Department of the Environment

TECHNICAL SUPPORT DOCUMENT FOR

Distributed Generation involving Stationary Internal Combustion Engines

Amendments to:

- **COMAR 26.11.02.01 – Definitions;**
- **COMAR 26.11.02.10 – Sources Exempt from Permits to Construct and Approvals; and**
- **COMAR 26.11.36.01 - .04 – Distributed Generation**

June 21, 2017

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Table of Contents

I. INTRODUCTION

The Environmental Protection Agency (EPA) has designated Maryland as nonattainment for the 2008 national ambient air quality standard (NAAQS) for ground-level ozone. Therefore, Maryland Department of the Environment (MDE, or Department) must continue to enact regulations to gain further reductions of the emissions of nitrogen oxides (NOx), a class of compounds that are precursors to ground-level ozone. Ground-level ozone is formed through the reaction of NOx and other compounds in the ambient air, particularly on hot, sunny days.

Distributed generators are typically stationary engines used to provide electric power when the normal supply is interrupted. Stationary engines are common combustion sources that collectively can have a significant impact on air quality and public health. In addition to NOx, stationary engines emit air pollutants when fuel is burned; including carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM). The health effects of these pollutants include a range of respiratory (breathing) issues, especially asthma among children and seniors. The Clean Air Act authorizes EPA to control emissions from stationary sources of air pollution.

These amendments reflect changes to the federal requirements for Stationary Internal Combustion Engines (ICE) and Reciprocating Internal Combustion Engines (RICE) (hereinafter collectively referred to as "stationary engines"). This action removes Maryland's outdated definitions and requirements from COMAR 26.11.36, and also clarifies definitions under the permitting requirements for stationary engines. There is no expected impact to emissions in Maryland, since federal regulations already exist to control the operation, reporting and maintenance of the stationary engines. However, the federal restrictions on engine use should avoid certain older, less-controlled engines from running on hot days, which results in public health protections.

The appendix contains summaries and research materials used to establish the proposed amendments.

II. PURPOSE OF AMENDMENTS AND NEW REGULATION

The Secretary of the Environment proposes to: (1) Amend Regulations **.01** and **.10** under **COMAR 26.11.02 Permits, Approvals, and Registration**; and (2) Amend Regulations **.01**, **.02**, and **.04**, repeal existing Regulation **.03**, and adopt new Regulation **.03** under **COMAR 26.11.36 Distributed Generation**. The primary purpose of this action is to amend existing requirements for emergency generators and load shaving units (engines) codified under COMAR 26.11.36 – Distributed Generation to reflect changes in the federal requirements for stationary engines. In addition, changes to Regulations .01 – Definitions, and .10 - Sources Exempt from Permits to Construct and Approvals, of COMAR 26.11.02 – Permits, Approvals, and Registration, are being completed to coincide with the amendments being made to COMAR 26.11.36.

EPA regulates stationary engines through two types of regulations, the National Emission Standards for Hazardous Air Pollutants (NESHAP) and New Source Performance Standards (NSPS). Specifically,

1.) NESHAP regulates emissions of hazardous air pollutants (HAPs) from new, existing and modified sources. These standards require application of technology-based emissions standards referred to as Maximum Achievable Control Technology (MACT). The NESHAP for RICE are outlined in the Code of Federal Regulations under 40 CFR Part 63, Subpart ZZZZ. Stationary Reciprocating Internal Combustion Engine is defined in 40 CFR § 63.6675;

2.) NSPS regulates emissions of criteria pollutants from new, modified, and reconstructed sources. NSPS standards require initial performance testing and ongoing monitoring to demonstrate compliance with established standards for that source category. The NSPS for Stationary Compression Ignition IC Engines is outlined in the Code of Federal Regulations under 40 CFR Part 60, Subpart IIII. The NSPS for Stationary Spark Ignition IC Engines is outlined in the Code of Federal Regulations under 40 CFR Part 60, Subpart JJJJ. Stationary Internal Combustion Engine is defined the same in 40 CFR § 60.4219 and 40 CFR § 60.4248.

MDE's action adopts 40 CFR Part 63, Subpart ZZZZ, and 40 CFR Part 60, Subpart IIII and JJJJ for stationary engines into COMAR 26.11.36 and makes the Maryland regulations consistent with the federal regulations.

This action will not be submitted to EPA for approval as part of Maryland's State Implementation Plan (SIP).

III. BACKGROUND

On May 18, 2009, MDE adopted new regulations under COMAR 26.11.09.08-1 which established NO_x emission requirements for emergency generators and load shaving units. Traditionally, stationary engines were installed at facilities as an emergency back-up of power in the event of a failure of electric power from the grid. Over time, as the cost of electricity increased, many facilities would operate their stationary engines during non-emergencies to reduce their electric bill during high-demand days. Owners of stationary engines also entered into contractual agreements to operate their stationary engines and perform other electricity curtailment activities to both reduce the cost of electricity and maintain electric system reliability. MDE adopted these regulations in an effort to achieve reductions in NO_x emissions during the summer ozone season when these practices were most frequently employed. Most stationary engines are fired with diesel fuel and have minimal NO_x emission controls which when operated resulted in excess NO_x emissions on the hottest and worst days for air pollution. Reductions in NOx emissions help the State to maintain and attain the NAAQS for ozone.

On June 13, 2011, MDE further amended and recodified the stationary engine regulations under a new Chapter COMAR 26.11.36 – Distributed Generation. The new COMAR 26.11.36 also established new annual reporting requirements for Curtailment Service Providers (CSPs) that negotiate contracts with facilities, that might operate onsite stationary engines under an electricity grid demand response event.

MDE excludes certain stationary engines from acquiring a “Permit to Construct & Registration Application” under COMAR 26.11.02 - Permits, Approvals and Registration. Emergency stationary engines with an output less than 500 hp and non-emergency stationary engines that serve as a primary source of power for agricultural equipment or industrial equipment, with an output less than 500 hp, are exempt from getting a permit to construct. The permit forms for this are located at MDE’s website under “Air Quality Permitting” and “Permits to Construct and Operate Application Forms”.

MDE is exempting certain portions of the federal requirements due to the decision of the D.C. Circuit Court of Appeals in Delaware v. EPA. [1] In that case, the Delaware Department of Natural Resources challenged the operation of stationary engines for up to 100 hours under Emergency Demand Response Operation. The court vacated portions of the 100 hour provision that allowed for emergency demand response operation in two circumstances: when a Reliability Coordinator (such as an independent electric grid operator) has declared an Energy Emergency Alert Level 2, or when there is a deviation of voltage or frequency of five percent or greater. The provisions that were vacated are 40 CFR § 60.4211(f)(2)(ii)-(iii), § 60.4243(d)(2)(ii)-(iii), and § 63.6640(f)(2)(ii)-(iii). Therefore, stationary engines are required to comply with the federal requirements in 40 CFR Part 63, Subpart ZZZZ and 40 CFR Part 60, Subpart IIII or JJJJ, except for these vacated provisions.

On April 15, 2016, EPA issued a guidance document addressing the vacatur of these provisions of the stationary engine NSPS and NESHAP rules, however; the CFR has not yet been updated to reflect these changes.

IV. REQUIREMENTS OF THE REGULATIONS

This action amends COMAR 26.11.36 - Distributed Generation by removing definitions from Regulation .01 and removing Regulation .03 - NOx Standards, which conflict with federal regulations. Additionally, this action will make changes to COMAR 26.11.02 - Permits, Approvals and Registration Regulations .01 – Definitions and .10 – Sources Exempt from Permits to Construct and Approvals, as needed in order to reflect the amendments being made to COMAR 26.11.36.

In summary, amendments to COMAR 26.11.36 and 26.11.02 incorporate 40 CFR Part 63, Subpart ZZZZ, 40 CFR Part 60, Subpart IIII or JJJJ, and changes necessitated by the vacatur language resulting from the above mentioned lawsuit. As currently required under COMAR 26.11.36.04, CSPs and their participating facilities are responsible for confirming that any

[1] *See*, Delaware v. EPA, 785 F .3d l (D.C. Cir. 2015); https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

stationary engine under contract to operate during electricity grid demand response (non-emergency events) operates and meets federal standards and emission limits.

MDE requires stationary engines to obtain a “Permit to Construct & Registration Application” under COMAR 26.11.02 - Permits, Approvals and Registration. Emergency stationary engines with an output less than 500 hp and non-emergency stationary engines that serve as a primary source of power for agricultural equipment or industrial equipment, with an output less than 500 hp, are exempt from permit to construct requirements.

This action affects the owner or operator of stationary engines. These engines are typically located at businesses, commercial, industrial and institutional facilities, to provide electric power when the normal supply is interrupted. A common term for this type of engine is “back-up generator or emergency generator”.

V. EXPECTED EMISSIONS REDUCTIONS

There is no expected impact to emissions, since 40 CFR Part 63, Subpart ZZZZ and 40 CFR Part 60, Subpart IIII or JJJJ already regulate the operation, reporting and maintenance of the stationary engines. However, the federal restrictions on engine use should prevent certain older, less-controlled engines from running on hot days, which results in less pollutants from these engines and greater public health protections

VI. ECONOMIC IMPACT

Economic Impact on Affected Sources, the Department, other State Agencies, Local Government, other Industries or Trade Groups, the Public

The economic impact to these engines has been determined under the federal regulations. The public health protections warrant the federal regulations, and Maryland is clarifying coordination of the federal and state regulations. This action will not have an economic impact on the Department, other state agencies, local government, other industries or trade groups, or the public.

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

VII. EQUIVALENT FEDERAL STANDARD

This action adopts the federal requirements as codified under 40 CFR Part 63, Subpart ZZZZ and 40 CFR Part 60, Subpart IIII or JJJJ. This action removes Maryland’s outdated definitions and requirements from COMAR 26.11.36.

VIII. <u>REGULATION</u>

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Title 26 DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

Chapter 02 Permits, Approvals, and Registration

Authority: Environment Article, §§1-101, 1-404, 1-601—1-606, 2-101—2-103, 2-301—2-303, and 2-401—2-404, Annotated Code of Maryland

.01 Definitions.

