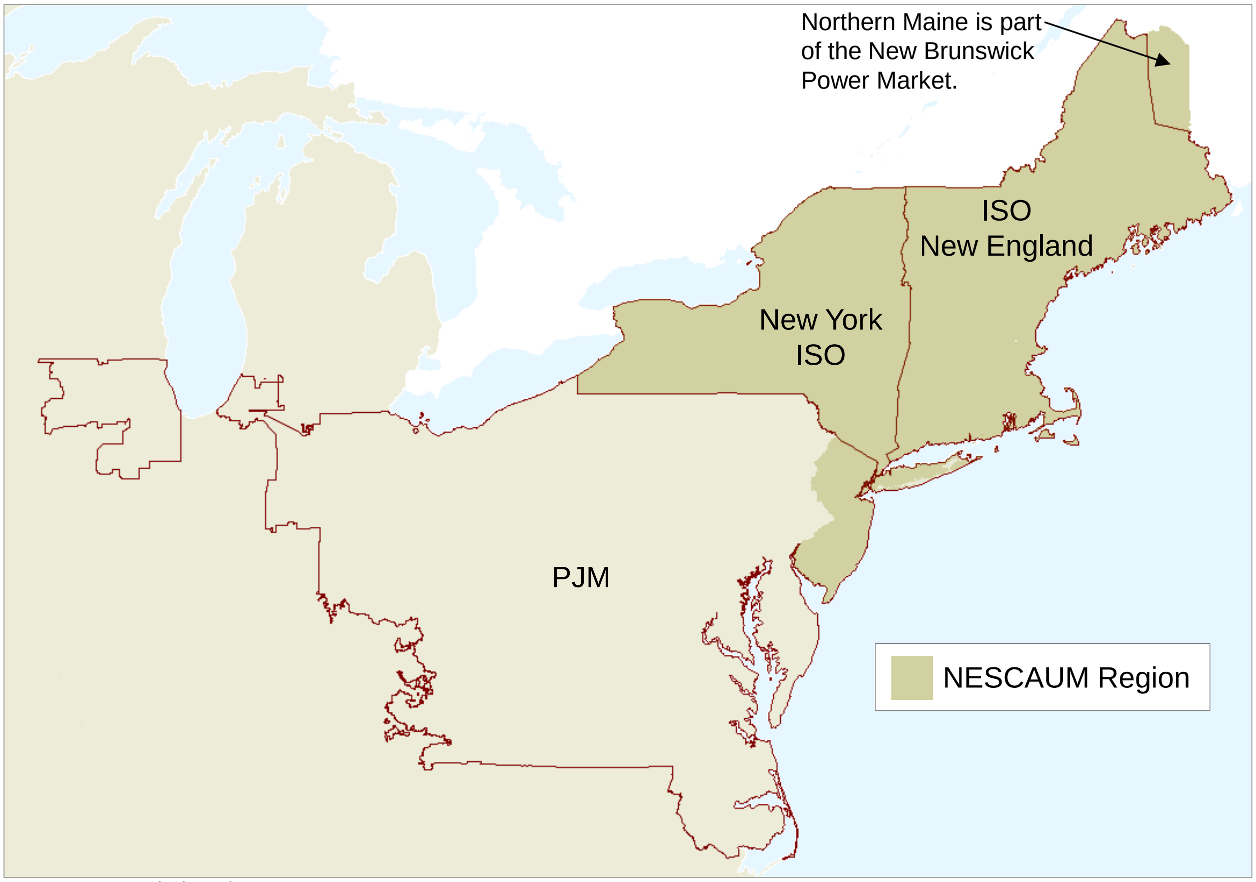
[2] PJM. *2015/2016 RPM Base Residual Auction Results* (PJM DOCS #699093). May 17, 2012.

[3] For the purpose of this report, the "Northeast region" is defined as the NESCAUM states, which include New England, New York, and New Jersey. New Jersey is part of the 13-state PJM Interconnection.

[4] An RTO is an ISO that meets the characteristics and performs the functions specified in FERC Rules at 18 CFR Part 35 Subpart F. ISO-NE, NYISO, and PJM are RTOs in addition to their status as ISOs.

electric industry in the 1990s. The ISOs/RTOs in the Northeast perform four primary functions: (1) managing the flow of power over the high-voltage transmission grid; (2) operating the competitive wholesale electricity markets in the region; (3) ensuring a reliable supply of power; and (4) planning the regional transmission grid.

Figure 2. Northeast Independent System Operators



Source: Ventyx Velocity Suite

The electric system must provide a reliable supply of power at all times, including when the demand for electricity surges or when equipment is down for maintenance or if some equipment fails for any reason. This requires sufficient resources—including generation assets, demand-side resources, and transmission assets—to maintain the stability of the electric grid by ensuring sufficient supply to satisfy the peak demand for electricity. The Northeast is a summer-peaking system, meaning that consumer demand for electricity peaks on hot summer days when air-conditioning use is at its highest. ISO-NE and NYISO, for example, both experienced their highest average peak loads on August 2, 2006 after a heat wave spread throughout the United States and Canada.[5] PJM set a record for peak load on July 22, 2011,[6] when temperature records

[5] ISO-NE. *Top 10 Demand Days*. Available at http://www.iso-ne.com/nwsiss/grid_mkts/demnd_days/. Accessed April 2012. NY-ISO. *Heat Pushes New York Power Use to Near Record Peak: Electricity demand third highest on record* (July 6, 2010). Available at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/Heat_Pushes_NY_Power_Use_to_Near_Record_Peak_070610.pdf. Accessed April 2012.

[6] PJM, *Top 10 Summer Peak Days.* Available at http://www.pjm.com/~/media/markets-ops/ops-analysis/top-10-all-time-summer-winter-peak-load-days.ashx. Accessed June 2012.

were broken throughout the NESCAUM region. On that day, Newark, New Jersey, recorded a record high of 108 degrees Fahrenheit with a heat index of 117 degrees.[7]

The three system operators in the Northeast rely on a diverse mix of generation and demand-side resources to balance the production and consumption of electricity. Failure to maintain this balance can lead to voltage fluctuations and then cascading failures across the grid. This report focuses on the intersection of these resources; namely, generation resources that function as demand-side resources; specifically, backup diesel generators participating in demand response programs. Typically, demand response involves the curtailment of electricity usage by consumers in response to a dispatch order from the ISO/RTO. FERC has strongly encouraged the expanded use of demand response beyond its historic use as primarily an emergency resource, due to its expected impact on participants. All three of the Northeast ISOs/RTOs have since adopted demand response programs that give these resources the opportunity to participate more fully in the capacity and energy markets, competing against traditional supply resources such as fossil-fueled generation based upon price, not reliability emergency conditions.[8]

Demand Response as a Resource

FERC defines demand response as “a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.”[9] In actual operation, demand response may consist of a variety of strategies to reduce electricity consumption. For example, demand response may involve actual reductions in electricity consumption (“curtailment”) by, for example, temporarily shutting down air conditioning, lighting, or manufacturing production lines. In this case, electricity customers may either cut back on their electricity use or shift their electricity use to a later period of time.

Figure 3. ISO-NE Control Room

Source: ISO New England Inc.

[7] NYC Area Weather. *July 22, 2011: Excessive Heat Continues*. Available at http://www.nycareaweather.com/2011/07/july-22-2011-excessive-heat-continues.html. Accessed July 2012.
[8] See, for example, Commissioner Wellinghoff’s Opening Remarks at the Commission Open Meeting (September 21, 2006), available at http://www.ferc.gov/media/statements-speeches/wellinghoff/2006/10-13-06-wellinghoff.asp. Accessed April 2012.
[9] 18 CFR 35.28(b)(4) (2011).

Demand response may also involve the use of backup generators, which are often diesel-fired, in lieu of consuming grid-based electricity ("backup generation"), which reduces electricity consumption from the grid as measured at the customer's meter. ISOs/RTOs often cannot identify what specific actions a customer may be taking to reduce metered demand. However, anecdotal evidence suggests demand response aggregators – companies that facilitate customers' participation in these programs – appear to be increasingly reliant on backup diesel generation as part of their overall portfolio. In effect, demand response programs appear to be shifting a portion of overall electricity demand from traditional generating resources that supply the grid to more dispersed, unregulated diesel generators.

Demand Response Examples

Cabot Creamery participates in the ISO-NE demand response program. During a demand response event, Cabot Creamery shuts down large refrigeration and ice-making machinery within its manufacturing facilities – temporarily eliminating 1,000 kilowatts (kW) of electric load on the New England electric grid. This represents the energy conservation or curtailment strategy of demand response.

In Baltimore, the University of Maryland-Baltimore participates in PJM demand response programs by implementing a variety of energy management strategies, including: turning off non-essential lighting during periods of high demand, reducing cooling demand, and remotely starting emergency and backup diesel-fired generators. This represents a mix of both strategies – curtailment and using backup generation as a replacement for grid-supplied electricity.

As a matter of national energy policy, there are several advantages to allowing demand response resources to compete with traditional generation, including expanding competition, creating a more diverse set of supply resources, and providing economic incentives for end-use customers to actively manage their energy consumption. However, concerns have also been raised as the ISOs/RTOs have dramatically expanded reliance on demand response as a resource. These concerns include impacts on the generation fleet, public health and the environment, and overall system reliability.

The ISOs/RTOs in the Northeast rely on capacity markets to secure the resources necessary to meet current and future electricity demand with an added margin of safety in the event of unplanned contingencies, such as an unexpected generation plant shutdown or extreme weather event.[10] Supply and demand resources (both existing and proposed) compete alongside one another in capacity markets (in PJM and ISO-NE) to meet the region's expected capacity needs. As a result, various market monitors have raised concerns that demand response resources may discourage the development of new generation resources, such as power plants and renewable

[10] In capacity markets, ISOs/RTOs typically conduct auctions for capacity resources several years into the future. Existing and new generation and demand-side resources register with the ISO/RTO and submit offers into the auctions. The ISO/RTO sets the amount of capacity that it will procure in the auction and is the sole purchaser of capacity through the auctions. The ISO/RTO allocates the costs of capacity on a *pro rata* basis among utilities or Load Serving Entities (LSEs) in its region. Successful bidders receive capacity payments prorated on a by megawatt-day or kilowatt-month. These capacity payments serve as an important revenue stream for both supply and demand-side resources.

resources, as well as energy efficiency resources that might otherwise be developed.[11] Demand response resources may also reduce the ability of generating facilities to pay for environmental upgrades using capacity payments.[12]

Federal Policies Addressing On-Site Generation

Both FERC and EPA have federal legal authorities that are pertinent to the use of on-site generators in demand response programs. Each is discussed in turn. To mirror EPA's terminology in current rulemakings, discussed below, we will use the following terminology for actual emergencies (e.g., loss of grid power) and permissible non-emergency use of these engines:

- **Emergency Usage** – Usage to preserve essential facility functions in the event of a loss of grid power or for situations that threaten the facility, such as fire pump use during a fire. These are the situations for which the emergency engine was originally purchased and installed. Under EPA rules, operation during true emergencies is unlimited.
- **Demand Response** – Time periods in which resources are called upon by the relevant RTO. This would include fluctuations in voltage or frequency of five or more percent. The current EPA proposal seeks to more clearly define permissible demand response programs using the North American Electric Corporation (NERC) Emergency Alert Level 2 as a threshold as well as to increase permissible non-emergency operation to 100 hours annually (from 15) if an engine participates in a demand response program called at or after NERC Level 2.
- **Peak Shaving** – Either situations where an engine participates in a demand response program called before NERC Level 2 or when a facility independently elects to reduce on-site electricity demand through the use of on-site generators, typically in response to economic signals associated with high real-time energy prices.

Federal Energy Regulatory Commission

The Energy Independence and Security Act of 2007 (EISA) directed FERC to develop a National Action Plan to maximize the amount of demand response developed and deployed in U.S. electricity markets. FERC has developed two Action Plan reports and has provided technical and market assistance to the ISOs and RTOs. FERC has also issued several orders to enable and encourage the participation of demand response in electricity markets.

- **Order No. 719** - FERC issued Order No. 719 in October 2008 to address barriers to demand response participation in ISO and RTO markets. Order No. 719 required system operators to accept bids from qualified demand response resources and allowed aggregators to bid demand response directly into the markets. The participation of aggregators has enabled a larger segment of the commercial, industrial, and institutional markets to participate in demand response programs.
- **Order No. 745** - In March 2011, FERC issued Order No. 745, which amended Commission regulations to require that demand response resources be allowed to

[11] Monitoring Analytics, LLC. *Comments of the Independent Market Monitor for PJM*. Docket No. EPA–HQ–OGC–2011–1030-0050.
[12] *Ibid*.

participate in and receive compensation from competitive electricity markets in the same manner as generation resources.[13] Specifically, "a demand response resource participating in an organized wholesale energy market must be compensated for the service it provides at the market price for energy when the demand response resource has the capability to balance supply and demand as an alternative to a generation resource and when the dispatch of demand response resource is cost-effective."[14] PJM, California ISO, the Southwest Power Pool, ISO-NE, NYISO, and the Midwest ISO filed tariff revisions to implement Order No. 745 in 2011.[15]

These actions have created greater financial incentives for demand response and backup generators to participate in competitive wholesale electricity markets. Where demand response resources, and in particular backup generators, were once only used as a true emergency resource, they are now a more integral part of the regional resource mix, garnering the same types of economic incentives given to traditional generators. In the November 2011 *Assessment of Demand Response and Advanced Metering Staff Report*,[16] FERC found that demand response potential in organized power markets increased by more than 16 percent since 2009, accounting for between 2.3 percent and 10.5 percent of 2010 peak demand.[17] Further, FERC staff observed that federal and state regulators "continue to focus on demand response, taking actions to remove barriers to wholesale demand response."[18]

Environmental Protection Agency

The Clean Air Act (CAA) requires EPA to establish emissions standards for sources of air pollutants, such as nitrogen oxides or carbon monoxide, as well as hazardous or toxic air pollutants, such as mercury or benzene. These pollutants are regulated under CAA sections 111 and 112, respectively, and are known as New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). NSPS generally regulate new sources, i.e., sources put into operation after issuance of the rule,[19] while NESHAPs regulate both new and existing sources, although the standards may differ.

EPA finalized NESHAP for existing, new, and reconstructed stationary reciprocating internal combustion engines (RICE) greater than 500 horsepower (HP) located at major sources of HAPs[20] on June 15, 2004.[21] EPA then promulgated NESHAP for new and reconstructed stationary RICE located at area sources and for new and reconstructed stationary RICE less than or equal to 500 HP located at major sources of hazardous air pollutants (HAPs or air toxics) on

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[13] Several stakeholders, including the California ISO (Cal-ISO), the California Public Utilities Commission (CPUC), Edison Electric Institute (EEI), and the Electric Power Supply Association (EPSA), have filed for court review of Order 745.
[14] FERC. *Demand Response Compensation in Organized Wholesale Energy Markets*. Order No. 745.
[15] FERC. *2011 Assessment of Demand Response and Advanced Metering Staff Report*. November 2011. Available at http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf. Accessed May 2012.
[16] The Energy Policy Act of 2005 (EPAct 2005) requires FERC to prepare and publish an annual report assessing electricity demand response resources.
[17] FERC. *2011 Assessment of Demand Response and Advanced Metering Staff Report*. November 2011. Available at http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf. Accessed May 2012.
[18] *Ibid*.
[19] While NSPS usually apply only to new sources, CAA subsection 111(d) requires EPA to regulate through the NSPS program existing sources' emissions of some air pollutants that are not addressed under other CAA sections. This provision is not applicable to RICE.
[20] A major source of HAP emissions is a stationary source that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAPs at a rate of 25 tons or more per year. An area source of HAP emissions is a source that emits HAPs but is not a major source.
[21] 69 FR 33474.

January 18, 2008.[22] EPA did not promulgate final requirements for existing stationary RICE located at area sources or for existing stationary RICE less than or equal to 500 HP located at major sources because the Agency determined at the time that it did not have sufficient information to inform regulation.[23] Subsequent court decisions further delayed regulation of these remaining classes of engines.

In 2010, EPA eventually finalized NESHAPs for small RICE at major sources and RICE of all sizes located at area sources (facilities with limited potential to emit air toxics). During the public comment period in 2009, several commenters highlighted the role of these engines in demand response programs. In addition, traditional integrated utilities may use these engines for voltage or frequency regulation outside of market-based demand response programs.[24]

In the final rule, which is scheduled to take effect for existing units in 2013, EPA established emission limits or work practice standards to reduce emissions of HAPs such as formaldehyde, benzene, and acrolein (see Table 1). At the same time, EPA allowed emergency backup diesel engines to operate for as long as necessary without meeting emission limits during actual emergencies (i.e., loss of grid power), as well as for up to 15 hours per year as part of a demand response program. In other words, EPA allowed engines to operate up to 15 hours per year for non-emergency reasons without emission limits. In the event of an emergency, backup diesel engines are permitted unlimited operation; however, "emergency" is not well-defined.[25] EPA received petitions for reconsideration requesting both a higher exemption and elimination of the exemption, from a coalition of curtailment service providers (CSPs) and the Delaware Department of Natural Resources and Environmental Control (DNREC), respectively.

Table 1. HAP Emissions from Reciprocating Internal Combustion Engines (RICE)

Acetaldehyde	Formaldehyde	Methanol	Selenium
Acrolein	Hexane	Methyl Chloride	Toluene
Benzene	Lead	Naphthalene	Xylene
Cadmium	Manganese	Nickel	1,3-butadiene
Chromium	Mercury	Polycyclic Aromatic Hydrocarbons (PAH)	2,2,4-trimethypentane

Source: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. 69 FR 33474.

[22] 73 FR 3568.
[23] Statutorily, NESHAP standards must be based on the performance of the best units in a given source category, and EPA did not believe the Agency had sufficient information to determine the best performers.
[24] Under EPA's existing and proposed rules, engines not seeking classification as "emergency" engines would be required to meet the applicable emissions standards, but in exchange, would not be bound by any operational limitations. This report focuses on engines classified as emergency, thus avoiding emission limits, while operating during non-emergency periods through participation in a demand response program.
[25] The 2010 final rule defines "Emergency stationary RICE" as "any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used for peak shaving are not considered emergency stationary ICE. Stationary CI ICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted [under the 15-hour demand response provisions]." 75 FR 9679.

To address litigation filed by the CSP coalition, on June 7, 2012, EPA proposed revisions to the RICE NESHAP.[26] With regard to demand response provisions, this proposal would increase the annual hourly limit for and refine the definition of permissible demand response operation. To maintain engines' status as "emergency" engines, and thus their exemption from emission standards, engines would be limited to 100 hours of operation per year under certain conditions.[27] EPA proposed that the operation hours would include the following: 1) maintenance and readiness testing and 2) participation in an "emergency demand response" program. To operate under the demand response option, the demand response program would be required to be called only after the relevant RTO has declared an emergency under NERC

Key Stakeholders in the Demand Response Debate

Curtailment Service Providers (CSPs) – Concerned that customers will not participate if backup generators are subject to air pollution emission limits; contend that the RICE NESHAP, if applied to these engines, would reverse environmental and reliability benefits of demand response.

Environmental and Health Organizations – Concerned with substantially higher emissions profile of diesel generation compared to traditional or renewable generation; support curtailment as demand response.

Environmental Protection Agency (EPA) – Attempting to balance environmental and reliability claims while carrying out the Agency's statutory obligation to address hazardous and criteria pollutants from these engines.

Federal Energy Regulatory Commission (FERC) – Concerned with overall system reliability; recently finalized rules to allow demand response resources to compete with generation resources.

Independent Power Producers (IPPs) – Concerned that a significant portion of demand response capacity is actually diesel generators; argue that all generators participating in electricity markets should be held to comparable environmental and reliability requirements.

Independent System Operators (ISOs) / Local Balancing Authorities – Concerned with overall system reliability and whether committed demand response resources will be available and will respond when called to do so by the ISO.

Municipal/Cooperative Utilities – Utilize diesel generators for a range of functions including frequency regulation and replacement power; argue that emission limits should not be imposed, particularly before the Mercury and Air Toxics Standards (MATS) for power plants take effect.