A. In this chapter and in COMAR 26.11.03, the following terms have the meanings indicated.

B. Terms Defined.

(1) − (17) (text unchanged)

(17-1)"Emergency Stationary Internal Combustion Engine" is defined in 40 CFR Part 60, Subpart IIII or JJJJ, as amended.

(17-2) "Emergency Stationary Reciprocating Internal Combustion Engine (RICE)" is defined in 40 CFR Part 63, Subpart ZZZZ, as amended.

(18) − (56) (text unchanged)

C. (text unchanged)

.02 - .09 (text unchanged).

.10 Sources Exempt from Permits to Construct and Approvals.

A person may construct or modify or cause to be constructed or modified any of the following sources without first obtaining, and having in current effect, a permit to construct:

A. – D. (text unchanged)

E. *Emergency* **[**S**]**stationary internal combustion engines or *emergency stationary reciprocating internal combustion engines (RICE*) with an output less than 500 brake horsepower (373 kilowatts) **[**and which are not used to generate electricity for sale or load shaving as that term is defined in COMAR 26.11.36.01B**]**;

E-1. Stationary internal combustion engines or stationary reciprocating internal combustion engines (RICE) that serve as a primary source of power for agricultural equipment or industrial equipment, with an output less than 500 brake horsepower (373 kilowatts).

F. – X. (text unchanged)

.11 - .19 (text unchanged).

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Title 26 DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

Chapter 36 Distributed Generation

Authority: Environment Article, §§1-101, 1-404, 2-101—2-103, 2-301—2-303, and 2-401—2-404, Annotated Code of Maryland

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) – (2) (text unchanged)

(3) "Demand response program" means a program that provides incentives to electricity consumers at a facility that curtails electricity usage **[**, particularly during peak periods or emergencies, and that affects pricing, system stability, and overall planning in the electricity market**].**

[(4) "Economic response program" means a demand response program where a facility is economically incentivized to curtail on-site electricity demand from the grid when prices are high, which primarily occurs during peak electricity demand periods.

(5) Emergency.

(a) "Emergency" means a condition where the primary energy or power source is disrupted or discontinued due to conditions beyond the control of the owner or operator of a facility, including:

(i) A failure of the electrical grid;

(ii) On-site disaster or equipment failure; or

(iii) Public service emergencies such as flood, fire, natural disaster, or severe weather conditions.

(b) "Emergency" includes a PJM declared emergency.

(6) "Emergency generator" means:

(a) A engine used only during an emergency or for testing and engine maintenance purposes; and

(b) An engine that operates during an emergency according to the procedures in the PJM Emergency Operations Manual for a PJM declared emergency.

(7) "Emergency response program" means a demand response program where a facility curtails on-site electricity demand only during an emergency declared by the PJM in accordance with Manual 13, Emergency Operations, Revision 40, Effective Date August 13, 2010, as amended.**]**

[(8)**]***(4)* "Engine" means a stationary *reciprocating* internal combustion engine *(RICE) or stationary internal combustion engine, subject to 40 CFR Part 63 Subpart ZZZZ and 40 CFR Part 60 Subparts IIII or JJJJ, as amended*.

[(9)**]***(5)* "Facility" means a commercial, institutional, or industrial establishment that has on-site capability to generate electric power to be used internally to reduce on-site electric power consumption, to reduce the overall electric system demand, or for other purposes.

[(10) Load Shaving Unit.

(a) "Load shaving unit" means an engine that operates for other than an emergency to generate electricity for use on-site or for sale.

(b) "Load shaving unit" does not include an engine:

(i) Whose primary function is to generate electricity for use by the public; or

(ii) That serves as the primary source of power for agricultural equipment or industrial equipment, including the period when equipment or a facility is being maintained and the engine is used in place of the primary power source.**]**

[(11)**]***(6)* "Participating engine" means an internal combustion engine located at a participating facility that is operated as part of a demand response program.

[(12)**]***(7)* "Participating facility" means a facility that has entered into a valid contract with a CSP to participate in a demand response program.

[(13) "PJM declared emergency" means a condition that exists where the PJM Interconnection, LLC notifies electric distributors that an emergency exists or may occur and it is necessary to implement the procedures in the PJM Manual 13 Emergency Operations, as revised.**]**

.02 Applicability.

This chapter applies to a person who owns or operates an *engine as defined in §.01B of this chapter* **[**emergency generator, load shaving unit,**]** or *a* curtailment service provider.

.03 [Emergency Generators and Load Shaving Units NOx Requirements] ***Requirements for Stationary Engines.***

*A. The owner or operator of an engine is subject to requirements under 40 CFR Part 63 Subpart ZZZZ, as applicable.**

B. The owner or operator of an engine is subject to requirements, as applicable, under:

(1) 40 CFR Part 60 Subpart IIII; or*

(2) 40 CFR Part 60 Subpart JJJJ.*

[A. Applicability and General Requirements for Emergency Generators and Load Shaving Units.

(1) The owner or operator of an emergency generator may not operate the generator except for emergencies, testing, and maintenance purposes.

(2) Except as provided in §A(5) of this regulation, this regulation does not apply to any engine that is fueled with natural gas or propane.

(3) This regulation does not apply to any engine that operates as a redundant system for power without direct or indirect compensation that is:

(a) Located at a nuclear power plant; or

(b) Located at a facility where operation of the engine is necessary to support critical national activities relating to security, aerospace research, or communications.

(4) The owner or operator of an emergency generator or load shaving unit may be subject to the federal standards for stationary internal combustion engines under 40 CFR Parts 60 and 63.

(5) The owner or operator of an emergency generator or load shaving unit may not operate the engine for testing and engine maintenance purposes between 12:01 a.m. and 2:00 p.m. on any day on which the Department forecasts that the air quality will be a code orange, code red, or code purple unless the engine fails a test and engine maintenance and a re-test are necessary.

(6) The owner or operator of an engine that is used for any purpose other than for emergency purposes shall install and operate a non-resettable hourly time meter on the engine for the purpose of maintaining the operating log required in §E of this regulation.

B. Requirements for Existing Load Shaving Units Installed on or Before January 1, 2009.

(1) The owner or operator of an existing load shaving unit that was installed on or before January 1, 2009, shall:

(a) Install a NOx control system to meet an emissions standard of 1.4 grams per brake horsepower or less;

(b) Replace the engine with a new engine that meets federal new source performance standards and was manufactured after January 1, 2009; or

(c) Not operate the engine for more than a total of 10 hours during the period of May 1 to September 30 of any year.

(2) The 10-hour limit in §B(1)(c) of this regulation is exclusive of the time that the unit operates for emergency purposes and the time for testing and engine maintenance.

(3) Upon request and on a case-by-case basis, the Department may, for the purpose of engine registration and compliance, treat a group of small engines, under the same or different ownership and performing the same function, as a single entity and establish alternative requirements for the engines.

(4) For engines to be equipped with NOx controls or replaced with a new engine that meets federal standards, compliance shall be achieved by July 1, 2010, or a later date approved by the Department.

(5) If an owner or operator purchases and installs a used engine, that engine, for the purpose of this regulation, is considered an existing engine unless the used engine was manufactured after January 1, 2009.

C. Requirements for New Load Shaving Units Installed After January 1, 2009.

(1) Except as provided in §§B(1)(b) and C(3) of this regulation, a load shaving unit that is installed after January 1, 2009:

(a) Shall be equipped with a NOx control system that meets a NOx emissions rate of not more than 1.4 grams per brake horsepower; or

(b) May not operate the engine for more than a total of 10-hours during the period of May 1 to September 30 of any year.

(2) The-10 hour limit in §C(1)(b) of this regulation is exclusive of the time that the unit operates for emergency purposes and the time for testing and engine maintenance.

(3) An engine with a capacity of 1,000 horsepower or less manufactured and installed after January 1, 2009, that meets applicable federal new source performance standards is exempt from the requirements in §C(1) of this regulation.

D. Alternative Method of Achieving Compliance.

(1) The owner or operator of a load shaving unit may, in lieu of meeting the requirements of §B or C of this regulation, achieve compliance by securing ozone season NOx allowances for the NOx emitted for load shaving purposes during the period of May 1 to September 30 of each year.

(2) The owner or operator of a load shaving unit who chooses to secure ozone season NOx allowances in lieu of complying with §B or C of this regulation shall:

(a) Secure not less than one ozone season NOx allowance;

(b) Round up to the next whole number if the number of allowances to be secured under §D(3)(c) or (4)(d) results in a fractional number;

(c) When calculating the amount of NOx emitted for load shaving purposes during the period May 1 to September 30 under §D(3)(a) or (4)(a) and (b) of this regulation, exclude from those calculations the amount of NOx emitted during the initial 10 hours of operation during that period; and

(d) Secure the ozone season NOx allowances by December 31 of each year and submit those allowances to the Department for retirement by February 1 of the following year.

(3) The owner or operator of an existing load shaving unit installed on or before January 1, 2009, who chooses to secure ozone season NOx allowances in lieu of compliance with §B of this regulation shall:

(a) Calculate, in tons, the total amount of NOx emitted during the period May 1 to September 30;

(b) Multiply the total tons of NOx emitted, as calculated in §D(3)(a) of this regulation, by three; and

(c) Secure at least the same number of ozone season NOx allowances as the number resulting from the calculation performed in §D(3)(b) of this regulation.

(4) The owner or operator of a new load shaving unit installed after January 1, 2009, who chooses to secure ozone season NOx allowances in lieu of compliance with §C of this regulation shall:

(a) Calculate, in tons, the total amount of NOx emitted during the period May 1 to September 30;

(b) Calculate, in tons, the total amount of NOx that would have been emitted during the period May 1 to September 30 if the engine had met the NOx emission rate of 1.4 grams per brake horsepower;

(c) Subtract the number calculated in §D(4)(b) from the number calculated in §D(4)(a), then multiply the result by five; and

(d) Secure at least the same number of ozone season NOx allowances as the number resulting from the calculations performed in §D(4)(c) of this regulation.

E. Record Keeping.

(1) The owner or operator of a load shaving unit shall maintain an operating log that includes the date the unit operated and the total operating time for each day that the unit operated.