State Environmental Agencies – Concerned that increased use of uncontrolled backup generators may increase the public's exposure to health damaging air pollution, while forcing more expensive pollution measures on other local sources in order to compensate for the increased air pollution.

Emergency Alert Level 2 or when there is a fluctuation in voltage or frequency of 5 percent or more.[28] In addition, EPA proposed a temporary provision allowing engines at area sources to maintain their emergency status while operating up to 50 hours per year as part of a non-emergency economic demand response or peak shaving program with a RTO or local distribution system operator. This exemption would expire in April 2017, when the Agency

[26] 77 FR 33812.

[27] Operation during emergencies – such as when the normal power supply is interrupted or the engine is needed for fire suppression – would remain unlimited.

[28] The full procedures of NERC's "NERC Emergency Alert Level 2" (Standard EOP-002-2 — Capacity and Energy Emergencies) may be viewed at http://www.nerc.com/files/EOP-002-2.pdf. Accessed June 2012.

expects the Mercury and Air Toxics Standards (MATS) to be fully implemented. EPA intends that this provision would allow flexibility as the electricity system completes the transition.

Current State Initiatives

Prior to federal regulations, stationary internal combustion engines have for the most part been regulated and permitted at the state and local level. This section summarizes current NESCAUM state regulation of non-emergency and emergency engines.

NESCAUM State Emissions Regulations

Emergency engines are often exempt from emissions limits or control technology requirements; however, their operation is usually limited to emergency situations and a maximum number of non-emergency hours. In some states, emergency units are allowed to operate under ISO/RTO emergency demand response programs, while in others, operation of emergency units remains constrained to actual outage situations only. Emergency units are generally precluded in all Northeast states from participating in non-emergency economic demand response programs. Many states require the use of ultra-low sulfur diesel (≤15 parts per million) for diesel-fueled emergency backup engines. Table 2 summarizes these requirements for NESCAUM states while Table 4 and Appendix A provide further detail.

Table 2. Summary of State Permitting Requirements for Distributed Generators

State	Non-Emergency Engines		Emergency Engines		
	Threshold	Requirements	Threshold	Restrictions	Demand Response
CT	PTE 15 TPY any individual air pollutant	If operating under RCSA section 22a-174-3a (individual permit), BACT/ LAER based on emissions If operating under RCSA section 22a-174-42 (distributed generator permit by rule), allowed operating hours and CO_2, NOx PM, CO emission limits determined in accordance with RCSA section 22a-174-42. ULSD or 10 grains sulfur/100 dscf for gaseous fuels required Owners of engines may also be subject to the emission limits and testing requirements in RCSA sections 22a-174-22(e) and 22a-174-22(k), if the engine meets the applicability thresholds	PTE 15 tpy any individual air pollutant. The owner has the option of obtaining an individual permit under RCSA section 22a-174-3a or operating under one of two permits-by-rule (RCSA sections 22a-174-3b and -3c)	If operating under an individual permit, run time restrictions will vary If operating under RCSA section 22a-174-3b, run time limited to 300 hrs/yr If operating under RCSA section 22a-174-3c, limitations on fuel purchased If operating under RCSA section 22a-174-3c, gaseous fuel purchase limited to 3,360,000 ft^3/yr, distillate oil purchase limited to 21,000 gal/yr, and propane purchase limited to 100,000 gal/yr	Participation in price response programs (e.g., non-emergency peak shaving) not allowed Participation in emergency demand response program allowed for 300 hr/yr using natural gas or ULSD when operating under RCSA sections 22a-174-3b or 22a-174-3c. Individual permit under RCSA section 22a-174-3a may have different restrictions
ME	5 MMBtu/hr (approx. 500 kW), 0.5 MMBtu/hr with combined heat input of 5 MMBtu/hr or operation-specific air permit (if at major source)	SCR over 20 TPY NOx, BACT case-by-case, on-road diesel maximum of 15 ppm sulfur content from diesel fuel, 1.5 lb NOx/MWh 0.07 lb PM/MWh 2.0 lb CO/MWh	0.5 MMBtu/hr (approx. 50 kW)	500 hrs/yr, used only during emergencies and maximum 50 hrs of maintenance and testing	Emergency generators are not allowed to participate in any voluntary demand-reduction program or any other interruptible supply arrangement with a utility, other market participant, or system operator.

State	Non-Emergency Engines		Emergency Engines		
	Threshold	Requirements	Threshold	Restrictions	Demand Response
MA	300 kW if installed on or before March 23, 2006 50 kW if installed after March 23, 2006	Case-by-case review if installed on or before March 23, 2006 Permit by rule following the RAP model rule if installed after March 23, 2006. A peaking power production unit, a load shaving unit, or a unit in an energy assistance program may elect a case-by-case BACT review in lieu of complying with emission limits of permit by rule. If installation of the engine results in facility being subject to major NSR, it is not allowed permit by rule	300 kW (approx. 3 MMBtu/hr) if installed on or before March 23, 2006 37 kW if installed after March 23, 2006	300 hrs/yr total usage If installed on or before March 23, 2006, operation cannot create a condition of air pollution If installed after March 23, 2006, RAP model rule requirements apply (non-road engine tiers, ULSD, etc.)	Participation in price response programs (e.g., non-emergency peak shaving) not allowed Existing and new engines burning ULSD or natural gas can operate if called by ISO-NE. EDRP currently allowed during OP-4, Action 6
NH	Aggregate total of all engines at a facility exceeding either: 1.5 MMBtu/hr (approx. 150 kW) for diesel 10 MMBtu/hr (approx. 1,000 kW) for gaseous fuels Aggregate total excludes engines less than 0.15 MMBtu/hr for diesel and 1.5 MMBtu/hr for gaseous fuels	Over 25 TPY or 4.5 MMBtu/hr require RACT	Must obtain general state permit	500 hrs/yr less than 25 TPY NOx	Can participate after implementation of Action 6 ISO-NE Operating Procedure 4 (OP4)

State	Non-Emergency Engines		Emergency Engines		
	Threshold	Requirements	Threshold	Restrictions	Demand Response
NJ	1 MMBtu/hr (approximately 100 kW), 5 TPY must meet SOTA requirements, 37 kW electricity generation	Stationary engine power output 37 kW or greater: 1.5 NOx rich-burn gaseous or liquid fuel and lean-burn gaseous fuel, 2.3 NOx lean-burn liquid and dual fuels, 0.90 g/bhp-hr NOx emission limit Limit .15g/bhp-hr NOx, 0.5 g/bhp-hr CO, 0.15 g/bhp-hr VOC, ammonia slip 10 ppmvd at 15% O_2, 0.02 g/bhp-hr liquid fuel firing, 500 ppmvd CO emissions at 15% O_2, 0.9g/bhp-hr NOx electricity, 30 ppm sulfur until Jul 2016 sulfur limit 15 ppm	1 MMBtu/hr (approx. 100 kW)	Emergency, maintenance, and testing operations only, maintenance and testing not during days forecasted to have poor air quality, 15 ppm fuel sulfur limit, no NOx requirements	Cannot participate in economic demand response programs; exempt for NOx requirements when there is a voltage reduction issued by PJM under its “emergency procedures.”
NY	NY: 300 kW, 33 kW if diesel, 400 bhp (300 kW) in ozone attainment areas, 200 bhp (147 kW) in ozone non-attainment areas, NYC: 12.5 TPY NOx, NY: 50 TPY NOx	90% NOx reduction from 1990, 1.5 g/bhp-hr natural gas, 2.0 g/bhp-hr landfill/digester gas, 2.3 g/bhp-hr distillate oil	No threshold	NY: 500 hrs/yr. including maintenance and testing, no permits, NYC: register but no restrictions	An engine participating in a demand response program is not considered to be an emergency engine per NYS DEC regulations.
RI	350,000 Btu/hr or 50 hp minor source or general permit for generators	BACT based on emissions for minor source permits or compliance with Regulation No. 43 for general permits	350,000 Btu/hr or 50 hp minor source or general permit for generators	500 hrs/yr for maintenance, testing, and emergencies only, maximum 1,900 lb/MWh CO_2, 15 ppm sulfur content liquid fuel, 10 grains of sulfur per 100 dry standard cubic feet gaseous fuel, 10% visible emissions, must meet EPA non-road emissions standards for Regulation No. 43 compliance only	Cannot participate in demand-reduction program unless implemented at same time as ISO New England
VT	450 bhp (337 kW)	Existing engines installed prior to 2007 have to meet EPA Tier 1; Engines installed after 2007 have to at least meet EPA Tier 2	No threshold	100 hrs/yr maintenance and testing; Emergency operating hours unrestricted	Can participate in emergency demand response programs; Cannot participate in economic peak shaving programs (non-emergency engine permit required)

Emerging State Reporting Requirements

Data on the enrollment and use of on-site generators in demand response programs is extremely limited because, unlike larger generating facilities, participating engines are generally exempt from reporting requirements at the state or federal level. The 2003 NESCAUM report sought to develop a more complete inventory of the numbers and types of backup generators that exist in the NESCAUM region. Estimates of installed diesel generator capacity suggest that the total population of diesel generators in the Northeast could include well over 30,000 units with a combined capacity exceeding 10 GW. In response, several states in the Ozone Transport Commission[29] have begun to require that demand response providers and program participants track and report the composition of demand response resources. In particular, both Delaware and Maryland are exploring requiring disclosure of demand response composition.

ISO/RTO Demand Response Programs

This section summarizes demand response programs in ISO/RTO markets within the NESCAUM region; the growth and composition of these programs, with a particular focus on reliability-based demand response programs; and the conditions under which backup diesel generators are dispatched.

Demand Response in Capacity Markets

Demand resources may participate in capacity markets in all three ISOs/RTOs. Many ISOs/RTOs, including ISO-NE and PJM, hold annual capacity auctions to acquire capacity for a one-year period three years in advance with the goal of ensuring reliable electricity supply.[30] With limited exceptions,[31] the auctions do not discriminate between fuel type or technology – from the RTO perspective, there is little distinction between a megawatt of supply and a megawatt of demand response or between emergency or non-emergency capacity resources.

Each resource that participates in a capacity auction is competing for the same value of capacity revenue. Capacity revenue typically comes in the form of a fixed payment for each unit of capacity regardless of the ultimate frequency of its use. In other words, a megawatt of generation that expects to operate frequently receives the same capacity payment as a megawatt of demand response that expects to operate infrequently. According to recent analysis by Synapse Energy Economics for EPA, the annual capacity market revenue available to one MW – in this example, a backup generator – in ISO-NE and PJM varies from under $10,000 per year to greater than $80,000 per year, depending upon the specific year and location in which the unit is installed.[32] Since the Synapse analysis, there have been two additional three-year forward capacity auctions in PJM and ISO-NE.

[29] The Ozone Transport Commission was created by the 1990 Clean Air Act Amendments as a multi-jurisdictional organization that includes the District of Columbia and the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia (known as the Ozone Transport Region). These jurisdictions collectively work together to address regional ground-level ozone problems.
[30] NYISO operates strip, monthly, and spot capacity auctions.
[31] See further detail regarding ISO-NE's 600 MW cap on the amount of RTEG resources in the forward capacity auction on page 16.
[32] Synapse Energy Economics. *Sample Revenue for a 1 MW Backup Generation Unit*. June 27, 2011.

Table 3 summarizes demand response enrollment in 2011 and 2015. While PJM differentiates between energy efficiency and demand response, ISO-NE does not. Furthermore, unlike ISO-NE and PJM, NYISO conducts seasonal (May-Oct/Nov-Apr), monthly, and spot capacity auctions rather than annual auctions for capacity needs three years in advance.

Table 3. Demand Response Enrollment by ISO

Demand Response Enrollment	ISO-NE	NYISO	PJM
2011 MW	2,554	2,173	11,800
Percent of 2011 Capacity	7%	6%	8%
Percent Back Up Generators 2011	23%	Approximately 10%	15%
2015 MW	3,628	N/A	14,832
Percent of 2015 Capacity	20%	N/A	TBD
Percent Backup Generators 2015	N/A	N/A	N/A

Source: ISO-NE, NYISO, PJM, MJB&A Analysis.

Participation of Backup Generators in Demand Response Programs

Backup generators are allowed to participate in every aspect of the reliability and economic based demand response programs in the ISO/RTO markets within the NESCAUM region, with two exceptions: ISO-NE, where most state air regulations preclude backup generators from participating in economic demand response programs, and NYISO, where behind-the-meter generation is not permitted in its energy market. Where backup generation is eligible to participate in the NYISO's reliability demand response programs, the NYISO requires that it adhere to all applicable laws and regulations. PJM does not limit the participation of backup generators but instead requires that the owner adhere to all applicable environmental regulations. In addition, while NYISO quantifies the generation capacity enrolled in demand response programs, PJM does not require explicit information regarding the source of demand response activity, including backup generation. Table 4 summarizes demand response program eligibility for backup generators, the environmental conditions for participation, and the dispatch trigger. Appendix B provides more detail for demand response programs in ISO-NE, NYISO, and PJM.

Table 4. Backup Generator Participation by ISO

ISO/RTO	Program Eligibility	Backup Generator	Conditions	Trigger	Financial Compensation
ISO-NE	Real Time Emergency Generation Resources	Yes	Federal, state and/or local air quality rules limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement	Operating Procedure No. 4 – Action During A Capacity Deficiency (OP-4) – Action #6	Monthly capacity payments and energy payments for events

ISO/RTO	Program Eligibility	Backup Generator	Conditions	Trigger	Financial Compensation
NYISO	Installed Capacity/Special Case Resource Program	Yes	Generators must adhere to all applicable operating hour and/or low sulfur fuel regulatory requirements. Participants must also report these requirements to NYISO at enrollment. In order to participate in the programs, engines must be model year 1995 or newer or demonstrate that their NOx emissions do not exceed 35 pounds per megawatt-hour (lb/MWh)	The NYISO will deploy the SCR and EDRP as one of its emergency procedures in conjunction with the In-day Peak Hour Forecast response to an Operating Reserve Peak Forecast Shortage or other operational emergency	Monthly capacity payments for SCRs and energy payments for events and tests
	Emergency Demand Response Program ("EDRP")	Yes			Energy payments for events
	Targeted Demand Response Program	Yes		Decision to activate TDRP resources made by Con Edison for local reliability issues in NYC	Monthly capacity payments and energy payments for events
PJM	Limited (earns capacity and energy revenues)	Yes	10 days up to 6 hours per day (i.e., 60 hours per year)	Decision to activate by PJM according to "Manual 13 Emergency Operations" Activated during capacity emergencies Emergency conditions include: an abnormal electrical system condition requiring manual or automatic action, a fuel shortage, or a condition that requires implementation of emergency procedures as defined in the PJM Manuals	Monthly capacity payments and energy payments for events
	Extended Summer (earns capacity and energy revenues)	Yes	Unlimited summer days up to 10 hours per day		Monthly capacity payments and energy payments for events
	Annual (earns capacity and energy revenues)	Yes	Unlimited days up to 10 hours per day		Monthly capacity payments and energy payments for events

Sources: ISO-NE, NYISO, PJM

ISO New England

ISO New England (ISO-NE), the RTO serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, has a long history with demand response programs and was one of the first ISOs to include demand-side resources in its forward capacity auction. As early as 1997, ISO-NE (then the New England Power Pool) adopted a demand response program that offered a fixed payment for voluntary reductions in load during capacity shortages. Over time, ISO-NE has modified and expanded these programs to include both reliability-based (e.g., emergency) programs and economic-based programs. Reliability-based resources participate in both the capacity and energy markets, while economic-based resources participate in the energy markets only.

In the reliability-based programs, customers reduce demand in response to system reliability conditions as determined by ISO-NE. The reliability-based demand response programs include

Real Time Demand Response (RTDR) resources and Real Time Emergency Generation (RTEG) resources.[33] A RTEG resource is a distributed generator whose federal, state, and/or local air quality rules limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of 5 percent of normal operating voltage that require more than 10 minutes to implement.[34]

These resources are called upon by ISO-NE under very specific system conditions as part of operating procedures to maintain system reliability as defined by ISO-NE manuals. RTDR resources are dispatched when ISO-NE forecasts the implementation of measures to increase capacity[35] the day before or during the operating day.[36] RTEG resources are dispatched when ISO-NE forecasts worsening grid conditions.[37,38]

ISO-NE Forward Capacity Market

Each year, ISO-NE develops a projection of future consumer demand and power system needs three years in advance and holds an auction to purchase resources that will satisfy the anticipated regional requirements. In April 2012, ISO-NE completed its sixth Forward Capacity Auction to meet the region's reliability needs in the 2015/2016 delivery year.[39]

Participation by demand-side resources in the ISO-NE capacity auction has been steadily increasing. In the 2010/2011 delivery year, demand-side resources accounted for 7 percent (2,554 MW) of the total capacity resources and will increase to 10 percent (3,645 MW) by 2015/2016 based on the results of the 2012 auction. Figure 4 below illustrates the cleared resources in each of the six forward capacity auctions – generating resources, demand resources, and imports from other control regions. ISO-NE caps the amount of RTEG resources in the forward capacity auction at 600 MW. This means that the effective payment rate applied to RTEG is prorated by the maximum amount of RTEG allowed to be purchased in the auction, 600 MW, divided by the total amount of RTEG that received a capacity supply obligation in the auction.

While cleared capacity has been increasing, capacity supply obligations, after bilateral and reconfiguration auctions, have not been increasing at the same rate. The charts below show initial auction results rather than the final obligations for the commitment period. Passive (non-dispatchable) resources have continued to grow significantly, while active resources have not.

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[33] RTDR resources may also participate in economic-based programs.

[34] ISO-NE. *ISO New England Inc. Transmission, Markets and Services Tariff*. Section I.2.2. Available at http://www.iso-ne.com/regulatory/tariff/sect_1/sect_i.pdf. Accessed June 2012.

[35] *Operating Procedure No. 4 – Action During A Capacity Deficiency (OP-4) – Action #2* or higher (where higher indicates a more severe market condition).

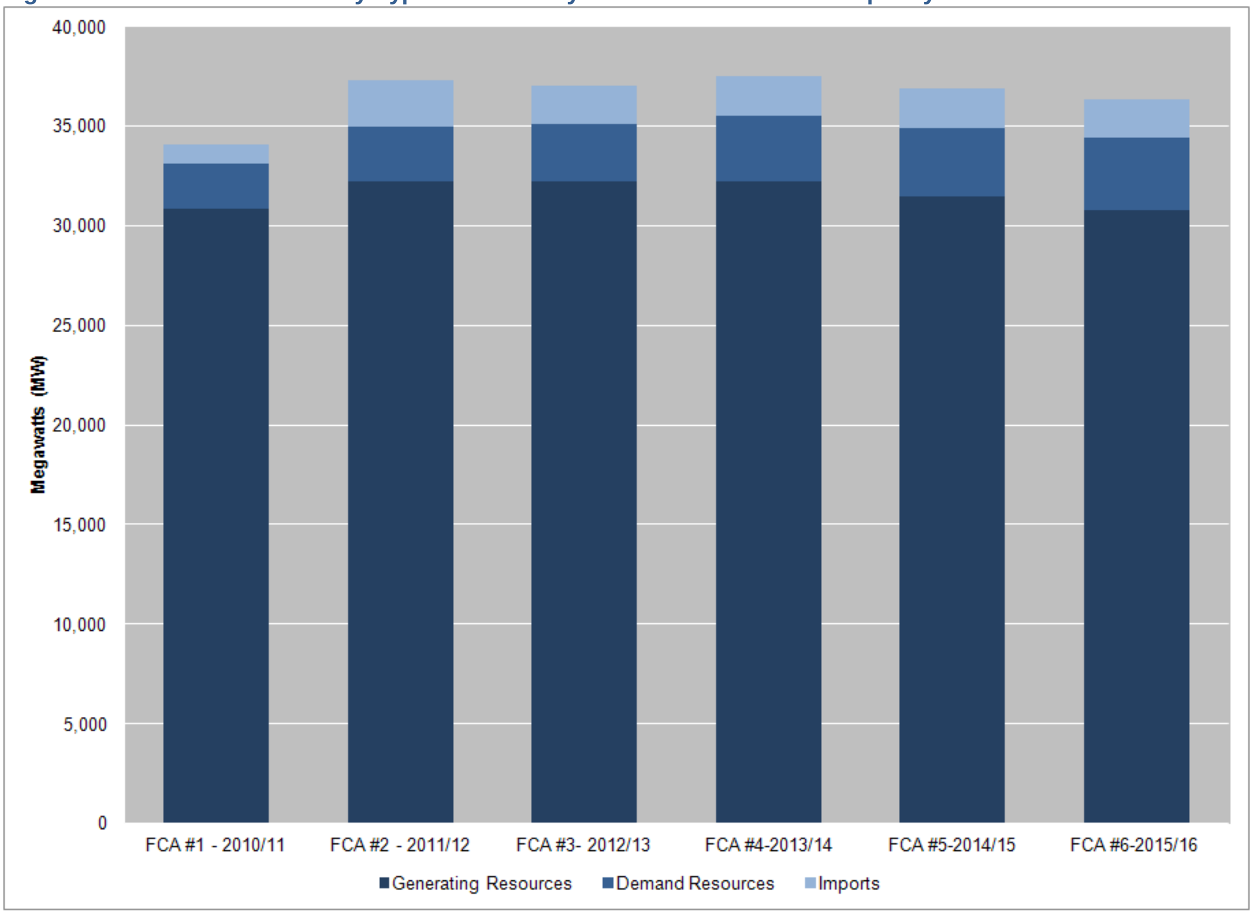
[36] ISO-NE OP-4 establishes criteria and guidance for actions during capacity deficiencies. OP-4 may be implemented any time an event occurs or is expected to occur that would result in insufficient resources to meet load and operating reserve requirements. This may include transmission facilities that are loaded beyond their transfer capabilities, abnormal voltage and/or reactive conditions, capacity deficiency in another power pool, or any other threat to the integrity of the ISO-NE system. OP-4 will normally precede implementation of manual load-shedding as required by Operating Procedure No. 7 - Action in an Emergency (OP-7). OP-4 Action 2 is the action taken by the ISO to dispatch RTDR Resources in the amount and location required in response to the depletion of the 30-minute operating reserve.

[37] OP-4 Action 6.

[38] ISO-NE dispatches RTEG resources, sharing reserves, and voltage reductions under Operating Procedure No. 4 Action 6. In this Action, ISO-NE implements a voltage reduction of five percent of normal operating voltage, which requires more than 10 minutes to implement, dispatches RTEG Resources in the amount and location required, and may alert the New York Independent System Operator (NYISO) that sharing of reserves may be required.

[39] ISO-NE. *Forward Capacity Market (FCA 6) Result Report*. April 4, 2012. Available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp16/fca16/fca_6_result_report.pdf. Accessed May 2012.

Figure 4. Cleared Resources by Type and Delivery Year ISO-NE Forward Capacity Auctions



Source: ISO New England Inc.

Resources cleared (e.g., accepted) in the forward capacity auction receive capacity payments on a dollars per kilowatt-month ($/kW-month) basis. As illustrated in Table 5, the clearing prices in the auctions spanned a range from $2.52/kW-month to a high of $4.25/kW-month.

Table 5. ISO-NE Forward Capacity Auction Results[40]

	FCA #1	FCA #2	FCA #3	FCA #4	FCA #5	FCA #6
Delivery Year	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Auction Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Total Cleared (MW)	**34,077**	**37,283**	**36,996**	**37,501**	**36,918**	**36,309**
Generating Resources (MW)	**30,865**	**32,207**	**32,228**	**32,247**	**31,439**	**30,757**
Demand Resources (MW)	**2,279**	**2,778**	**2,867**	**3,261**	**3,468**	**3,628**
Imports (MW)	**934**	**2,298**	**1,900**	**1,993**	**2,011**	**1,924**
Prorated Price ($/kW-month)	**$4.25**	**$3.12**	**$2.54**	**$2.52**	**$2.86**	**$3.13**

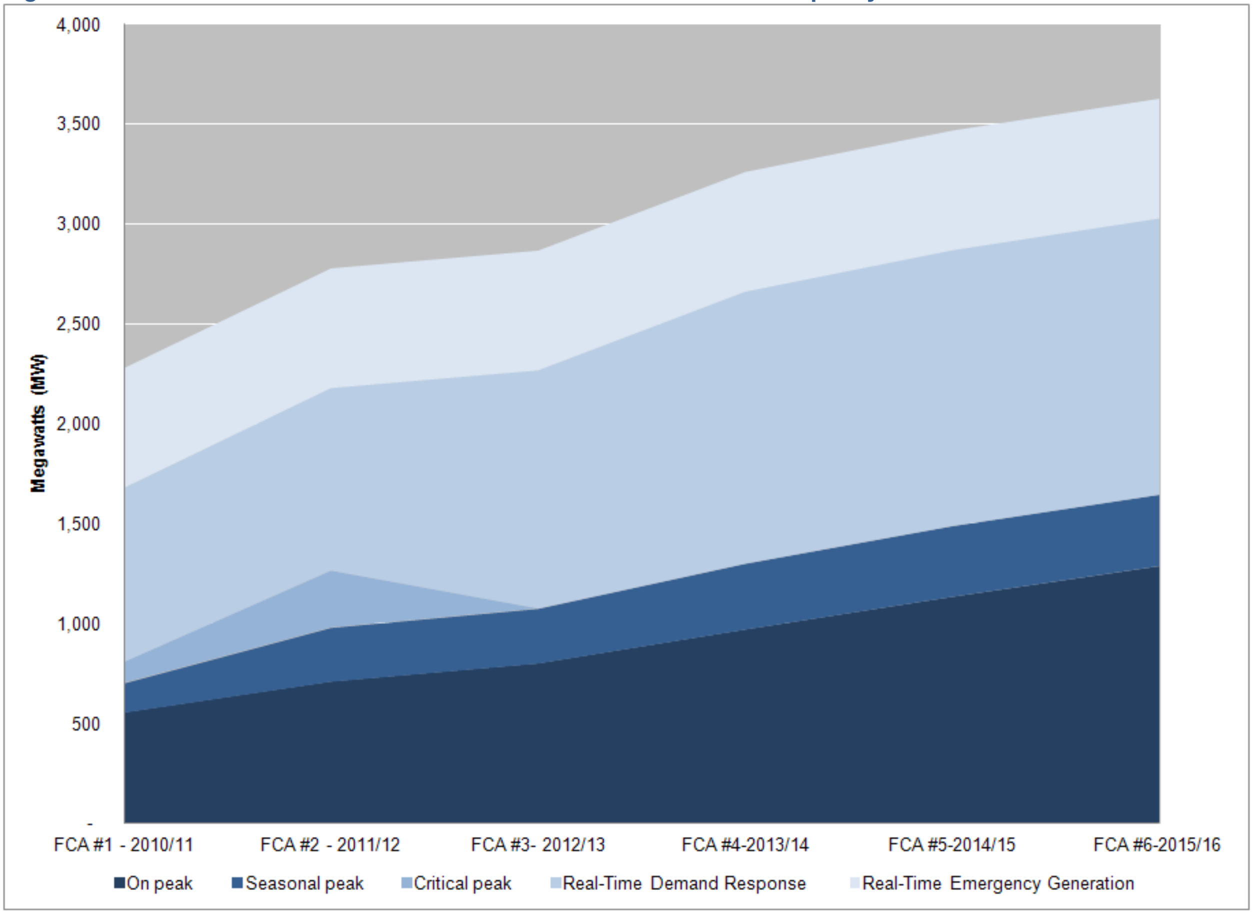
Source: ISO New England Inc.
Initial results from each auction; amounts change with monthly and annual reconfiguration auctions.

ISO-NE reports the total enrolled capacity by demand resource category on a monthly basis. As of May 2012, there were 1,161 MW of RTDR, 618 MW of RTEG, 564 MW of on-peak, and 359

[40] ISO-NE. *Sixth Forward Capacity Market Auction Procures Power System Resources Needed for 2015–2016* (Press Release). April 6, 2012.

MW of seasonal peak resources enrolled in the programs.[41] The makeup of cleared demand response resources by auction is illustrated in Figure 5.[42]

Figure 5. Growth of Cleared Demand Resources in ISO-NE Forward Capacity Auctions



Sources: ISO New England Inc., MJB&A Analysis

Based on the auction clearing prices, from 2012-2016, a backup generator would earn over $130,000 per MW in capacity market revenue as illustrated in Table 6 below.

Table 6. Capacity Market Revenue to a 1 MW Backup Generator – ISO-NE

Delivery Year	Clearing Price ($/kW-month)	Calendar Year	Jan-May Revenue	Jun-Dec Revenue	Calendar Year Revenue
2012/13	$2.41	2012	$12,350	$16,870	$29,220
2013/14	$2.19	2013	$12,050	$15,330	$27,380
2014/15	$2.37	2014	$10,950	$16,618	$27,568
2015/16	$3.04	2015	$11,870	$21,308	$33,178
2016/17	TBD	2016	$15,220	TBD	TBD; at least $15,220*
Total			$62,440	$70,126	$132,566

Source: Synapse Energy Economics, Sample Revenue for a 1 MW Backup Generation Unit, June 27, 2011.
Results of ISO-NE Forward Capacity Auctions 2012/13-2015/16, MJB&A Analysis.
*Only the first five months of 2016. The clearing price for the last seven months will be known in June 2013.

[41] ISO-NE. *Demand Resource Asset Enrollments*. May 1, 2012. Available at http://www.iso-ne.com/genrtion_resrcs/dr/stats/enroll_sum/2012/dr_enrollments_05_01_2012with_dispatch.ppt. Accessed May 2012.
[42] Critical peak resources no longer exist as a demand resource option.

NYISO

Similar to ISO-NE, the New York Independent System Operator (NYISO) divides demand response programs into economic- and reliability-based programs.

NYISO Capacity Market

NYISO operates a capacity market that incorporates semi-annual, monthly, and spot capacity auctions to ensure resource adequacy. Eligible capacity resources (including owners of backup generators) may sell capacity in bilateral contracts (such as with a Load Serving Entity (LSE)) or offer directly into Installed Capacity (ICAP) auctions. NYISO classifies three demand response programs, summarized below, as emergency demand response resources and thus called when NYISO forecasts a reliability issue.

1. *Emergency Demand Response Program (EDRP*). The EDRP program is limited to interruptible loads or loads with a qualified behind-the-fence local generator (e.g., backup generation). Generators must adhere to all applicable operating hour and/or low sulfur fuel regulatory requirements. Participants must also report these requirements to NYISO at enrollment. In order to participate in the EDRP program, the NYISO has established guidelines in the absence of any environmental limitations specifically applicable to demand response: engines must be model year 1995 or newer or demonstrate that their NOx emissions do not exceed 35 pounds per megawatt-hour (lb/MWh).[43] Participation during a NYISO-determined reliability event is voluntary, meaning that there are no consequences for enrolled EDRP resources that fail to curtail. Participants receive energy payments if called, but no capacity payments for participation.
2. *Installed Capacity/Special Case Resource (ICAP/SCR) Program*. These resources participate in the capacity market and accept an obligation to respond when called upon by the NYISO in exchange for capacity payments. Participation in the ICAP/SCR program is limited to resources with interruptible loads or loads with a qualified behind-the-fence local generator. Participation during a reliability event is mandatory, provided that the 21-hour advance notice has been issued by the NYISO; otherwise response is voluntary. These resources must also participate in a mandatory test during each capability period or season.
3. *Targeted Demand Response Program (TDRP).* This program curtails EDRP and SCR resources during periods of high demand to ensure reliability within New York City. While SCR resources are normally required to curtail usage when called, provided proper notice has been given, response under the TDRP program is voluntary.

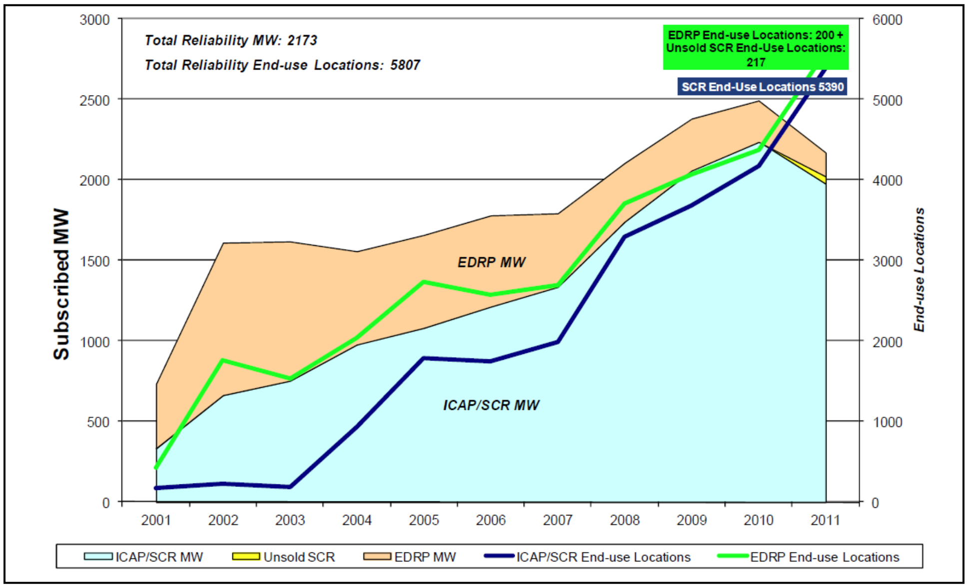
The demand response resources in NYISO reliability programs represented approximately six percent of the 2011 reliability requirement of 37,782 MW. SCR represented 93 percent of the total resources enrolled in NYISO reliability programs and 91 percent of the reliability programs' total enrolled capacity.[44] SCR is also the fastest-growing demand response program

[43] NYISO. *Emergency Demand Response Program Manual* (Manual 7). December 2010. Available at http://www.nyiso.com/public/webdocs/products/demand_response/emergency_demand_response/edrp_mnl.pdf. Accessed June 2012.

[44] NYISO. *Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs*. January 17, 2012. Available at http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2012/01/NYISO_DR_Lttr-COS-PblcReport_20120117.pdf. Accessed June 2012.

operated by the NYISO, increasing to roughly 2 GW in 2011. This growth is likely due to the fact that SCR participants receive monthly payments for capacity in the capacity market.[45] At the same time as SCR program registration has steadily increased since 2001, EDRP program registration has gradually declined since 2002 as resources switch from the EDRP program to the SCR program in order to earn revenue from the NYISO capacity market. From May 2001 through July 2011, combined enrollment in EDRP and SCR has grown from approximately 200 MW to 2,173 MW and the total number of end-use locations has increased from approximately 200 in March 2002 to 5,816 in July 2011. Since participation in EDRP and ICAP/SCR became mutually exclusive, EDRP enrollment and capacity have continued to decrease while ICAP/SCR enrollment and capacity have increased (see Figure 6).[46]

Figure 6. Historical Growth in Resources and MW in NYISO Reliability Programs



Source: NYISO

SCR resources receive capacity payments, typically on a monthly basis, to ensure availability to curtail power usage upon request by NYISO. In addition, SCR resources receive energy payments when called for events and tests.[47]

In contrast, EDRP resources receive energy payments only for actual power reductions when called upon by the NYISO based on measured energy reduction during an event, with a minimum rate of $500/MWh or the actual locational marginal price (LMP), whichever is higher; payment is guaranteed for a minimum of four hours of verified load reduction.

The NYISO capacity auctions determine clearing prices for three distinct locations: New York City, Long Island, and New York Control Area (NYCA). In New York City, the spot price averaged $8.36/kW-month in the summer 2011. In NYCA, the spot price averaged $0.29/kW-month in the same time period.[48] The Long Island price was set by the NYCA price for the all months except for September.[49,50]

[45] Potomac Economics. *2011 State of the Market Report for the New York ISO Markets*. April 2012.
[46] NYISO, *Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs*, January 17, 2012.
[47] *Ibid*.
[48] Potomac Economics. *2011 State of the Market Report for the New York ISO Markets*. April 2012.
[49] NYISO. *Annual Report to the Federal Energy Regulatory Commission on the NYISO's Installed Capacity ("ICAP") Demand Curves and New Generation Projects in the New York Control Area*, December 20, 2011.

NYISO allows CSPs to separately report the composition of load reduction and enrolled generators in the ICAP/SCR and EDRP programs. NYISO reports this enrollment data (in MW) by NYISO zone and resource type. According to the June 2011 report, approximately 9 percent of the total ICAP/SCR resource enrollment is made up of generators and 85 percent of the total EDRP resource enrollment is made up of generators.[51] However, it is important to note that historic data show that enrollment in the ICAP/SCR program and the EDRP change on a monthly basis. For example, between May 2011 and June 2011, there was an increase of 11 percent in the ICAP/SCR program. In addition, there was a 70 percent increase in the EDRP program between May 2011 and July 2011.[52]

Based on the average spot price of $8.36/kW-month in New York City, a backup generator would have earned over $50,000 in capacity market revenues per MW during the six-month summer period in 2011.

PJM

PJM Interconnection is the RTO that spans 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. The PJM region has a total of 14,832 MW of demand response resources are committed as capacity resources for the 2015/2016 delivery year, representing slightly less than nine percent of anticipated capacity needs.[53]

Demand response programs in PJM are organized as Economic and Emergency Load Response Programs. PJM also enables demand resources to participate and submit bids for reductions in the Synchronized Reserve, Regulation, and Day-Ahead Scheduling Reserves markets (discussed below).

PJM Capacity Market

PJM procures all capacity for load serving entities (LSEs), the organizations responsible for delivering electricity to end-use customers, through the Reliability Pricing Model (RPM).[54] Capacity is obtained three years in advance of its delivery year. For example, the capacity auction held in May 2012 obtained capacity for the 2015/2016 delivery year. The generating unit retirement impacts of EPA's Mercury and Air Toxics Standards (MATS) and the High Electricity Demand Day Rule (HEDD)[55] in New Jersey, which have compliance deadlines of April 16, 2015 and May 1, 2015 respectively, influenced the RPM auction results.[56] Over the

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[50] ICAP prices for Summer 2012 are based on a new demand curve. Data for 2012 will be available on the NYISO website at http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp.

[51] NYISO. *Semi-Annual Report on Demand Response Programs* (Docket No. ER01-3001). June 3, 2011.

[52] NYISO. *Semi-Annual Reports on Demand Response Programs and New Generation Projects* (Docket Nos. ER01-3001-000 and ER03-647-000). June 1, 2012.

[53] PJM. *2015/2016 RPM Base Residual Auction Results*. May 18, 2012. Available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx. Accessed June 2012

[54] The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

[55] New Jersey State Department of Environmental Protection, *New Jersey Administrative Code, Title 7 Chapter 27 Subchapter 19, Control and Prohibition of Air Pollution from Oxides of Nitrogen*. Available at http://www.nj.gov/dep/aqm/Sub19.pdf Accessed July 2012.