(2) The operating log shall be maintained for 5 years and made available to the Department upon request.

F. Determining a Violation. A load shaving unit required to meet the NOx emissions standards or the operational limitations in this regulation may be subject to a penalty for each day the unit operates in violation of the requirements.**]**

** In May 2015, the United States Court of Appeals for the District of Columbia Circuit vacated paragraphs 40 CFR 60.4211 (f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii). Therefore, engines subject to this chapter do not have to comply with those provisions.*

.04 Annual Report Requirement for Curtailment Service Providers (CSPs).

A. A CSP that administers a demand response program for a participating facility in the State shall provide the following information to the Department in an annual report:

(1) – (2) (text unchanged)

(3) A description of the demand response program for each participating engine **[**, that is, whether it is an economic response program or an emergency response program**]**;

(4) As called for by the CSP, the dates on which each engine was requested to operate during the year and the hours of operation on each date, including:

(a) The reason for operating the engine under a demand response program **[**, that is, whether it is an economic response program or an emergency response program**]**;

(b) – (c) (text unchanged)

(5) – (7) (text unchanged)

B. – C. (text unchanged)

APPENDIX

AQCAC Briefing Paper for Distributed Generation Regulation Amendments
06/01/2017

<u>APPENDIX</u>

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06/01/2017

06/01/2017

AQCAC Briefing Paper for Distributed Generation Regulation Amendments

On March 13, 2017, the Maryland Department of the Environment (MDE) presented to the Air Quality Control Advisory Council (AQCAC or Council) proposed amendments to Distributed Generation regulations. Though the Council voted to adopt the proposed amendments, the Council also requested that MDE prepare a summary to clarify some items that were discussed during MDE's presentation. This document addresses those questions.

Estimated NOx emissions during a DR event

During discussion of emergency and non-emergency engines in demand response (DR) programs, the Council made an inquiry as to an estimated mass of NOx emissions during a DR event. MDE explained how the Distributed Generation regulations, codified under COMAR 26.11.36, require Curtailment Service Providers (CSPs) to submit annual reports on the frequency, duration and capacity of the DR programs. CSPs have enrolled facilities that can curtail electricity demand, either through running engines or shutting down processes (or air conditioning or other reduction).

As required by the regulations, CSPs began providing reports to MDE annually starting in 2012 (for the year 2011). At the time, engines enrolled in DR programs included emergency engines; however, federal regulations did not require facilities to submit annual reports. Based on CSP reports required to be submitted to MDE, an estimated 5,800 hours of DR was reported in Maryland in 2011. One DR event occurred on May 31, 2011. During this event less than 600 hours of DR responded, of which approximately 250 hours was attributed to the operation of emergency engines. MDE calculated less than 1.5 tons of NOx was emitted, based on the potential maximum NOx emissions from diesel fueled engines of a specific size and age[1]. A second DR event occurred on July 22, 2011. On this date, approximately 5,000 hours of DR responded, of which an estimated 2,000 hours was attributed to the operation of emergency engines. Based again on the potential maximum NOx emissions from diesel fueled engines, an estimated 7 tons of NOx was emitted. See ***Appendix A*** for details on CSP summary events and MDE NOx calculations.

CSPs had the flexibility to respond to a DR event through either economic price signals or emergency capacity requirements under PJM Initiated Load Management Events. PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in 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. PJM maintains a list of DR or Initiated Load Management Events, which can be downloaded from http://www.pjm.com/markets-and-operations/demand-response.aspx, and is included in ***Appendix B***. In Maryland, emergency DR events were called four times in 2010, two

[1] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

times in 2011, one time in 2012 and two times in 2013, during the ozone season. PJM last initiated an emergency DR event in March 2014 for the regions including Maryland. Therefore emergency engines have not been called to operate in response to an emergency DR event since the summer of 2014 in Maryland. The non-operation of emergency engines during DR events has been beneficial to air quality and has avoided large spikes of NOx emissions on hot summer days, as was the case during the July 2011 DR event.

As of May 2016, emergency engines are no longer allowed to operate during DR events. In Delaware v. EPA, the D.C. Circuit Court of Appeals found that the EPA acted arbitrarily and capriciously when it allowed the operation of emergency engines in DR programs for up to 100 hours per year.[2] The court mandated revisions to 40 CFR Part 63 Subpart ZZZZ, and 40 CFR Part 60 Subparts IIII and JJJJ.[3] These sections are incorporated into the proposed amendments to COMAR 26.11.36 and preclude existing and new emergency engines from responding to DR events. Per these EPA regulations, only non-emergency engines, as determined through a thorough review of federal requirements, are allowed to respond to DR events.

While historically MDE's regulations were more stringent than the federal regulations, this is no longer the case, and both State and federal regulations will now prevent the operation of emergency engines except for during periods of grid failure. Thus, the DR events of 2011 and 2012, summarized above, where emergency engines operated in response to either economic price signal or emergency capacity requirements, can no longer occur.

Pollutant Control Restrictions

The Council inquired about existing emergency engines over 500 brake horsepower (bhp) that might be re-purposed in order to participate in DR. The Council asked if the Department could confirm that some existing emergency engines may only be required to install a CO catalyst, and not NOx emission control devices, in order to participate in DR programs.

All engines used to generate electricity as a generator must follow the stationary internal combustion engine regulations: 40 CFR Part 63 Subpart ZZZZ (NESHAP) and 40 CFR Part 60 Subparts IIII and JJJJ (NSPS).

- **National Emission Standards for Hazardous Air Pollutants (NESHAP)** – which regulate emissions of hazardous air pollutants (or HAPs) from new, existing and modified sources. These standards require application of technology-based emissions standards referred to as Maximum Achievable Control Technology (MACT).
- **New Source Performance Standards (NSPS)** – which regulate emissions of criteria pollutants from new, modified and reconstructed sources. These standards require initial performance testing and ongoing monitoring to demonstrate compliance with established standards for that source category.

Generally, all stationary engines constructed, modified or reconstructed after 2005 follow NSPS and engine emissions for non-emergency engines are more stringent than the same year, size and fuel type emergency engine.

[2] Delaware v. EPA, 785 F. 3d1 (2015)
[3] https://www.epa.gov/sites/production/files/2016-06/documents/ricevacaturguidance041516.pdf

As of May 2016, an emergency engine, any size, cannot participate in a DR program, but an engine that meets the federal standards for a non-emergency engine can be in a DR program. See ***Appendix C*** for a list of documents detailing the Vacatur of NESHAP and NSPS Provisions for Emergency Engines. That means some engine owners may choose to retrofit their engine to meet the non-emergency standards so they can be in a DR program. Some engine owners may choose to purchase a non-emergency compliant NSPS engine. For example, if a facility would like to repurpose a diesel engine > 500 bhp built in 2003, the engine may change from an emergency engine to a non-emergency engine, by reducing CO by 70% to meet the non-emergency NESHAP standards and then can run to power equipment or be in a DR program.

Therefore, it is generally true that some existing emergency engines may only be required to install a CO catalyst, and not NOx emission control devices, in order to participate in DR programs, but it is complicated by the age, size, fuel type, location and use of an engine. The EPA provides a number of resources, including menu driven guidance, to be used in determining the specific compliance requirements and permit limitations for a specific engine. See ***Appendix D*** for a list of EPA guidance and rule summaries.

MDE's Air Quality Permits Program is currently in the process of creating a guidance document covering requirements for internal combustion engines, including the minimal requirements to re-purpose previously permitted emergency engines to operate as a non-emergency engine in a DR program. This permit guidance document will cover aspects pertaining to engines including reporting, monitoring, and emission standards. In order to participate in a DR program, an emergency engine may use a diesel oxidation catalyst or non-selective catalytic reduction (SNCR) to reduce CO emissions, a selective catalytic reduction (SCR) to reduce NOx, or may replace the engine all together. There are some engines that meet both emergency and non-emergency emission standards, based on their Tier certification[4] and manufacture date between 2004 - 2007. MDE will work with each applicant to answer emission requirement specifics when re-purposing an emergency to a non-emergency engine. MDE will continue to receive guidance from EPA and engine manufacturers.

At this time, the Department is not considering additional restrictions beyond the federal requirements for stationary engines. The federal rules restrict the operation of emergency engines (which are typically the engines that emit more pollutants). The federal rules have very stringent requirements for new stationary engines. These requirements protect the public from local and transported pollution.

<u>Operation of Small, non-permitted Generators in Maryland</u>

The Council inquired if MDE was tracking the operation of small generators being used to generate electric power for on-site use. The Council also asked as to whether these generators may be operating as part of a DR program.

An engine may be used to generate electricity as a generator, or an engine may be used as a primary source of power to directly power equipment. Regulation .10 of COMAR 26.11.02 lists the sources that are exempt from requiring a permit to construct. MDE is not exempting engines used to generate electricity for on-site use as a power generator. If a small (<500 bhp) engine is used to generate electricity for on-site use in a non-emergency manner, this is a non-emergency generator and any size non-emergency generator is not exempt from permit to construct requirements. This

[4] https://www.dieselnet.com/standards/us/stationary_nsps_ci.php#reg

includes DR operation.

MDE does exempt, from permit to construct requirements, the small (<500 bhp) non-emergency engines that serve as a primary source of power for agricultural or industrial equipment such as pumps, heating or cooling equipment, chillers, etc. These engines have always been exempt under COMAR 26.11.02.10 because they are not used to generate electricity for sale, for peak shaving or DR programs. MDE does not track these small non-emergency engines that are used as a primary source of power for equipment unless the facility is a major source subject to federal Title V permit requirements. Those facilities must list all emission units, including insignificant activities, at their facility. Small non-emergency engines that are used as a primary source of power for equipment at a Title V facility would be listed as an insignificant activity in the facility's Title V permit.

Regardless of whether the engine is exempt from getting a permit to construct from MDE, all engines are required to follow the federal rules. Even without a permit to construct, small non-emergency engines that are used as a primary source of power for equipment are still subject to federal NSPS or NESHAP regulations, as applicable. All owners and operators must follow the federal rules. An engine owner may not choose to re-purpose an emergency engine and run it continuously without meeting more stringent non-emergency standards, either under NESHAP or NSPS.