[56] PJM. *2015/2016 RPM Base Residual Auction Results.* May 18, 2012.

next three years, over 14,000 MW of generation retirements have been announced in PJM.[57] There are over 6,600 MW of HEDD units in PJM that must comply with the New Jersey regulation by shutting down or installing emission controls. Several units are scheduled for deactivation in 2015.[58]

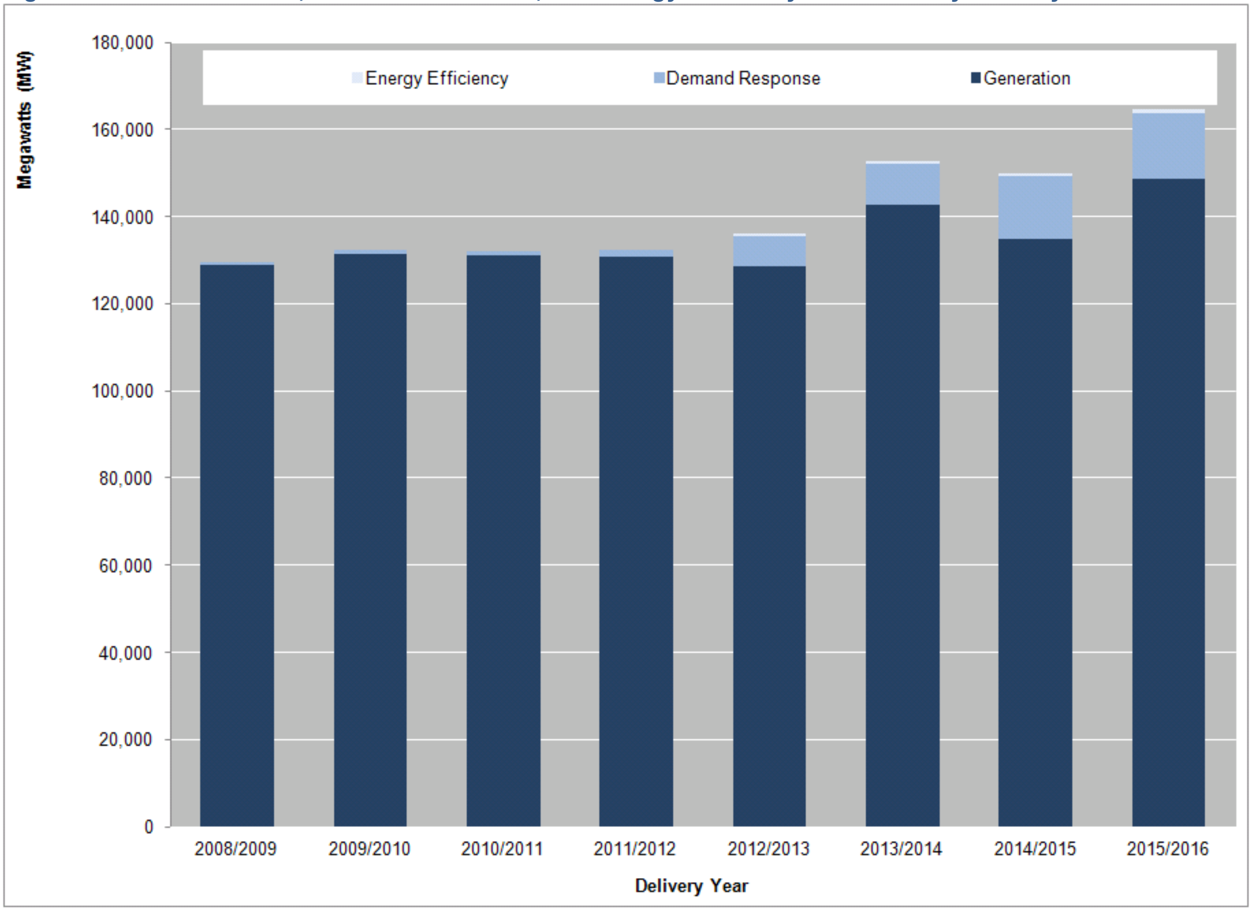
Demand-side resources may be bid into the RPM's Base Residual Auction, one of the incremental auctions, or may take on a capacity obligation through the bilateral market, such as through a CSP. There are three separate opportunities for emergency demand response in the RPM capacity market, with differing requirements. Demand-side resources in PJM include:

- *Limited Demand Resources*. These must agree to be interrupted up to 10 times between June and September for up to six consecutive hours in duration, any weekday from noon until 8 pm.
- *Extended Summer Demand Resources*. These must agree to be interrupted an unlimited number of times between June and October for up to 10 consecutive hours in duration between 10 am and 10 pm.
- *Annual Demand Resources*. These must agree to be interrupted an unlimited number of times from June to the following May for up to 10 consecutive hours in duration (June through October and the following May from 10:00 am to 10:00 pm; November through April from 6:00 am to 9:00 pm).

Demand-side resource participation in the PJM capacity market has increased by almost nine times since the introduction of the RPM capacity market in 2006; however, it should be noted that the PJM region has expanded significantly since 2007. In 2011, American Transmission Systems, Inc. (ATSI), the transmission affiliate of FirstEnergy, and Cleveland Public Power (CPP) were integrated into PJM. These integrations expanded the number and diversity of resources available in PJM. Participation in the 2006/2007 delivery year was under 1,700 MW. However, commitments through the 2015/2016 delivery year are over 10,600 MW each year and almost 15,000 MW for 2015/2016, as shown in Figure 7.[59]

[57] *Ibid*.
[58] Monitoring Analytics, LLC. *Quarterly State of the Market Report for PJM: January through March.* May 17, 2012. See Tables 11-12 and 11-13, Page 197. Available at http://pjm.com/documents/reports/~/media/documents/reports/state-of-market/2012/2012q1-som-pjm.ashx. Accessed June 2012.
[59] PJM. *2015/2016 RPM Base Residual Auction Results*. May 18, 2012.

Figure 7. PJM Generation, Demand Resources, and Energy Efficiency Resources by Delivery Year



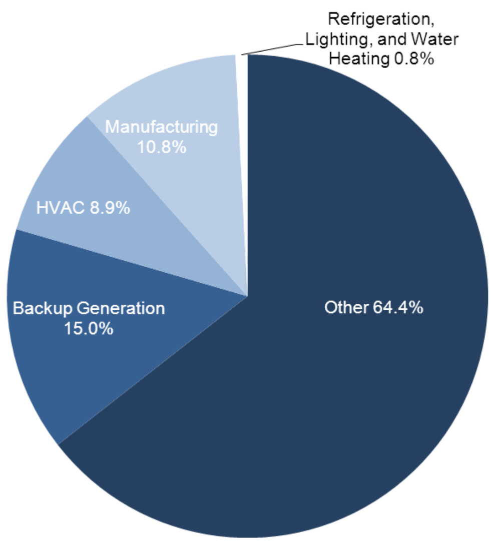
Source: PJM, Load Management Performance Report, December 2011.

For the 2015/2016 delivery year, Limited Demand Resources accounted for 62 percent of all demand response resources that cleared the auction (9,247 MW), while Extended Summer Demand Resources account for 35 percent (5,202 MW) and Annual Demand Resources account for 3 percent (383 MW).

PJM produces a monthly and annual Load Response Activity Report.[60] Beginning in April 2012, covering the 2011/2012 Delivery Year, PJM began reporting the makeup of demand response resources.[61] As illustrated in Figure 8, the data indicate that backup generation represents at least 15 percent of the total demand resource capacity for the 2011/2012 delivery year, or approximately 1,770 MW out of a total 11,800 MW. However, Curtailment Service Providers registering participating end-use sites were allowed to select an “other” category, which was not defined in the report. This category includes the majority – 65 percent – of all demand response resources. Presumably, this category represents participants that use a combination of backup generation as well as other load curtailment activities.[62] It is therefore reasonable to assume that

[60] PJM. *Load Management Performance Report*. December 2011.
[61] PJM. *Load Response Activity Report April 2012*. April 10, 2012.
[62] As EnerNOC, a national demand response provider, notes in their 2011 Annual Report, “Demand response is achieved when C&I customers reduce their consumption of electricity from the electric power grid in response to a market signal, such as capacity constraints, price signals or transmission-level imbalances. [Commercial and industrial] customers can reduce their consumption of electricity by reducing demand (for example, by dimming lights, resetting air conditioning set-points or shutting

Figure 8. PJM Demand Response Resources 2011/12



Source: PJM, Load Response Activity Report April 2012, April 10, 2012.

the actual level of backup generation as a component of total demand response resources is higher than the 15 percent highlighted in Figure 8.

Resources that clear the capacity auctions receive monthly capacity payments. The latest PJM auction procured 164,561 MW of capacity resources at a base price of $136 per MW-day[63] (see Table 7). This represents a 20 percent reserve margin for the region.

Table 7. RPM Base Residual Action Resource Clearing Price Results

Auction Results	2008/2009	2009/2010	2010/2011	2011/2012*	2012/2013	2013/2014**	2014/2015***	2015/2016
Resource Clearing Price	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00
Cleared UCAP (MW)	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2
Reserve Margin	17.5%	17.8%	16.5%	18.1%	20.9%	20.2%	19.6%	20.2%

*2011/2012 BRA was conducted without Duquesne zone load.
**2013/2014 BRA includes ATSI zone load
***2014/2015 BRA includes Duke zone
****2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under FRR Alternative
Source: PJM

Capacity prices in PJM differ depending upon the location of the unit and demand response product type, with capacity prices in the congested Mid-Atlantic region (MAAC)[64] often much higher than less congested areas of western PJM. Based on the auction clearing prices in the PJM auctions for MAAC, from 2012-2016, a backup generator would earn over $250,000 per MW as illustrated in Table 8, in addition to energy payments if called to operate.

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down production lines) or they can self-generate electricity with onsite generation (for example, by means of a back-up generator or onsite cogeneration)."

[63] PJM's all-time peak demand is 158,448 MW.

[64] The MAAC area consists of the transmission system of Atlantic City Electric, Baltimore Gas and Electric Company, Delmarva Power, Jersey Central Power and Light Company (JCP&L), Metropolitan Edison Company (Met-Ed), PECO, Pennsylvania Electric Company (Penelec), Pepco, PPL Electric Utilities, Public Service Electric and Gas Company (PSE&G), and Rockland Electric Company.

Table 8. Capacity Market Revenue to a 1 MW Backup Generator – PJM MAAC

Delivery Year	Clearing Price ($/MW-day)	Calendar Year	Jan-May Revenue	Jun-Dec Revenue	Calendar Year Revenue
2012/13	$133.37	2012	$16,610	$28,541	$45,151
2013/14	$226.15	2013	$20,139	$48,396	$68,535
2014/15	$136.50	2014	$34,149	$29,211	$63,360
2015/16	$167.46	2015	$20,612	$35,836	$56,448
2016/17	TBD	2016	$25,286	TBD	At least $25,286*
Total			$116,795	$141,985	$258,780

Source: Synapse Energy Economics, Sample Revenue for a 1 MW Backup Generation Unit, June 27, 2011. PJM Base Residual Auction Results 2012/13-2015/16, MJB&A Analysis.
*Only the first 151 days of 2016. The clearing price for the remaining 214 days will be known in June 2013.

State-Level Challenges

Air Quality Goals

Air quality in the United States, including the northeastern states, has been improving in recent years in many respects. This has been the result of concerted efforts between state and federal air quality planners working to implement environmental laws passed by Congress and state legislatures as well as with active participation by industry and public interest groups. At the same time, an increasing body of scientific knowledge has found harmful health impacts caused by air pollution at levels below existing national health standards. These impacts are more than inconveniences – they have been linked to serious respiratory and cardiovascular effects, and even increased risk of premature death. As a result, air quality standards continue to be strengthened in light of advances in scientific understanding of the public health harms occurring at lower air pollution concentrations.

Of particular note to the northeastern states are recent or expected changes to national health standards for ground-level ozone, or smog, fine particulate matter (PM), and nitrogen dioxide (NO_2). These pollutants have been the focus of control measures for a number of years, with some success. The need for greater health protection, however, will require additional air pollution reductions. As the largest pollution sources become better controlled to meet tighter national standards, air quality planners' attention is shifting to smaller sources that are relatively uncontrolled and that represent an increasing share of harmful emissions.

A specific example is the expanding usage of diesel internal combustion engines that have historically been used for emergency backup generation in the event of a power failure.[65] However, as discussed above, these units have been repurposed as owners join demand response programs to receive financial compensation for reducing electricity demand from the grid. For air quality planners, this is most immediately a concern on high electric demand days (HEDD). These days may be few in number over the course of a summer (or several summers), but high electricity demand days typically correlate with the highest temperature days as a result of more air conditioner usage. This is a concern because these hot, stagnant, sunny days are also the most meteorologically conducive for air pollution build-up across a large regional scale. Therefore, even if diesel engines operate relatively rarely on only the highest electricity demand days, their emissions on those specific days can be relatively significant and occur at the worst possible times for air pollution. These engines also have the potential to affect attainment of the 1-hour NO_2 standard, a largely localized pollutant. The increasing financial incentives for the use of diesel engines in economic demand response programs threatens to undermine successful efforts to date in reducing air pollution and impede states from achieving increasingly more health-protective air quality standards in the future.

Regional Air Pollution Transport

The Northeast U.S. is subject to air pollutant transport contributing to ground-level ozone and fine particulate problems that occurs across large distances. Scientific studies of the regional transport problem have uncovered a rich complexity in the interaction of meteorology and

[65] This section focuses on diesel-powered generators given their higher emissions profile than natural gas-fired engines.

topography with pollutant formation and transport.[66] Large scale high pressure systems covering hundreds of thousands of square miles are the source of classic severe pollution episodes in the eastern United States, particularly in summer. These large, synoptic scale systems create particularly favorable conditions for the oxidation of precursors that lead to ground-level ozone and fine particulates. The systems move from west to east across the United States, bringing air pollution emitted by large coal-fired power plants and other sources located outside the Northeast into the region. This then adds to the pollution burden within the Northeast on days when the region's own air pollution sources are themselves contributing to poor air quality. At times, the high pressure systems may stall over the East for days, creating particularly intense air pollution episodes. The high pressure systems transporting polluted air into the Northeast are also characteristically associated with hot, stagnant, sunny conditions, the same conditions leading to increased electricity demand.

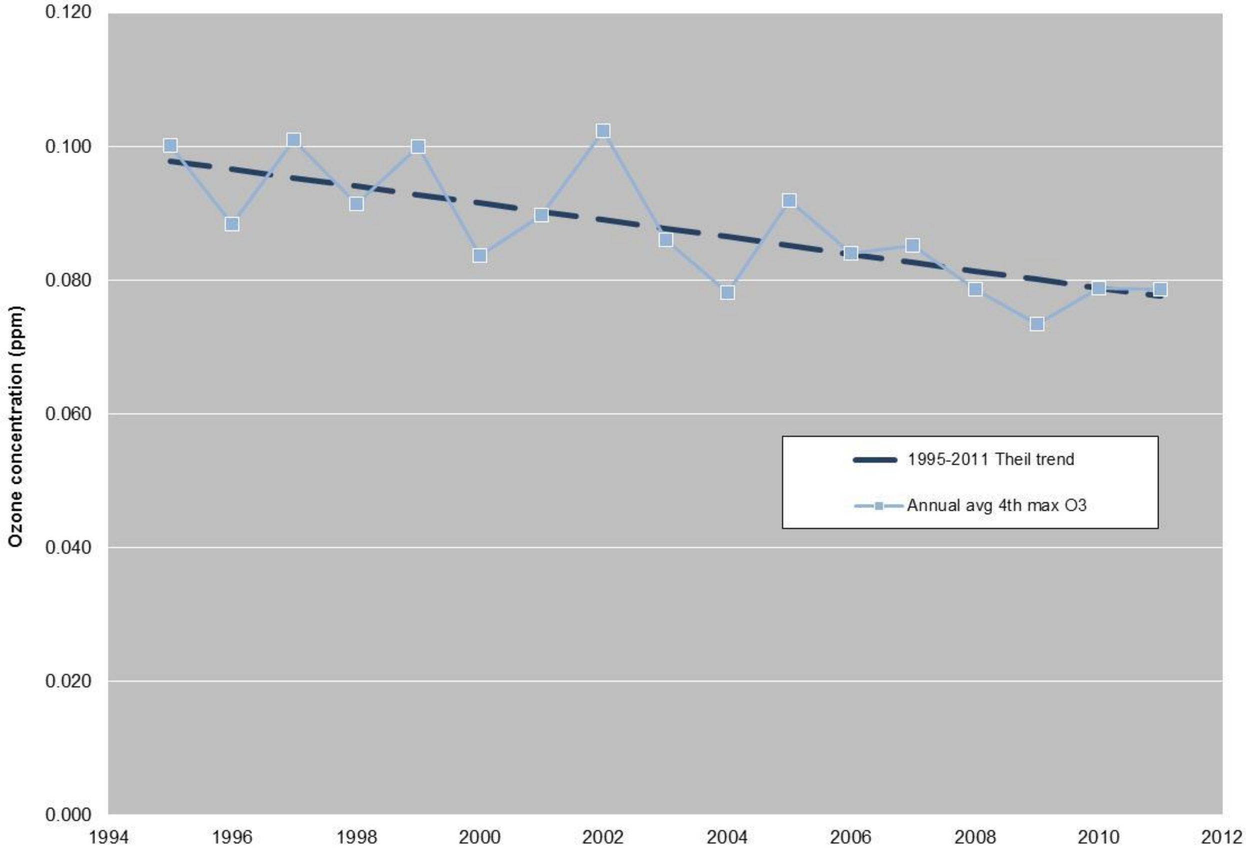
Ground-Level Ozone

Ground-level ozone affects public health throughout the Northeast. Ozone reacts with lung tissue, causing short- and long-term lung damage and reduced lung function. It can affect otherwise healthy children and adults who are very active outdoors during high ozone episodes. It places additional stress on individuals with existing respiratory illnesses such as emphysema and bronchitis, and can impair the body's respiratory system immune response. It triggers asthma attacks and aggravates existing asthmatic conditions, resulting in increased hospital emergency room visits. Recent research has found an increased risk of death from ozone exposure in compromised populations (e.g., diabetes, cardiovascular, pulmonary disease).

States in the Northeast have made significant progress in reducing exceedances of the national standards for ground-level ozone. New York City, for example, has seen a noticeable decline in the highest observed ozone concentrations over the past 15 years (Figure 9). These improvements are due to reduced emissions of the ozone precursors nitrogen oxides (NOx) and volatile organic compounds (VOCs) within the region, as well as corresponding emissions reductions in other parts of the country from which ozone and its precursors are transported into the Northeast.

[66] See, e.g., NESCAUM's 2010 reports entitled *The Nature of the Ozone Air Quality Problem in the Ozone Transport Region: A Conceptual Description*, prepared for the Ozone Transport Commission and available at http://www.nescaum.org/documents/2010_o3_conceptual_model_final_revised_20100810.pdf/) and *The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description*, available at http://www.nescaum.org/documents/2010-pm-conceptual-model-_final_revised-20100810.pdf/.

Figure 9. New York City Trend in Annual 4th-Maximum 8-hour Ozone Average, 1995-2011[67]



Note: The light blue line with markers is the plot of the observed annual fourth-maximum 8-hour ozone concentrations averaged across air monitoring sites in the New York City metropolitan area. The dashed line is a statistical fit ("Theil trend") of the monitored concentrations showing a downward trend of approximately 20 percent from 1995 to 2011.

Since the passage of the federal Clean Air Act Amendments in 1990, studies have found that health damage occurs at ozone concentrations below existing health standards. In 1997, EPA revised the national ozone standard from 0.12 parts per million (ppm) averaged over one hour to 0.08 ppm averaged over eight hours. In 2008, EPA again lowered the ozone health standard to 0.075 ppm averaged over eight hours to better reflect current scientific understanding of health impacts and as required by the Act. At the same time, however, an independent health panel created under the federal Clean Air Act recommended that a more protective ozone health standard should fall within the range of 0.060 to 0.070 ppm. EPA is now reviewing the current 0.075 ppm ozone standard for possible further tightening by 2014.

Figure 10 shows the status of ozone air monitors in the eastern U.S. relative to the current 0.075 ppm ozone standard based on monitoring data from 2009 to 2011. Orange squares and one red cross indicate monitors that measured ozone levels higher than the 0.075 ppm national health standard during this period.[68] As seen within the red oval on Figure 10, much of the densely populated Northeast Corridor experienced ozone levels above the current health standard.