MDE's Air Quality Compliance Program monitors Title V, synthetic minor and general permit sources, as well as addressing public concerns. County health departments and permit/enforcement inspectors may also investigate the operation of engines to ensure requirements are being met and public health is being protected.

APPENDICES

Appendix A Supporting Documents and Data for CSP Demand Response Events

1. Summary of Maryland CSP Reports for 2011 and 2012
2. Load Management Performance Report 2011/2012. *PJM, December 2011*
3. PJM Dashboard, Emergency Procedure Postings, 07.22.2011
4. EPA Nonroad Compression-Ignition Engines: Exhaust Emission Standards
5. Total NOx Emissions, July 2011, Maryland Electric Generating Units
6. PJM Emergency Posting and CSP Demand Response, 2011 – 2014

Appendix B PJM Interconnection Supporting Documents for Demand Response Events

1. Summary of PJM-Initiated Load Management Events, 1991 – Present
2. PJM Top 10 All Time Summer/Winter Peak Load Days
3. 2016 Demand Response Operations Markets Activity Report: May 2017. *PJM Demand Side Response Operations, May 11, 2017*
4. New Air Quality Rules have Dramatically Changed the Demand Response Resource Mix. *Greentechmedia.com, November 3, 2016*

Appendix C Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines

1. EPA Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines, April 15, 2016
2. RICE NESHAP Requirements for Stationary Engines at Area Sources of Hazardous Air Pollutants, September 19, 2013

3. Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration, OAR-2008-0708, April 1, 2013
4. Delaware v. EPA, 785 F. 3d1 (2015). Argued September 26, 2014. Decided May 1, 2015.
5. Delaware Department of Natural Resources and Environmental Control, et al., v. United States Environmental Protection Agency. USCA Case #13-1093, Document #1562706, Filed: 07/15/2015
6. United States Court of Appeals for the District of Columbia Circuit, No. 13-1093, Issued 05/04/2016
7. United States Court of Appeals for the District of Columbia Circuit, USCA Case #13-1233, Document #1574665, Filed: 09/23/2015
8. DC Circuit Vacates Portions of EPA's Emergency Generator Rule. *www.Taftlaw.com, September 4, 2015*
9. DC Circuit Reverses 100-hour Exemption for Backup Generators. *Lexology. May 11, 2015.*

Appendix D Supporting Documents Associated with 40 CFR Part 60 Subpart IIII, 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ, Summary of Compliance Criteria for Stationary Engines

1. EPA Compliance Requirements for Stationary Engines Links and Summary Tables.
2. EPA Guidance and Tools for Implementing Stationary Engine Requirements Links.
3. EPA Tier Emission Standards – titled "Nonroad Compression-Ignition Engines: Exhaust Emission Standards"
4. EPA Rule Link and Fact Sheet: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines.
5. EPA Implementation Tools Link: NESHAP for Reciprocating Internal Combustion Engines.
6. EPA Rule Link and Fact Sheet: New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines.
7. Implementation Tools: NSPS for Compression Ignition Internal Combustion Engines.
8. EPA Rule Link and Fact Sheet: New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines.
9. EPA Implementation Tools Link: NSPS for Spark Ignition Internal Combustion Engines.
10. EPA's Air Quality Regulations for Stationary Engines. Melanie King, U.S. Environmental Protection Agency. June 18, 2014.

Appendix A
Supporting Documents and Data for CSP Demand Response Events

1. Summary of Maryland CSP Reports for 2011 and 2012
2. Load Management Performance Report 2011/2012. *PJM, December 2011*
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Summary of CSP Reports
For 2011 and 2012

				Combination			Curtailment		Generator		
5/31/2011	hours	number of participants	NOx (tons)	hours	number of participants	NOx (tons)	hours	number of participants	hours	number of participants	NOx (tons)
economic	3	3	0.005						3	3	0.005
emergency	560	515	1.651	37	34	0.318	279	249	244	232	1.333
unknown											
TOTAL	563	518	1.656	37	34	0.318	279	249	247	235	1.338
	563	518	1.656	37	34	0.318	279	249	247	235	1.338

				Combination			Curtailment		Generator		
7/22/2011	hours	number of participants	NOx (tons)	hours	number of participants	NOx (tons)	hours	number of participants	hours	number of participants	NOx (tons)
economic	10	2	0.000						10	2	
emergency	3916	694	5.194	202	34	0.240	2182	379	1532	281	4.953
unknown	1055	207	2.007				857	168	198	39	2.007
TOTAL	4981	903	7.200	202	34	0.240	3039	547	1740	322	6.960
	4981	903	7.200	202	34	0.240	3039	547	1740	322	6.960

				Combination			Curtailment		Generator		
8/17/2011	hours	number of participants	NOx (tons)	hours	number of participants	NOx (tons)	hours	number of participants	hours	number of participants	NOx (tons)
economic											
emergency	1	1	0.000				1	1	0		
unknown	169	169	0.113				147	147	22	22	0.113
TOTAL	170	170	0.113				148	148	22	22	0.113
	170	170	0.113	0	0	0.000	148	148	22	22	0.113

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

Summary of CSP Reports
For 2011 and 2012

9/16/2011	hours	number of participants	NOx (tons)	Combination hours	Combination number of participants	Combination NOx (tons)	Curtailment hours	Curtailment number of participants	Generator hours	Generator number of participants	Generator NOx (tons)
economic											
emergency	55	55	0.091				43	43	12	12	0.091
unknown											
TOTAL	55	55	0.091				43	43	12	12	0.091
	55	55	0.091	0	0	0.000	43	43	12	12	0.091

6/27/2012	hours	number of participants	NOx (tons)	Combination hours	Combination number of participants	Combination NOx (tons)	Curtailment hours	Curtailment number of participants	Generator hours	Generator number of participants	Generator NOx (tons)
economic											
emergency	19	19	0.055				18	18	1	1	0.055
unknown											
TOTAL	19	19					18	18	1	1	0.055
	19	19	0.055	0	0	0.000	18	18	1	1	0.055

7/18/2012	hours	number of participants	NOx (tons)	Combination hours	Combination number of participants	Combination NOx (tons)	Curtailment hours	Curtailment number of participants	Generator hours	Generator number of participants	Generator NOx (tons)
economic	5	5	0.004				3	3	2	2	0.004
emergency	1675	1386	2.892	241	239	0.270	1032	791	402	356	2.621
unknown											
TOTAL	1680	1391	2.896	241	239	0.270	1035	794	404	358	2.626
	1680	1391	2.896	241	239	0.270	1035	794	404	358	2.625

9/13/2012	hours	number of participants	NOx (tons)	Combination hours	Combination number of participants	Combination NOx (tons)	Curtailment hours	Curtailment number of participants	Generator hours	Generator number of participants	Generator NOx (tons)
economic											
emergency	20	20	0.002	8	8	0.001	11	11	1	1	0.001
unknown											
TOTAL	20	20	0.002	8	8	0.001	11	11	1	1	0.001
	20	20	0.002	8	8	0.001	11	11	1	1	0.001

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

Load Management Performance Report 2011/2012

December 2011

PJM has made all efforts possible to accurately document all information in this report. However, PJM cannot warrant or guarantee that the information is complete or error free. The information seen here does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing: http://www.pjm.com/documents/agreements/pjm-agreements.aspx

For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing: http://www.pjm.com/documents/manuals.aspx

Table of Contents

Executive Summary

Demand Side Resources have the ability to participate as a capacity resource in the PJM capacity market (Reliability Pricing Model or "RPM") or to support a Load Serving Entities Fixed Resource Requirement ("FRR") plan. For the 2011/2012 Delivery Year there are two different Load Management product types available which have the same availability requirement: Demand Resources ("DR") and Interruptible Load for Reliability ("ILR). A Curtailment Service Provider ("CSP") is the PJM member that nominates the end use customer(s) as a capacity resource and is fully responsible for the performance of the resource. Load Management products are required to respond to PJM Load Management event which may occur from noon through 8pm on non-holiday weekdays from June through September during PJM system emergencies or receive a penalty. Load Management that is not dispatched during a system emergency must perform a mandatory test to demonstrate it can meet its capacity commitment or receive a penalty.

PJM called on Load Management (ILR and DR) three times during the 2011. Figure 1 below shows a summary of the events. There were two calls made in May and one in July. The 2 May events occurred at the end of the 2010/2011 Deliver Year and were outside the mandatory compliance period. Performance during each May event was lower than expected (80%) and much lower than the committed amount of capacity (40%). Since the events took place outside of the compliance measurement period, reductions are expected to be lower than during the compliance measurement months. When there is a potential for an event to occur outside of the compliance measurement period, PJM estimates an expected level of reductions based on input from the CSP. CSPs had indicated they expected resources would be able to deliver 50% of their commitments. CSPs are incented to perform by the ability to receive emergency energy revenue and to help during a system emergency Load Management performance for the July event was 91% of required reductions which was lower than expected. Performance is mandatory in July and, accordingly, PJM expected performance to be closer to 100%. The 91% performance result is lower than the 2010/2011 overall result of 100%.

Figure 1: 2011 Load Management Events Summary

Event Date and Zones	Committed MW*	Reduction MW	Performance
5/26, Norfolk portion of DOM	71	58	82%
5/31, Mid-Atlantic , DOM	1,033	856	83%
7/22, BGE, DPL, DUQ, JCPL, METED, PECO	2,296	2,097	91%
*Note: Committed MW for May events are the expected MW.			

The summer 2011 events varied in size and length. The two May events were short (one and two hours) and small (one sub-zonal) in comparison to the July event that was a large multi-zone event during wide spread record breaking heat. On July 22nd the heat indices in the Delaware Valley ranged from 110°F to 120°F. The event lasted for four hours in two zones, five hours in four zones and the maximum duration of six hours in the BGE zone. Not all CSPs responded with their committed amounts in all of the zones where they participate. In the July event 55% of the CSP/zones did not -- compared to 40% last summer. Conversely, 45% met or exceeded their commitments (vs. 60% last year). Underperformance penalties[1] totaled $5.6 million or about 1.3% of the total DR and ILR revenue of $420 million. CSP credits for energy reduced during all three events totaled $15 million.