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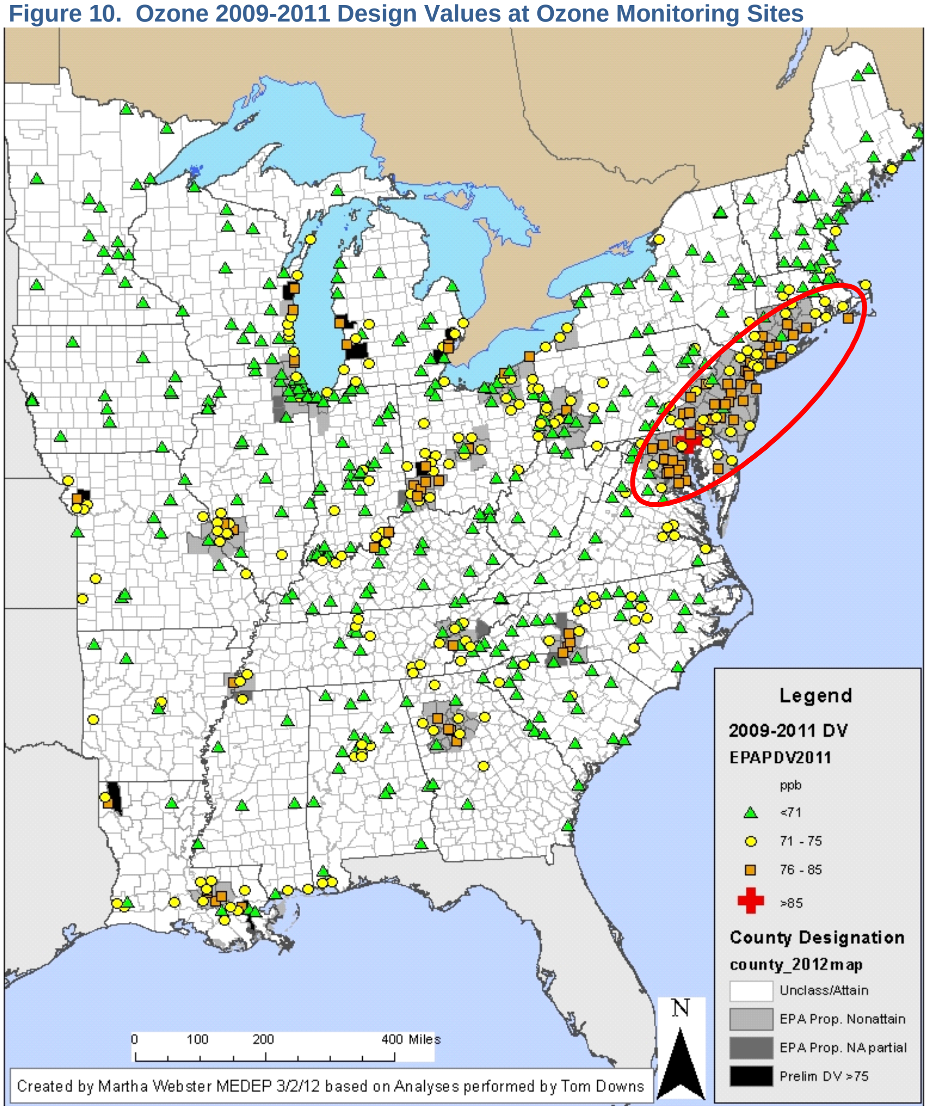
[67] An area's achievement of the federal air quality standards is calculated based on the fourth-highest daily ozone average each year.

[68] The red cross indicates a monitor in Maryland that measured ozone concentrations above the 1997 0.08 ppm ozone health standard.

Figure 10. Ozone 2009-2011 Design Values at Ozone Monitoring Sites



Source: Maine Department of Environmental Protection

Fine Particulate Matter

Fine particulate matter (PM) poses a significant risk to human health due to its ability to penetrate deep into the lungs and pass into the bloodstream. In the lungs, fine PM can irritate lung tissue, aggravate asthma symptoms, contribute to chronic bronchitis, and reduce overall lung function. In the bloodstream, fine PM can lead to heartbeat irregularities, heart attacks, and even premature death in people with cardiovascular disease. Fine PM is also a major contributor to regional haze (reduced visibility).

Fine PM levels have dropped in the Northeast overall due to reductions in direct PM emissions as well as emissions reductions of precursor pollutants[69] within the Northeast and in upwind regions.[70] Despite success in reducing fine PM concentrations, however, the greater New York

[69] PM is both emitted directly as well as formed in the ambient air from precursor pollutants including NOx and SO_2.

[70] Similar to ozone, PM is also transported long distances and thus air quality in the NESCAUM region depends on local emissions as well as those in the Midwestern and Southern U.S.

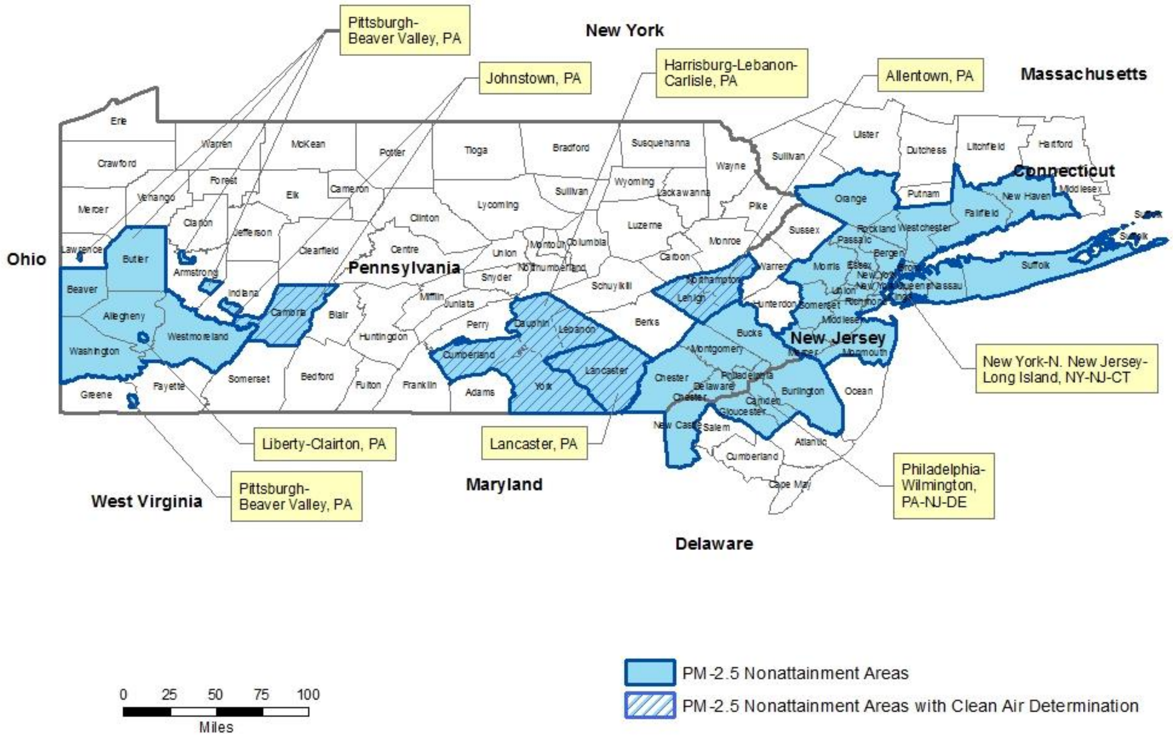
City area continues to pose a challenge for air quality managers, and remains in nonattainment of the current standards.

Particulate matter standards have long been a part of national efforts to improve air quality. The first fine PM standards were introduced in 1997 as the connections between fine PM and respiratory and pulmonary health effects became clearer. The 1997 standards were set at a level of 65 micrograms per cubic meter (μg/m^3) for a daily average[71] and an annual average of 15 μg/m^3.[72] In 2006, the daily limit was lowered to 35 μg/m^3 and the 1997 annual limit was retained.[73] Most areas in the Northeast are in attainment of the 2006 fine PM standards, with the exception of the Pittsburgh-Beaver Valley, PA area; the Philadelphia, PA-Wilmington, DE area; and the greater New York City metropolitan area. Figure 11 shows areas in Connecticut, Delaware, New Jersey, New York, and Pennsylvania that do not attain the fine PM standards as of March 2012.[74]

Air quality planners expect that if current progress continues, all areas of the Northeast should meet the 2006 fine PM standards by 2015. As with ozone, however, research advances have discerned health impacts at fine PM concentrations below the current federal standards. In recognition of this, EPA has proposed revising the annual standard from 15 μg/m^3 to within the range of 12 to 13 μg/m^3 while retaining the current 24-hour standard at 35 μg/m^3. The EPA is also proposing a separate 24-hour PM standard for visibility protection.[75] As the result of a court order, EPA has negotiated a legal consent agreement to finalize revisions to the PM standards by December 14, 2012.[76]

[71] Attainment based on the 98th percentile of monitored values over three years.
[72] Attainment based on a three-year average.
[73] However, in 2009, the D.C. Circuit remanded the annual standard to EPA for the Agency to either revise or adequately justify setting the standard outside the range recommended by CASAC.
[74] Areas shown as nonattainment with clean air determinations means that monitors in the area show attainment but the process to redesignate the area as attainment is not yet complete.
[75] 77 FR 38890.
[76] *American Lung Association v. U.S. EPA*, Civil Action No. 1:12-cv-00243-RLW (D.D.C.).

Figure 11. Nonattainment areas for the 2006 fine PM standards in Connecticut, Delaware, New Jersey, New York, and Pennsylvania



Source: EPA. Pennsylvania, New York, New Jersey, Connecticut, Delaware PM-2.5 Nonattainment Areas (2006 Standard). July 20, 2012. Available at http://www.epa.gov/oaqps001/greenbk/panynjctde25b.html. Accessed July 31, 2012.

Nitrogen Dioxide (NO_2)

Nitrogen dioxide (NO_2) is a highly reactive reddish brown gas that forms quickly from oxidation of nitric oxide (NO) emitted by stationary diesel engines, as well as cars, trucks and buses, power plants, and off-road equipment. In 2010, EPA established a new national NO_2 health standard at 100 parts per billion (ppb) averaged over 1 hour, based on a 3-year average of the annual 98th percentile of hourly concentrations.[77] Sub-daily short-term exposure to NO_2 can cause an array of respiratory problems, including increased asthma symptoms, more difficulty controlling asthma, and an increase in respiratory illnesses and symptoms. Children, the elderly, and asthmatics are particular sensitive populations.[78]

The new 1-hour standard supplements the pre-existing NO_2 standard set at an annual mean of 53 ppb, which all areas of the country currently meet. For the new 1-hour NO_2 health standard, EPA classifies all areas of the country as "unclassifiable/attainment," meaning that EPA believes available information does not indicate any areas violate the standard. NO_2 concentrations, however, can be highly localized near NO_2 sources, and these levels may not be readily observed with the current national air monitoring network.[78] In a recent screening analysis by the Delaware Department of Natural Resources and Environmental Control (DNREC), modeling of a single uncontrolled Tier 0 diesel RICE suggested that it could exceed the new 1-hour NO_2

[77] 75 FR 6474.
[78] 77 FR 9532.

health standard when considering the existing background. Emissions from multiple diesel RICE in close proximity could exceed the 1-hour NO_2 standard regardless of background.[79]

Diesel Exhaust

Exposure to diesel PM has been linked to increased cancer and non-cancer health risks. EPA considers diesel exhaust a likely human carcinogen via inhalation.[80] The California Air Resources Board (CARB) has listed diesel exhaust as a chemical known to cause cancer and has developed quantitative factors for estimating cancer risk from exposures.[81] In June 2012, the International Agency for Research on Cancer, which is part of the World Health Organization, classified diesel exhaust as a known human carcinogen (Group 1) based on an increased risk for lung cancer.[82] Short-term exposures may cause lung irritation and exacerbation of asthma or allergies, while chronic exposures may result in lung cancer or lung damage.[83]

Recent rulemakings, including a 2007 diesel particulate emission standard and a 2010 diesel NOx standard, have spurred the development of new technologies that reduce emissions of diesel PM and other harmful pollutants by approximately 90 percent. Results from a recent study on laboratory rats and mice suggest that post-2007 diesel engine exhaust has much lower PM levels and associated health impacts.[84] While newer diesel engines have emissions that may lead to fewer health impacts, many older diesel engines, including those used for emergency backup generation, remain in place and represent a significant potential source of diesel emissions should their activity levels increase through demand response programs.

Figure 12 and Figure 13 demonstrate the local impact of diesel PM from a single diesel emergency generator. Figure 12 shows daily profiles of diesel exhaust (measured as black carbon PM) averaged over 23 weeks at a downtown urban site in Boston for weekdays, Saturdays, and Sundays. The profiles reveal that an emergency diesel generator (exact location unknown) close to the monitoring location is tested on Saturdays at 11 a.m. The early morning maxima for all days, followed by decreases for the remainder of the day, likely reflects mobile source diesel exhaust that dissipates after the early morning rush hours.

[79] A. Mirzakhalili, Director, DNREC Division of Air Quality. *Air Quality Impacts of Diesel Generators Participating in Electricity Peak Shave and Demand Response Programs.* Presentation to the Mid-Atlantic Distributed Resources Initiative Work Group (MADRI), Washington, DC, June 8, 2012. Available at http://sites.energetics.com/madri/pdfs/Mirzakhalili_20120607.pdf. Accessed June 25, 2012.

[80] EPA. *Integrated Risk Information System (IRIS): Diesel engine exhaust*. February 28, 2003. Available at http://www.epa.gov/iris/subst/0642.htm.

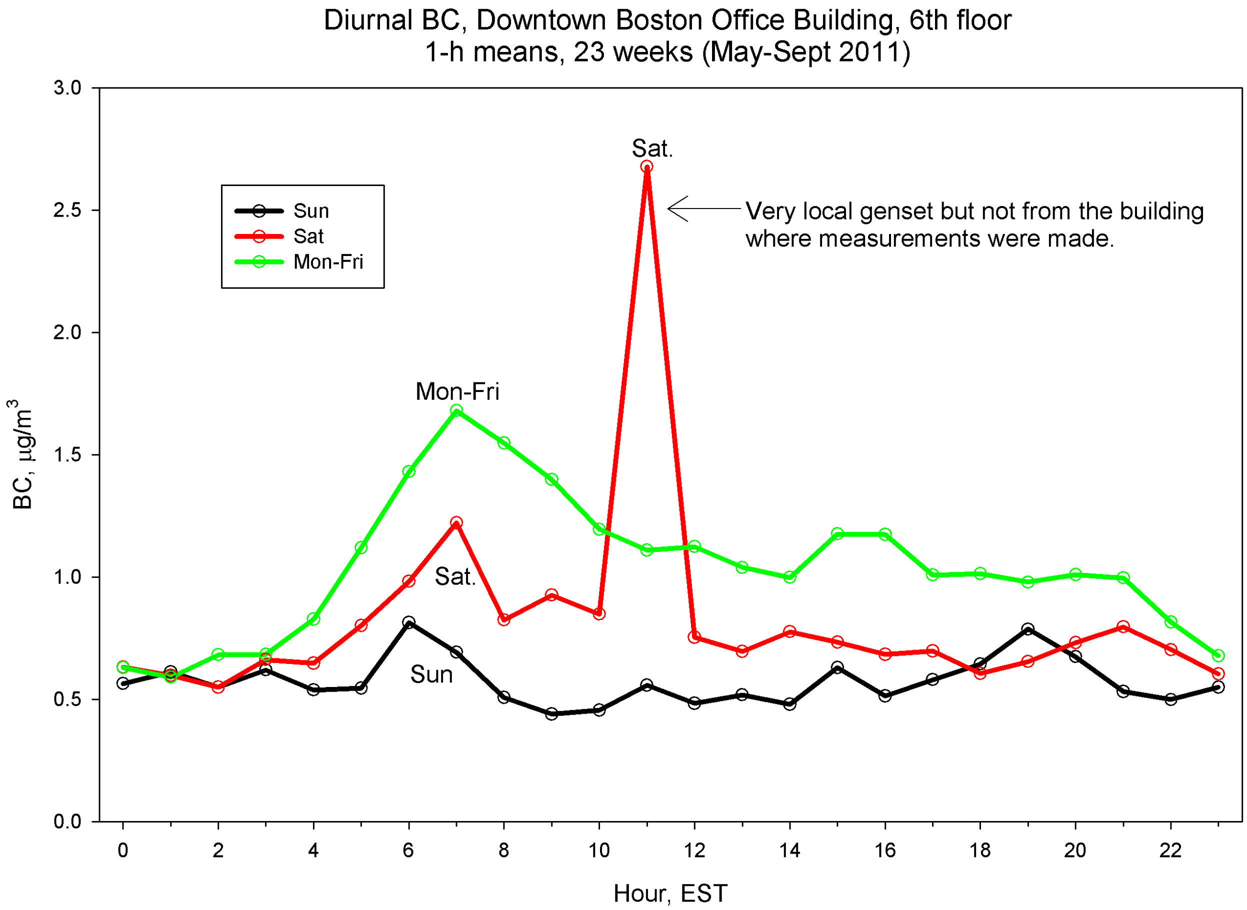
[81] California Environmental Protection Agency, Office of Environmental Health Hazard Assessment. *Technical Support Document for Cancer Potency Factors*. 2009. Available at http://www.oehha.ca.gov/air/hot_spots/2009/TSDCancerPotency.pdf.

[82] International Agency for Research on Cancer, World Health Organization. *IARC: Diesel Engine Exhaust Carcinogenic* (Press Release No. 213). June 12, 2012. Available at http://press.iarc.fr/pr213_E.pdf.

[83] EPA. *Health Assessment Document for Diesel Engine Exhaust* (EPA/600/8-90/057F). Prepared by the National Center for Environmental Assessment, Washington, DC, for the Office of Transportation and Air Quality. 2002.

[84] Advanced Collaborative Emissions Study (ACES). *Advanced Collaborative Emissions Study Subchronic Exposure Results: Biologic Responses in Rats and Mice and Assessment of Genotoxicity* (Research Report 166). 2012. Health Effects Institute, Boston, MA. Available at http://pubs.healtheffects.org/getfile.php?u=709.

Figure 12. Weekday, Saturday, and Sunday daily black carbon PM profiles for a site in Boston



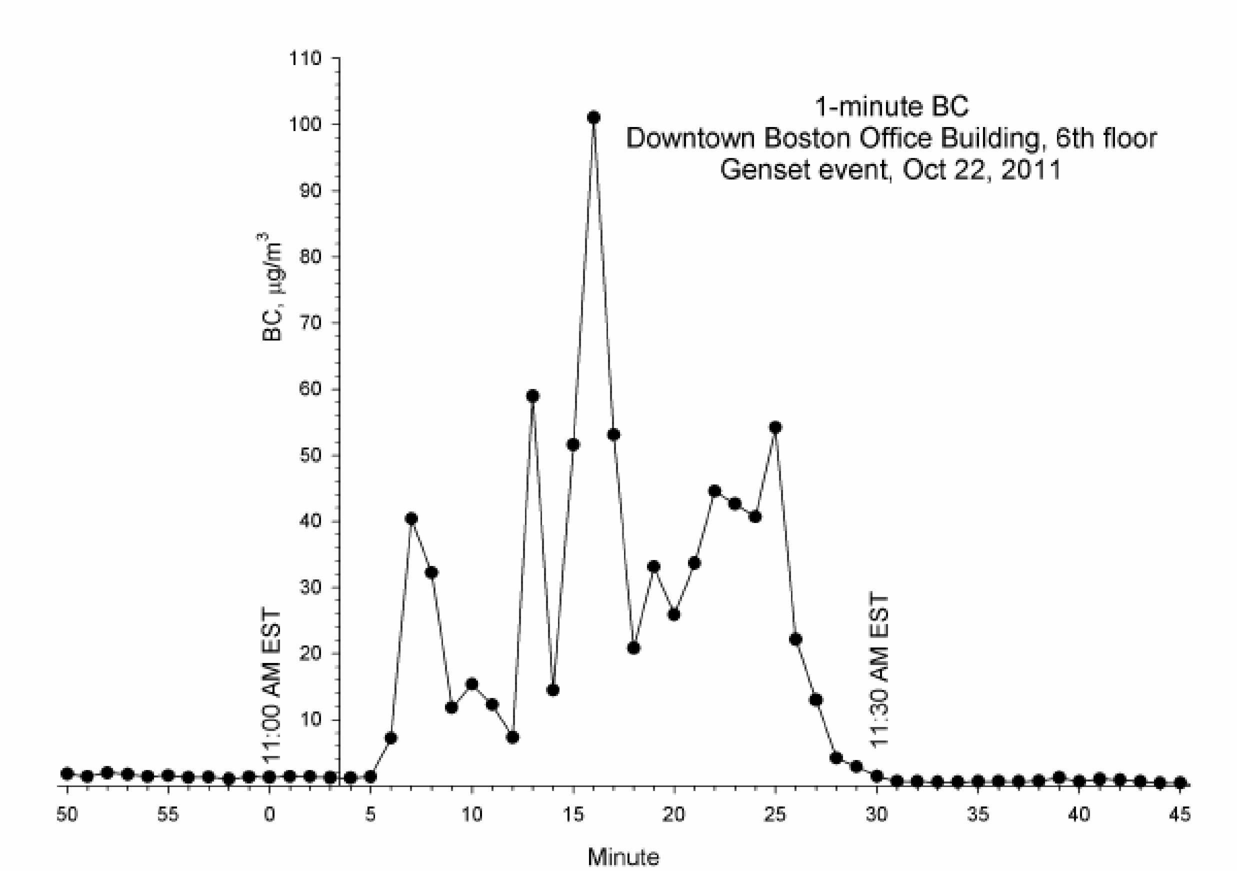
Source: Northeast States for Coordinated Air Use Management (NESCAUM)

Figure 13 displays 1-minute profiles of black carbon PM during a single Saturday afternoon peak. It clearly shows that the diesel generator operates for twenty minutes and that the maximum one-minute spike exceeds 100 µg/m^3. This illustrates the potential public health threat of multiple diesel generation sets if called upon to meet peak demand within a heavily populated urban core. Air quality modeling by DNREC[85] and studies appearing in the peer-reviewed scientific literature[86] also indicate the potential for $PM_{2.5}$ increases at levels of concern for public health from backup diesel generators operating in peak demand response programs.

[85] A. Mirzakhalili, Director, DNREC Division of Air Quality. *Air Quality Impacts of Diesel Generators Participating in Electricity Peak Shave and Demand Response Programs.* Presentation to the Mid-Atlantic Distributed Resources Initiative Work Group (MADRI), Washington, DC, June 8, 2012. Available at http://sites.energetics.com/madri/pdfs/Mirzakhalili_20120607.pdf. Accessed June 25, 2012.

[86] Gilmore, E.A., P.J. Adams, and L.B. Lave. *Using Backup Generators for Meeting Peak Electricity Demand: A Sensitivity Analysis on Emission Controls, Location, and Health Endpoints*. *J. Air & Waste Manage. Assoc. 60, 523-531, doi:10.3155/1047-3289.60.5.523* (2010); *see also* Gilmore, E.A., L.B. Lave, and P.J. Adams. *The Costs, Air Quality, and Human Health Effects of Meeting Peak Electricity Demand with Installed Backup Generators*. *Environ. Sci. Technol.* 40, 6887-6893, doi:10.1021/es061151q (2006).

Figure 13. Fine timescale black carbon PM readings for an event at a site in Boston



Source: Northeast States for Coordinated Air Use Management (NESCAUM)

Emissions Estimates

NOx emissions from the electric generating sector are highly variable on a day-to-day basis in the Northeast. For example, Figure 14 shows daily NOx emissions (bars) from electric generating units (EGUs) in New Jersey and downstate New York during the summer of 2011. The figure also shows the daily maximum temperatures recorded at Newark, New Jersey. The figure clearly shows a generally positive relationship between daily maximum temperatures and EGU NOx emissions, consistent with increased air conditioning loads on the hottest days.

The height of the stacked bars indicates the daily total NOx emissions from EGUs in the region. Over the 2011 time period shown in Figure 14, the average daily EGU NOx emissions are 62.6 tons. By comparison, EGU NOx emissions in this region over the same time period in 2002 averaged 286.5 tons per day.[87] While EGU NOx emissions have decreased significantly since 2002, the high day-to-day variability remains, with the 2011 period having eight days with more than double the average summer day NOx emissions. The days with the highest EGU NOx emissions coincide with the warmest days.

[87] NESCAUM. *High Electric Demand Day and Air Quality in the Northeast*. 2006. Available at http://www.nescaum.org/documents/high-electric-demand-day-and-air-quality-in-the-northeast/final-white-paper-hi-electric-demand-day-06052006.pdf/.

Figure 14 further segments EGU NOx emissions according to the fossil fuel used to generate electricity. The bars divide the emissions by the primary unit fuel type: utility diesel[88] (purple), residual oil (green), natural gas (red), and coal (blue). The days with the highest NOx emissions from diesel-fired EGUs (on both a relative and absolute basis) are the same as the days with the highest overall emissions. The NOx emissions from diesel EGUs on July 22 (when the maximum temperature reached 108°F in Newark, NJ) are 52.5 tons; this amount is greater than the total emissions from all fuel types on more than half the days during the entire period shown in the figure. On the low demand days, the relative contribution by diesel EGUs is very small, indicating that most of the diesel-fuel units in the area are operating largely to meet the highest peak demand loads.

Figure 14. Daily NOx Emissions Variability from EGUs in NJ and Downstate NY Based on Fuel Type

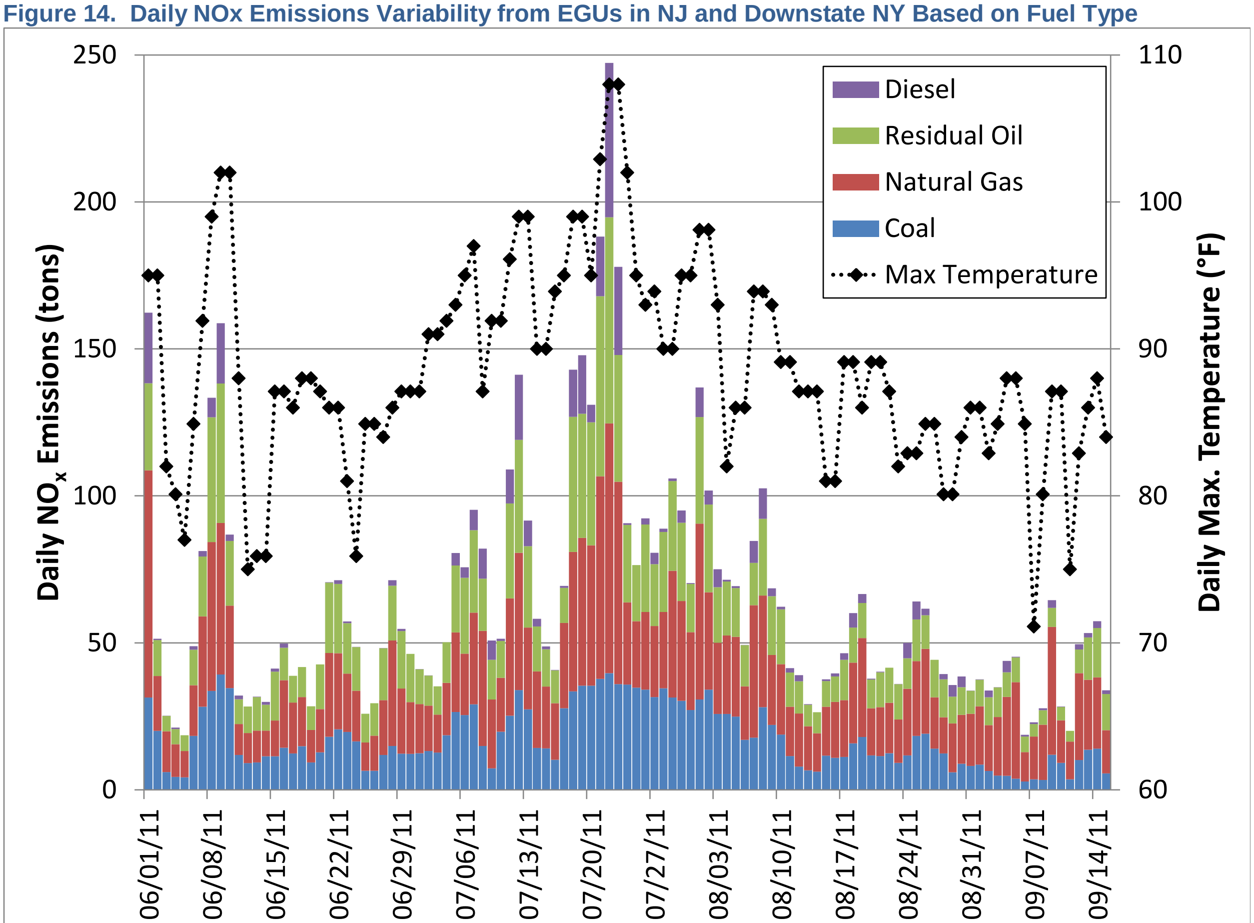


Figure notes: Stacked bars are daily EGU NOx emissions by fossil fuel type. Emissions data were obtained in April 2012 from the EPA Clean Air Interstate Rule NOx (CAIRNOx) Annual Program (http://ampd.epa.gov/ampd/). The NOx emissions are from EGUs operating in all of New Jersey and the downstate New York counties of Bronx, Kings, Nassau, New York, Orange, Queens, Richmond, Rockland, and Suffolk. The black diamond line is a plot of the maximum daily temperature recorded in Newark, New Jersey (Source: Old Farmer's Almanac, http://www.almanac.com/weather/history).

Emissions Factors for Stationary Internal Combustion Engines

Table 9 displays NOx and PM emissions factors for stationary internal combustion diesel engines on an output basis (pounds per megawatt-hour). Tier 1 through 4 emission standards

[88] This represents only EGUs' use of diesel, not the distributed generation from backup generators discussed throughout this report.

indicate increasingly stringent emission limits established by EPA beginning in 2006 for new and modified engines.[89] While new stationary diesel engines have become relatively cleaner in recent years, there remain a large number of older "pre-Tier" backup generators in place prior to the implementation of these standards. In 2003, NESCAUM estimated that the total population of diesel generators in the Northeast could include well over 30,000 units with a combined capacity exceeding 10 GW.[90] These engines historically have primarily or exclusively provided backup power in emergency (i.e., outage) situations and in some cases to reduce reliance on grid-supplied electricity during periods of peak demand. Because of their infrequent use, these engines typically remain in place for decades.

For comparative purposes, Table 9 also includes average NOx emissions rates based on historical 2010 data from fossil fuel EGUs in New Jersey.[91] These rates are sub-divided by fuel use and EGU type. The EGU type was designated by the 2010 operation hours: (1) "baseload" operated greater than 50 percent of the year; (2) "load-following" operated between 10 and 50 percent of the year; and (3) "peaking" operated less than 10 percent. The bracketed minimum and maximum values show the wide range of emissions rates across EGUs even when using the same fuel.

Only Tier 4 stationary diesel engines have NOx emission rates comparable to the EGUs operating in New Jersey. Tier 4 engines, however, are not representative of the vast majority of installed stationary diesel generators that would be called upon under demand response programs. Although NESCAUM has found it difficult to establish reliable estimates for the population and size distribution of stationary diesel engines in the Northeast,[92] it seems likely that the stock of stationary diesel engines available for demand response programs is dominated by pre-2006 ("pre-Tier") stationary engines that have the highest NOx emission rates.

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[89] 71 FR 39154.

[90] NESCAUM. *Stationary Diesel Engines in the Northeast*. 2003. Available at http://www.nescaum.org/documents/rpt030612dieselgenerators.pdf/.

[91] Emissions data provided by the New Jersey Department of Environmental Protection, April 27, 2012.

[92] NESCAUM. *Stationary Diesel Engines in the Northeast*. 2003. Available at http://www.nescaum.org/documents/rpt030612dieselgenerators.pdf/.

Table 9. Comparison of Emission Factors for Stationary Diesel Engines with New Jersey EGU 2010 Historical Emission Rates (lb/MWh)

	NOx (lb/MWh)	PM (lb/MWh)
Diesel		
pre-Tier: < 600 hp	**41.47**	**2.95**
pre-Tier: > 600 hp	**32.04**	**0.94**
Tier 1 (Phased in between 1996 and 2000)	**20.39**	**1.18**
Tier 2 (Phased in between 1999-and 2006)	**14.19**	**0.44**
Tier 3(Phased in between 2006 to 2008)	**8.87**	**0.44**
Tier 4 (Phased in between 2008 and 2014)	**0.89**	**0.04**
NJ 2010 EGUs		
Coal: Baseload	**1.62 [1.43-1.81]**	
Coal: Load Following	**2.24 [0.87-4.40]**	
Natural Gas: Baseload	**0.15 [0.05-0.27]**	
Natural Gas: Load Following	**0.41 [0.32-0.72]**	
Natural Gas: Peaking	**5.21 [0.06-25.60]**	
Residual Oil: Peaking	**2.11 [1.94-2.28]**	
Diesel Oil: Peaking	**13.10 [4.00-31.44]**	

Sources: EPA AP42; EIA, 2011; Communication from New Jersey Department of Environmental Protection (April 27, 2012)

Challenges for Air Quality

Meeting current as well as future ozone and PM standards will require that air quality managers pursue emission reductions from additional sources of NOx and PM emissions. Addressing emissions from the electric generation sector on high electric demand days will be a key component in meeting these challenges. For example, electric demand is typically highest on high temperature days in the Northeast due primarily to increased demand for air conditioning. High temperature days often are also conducive for the formation of high ozone levels. On these days, NOx emissions from electricity generation increase significantly relative to other days. Ensuring that areas meet current and future air quality standards will require more effective and innovative approaches for generating sources operating mainly on high demand days. Historically, these types of generators have not been subject to NOx and PM controls because of their limited use and relatively low total seasonal emissions. This rationale breaks down, however, when looking at the sources' contributions on the most important smog-forming days as well as their expanding usage.

Reducing emissions from small diesel generators used in demand response programs is complicated by the fact that these sources are widely distributed and difficult to identify. Because the sources are relatively small and originally dedicated for backup emergency generation only, they have not always needed to obtain operating permits. In addition, the frequency and duration of deployment periods for these types of generators when used as demand response resources are difficult to estimate because their activity levels have not historically been reported. But, with the financial incentives now available to these resources, one can expect the usage of these resources to increase. As a result, air quality managers will not have complete knowledge about their locations and activity levels when used in demand response programs, making it difficult to assess the extent of their emissions impact on peak demand days and apply emissions restrictions where necessary. However, given the substantial differences in emissions between these backup diesel generators and other generators, there is the potential that the emissions impact and thus health impact could be significant, as discussed below.

Air Quality Impact Analysis

Overview of Goals and Data Limitations

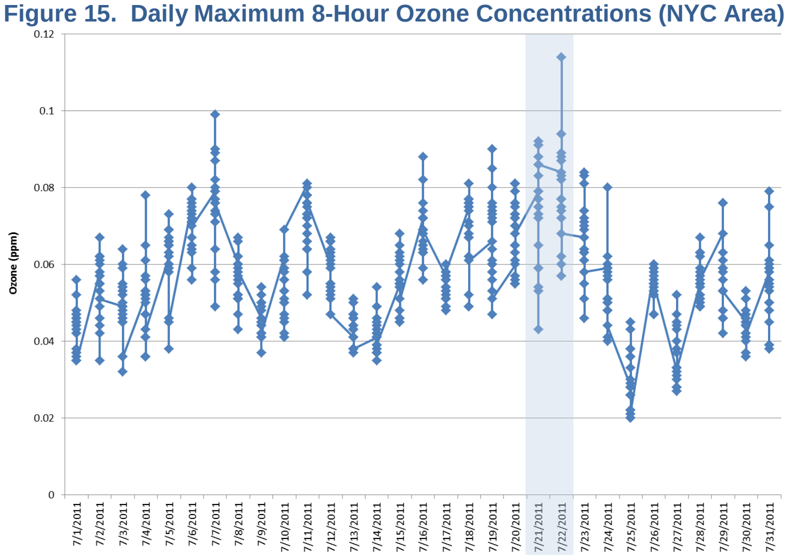
As noted previously, limited data are available with regard to the number and location of small stationary engines or their participation in economic demand response programs. As an illustration, in the preamble to the Agency's proposal to increase these engines' allowable participation in demand response programs, EPA notes that the Agency "does not have specific information about the location of the stationary RICE affected by this rule."[93]

Below, we estimate the air quality impacts of these engines' participation in demand response programs during an event in 2011. We also touch on the potential long-term impacts of these units' participation. See Appendix C for detailed information regarding the assumptions and sources used for estimating the impacts of backup generators in demand response events.

Demand Response Events

In this section, we estimate the air emissions impact of using backup generators as demand response resources on two recent high-electric demand days: July 21 and 22, 2011. Electric loads soared in the NESCAUM region on these days when high temperatures were recorded throughout the Northeast. All three ISOs in the NESCAUM region dispatched demand resources – NYISO on July 21 and 22, and PJM and ISO-NE on July 22. As shown in Figure 15, these days also coincided with the highest ozone readings that month. In fact, the highest ozone level recorded in the New York City metropolitan area in 2011 occurred on July 22.[94]

Figure 15. Daily Maximum 8-Hour Ozone Concentrations (NYC Area)



Source: U.S. EPA AirData. Available at http://www.epa.gov/airdata. Accessed June 2012.

[93] 77 FR 33831.

[94] EPA AirData. Accessed June 2011. Available at http://www.epa/gov/airdata.

In order to estimate the air quality impact of operating backup generators as part of demand response resources, particularly on poor air quality days, we obtained information from ISO demand response reports and estimated emissions associated with varying percentages of assumed backup generation participation in these events on July 21 and 22, 2011.

NYISO

NYISO deployed demand response resources twice in July 2011. During the first event, which occurred on July 21 from 1:00 pm to 6:00 pm, CSPs deployed an average of 666 MW of demand response resources per hour in the New York City region. These resources provided over 3,300 MWh of estimated load reductions.

NYISO called for a second deployment of demand response resources from 12:00 pm to 6:00 pm in NYC and from 1:00 pm to 6:00 pm in all other load zones except northern New York State on July 22 when peak load reached 33,865 MW. During this second deployment, an average of 1,417 MW of demand response resources responded per hour statewide, resulting in total load reductions of 7,500 MWh.

PJM

The PJM Interconnection experienced a new all-time peak demand of 158,450 MW on July 21, 2011. Despite the record load, the ISO did not call a load management event. However, more than 90 MW of demand response resources provided load reduction due to high real-time energy prices.

On July 22, 2011, PJM activated a load management event in six zones. Responding resources achieved a reduction of approximately 2,000 MW combined.[95] During the July 22 event, demand response resources reduced over 13,700 MWh of load in PJM; however, only about 7 percent (987 MWh) of these reductions came from sources within the NESCAUM region through reductions with the territory of Jersey Central Power & Light (JCPL). An additional 4,921 MWh (36 percent) of reductions were achieved in zones immediately upwind of NESCAUM states, within the territory of PECO and METED. Table 10 below provides the load management event details by zone and an estimate of the total demand reduced.

Table 10. July 22, 2011, PJM Load Management Event by Zone

PJM Zone	Approximate Event Duration	Reduction MW	MWh*
BGE	12:00 – 6:00 p.m.	962	5,772
DPL	1:00 – 8:00 p.m.	128	896
DUQ	1:00 – 8:00 p.m.	163	1,141
JCPL	1:00 – 8:00 p.m.	141	987
METED	1:00 – 8:00 p.m.	206	1,442
PECO	1:00 – 8:00 p.m.	497	3,479
Total		**2,097**	**13,717**

Source: PJM, Load Management Performance Report – 2011/2012. MJB&A Analysis.
*We assume that the MW reduction is in place for the entire duration of the event. However, this may not necessarily be the case and would result in an overestimation of the MWh.

95 PJM. Load Management Performance Report 2011/2012. Available at http://pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/load-management-performance-report-2011-2012.ashx. Accessed June 2012.