[1] May events occur outside of the compliance measurement period and there are no event penalties.

DR and ILR that was not dispatched during the July emergency event were required to perform a mandatory 1 hour test. Each CSP must test all DR/ILR resources that were not required to respond to the July event in a zone at the same time. The test results for the 2011/2012 Delivery Year demonstrate that in aggregate, committed Demand Side Resources performed at 107% of their committed capacity values. Test results in excess of committed capacity values totaled 660 MW for the 8,860 MW of Demand Side Resources required to test. Similar to performance during the events, individually not all CSPs tested to their committed zonal amounts, but that number was small. Test failure charges totaled $6.4 million, about 1.5% of total revenue.

Load Management Overview

PJM Interconnection, L.L.C. (PJM) procures capacity for its system reliability through the Reliability Pricing Model (RPM). The sources for meeting system reliability are divided into four groups:

1) Generation Capacity
2) Transmission Upgrades
3) Demand Side Resources - Load Management
4) Energy Efficiency

For the 2011/2012 Delivery Year[2], Load Management Resources were registered as either Demand Resource (DR) or Interruptible Load for Reliability (ILR). DR 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. ILR is registered in the spring prior to the commencement of the Delivery Year until 2012/2013 when ILR has been eliminated per the Federal Energy Regulatory Commission (FERC) approved tariff. This is the last year for ILR. Although the timing and methods for becoming DR or ILR Resources are different from one another, within the Delivery Year the performance obligations for both types of Resources are the same.

DR and ILR agree to be interrupted up to ten (10) times per Delivery Year by PJM. The interruptions may be up to six (6) consecutive hours in duration on non-holiday weekdays from noon until 8 PM EPT in the months from May through September (and from 2 PM until 10 PM EPT from October through April). The interruptions must be implemented within two hours of notification by PJM. Those Resources that can be fully implemented within one hour of notification are considered Short Lead Time Resources, while those that require more than one hour but not more than two hours of notification are considered Long Lead Time Resources. This agreement by Load Management Resources to allow PJM to provide notice of the interruptions enables PJM to procure less generation capacity while maintaining the same level of reliability according to the current reliability criteria and practices within the PJM market.

DR and ILR compliance can be more complex to measure than compliance for generation resources meeting their capacity obligations. In order to ensure the reliability service for which a Resource is paid has actually been provided, PJM utilizes three different types of Measurement and Verification methodologies. DR and ILR Resources can choose to be measured using:

- Direct Load Control (DLC) – Load Management for non-interval metered customers which is initiated directly by a Curtailment Service Provider's (CSP) market operations center, employing a communication signal to cycle HVAC or water heating equipment. This is traditionally done for residential consumers and requires the necessary statistical study as outlined in PJM Manual 19.
- Firm Service Level (FSL) – Load Management achieved by a customer reducing its load to a pre-determined level upon the notification from the CSP's market operations center. Industrial customers with a high load factor normally use this approach because they understand the electricity usage for their base

[2] The Delivery Year for the capacity construct corresponds to PJM's Planning Year which runs each year from June 1 until May 31 of the following year

electrical equipment that must operate even during an emergency situation. This is one of the easiest to verify since the firm service level amount is simply compared to the metered load during an event or test.

- Guaranteed Load Drop (GLD) – Load Management achieved by a customer reducing its load when compared to what the load would have been absent the PJM emergency or test event. This is normally utilized by customers that have a variable load profile to capture the impact of the system relative to what it would have been during the time periods under review.

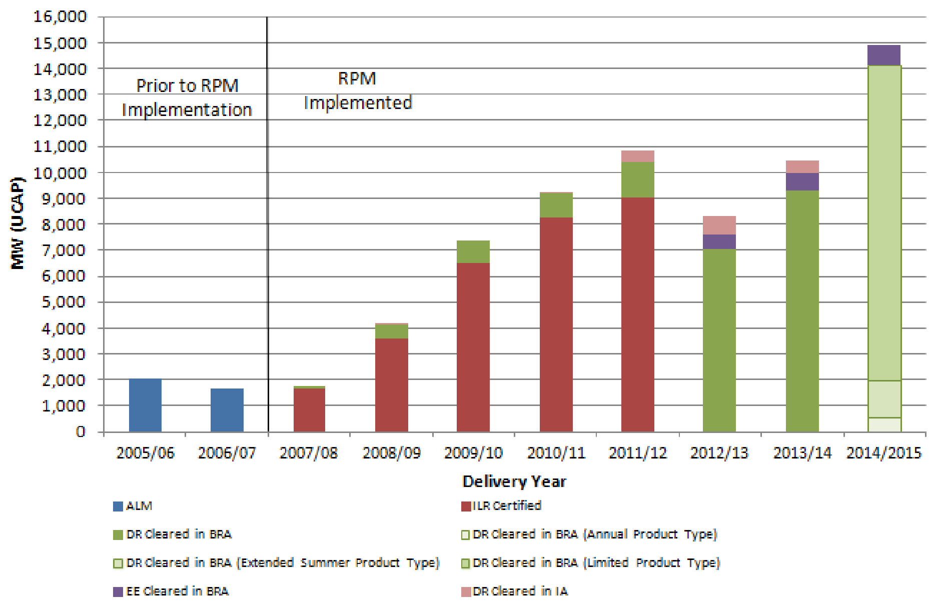
Load Management Participation Summary

The capacity numbers in this report are in terms of either Installed Capacity (ICAP) or Unforced Capacity (UCAP) depending upon which is most relevant. PJM calculates the Resource amounts required to meet the reliability standard in terms of UCAP which is also utilized to measure compliance with a RPM commitment. PJM determines the UCAP value of different types of Resources that are offered into the RPM auctions based on methods described in the PJM manuals.

For a conventional generation resource, ICAP value is the summer net dependable rating. The UCAP value is the ICAP value reduced by historical average forced outage and forced derating. Therefore, the UCAP value represents the average availability of capacity from a generating unit after forced outages and forced deratings. For a Load Management Resource, ICAP value is the nominated load reduction. The nominated load reduction for a Firm Service Level, Guaranteed Load Drop, or Direct Load Control resource is calculated in accordance with the PJM Capacity Market Manual, Manual 18. The UCAP value is calculated in two steps: First, the nominated load reduction is discounted to account for its reduced impact during higher load periods by multiplying by the Demand Resource Factor. Then, the value is increased to gross up the load reduction by the approved reserve margin.

Load Management participation in the PJM capacity construct has increased over time. ALM participation five years ago in the 2006/2007 Delivery Year was under 1,700 Megawatts (MW). However, the Load Management commitments from the current year through the 2014/2015 Delivery Year average over 10,600 MW each year and up to 14,000 MW by 2014/2015. (Note that there is a dip in Delivery Year 2012/2013. This is likely due to being the first year without ILR.) This increase in participation by Load Management Resources reduces the need for generation capacity by providing reductions in demand at the system operator's request. Below is a graphical representation of the growth in Load Management participation at PJM in MWs of UCAP.

Figure 2: Load Management Participation History (UCAP)



In PJM, capacity is priced based on location to reflect the locational reliability requirements in various sub-regions of the market. The location of the capacity commitments are grouped by the Transmission Zones. Although capacity obligations are measured in UCAP, the most straightforward examination of Load Management participation by Zone is in MWs of ICAP. An ICAP value is converted to UCAP by applying a DR factor[3] and Forecast Pool Requirement (FPR) factor[4]. The DR factor accounts for load forecast uncertainty while the FPR is an adjustment for unforced reserve margin. For the 2011/2012 Delivery Year, Load Management Resources commitments represented 11,442 MW[5] of ICAP while total registered Load Management represented 11,821 MW. Registered Load Management may be in excess of the commitment if the CSP has indicated they have the potential to deliver an amount that is higher than their actual commitment[6].

[3] See "Demand Resource (DR) Factor"; http://www.pjm.com/~/media/committees-groups/committees/cmec/20090805/20090805-item-07b-dr-factor.ashx

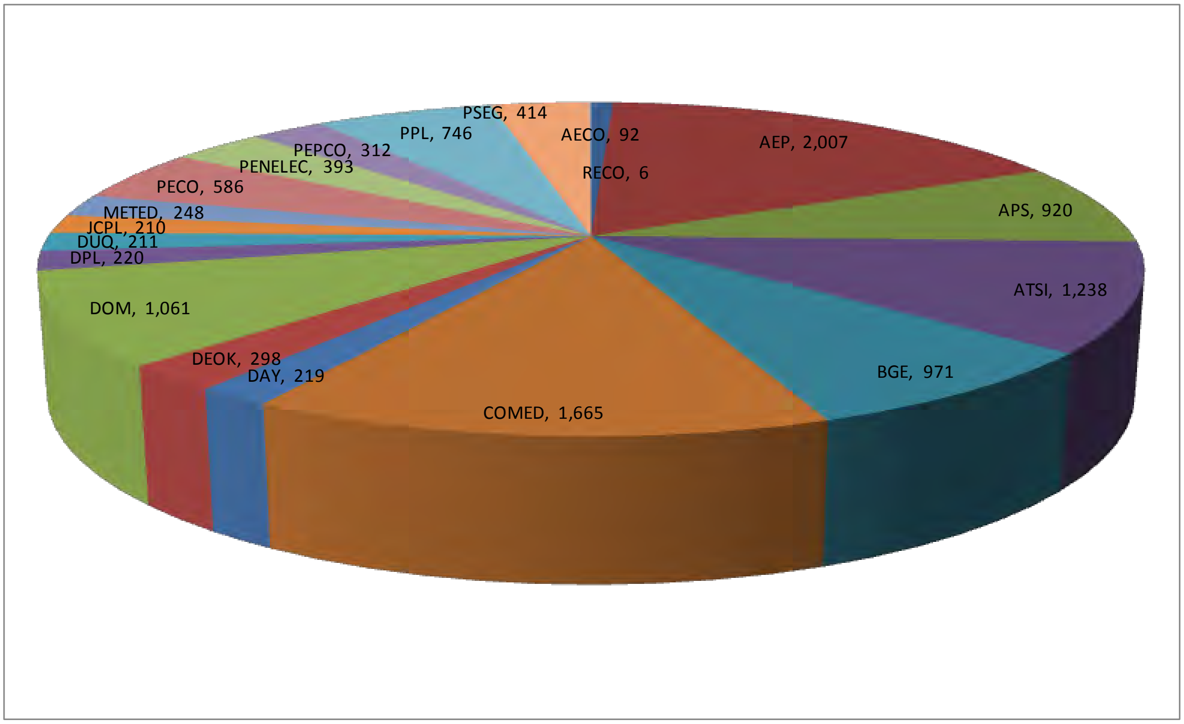
[4] The amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

[5] Includes RPM auctions and FRR commitments

[6] For example, a CSP may clear 10 MW of resources in an RPM auction but register 11 MW load reduction capability by end use customers to fulfill such commitment.