ISO-New England

ISO-NE called 643 MW of Real-Time Demand Response resources on July 22 and estimated that actual reductions totaled 663 MW.[96] ISO-NE did not call Real-Time Emergency Generation resources; therefore backup emergency generators that are air permit-restricted were not called.[97]

Emissions Estimates

Due to the lack of publicly available data on demand response resources, estimating potential emissions from engines that may participate in these programs requires making several key assumptions. For NYISO events, we utilized NYISO-reported data on generator enrollment in its demand response programs. For PJM events, we created three scenarios based on different levels of engine penetration ranging from 15 to 50 percent. We do not estimate emissions associated with ISO-NE's dispatch of RTDR resources in this section given that any generation resources enrolled in RTDR are likely permitted and have emissions controls. The following estimates for NYISO and PJM assume that the average participating generator has emissions rates similar to a pre-2000 vintage engine greater than 600 horsepower (hp).

July 21 NYISO Event Emissions Estimates

We estimated NOx and PM emissions associated with the demand response resources that operated during the NYISO demand response event on July 21. Depending on the resources that responded on July 21, demand response resources called during the July 21 event could have contributed almost 11 tons of NOx and 0.31 tons of PM.

As discussed above, the July 21 event was only called for NYISO zones in close proximity to New York City. Therefore, the emissions would be concentrated within the metropolitan area, which is already in nonattainment for both $PM_{2.5}$ and ozone.

July 22 NYISO Event Emissions Estimates

We estimated the NOx and PM emissions associated with the demand response resources that operated during the NYISO demand response event on July 22. Depending on the resources that responded on July 22, demand response resources called during the July 22 event could have contributed over 15 tons of NOx and 0.45 tons of PM.

Table 11 estimates NOx and PM emissions associated with varying levels of backup generators making up the demand response resources that operated during the PJM demand response event on July 22. As the table illustrates, demand response resources called during the July 22 event could have contributed between 33 and 110 tons of NOx and between 1 and 3.2 tons of PM in PJM.

Table 11. Estimated Emissions – PJM (July 22, 2011 Demand Response Event)

Pollutant	15% Penetration	25% Penetration	50% Penetration
NOx (tons)	33.0	54.9	109.9
PM (tons)	1.0	1.6	3.2

Source: NESCAUM and MJB&A Analysis.

[96] ISO-NE. Semi-Annual Status Report on Load Response Programs of ISO New England Inc. December 30, 2011. Available at http://www.iso-ne.com/regulatory/ferc/filings/2011/dec/er03-345-000_-12-30-11_semi-annual_load_resp_rprt.pdf.
[97] *Ibid*.

Approximately 43 percent of these potential emissions would have been from generators located in or immediately upwind of nonattainment areas in New York and New Jersey. Thus, while these engines' emissions are relatively minor when viewed over the course of a year (see Figure 15), they may significantly contribute to elevated levels of harmful pollutants on the days when emissions have the most impact on air quality. As discussed above, it only takes a few days per year of high localized emissions and poor air quality to tip an area into nonattainment, with the attendant region-wide costs to public health and the economy.

While the emissions impact is potentially large, it is important to note that these ranges are just estimates, given the lack of publicly available data. In addition to being sensitive to the level of generator participation, emission estimates are also sensitive to the assumptions regarding the types of generators used and the controls installed. If the average engine were assumed to meet EPA's Tier 2 standard, which began to phase in for 2001, potential emissions would decrease by more than 50 percent. The variability of these estimates once again highlights the need for greater transparency in the demand response market and emission control requirements for participating engines.

Potential Long-Term Impacts

An indirect but potentially significant consequence of expanding usage of backup generators in demand response programs is the displacement of other potentially lower-emitting demand- and supply-side resources that would otherwise be selected in capacity markets to serve a region's future power needs. Each megawatt that clears—is selected in—a capacity market necessarily displaces alternative potential resources. Thus, the resources that clear the capacity market partially determine the generation mix of the electricity market and air pollution emissions over time.

Other demand-side resources effectively represent an emission rate of zero and therefore provide an overall air quality benefit associated with reduced demand for electricity. New supply-side generation resources are subject to emissions and operational permit limitations. For example, new natural gas-fired combustion turbines and natural gas combined cycle facilities are highly controlled and have very low emission rates.[98] Also, the resources selected to serve future capacity needs will also vary in terms of their operational characteristics. A new combined cycle power plant would be available throughout the year and is able to provide other services to maintain reliable operations of the transmission system. Backup generators would only be available for a limited number of hours each year. System operators have expressed concerns that these resources may not be available if they reach their hourly limit.

In order to evaluate the long-term consequences of allowing uncontrolled diesel engines to compete in the forward capacity markets of the region, an economic dispatch model would be required that could simulate the operations of the current grid mix versus a scenario where backup generators were limited in the market and/or required to install pollution control equipment. This is beyond the scope of this study; however, we would encourage EPA to undertake such an analysis in evaluating the impacts of the proposed RICE NESHAP Rule. In PJM, the market procured almost 15,000 MW of demand-response resources in its latest forward capacity auction. A megawatt is enough electricity to power 800 to 1,000 homes. In contrast,

[98] According to EPA, emission rates for new natural gas combined cycle facilities are 0.09 lb NOx/MWh and 0.0041 lb SO_2/MWh.

almost 2,000 MW of new generating capacity and more than 5,000 MW of additional demand resources failed to clear the auction. Evaluating these market dynamics is critical to understanding the longer-term environmental implications of allowing uncontrolled diesel engines to compete in the region's forward capacity auctions.

Observations and Recommendations

In light of the identified information gaps and public health concerns described in this report, we make the following observations and recommendations that can help address these issues.

Observations

- Air quality planners are challenged in addressing emissions from uncontrolled engines due to the lack of information on the locations of these sources, the times at which these sources may operate, the public's exposure to increased levels of diesel exhaust from these sources, and the resulting public health harms from the increased exposure.
- Preliminary screening analyses indicate that uncontrolled diesel backup generators operating under the exemption included in EPA's recent proposal could by themselves create hotspots exceeding the national health-based 1-hour NO_2 air standard.
- Increased utilization of uncontrolled diesel backup engines in economic demand response programs such as peak shaving may hinder areas from maintaining or achieving national air quality standards. Even though the proposed exemption for such use may be temporary, if usage over the next five years causes an area to violate or fail to attain a standard, that area will face additional years of planning and control requirements as a result of the interim increase in emissions from use of backup generators in non-emergency situations.
- In addition to the short-term emissions impacts, there may also be longer term impacts with regard to future resource mixes in the electricity markets. An economic dispatch model to simulate the operations of the current grid mix versus a scenario where backup generators were limited in the market and/or required to install pollution control equipment would aid air quality planners to understand the potential for broader impacts and emission trends over time.
- Several NESCAUM states have been seeking to address emissions on high electric demand days, including regulation of peaking units. These regulations are resulting in the installation of pollution controls as well as unit shutdowns. Policies that permit the use of uncontrolled diesel-fired backup generators in economic or price-responsive demand response programs impede the progress that states are making to address electric sector emissions.

Recommendations

- ISOs should have the authority to collect information on the source of demand response resources from aggregators and other market participants. To improve transparency, ISOs should provide a breakdown of the resources in their demand response programs by zone similar to NYISO's approach. In addition to being necessary to accurately determine their impact, it would be important for the system operator to know what comprises system resources in order to ensure a reliable system.

- ISOs should consider separating backup generation resources into a stand-alone demand response program category similar to ISO-NE to better track their utilization for peak shaving and emergency demand response.
- The Environmental Protection Agency (EPA) should require the use of ultra-low sulfur diesel for all backup diesel engines that participate in demand response programs, similar to the existing requirements in most NESCAUM states.
- States and EPA should identify a reasonable timeframe for phasing out the participation of the oldest, dirtiest diesel engines in demand response programs.
- Operators and aggregators of engines seeking to participate in economic or price-responsive demand response programs while remaining classified as emergency engines and thereby avoiding air pollution emissions standards should register and enroll engines directly with the relevant ISO and air quality agency; other indirect operation should be considered peak shaving and subject to air pollution emissions standards.
- Owners of backup diesel generators earning capacity revenue as electric generators in non-emergency demand response programs should be required to install appropriate pollution controls, taking into account population exposure, revenues received, control costs, and any other relevant factors.

Appendix A: State Emergency Engine Regulations

A summary of NESCAUM states' regulations covering emergency backup generators is provided below.

<table>
<tr><th>State</th><th>Summary of Regulation</th></tr>
<tr><td>Connecticut</td><td>
Regulations of Connecticut State Agencies (RCSA) section 22a-174-22(a)(3)
"Emergency engine" means a stationary reciprocating engine or a turbine engine which is used as a means of providing mechanical or electrical power only during periods of testing and scheduled maintenance or during either an emergency or in accordance with a contract intended to ensure an adequate supply of electricity for use within the state of Connecticut during the loss of electrical power derived from nuclear facilities. The term does not include an engine for which the owner or operator of such engine is party to any other agreement to sell electrical power from such engine to an electricity supplier, or otherwise receives any reduction in the cost of electrical power for agreeing to produce power during periods of reduced voltage or reduced power availability.
RCSA section 22a-174-22(a)(4)
"Emergency" means an unforeseeable condition that is beyond the control of the owner or operator of an emergency engine and that:
(A) Results in an interruption of electrical power from the electricity supplier to the premises;
(B) Results in a deviation of voltage from the electricity supplier to the premises of three percent (3%) above or five percent (5%) below standard voltage in accordance with subsection (a) of section 16-11-115 of the Regulations of Connecticut State Agencies;
(C) Requires an interruption of electrical power from the electricity supplier to the premises enabling the owner or operator to perform emergency repairs;
(D) Requires operation of the emergency engine to minimize damage from fire, flood, or any other catastrophic event, natural or man-made; or
(E) Notwithstanding section 22a-174-22(a)(3) of the Regulations of Connecticut State Agencies, requires operation of the emergency engine under an agreement with the New England region system operator during the period of time the New England region system operator is implementing voltage reductions or involuntary load interruptions within the Connecticut load zone due to a capacity deficiency.
RCSA section 22a-174-3a -Permit required for new or modified emission unit if potential emissions of individual air pollutant ≥ 15 tons per year.
RCSA section 22a-174-3b(e) – In lieu of obtaining a permit under RCSA section 22a-174-3a, the owner of an emergency engine may operate under this permit-by-rule if the owner limits operation to less than 300 hours per year (no non-emergency operation) and uses fuel with a sulfur content ≤ 15ppm. No state notification is required but owners are responsible for recordkeeping.
RCSA section 22a-174-3c – In lieu of obtaining a permit under RCSA section 22a-174-3a, the owner of an emergency engine may operate under this section if the owner restricts fuel purchases at the facility to 3.36 million cubic feet of gaseous fuel, 21,000 gallons of distillate fuel or 100,000 gallons of propane. Owner must maintain records of fuel purchases.
RCSA section 22a-174-42– In lieu of obtaining a permit under RCSA section 22a-174-3a, the owner of a distributed generator may operate under this permit-by-rule if the owner operates the generator to meet the restrictions on hours of operation and complies with the emissions limitations and other requirements of the regulation. Notification and recordkeeping are required.

Emissions limitations (lb/MWh):
<table>
<tr><th></th><th>Nitrogen Oxides</th><th>Particulate Matter</th><th>Carbon Monoxide</th></tr>
<tr><td>Installed prior to 1/1/05</td><td>4.0</td><td>0.7</td><td>10</td></tr>
<tr><td>Installed on or after 1/1/05</td><td>0.6</td><td>0.7</td><td>10</td></tr>
<tr><td>Installed on or after 5/1/08</td><td>0.3</td><td>0.07</td><td>2</td></tr>
<tr><td>Installed on or after 5/1/12</td><td>0.15</td><td>0.03</td><td>1</td></tr>
</table>
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<table>
<tr><th>State</th><th>Summary of Regulation</th></tr>
<tr><td>Maine</td><td>
Maine rule 06-096 C.M.R. ch. 148 “Emissions from Smaller-scale Electric Generating Sources” (http://www.maine.gov/sos/cec/rules/06/096/096c148.doc) applies to all non-mobile generators greater than or equal to 50 kW installed after January 1, 2005.
"Emergency generators" means generators used only during emergencies or for maintenance purposes, provided that the maximum annual operating hours shall not exceed 500 hours per calendar year, with a maximum of 50 hours for maintenance and testing. Emergency generators are not allowed to participate in any voluntary demand-reduction program or any other interruptible supply arrangement with a utility, other market participant, or system operator.
All diesel-powered generators must use diesel fuel with sulfur content no greater than 15 parts per million (ppm).
Depending on installation date, non-emergency generators are subject to the following emission standards:
<table>
<tr><th></th><th>Nitrogen Oxides</th><th>Particulate Matter</th><th>Carbon Monoxide</th></tr>
<tr><td>Installed on or after January 1, 2005</td><td>4.0 lb/MWh</td><td>0.7 lb/MWh</td><td>10.0 lb/MWh</td></tr>
<tr><td>Installed on or after January 1, 2009</td><td>1.5 lb/MWh</td><td>0.07 lb/MWh</td><td>2.0 lb/MWh</td></tr>
<tr><td>Installed on or after January 1, 2013</td><td>reserved</td><td>reserved</td><td>reserved</td></tr>
</table>
Combined heat and power (CHP) generators meeting heat recovery, electric energy output, and design efficiency criteria given in the rule can take a credit for heat recovered from exhaust in meeting the emission standards.
Through its 06-096 C.M.R. ch. 115 “Major and Minor Source Air Emission License Regulations,” engines greater than 5 MMBtu/hr (approximately 500 kW output) must obtain a permit. Permits are also required for smaller engines (down to a heat rate input of 0.5 MMBtu/hr, or approximately 50 kW) if they are located at a facility with a combined heat input of 5 MMBtu/hr or more. Finally, facilities with operation-specific air permits must obtain permits for any on-site engines larger than 0.5 MMBtu/hr.
ME DEP requires non-emergency engines to use on-road diesel fuel and install selective catalytic reduction (SCR) technology for NOx control if their potential annual NOx emissions exceed 20 tons as best available control technology. Emergency engines larger than 0.5 MMBtu/hr require a permit, and are restricted to no more than 500 hours of operation each year. There are no additional restrictions preventing engines from participating in demand response programs.
</td></tr>
</table>

<table>
<tr><th>State</th><th>Summary of Regulation</th></tr>
<tr><td>Massachusetts</td><td>
Emergency and non-emergency engines are subject to installation self-certification requirements and do not result in engine-specific approval.
An emergency or standby diesel or spark ignition stationary engine with a rated power output at least 37 kW installed after March 23, 2006 must comply with the applicable emission limits set by the EPA for non-road compression ignition engines (40 CFR 89) for the most recent model year up to and including the year of installation. A natural gas-fired or other spark ignition emergency engine may need add-on catalytic control to meet the part 89 emissions standard.
A diesel engine must use ultra-low sulfur fuel. There are certain stack height and modeling requirements depending on engine capacity and stack location relative to nearby buildings and sensitive receptors.
The emergency category allows operation for a total of no more than 300 hours per year, including scheduled maintenance and testing and emergency, standby operation (e.g., power outages). Emergency demand response is allowed, described as “periods during which the regional transmission organization directs the implementation of voltage reductions, voluntary load curtailments by customers, or automatic or manual load shedding within Massachusetts in response to unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or other such emergency conditions.” [These conditions conform to ISO-NE Operating Procedure 4 (Revision 11, effective 2011 Dec 9), Action 6.]
Under 310 CMR 7.26(43), a non-emergency engine with a rated power output equal to or greater than 50 kW installed after March 23, 2006 must meet the emission standards [RAP Model Rule for Distributed Generation]. As of January 1, 2012, the following took effect:
<table>
<tr><td>Pollutant</td><td colspan="2">Emission Limitation</td></tr>
<tr><td>Oxides of Nitrogen</td><td>0.15</td><td>lb/MWh</td></tr>
<tr><td>Particulate Matter (Liquid Fuel only)</td><td>0.03</td><td>lb/MWh</td></tr>
<tr><td>Carbon Monoxide</td><td>1</td><td>lb/MWh</td></tr>
<tr><td>Carbon Dioxide</td><td>1650</td><td>lb/MWh</td></tr>
</table>
A non-emergency engine in a combined heat and power (CHP application) may apply for relief from these emission limitations in the form of emission reduction credits (ERCs) calculated from the design avoided fuel combustion in an existing or new separate thermal-only unit (e.g., boiler), pursuant to 310 CMR 7.26(45).
For certain bio-fuel-fired engines, and some other categories, there is an option to submit a Plan Application for MassDEP approval. This would entail a BACT analysis and modeling, and would presumably allow a less stringent emission limit than above.
Prior to 2006, there were a variety of different rated capacity thresholds for preconstruction review or eligibility for permit-by-rule provisions.
Facilities with a combined heat input greater than 10 MMBtu/hr must file a statement of emissions at least every three years.
</td></tr>
<tr><td>New Hampshire</td><td>
New Hampshire Administrative Rule Env-A 600 (statewide permit system), Env-A 1300 (NOx RACT)
One or more engines at a source powered by liquid fuel (i.e., diesel) require a permit in New Hampshire if the combined engines have an aggregate heat rate input of 1.5 MMBtu/hr (approximately 200 horsepower) or greater (individual engines with a heat input rate less than 0.15 MMBtu/hr are excluded). A higher size threshold of 10 MMBtu/hr (1 MW output) for all engines combined applies to engines at a source that operates on gaseous or LPG fuel (individual engines with a heat input rate less than 1.5 MMBtu/hr are excluded). Additionally, if the potential of all engines is 25 tons per year of NOx or greater the engine will be subject to NOx Reasonably Available Control Technology (RACT) requirements per Env-A 1306. Non-emergency internal combustion engines with a combined heat rate input exceeding 4.5 MMBtu/hr will be subject to NOx RACT requirements per Env-A 1307.
Owners of permitted emergency generators may operate during periods in which ISO New England, or any successor Regional Transmission Organization, directs the implementation of operating procedures for voltage reductions of 5% of normal operating voltage requiring more than 10 minutes to implement, voluntary load curtailments by customers, or automatic or manual load-shedding, in response to, or to prevent the occurrence of, unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or other such emergency conditions (ISO New England Operating Procedure 4 - Action 6 and NERC Emergency Action Level 2). The emergency generators are prohibited from being used as load shaving units in peak shaving program. Emergency engines must obtain a general state permit, must operate less than a maximum of 500 hours per year, and must emit less than 25 tons per year of NOx if the theoretical potential from all devices at the facility exceed 50 tons per year NOx. If these requirements are not met, refer to Env-A 1301.02(j) and Env-A 1311 for additional NOx RACT requirements.
</td></tr>
</table>

State	**Summary of Regulation**
New Jersey	Permit applicability for engines generating electricity for new or modified is 37 kW and for existing is 148 kW or greater. Permit applicability for all other engines is a heat rate input greater than 1 MMBtu/hr (equivalent to about 100 kW output). In addition, any new or modified engine with the potential to emit more than 5 tons per year of any criteria pollutants must meet "state of the art" (SOTA) control technology requirements. The applicable SOTA performance standards for new or modified engines are 0.15 g/bhp-hr for NOx, 0.5 g/bhp-hr for CO and 0.15 g/bhp-hr for volatile organic compounds (VOC). In addition, ammonia slip is limited to 10 ppmvd @ 15% O_2. For liquid fuel firing, the particulate limit is 0.02 g/bhp-hr and the sulfur limit is 30 ppm (effective July 1, 2016, the allowable sulfur limit will be 15 ppm by weight). Meanwhile, existing engines producing electricity must also comply with minimum emissions performance requirements, specifically: (1) Rich burn NOx emissions limit of 1.5 g/bhp-hr for gaseous and liquid fuel; (2) Lean burn NOx emissions limit of 1.5 g/bhp-hr or an emission rate which is equivalent to 80 percent NOx reduction from the uncontrolled NOx emission level for gaseous fuels; (3) A NOx emissions limit of 2.3 g/bhp-hr for liquid and dual fuels; and (4) A CO emissions limit (on all engines) of 500 ppmvd at 15% O_2. New or modified engines producing electricity have to comply with NOx limit of 0.9 grams per bhp-hr. Emergency engines are exempt from NOx control requirements provided it is operated only: i. During the performance of normal testing and maintenance procedures, as recommended in writing by the manufacturer and/or as required in writing by a Federal or State law or regulation; ii. When there is power outage or the primary source of mechanical or thermal energy fails because of an emergency; or iii. When there is a voltage reduction issued by PJM and posted on the PJM website (www.pjm.com) under the "emergency procedures" menu.

State	**Summary of Regulation**
New York	The New York State Department of Environmental Conservation (NY DEC) has established a permitting threshold for IC engines located outside of any severe ozone nonattainment areas of 400 bhp (approximately 300 kW). IC engines located within any severe nonattainment areas (New York City, Long Island, and the lower Hudson Valley) a lower permitting threshold of 200 bhp (147 kW) applies. The current NYS DEC definition of an emergency power generating stationary internal combustion engine is a stationary internal combustion engine that operates as a mechanical or electrical power source only when the usual supply of power is unavailable, and operates for no more than 500 hours per year. The 500 hours of annual operation for the engine include operation during emergency situations, routine maintenance, and routine exercising (for example, test firing the engine for one hour a week to ensure reliability). A stationary internal combustion engine used for peak shaving generation is not an emergency power generating stationary internal combustion engine. Note that an engine participating in a demand response program is not considered to be an emergency engine per NYS DEC regulations. The following requirements under Subpart 227-2 (NOx RACT) apply to stationary internal combustion engines at existing major stationary sources of NOx only. The presumptive limits outlined in Subpart 227-2 are: (1) For internal combustion engines fired solely with natural gas: 1.5 grams per brake horsepower-hour. (2) For internal combustion engines fired with landfill gas or digester gas (solely or in combination with natural gas): 2.0 grams per brake horsepower-hour. (3) For internal combustion engine fired with distillate oil (solely or in combination with other fuels): 2.3 grams per brake horsepower-hour. Compliance with these emission limits must be determined with a one hour average unless the owner or operator chooses to use a CEMS under the provisions of section 227- 2.6(b) of this Subpart. (4) For stationary internal combustion engines fired primarily with fuels not listed above, the owner or operator must submit a proposal for RACT to be implemented that includes descriptions of: i) the available NO_x control technologies, the projected effectiveness of the technologies considered, and the costs for installation and operation for each of the technologies; and ii) the technology and the appropriate emission limit selected as RACT considering the costs for installation and operation of the technology. (5) Any stationary internal combustion engine may rely on an emission limit that reflects a 90 percent or greater NOx reduction from the engine's actual 1990 baseline emissions, if such emissions baseline exists. (6) Emergency power generating stationary internal combustion engines, and engine test cells at engine manufacturing facilities that are used for either research and development purposes, reliability testing, or quality assurance performance testing are exempt from the requirements of this subdivision. In general, NYS DEC issues three types of permits: (1) “Registration certificates” with a “cap-by-rule” which restricts actual NOx emissions in the area consisting of the New York City Metropolitan Area and Lower Orange County Metropolitan Area to no more than 12.5 tons per year and NOx emissions in other areas to no more than 50 tons per year; (2) state facility permits for facilities that do not qualify for a registration certificate, but whose potential to emit is lower than the threshold for Title V permits; and (3) Title V permits, if the potential to emit is higher than Title V thresholds. Additional permitting requirements may be written and enforced by the New York City Department of Environmental Protection (as distinct from the NYS DEC) for units located in New York City.

State	**Summary of Regulation**
Rhode Island	Rhode Island Air Pollution Control Regulation No. 43 "General Permits for Smaller-scale Electric Generation Facilities," May 15, 2007 (http://www.dem.ri.gov/pubs/regs/regs/air/air43_07.pdf). Rhode Island's rule for smaller-scale electric generators covers stationary internal combustion engines 50 hp or larger not subject to major source permitting requirements. Generators must obtain a minor source or general (pre-approved minor source) permit. Emergency generators must meet the appropriate Tier-level emission standards set by the US EPA for non-road engines (40 CFR 89) depending on date installed. Also, emergency generators must meet a CO_2 standard of 1,900 lb/MWh if installed on or after 5/15/07. The sulfur content of any liquid fuel burned in the emergency generator must not exceed 15 ppm by weight and for gaseous fuel not more than 10 grains of sulfur per 100 dry standard cubic feet. Visible emissions from emergency generators may not exceed 10%. Emergency generators are allowed to operate up to a maximum of 500 hours per year for maintenance, testing, and emergencies. Emergency generators shall not be operated in conjunction with any voluntary demand-reduction program or any other interruptible power supply arrangement with a utility, other market participant or system operator unless such program is implemented at the same time as ISO New England, or any successor Regional Transmission Organization, directs the implementation of operating procedures for voltage reductions, voluntary load curtailments by customers or automatic or manual load shedding within Rhode Island in response to unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels or other such emergency conditions. Generators not able to meet the General Permit requirements must obtain a minor source permit.
Vermont	Vermont Air Pollution Control Regulations adopted through September 2011 (http://www.anr.state.vt.us/air/docs/APCR%202011.pdf) Vermont requires permits for stationary IC engines of 450 bhp and greater, excluding emergency use engines (see 5-401 of Regulations). Vermont defines an "Emergency use engine" as an engine used only for emergency purposes and up to 100 hours per year for routine testing and maintenance. Emergency purposes are limited to periods of time when the usual power source is temporarily unavailable, the Independent System Operator has determined a power capacity deficiency exists (ISO-NE OP4) and has implemented a voltage reduction of 5 percent or more of normal operating voltage, or a fire or flood requires water pumping to minimize property damage. Permit amendments are required for any engine greater than 200 bhp (excluding emergency use engines) if it is to be located at any site that is classified as an air contaminant source for some other reason and already has an existing air permit. In addition to permitting requirements, all reciprocating internal combustion engines 450 bhp-hr or greater installed after July 1, 1999 (including emergency use engines installed) must meet minimum emissions standards comparable to federal requirements for non-road sources according to the date installed. Engines installed prior to July 1, 1999 (excluding emergency use engines) were required to be upgraded to meet federal Tier I non-road emission standards by no later than July 1, 2007.

Appendix B: Demand Response Program Requirements

A summary of ISO-NE demand response programs is provided below.

Name	Service Type	Minimum Resource Size	Minimum Reduction Amount	Aggregation Allowed	Backup Generation Eligible?	Primary Driver	Trigger	"Peak" Hours Only?
Real Time Demand Response Resource (RTDR)	Capacity	100 kW	1 kW	Yes	No	Reliability	Critical Peak Hours: OP4 Action 2 or higher and Forecast Peak Hours whenever Day-Ahead Forecast ≥ 95% of 50/50 Seasonal Peak forecast for the applicable season	No
Real Time Emergency Generation Resource	Capacity	100 kW	1 kW	Yes	Yes	Reliability (compensation limited to 600 MW)	Operational Procedure OP4 Action 6	No
On-Peak Demand Resources	Capacity	100 kW	1 kW	Yes	No	Reliability	On-Peak (hours ending 5:00-7:00 pm winter season, 1:00-5:00 pm summer season)	Yes
Seasonal Peak Demand Resources	Capacity	100 kW	1 kW	Yes	No	Reliability	Real time hourly load is ≥ to 90% of 50/50 system peak load forecast for the applicable season	Yes
Transitional Demand Response	Energy	100 kW	100 kW	Yes	No	Economic	Day-Ahead LMP ≥ Offer Price	Yes

Source: ISO/RTO Council, North American Wholesale Electricity Demand Response Program Comparison, December 2011.

A summary of NYISO demand response programs is provided below.

Name	Service Type	Minimum Resource Size	Minimum Reduction Amount	Aggregation Allowed?	Backup Generation Eligible?	Primary Driver	Trigger	"Peak" Hours Only?
Day-Ahead Demand Response Program	Energy	1 MW	1 MW	Yes	No	Economic	Energy Price > Offer Price (Security Constrained Unit Commitment)	No
Demand Side Ancillary Services Program	Spinning Reserve	1 MW	1 MW	No	No	Economic	Energy Price > Offer Price (Security Constrained Economic Dispatch)	No
Demand Side Ancillary Services Program	Non-Synchronous Reserve	1 MW	1 MW	No	Yes	Economic	Energy Price > Offer Price (Security Constrained Economic Dispatch)	No
Demand Side Ancillary Services Program	Regulation	1 MW	1 MW	No	No	Economic	Energy Price > Offer Price (Security Constrained Economic Dispatch)	No
Emergency Demand Response Program	Energy	100 kW (per zone)	100 kW (per zone)	Yes	Yes	Reliability	Operational Procedure	No
Installed Capacity Special Case Resources (Energy Component)	Energy	100kW (per Zone)	100 kW (per Zone)	Yes	Yes	Reliability	Operational Procedure	No
Installed Capacity Special Case Resources (Capacity Component)	Capacity	100 kW (per zone)	100 kW (per zone)	Yes	Yes	Reliability	Operational Procedure	No

Source: ISO/RTO Council, North American Wholesale Electricity Demand Response Program Comparison, December 2011.

A summary of PJM demand response programs is provided in the table below.

Name	Service Type	Minimum Resource Size	Minimum Reduction Amount	Aggregation Allowed?	Backup Generation Eligible?	Primary Driver	Trigger	"Peak" Hours Only
Economic Load Response (Energy)	Energy	100 kW	100 kW	Yes	Yes	Economic	Self-Scheduled, Cleared Day-Ahead Bid, or Real-Time Dispatch	No
Emergency Load Response - Energy Only	Energy	100 kW	100 kW	Yes	Yes	Economic	Operational Procedure	No
Economic Load Response (Synchronized Reserves)	Reserve	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure	No
Economic Load Response	Reserve	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure	No
Day ahead scheduling reserve	Reserve	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure	No
Full Emergency Load Response (Limited DR)	Capacity and Energy	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure 10 days up to 6 hours per day	Yes

Name	Service Type	Minimum Resource Size	Minimum Reduction Amount	Aggregation Allowed?	Backup Generation Eligible?	Primary Driver	Trigger	"Peak" Hours Only
Full Emergency Load Response (Extended Summer DR)	Capacity and Energy	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure Unlimited summer days up to 10 hours per day	Yes
Full Emergency Load Response (Annual DR)	Capacity and Energy	100 kW	100 kW	Yes	Yes	Reliability	Operational Procedure Unlimited days up to 10 hours per day	Yes

Source: ISO/RTO Council, North American Wholesale Electricity Demand Response Program Comparison, December 2011.

Appendix C: Demand Response Event Scenario Details

This Appendix C describes the sources and methodology used to estimate potential emissions from diesel generators that participate in demand response programs. In particular, this report selected demand response events called by NYISO, PJM, and ISO-NE from July 21 – 22, 2011.

NYISO Enrollment Details

Tables C-1 and C-2 provide enrollment data in MW by NYISO zone and resource type. NYISO requires that CSP separately report the MW of load reduction and MW of enrolled generators. However, it is important to note that historic data show that enrollment in the ICAP/SCR program and the EDRP change on a monthly basis. For example, between May 2011 and June 2011 there was an increase of 11 percent in enrolled MW in the ICAP/SCR program. In addition, there was a 70 percent increase in enrolled MW between May 2011 and July 2011 in the EDRP program.[a] However, for our analysis we assume that the percentage of generators by zone remains constant in both the ICAP/SCR program and EDRP program.

Table C-1. NYISO ICAP/SCR Enrollment by Zone (May 2011)

NYISO Zone	Number of Resources	MW of Load Reduction	MW of Enrolled Generators	Total MW	Percent Generators
A	510	384.6	5.4	390	1%
B	250	105	10.1	115.1	9%
C	322	124.2	3	127.2	2%
D	22	314.2	0.2	314.4	0%
E	156	40.5	4.1	44.6	9%
F	199	124.8	9.5	134.3	7%
G	148	57.6	6.9	64.5	11%
H	21	8.4	0.4	8.8	5%
I	129	38	3.7	41.7	9%
J	2545	340	103.5	443.5	23%
K	984	119.5	25.3	144.8	17%
Totals	**5286**	**1656.8**	**172.1**	**1828.9**	**9.4%**

Source: NYISO Semi-Annual Report on Demand Response Programs; Docket No. ER01-3001- June 3, 2011, MJB&A Analysis.

Table C-2. NYISO EDRP Enrollment by Zone (May 2011)

NYISO Zone	Number of Resources	MW of Load Reduction	MW of Enrolled Generators	Total MW	Percent Generators
A	13	0.6	9.9	10.5	94%
B	1	0	1	1	100%
C	27	3.2	11.9	15.1	79%
D	8	0.6	3.1	3.7	84%
E	26	1.1	24	25.1	96%
F	10	0.9	4.4	5.3	83%
G	13	0	17.1	17.1	100%

[a] NYISO. Docket Nos. ER01-3001-000 and ER03-647-000. June 1, 2012.

NYISO Zone	Number of Resources	MW of Load Reduction	MW of Enrolled Generators	Total MW	Percent Generators
H	3	0.3	1.5	1.8	83%
I	13	2	1.7	3.7	46%
J	22	4.6	0.5	5.1	10%
K	0	0	0	0	0%
Totals	136	13.3	75.1	88.4	85%

Source: NYISO Semi-Annual Report on Demand Response Programs; Docket No. ER01-3001- June 3, 2011, MJB&A Analysis.

July 21 NYISO Event Details

Tables C-3 and C-4 provide hourly load reduction data in MW by NYISO zone and resource type.

Table C-3. July 21, 2011, NYISO ICAP/SCR Load Management Event by Zone (MW)

NYISO Zone	HB 13[1]	HB 14	HB 15	HB 16	HB 17	Percent Generators
G	58.2	63.1	65.8	66.4	64.3	11%
H	9.8	10	10.2	10.3	10.4	5%
I	20.7	26.1	27.8	29.1	30.2	9%
J	402.6	429	438.9	449.1	465.7	23%
K	109.7	117.5	121.9	127.5	130.2	17%
Total	601	645.7	664.6	682.4	700.8	

Source: NYISO, Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs, January 17, 2012, MJB&A Analysis.

1. HB stands for "Hour Beginning" using a 24-hour clock. For example, HB 13 stands for the hour beginning at 1:00 pm and HB 17 stands for the hour beginning at 5:00 pm.

Table C-4. July 21, 2011, NYISO EDRP Load Management Event by Zone (MW)

NYISO Zone	HB 13[1]	HB 14	HB 15	HB 16	HB 17	Percent Generators
G	0.2	0.2	0.1	0	0	100%
H	0	0	0.1	0.2	0.2	83%
I	0.2	0.3	0.3	0.3	0.2	46%
J	5	5.7	6.8	7	5.5	10%
K	1.1	1.5	1.2	1.2	0.6	0
Total	**6.5**	**7.7**	**8.5**	**8.7**	**6.5**	

Source: NYISO, Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs, January 17, 2012, MJB&A Analysis.

July 22 NYISO Event Details

Tables C-5 and C-6 provide hourly load reduction data in MW by NYISO zone and resource type.

Table C-5. July 22, 2011, NYISO ICAP/SCR Load Management Event by Zone (MW)

NYISO Zone	HB 12	HB 13	HB 14	HB 15	HB 16	HB 17	Percent Generators
A		305.1	326.6	341.1	343.6	347.5	1%
B		96.5	102.4	105.4	107.5	109.7	9%
C		110.9	128.8	135.6	140.1	140.5	2%

NYISO Zone	HB 12	HB 13	HB 14	HB 15	HB 16	HB 17	Percent Generators
E		39.1	49.6	52.7	54.5	55.3	9%
F		116.2	127	130.5	135.4	133.2	7%
G		61.3	66.1	69	70	69.8	11%
H		8.7	8.8	8.8	8.9	9.0	5%
I		26.3	27.1	28	28.9	32.	9%
J	367.3	393.8	437.9	456.2	472	499.2	23%
K		96	102.8	107.9	113.1	116.1	17%
Total	367.3	1253.9	1377.1	1435.2	1474	1512.4	

Source: NYISO, Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs, January 17, 2012, MJB&A Analysis.

Table C-6. July 22, 2011, NYISO EDRP Load Management Event by Zone (MW)

NYISO Zone	HB 12	HB 13	HB 14	HB 15	HB 16	HB 17	Percent Generators
A		0.3	0.3	0.4	0.7	0.7	94%
B		0.0	0.0	0	0	0.0	100%
C		1.5	2.0	1.6	1.4	1.4	79%
E		3.6	5.5	4.4	3.1	1.6	96%
F		0.6	0.7	0.7	0.5	0.3	83%
G		0.2	0.2	0.1	0		100%
H		0	0.1	0.1	0	0.0	83%
I		0.5	0.6	0.5	0.6	0.5	46%
J	12.6	12.4	13.3	13.6	13.7	12.3	10%
K		1	1.1	1	1.1	1.2	0%
Total	**12.6**	**20.1**	**23.7**	**22.6**	**21.2**	**18.0**	

Source: NYISO, Annual Report to the Federal Energy Regulatory Commission on the NYISO's Demand Side Management Programs, January 17, 2012, MJB&A Analysis.

PJM Enrollment Details

According to PJM, approximately 15 percent of the demand response resources registered in the 2011/2012 delivery year is comprised of backup generation. However, approximately 60 percent of its demand response resources are listed as "other." Therefore, the actual participation figure could range from 15 to 75 percent. Because of the limited data available in PJM, in order to estimate the impact of these engines' participation in demand response programs on air quality, the PJM analysis in this report relies on a range of scenarios in which demand response backup generators comprise 15, 25, and 50 percent of demand response.

July 22 PJM Event Details

Table C-7 provides data on the load reduction by PJM zone on July 22.

Table C-7. July 22, 2011, PJM Load Management Event by Zone

PJM Zone	Hour Ending[1]	Reduction MW
BGE	HE 1300-1800	962
DPL	HE 1400-2000	128
DUQ	HE 1400-2000	163
JCPL	HE 1400-2000	141
METED	HE 1400-2000	206
PECO	HE 1400-2000	497
Totals		**2,097**

Source: PJM, Load Management Performance Report – 2011/2012. MJB&A Analysis.

1. HE is an abbreviation for Hour Ending. For example, HE 1500 – 1800 is the same as the expression 2:00 PM until 6:00 PM. The times shown for each event are the beginning and end of compliance reporting times. Events are not called or released exactly on the hour and all resources are expected to improve reliability by decreasing load or increasing generation as soon as practicable.

Since PJM only provides data on megawatts of load reduced, the total MWh of reduced demand must be estimated. This report assumes that each megawatt of reduced load is achieved for the entire duration of the load management event. While this may not necessarily be the case, this assumption provides a straightforward method for estimating total MWh of reduced demand. However, this method may overestimate the total MWh reduced. Table C-8 provides the estimates of MWh of reduced demand in PJM during the July 22 event by zone.

Table C-8. Estimated Reduced Demand by Zone in PJM during July 22, 2011 Event

PJM Zone	Hour Ending[1]	MWh
BGE	HE 1300-1800	5,772
DPL	HE 1400-2000	896
DUQ	HE 1400-2000	1,141
JCPL	HE 1400-2000	987
METED	HE 1400-2000	1,442
PECO	HE 1400-2000	3,479
Totals		**13,717**

Source: PJM, Load Management Performance Report – 2011/2012. MJB&A Analysis.

Emission Rates

Table C-9 illustrates NOx and PM emission rates associated with various engine types and EPA engine Tier.

Table C-9. NOx and PM Emission Rates for Various Engine Standards

Standard	NOx Rate (lb/MWh)	PM Rate (lb/MWh)
pre-Tier: < 600 hp	41.47	2.95
pre-Tier: > 600 hp	32.04	0.94
Tier 1	20.39	1.18
Tier 2	14.19	0.44
Tier 3	8.87	0.44
Tier 4	0.89	0.04

Source: EPA

The scenarios described in this report assumed that the average participating generator has emissions rates similar to a pre-2000 vintage engine greater than 600 horsepower (hp). The resulting emission rates (32.04 lb/MWh for NOx and 0.94 lb/MWh for PM) were multiplied by the megawatt-hour reductions assumed to be provided by generators. The MWh provided by generators is dependent on the scenario, which determines the percent of total reductions provided by generators.