Following is an illustration of how the registration of Load Management Resources were spread across the 19 Zones for the 2011/2012 Delivery Year (note that the DEOK zone will not be effective until January 1, 2012). Ninety-seven members operate as a Curtailment Service Provider where over 1 million end use customers across almost every segment (residential, commercial, industrial, government, education, agricultural, etc.) participate as a Load Management resource

Figure 3: 2011/2012 Load Management Participation by Zone (MW ICAP)



Atlantic City Electric (AECO), American Electric Power (AEP), American Transmission Systems, Inc (ATSI), Allegheny Power (APS), Baltimore Gas and Electric (BGE), Commonwealth Edison (COMED), Dayton Power & Light (DAY), Dominion Virginia Power (DOM), Delmarva Power and Light (DPL), Duke Energy Ohio and Kentucky (DEOK), Duquesne Light (DUQ), Jersey Central Power & Light (JCPL), Metropolitan Edison (METED), PECO (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Co. (PEPCO), PPL Electric Utilities Corp. (PPL), Public Service Electric and Gas Co. (PSEG), Rockland Electric Company (RECO).

Figure 4 below illustrates the percentage of ICAP registered by the major methods where 53% represents Guaranteed Load Drop that is not exclusively provided by a back up generation resource as measured through the output of the backup generator, 8% represents Guaranteed Load Drop that is exclusively provided through a back up generation resource, 32% represents Firm Service Level and 8% represent residential direct load control type resources.[7] Note that although MWs from resources registered as Guaranteed Load Drop via Generation account for 8% of the total nominated load, event and test data submissions show that generator output accounts for 6% of the nominated total, slightly less than the registered amount.

Figure 4: Percent of Registered ICAP

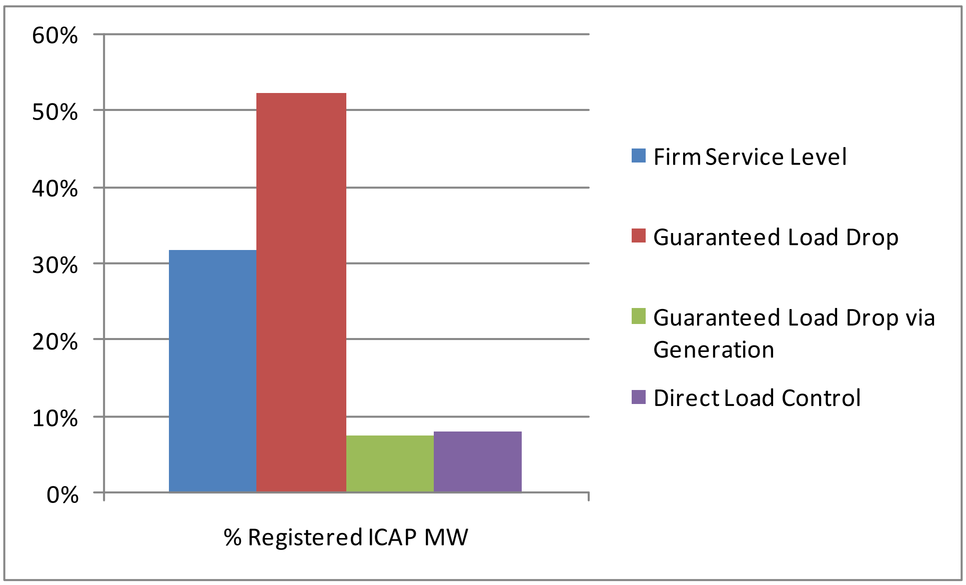
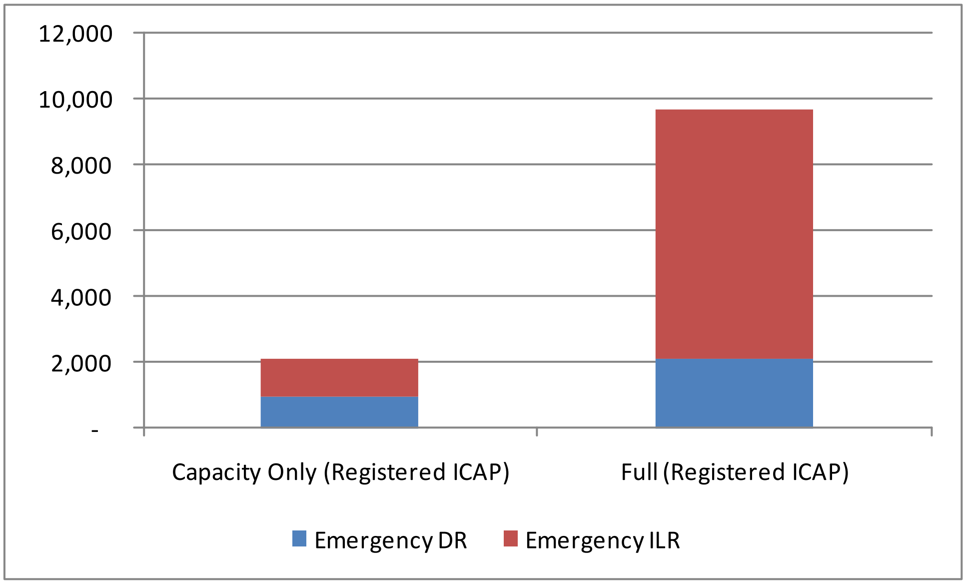


Figure 5 represents the current number of registration ICAP MWs for ILR compared to DR. The registration type is further segmented to show the number of MWs registered as an Emergency Full resource that receive both capacity revenue stream as well as an emergency energy revenue stream when there is an emergency load management event, compared to the number of MWs registered as Capacity Only which indicates the CSP is not eligible for any emergency energy payments during an event. 8,731 MW were registered as ILR while 3,090 MW were registered as DR while approximately 18% of the total was registered as Capacity Only.

[7] Firm Service Level and Guaranteed Load Drop (other) may include load reductions achieved with back up generation done in conjunction with another type of control within the facility. Guaranteed Load Drop (back up gen only) represents an estimate of facilities that substantiate load reduction based on meter data from the back up generator, exclusively.

Figure 5: MW of Registered ICAP as DR and ILR



2011 Load Management Events

Load Management Resources with an emergency load response registration are relied upon by PJM planning and PJM system operations to help maintain the safe and reliable operation of the PJM region. PJM had three Load Management events in 2011 (two at the end of 2010/2011 DY and one in 2011/2012 DY). Following is an overview of PJM Load Management events over the past 12 years.

Figure 6: Load Management Event History

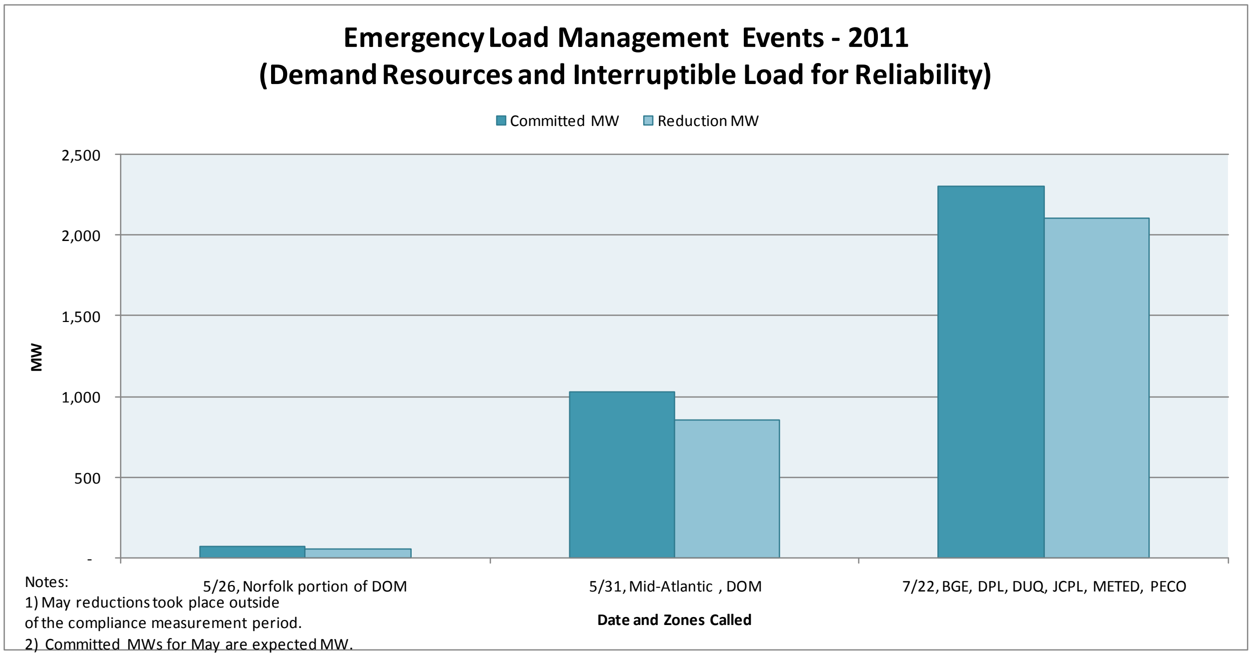
Delivery Year	Event History
2011/2012	Friday, July 22nd, HE 1300[8] – 1900[9]
2010/2011	Tuesday, May 31st, HE 1800 – 1900 Thursday, May 26th, HE 1800 – 1800 Friday, September 24th, HE 1400 – 1800 Thursday, September 23rd, HE 1200 - 2000 Wednesday, August 11th, HE 1500 – 1900 Wednesday, July 7th, HE 1500 – 1900 Friday, June 11th, HE 1700 – 2000
2009/2010	Wednesday, May 26th, HE 1900 – 2000
2008/2009	No events
2007/2008	Wednesday, August 8th, HE 1500 - 1800
2006/2007	Thursday, August 3rd, HE 1500 – 1900 Wednesday, August 2nd, HE 1600 – 1900
2005/2006	Thursday, August 4th, HE 1600 - 1700 Wednesday, July 27th, HE 1400 - 1800
2004/2005	No events
2003/2004	No events
2002/2003	Tuesday, July 30th, HE 1300 - 1800 Monday, July 29th, HE 1500 - 1800 Wednesday, July 3rd, HE 1300 – 1800
2001/2002	Friday, August 10th, HE 1300 - 1400 Thursday, August 9th, HE 1300 - 1800 Wednesday, August 8th, HE 1400 - 1800 Wednesday, July 25th, HE 1600 - 1700
2000/2001	No events

[8] HE in the table is an abbreviation for Hour Ending. For example, HE 1500 – 1800 is the same as the expression 2:00 PM until 6:00 PM.

[9] 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. The times shown are a summary of all Zones but the event may have been shorter or not even called in some Zones.

PJM calls Load Management events by zone (or sub-zone) and by lead time. This allows PJM to address system conditions in a targeted, measured and phased manner. Figure 7 below depicts the overall performance for each of the 2011 Load Management events:

Figure 7: 2011 Load Management Events



Looking further into each event, the Figures 8, 9 and 10 below show the hourly performance values for each event. As can be seen in both overall and hourly performance, the results are lower than anticipated. Review of the data shows that not just a single CSP had performance issues. There was a general lower than expected performance. The May events took place in the final week (and in the case of May 31, the final day) of the 2010/2011 DY. Many CSPs did not expect an event that late in the DY and some end-use sites were about switch CSPs for the upcoming DY. These may be reasons for lower than anticipated performance.

In the July event the under-performance cannot be attributed to one or two CSPs. Under-performance was a general problem. The data do show that some single large end-use sites had performance problems. Their relatively large size puts greater reliance on them for overall performance. PJM plans to discuss the performance with CSPs. It should be noted that the under-performing CSPs where charged penalties in accordance with PJM rules.

Figure 8: May 26, 2011 Hourly Performance

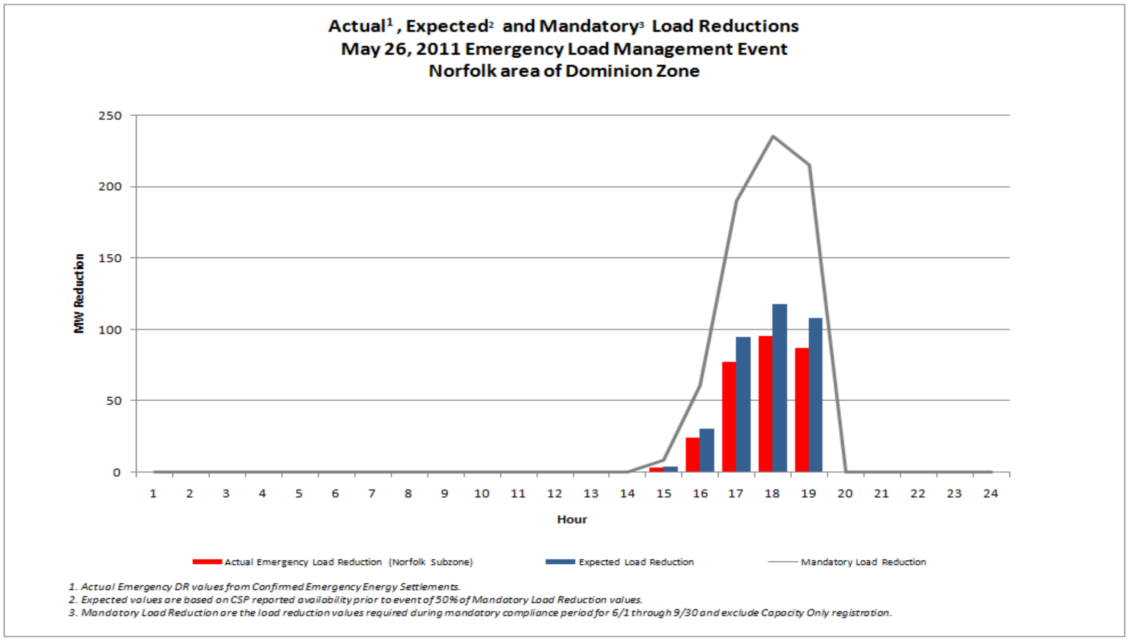


Figure 9: May 31, 2011 Hourly Performance

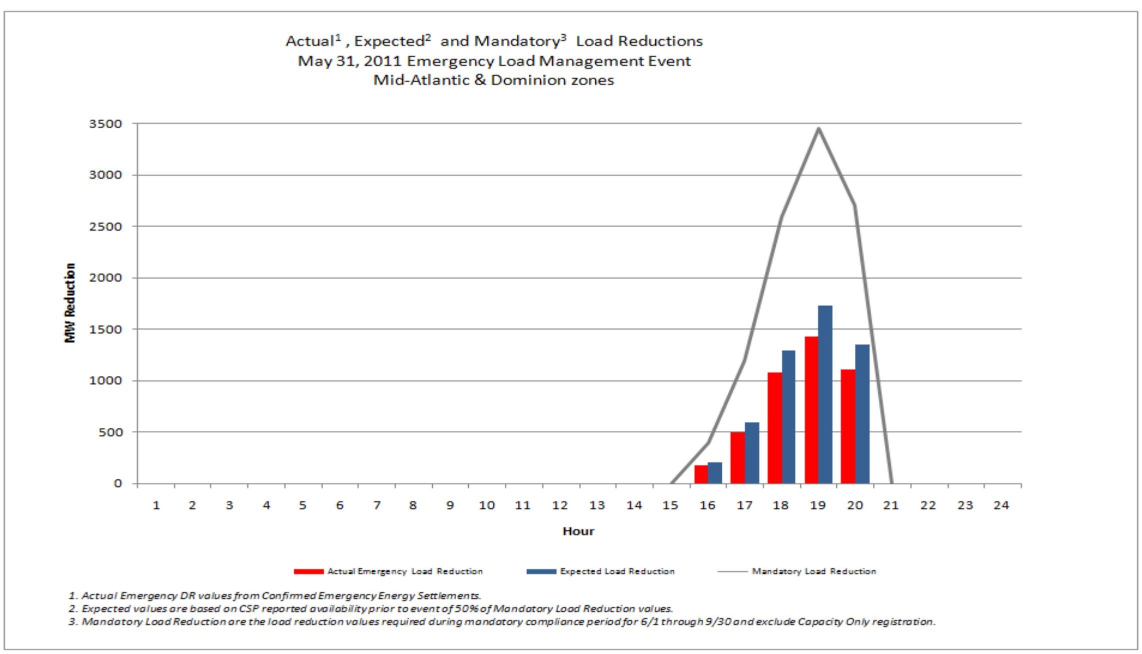
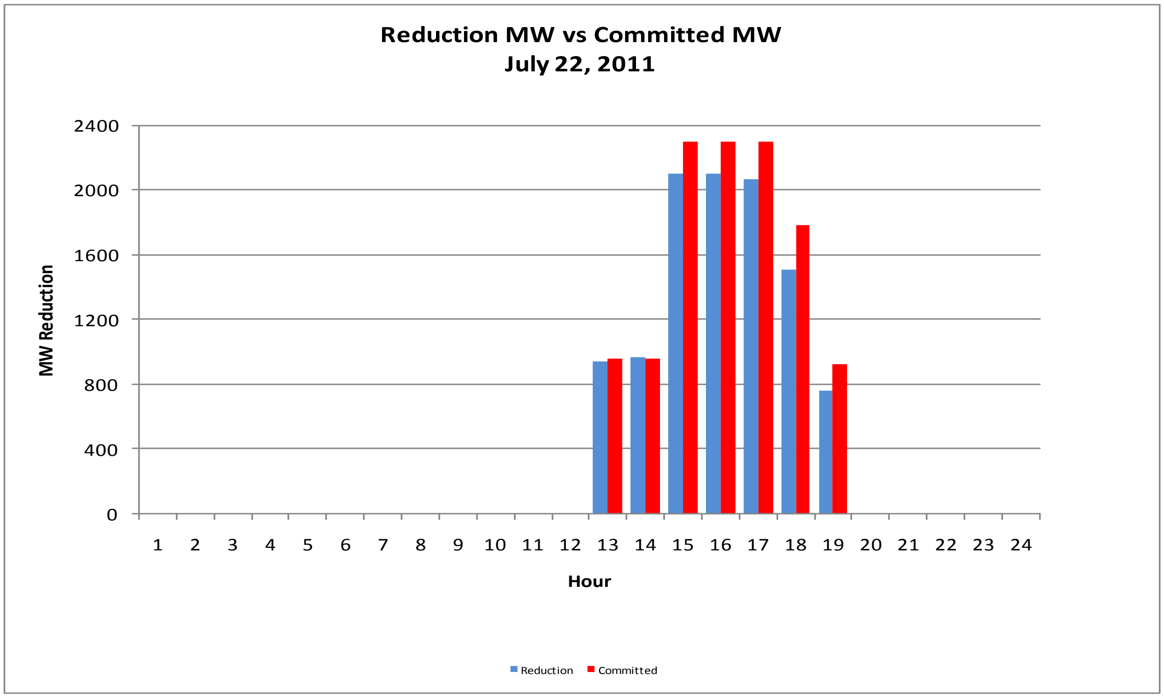


Figure 10: July 22, 2011 Hourly Performance



Event performance measurement can also be broken down by the specific zones called upon and the lead time of the resources. Long lead time resources were called on for both events in May. The May 26th event was in the Norfolk subzone of Dominion and the 31st event was in the Mid-Atlantic zones. The July 22, 2011 event was called in six zones for long lead time resources. In the BGE zone short lead time resources were also called. Performance for that Load Management event, by zone and lead time, is depicted in Figure 11 below. Zonal performance ranged from 87% to 106%.

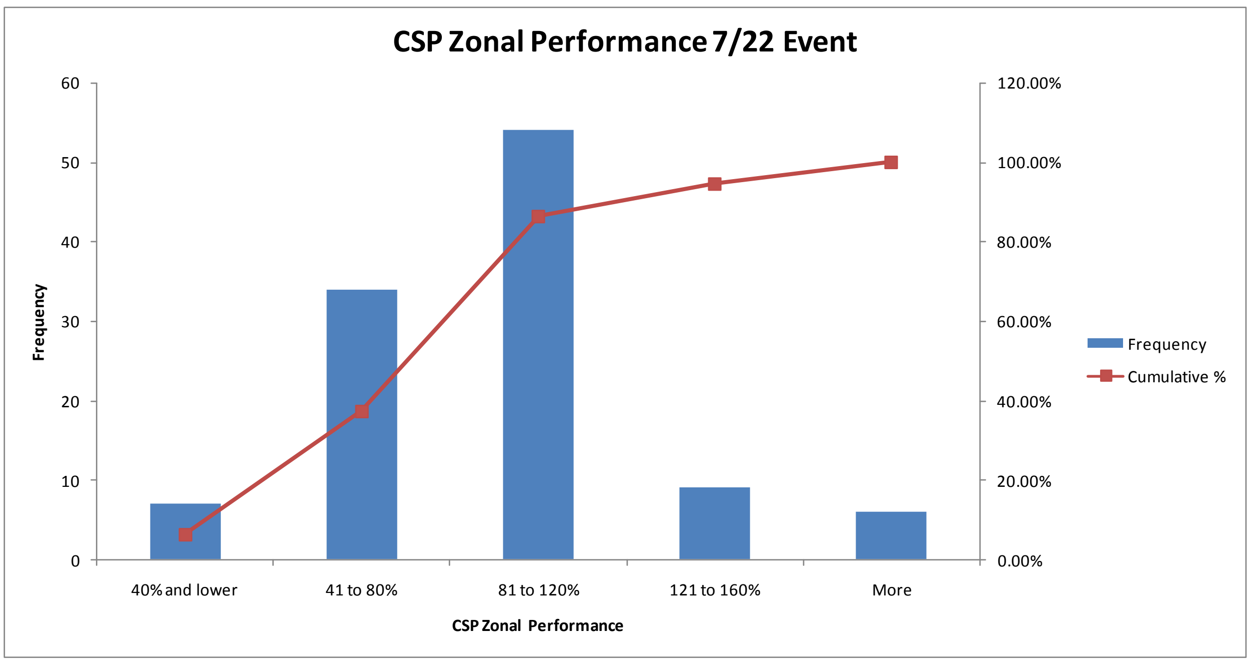
Figure 11: 2011 Load Management Event Performance by Zone

Eventdate	Committed MW	Reduction MW	Performance MW	Performance Percentage	Zone	Lead Time
5/26/2011	71	58	-13	82%	DOM	Long
5/31/2011	756	655	-101	87%	Mid-Atlantic	Long
5/31/2011	277	201	-76	73%	DOM	Long
7/22/2011	518	522	4	101%	BGE	Short
7/22/2011	439	440	1	100%	BGE	Long
7/22/2011	167	128	-39	77%	DPL	Long
7/22/2011	182	163	-19	90%	DUQ	Long
7/22/2011	177	141	-36	80%	JCPL	Long
7/22/2011	240	206	-34	86%	METED	Long
7/22/2011	573	497	-76	87%	PECO	Long
Notes on May 26 and 31: Events were in DY 2010/2011 outside of compliance measurement period. Committed MW is average expected MW.						

CSP Events Performance

CSP performance is measured for each event by zone for all resources that were dispatched by PJM. The combined ILR and DR reductions made in a zone are compared to each CSP's reduction commitment. Under performance is penalized and over performance can be rewarded (within limits and to the extent that there were underperformance penalties paid, see Event Performance Penalties). Figure 12 below depicts the performance of all CSP/zone combinations over the July 2011/2012 DY Load Management event. It can be seen that performance is approximately normally distributed. Fifty-six percent of CSPs zonal performance was within the 81% to 120% range while 88% were between 41% and 160%. And, as expected, some performed better, others worse.

Figure 12: CSP Zonal Performance 7/22 Event



When comparing the event performance in 2011 with that of 2010 we see shifted results. In 2011 the CSP zonal performance shows a measurable shift out of the 81% to 120% and 121% to 160% categories into the 41 to 80% range – consistent with the lower 2011 event performance results. The portion of CSP zonal performance at both tails of the distribution was virtually unchanged. Figure 13 below depicts the performance of all CSP/zone combinations over all of both the 2010 and 2011 Load Management events. It should be noted that there was only a single compliance event in 2011 as compared to five in 2010.

Figure 13: CSP Zonal Performance 2010 vs. 2011

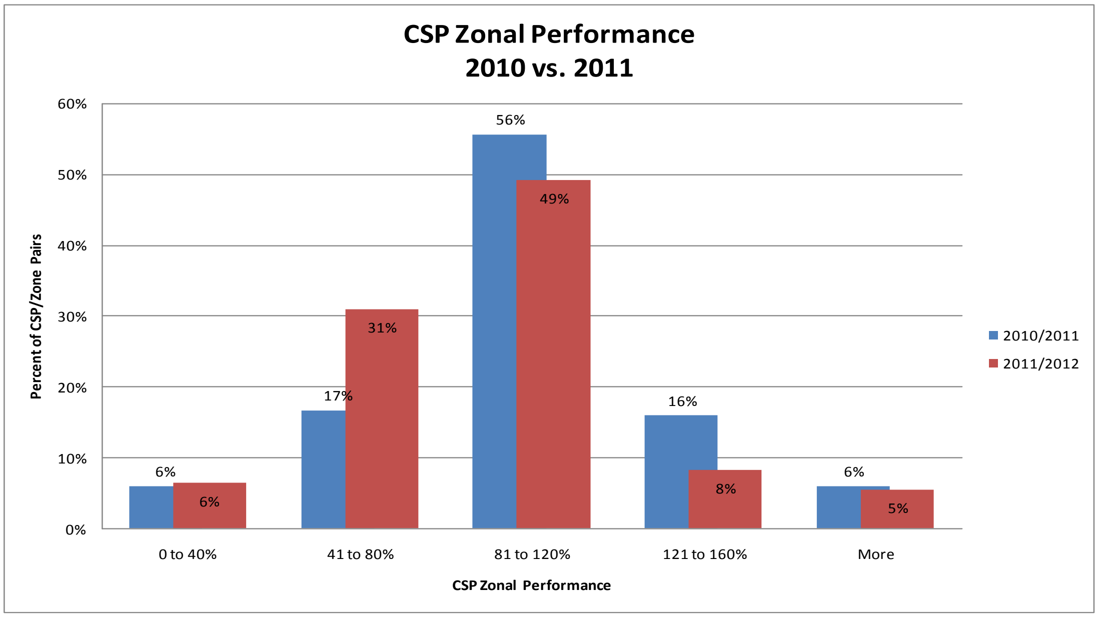
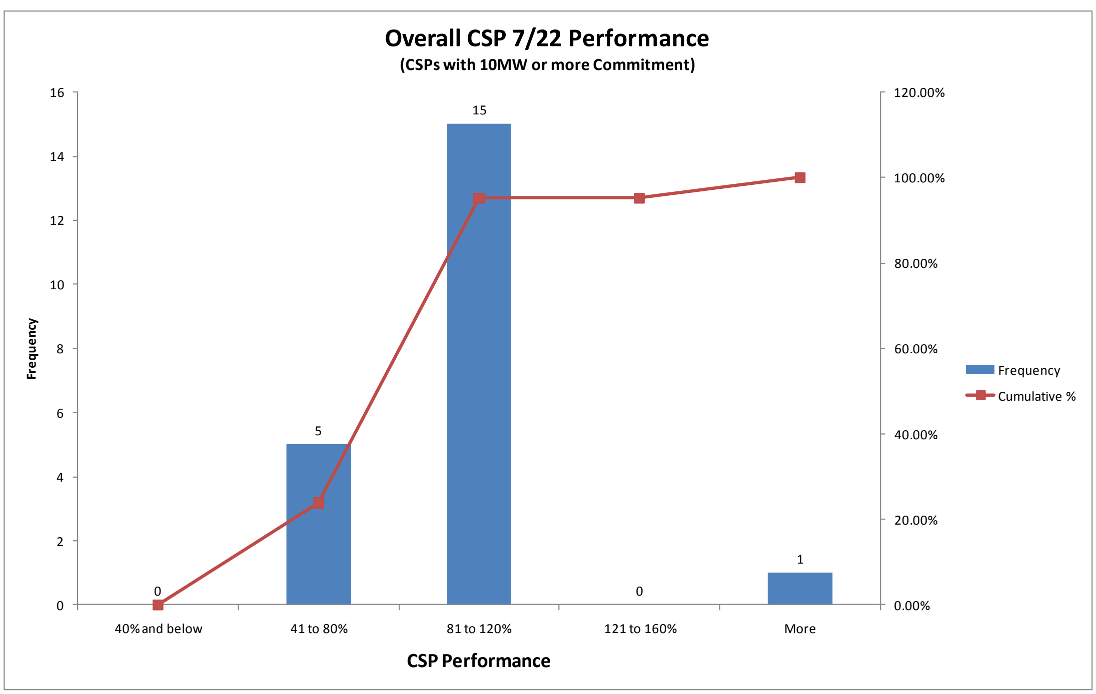


Figure 14 shows the combined – across zones -- performance of large CSPs for the event. There were 21 CSPs with commitments of at least 10MWs. For purposes of the analysis these are considered large CSPs. The majority performed in the normal range, but a sizeable number were in the 41 to 80 percent range. One large CSP showed performance above 160% and none of them had performance score below 40%.

Figure 14: Overall Large CSP July 22 Performance



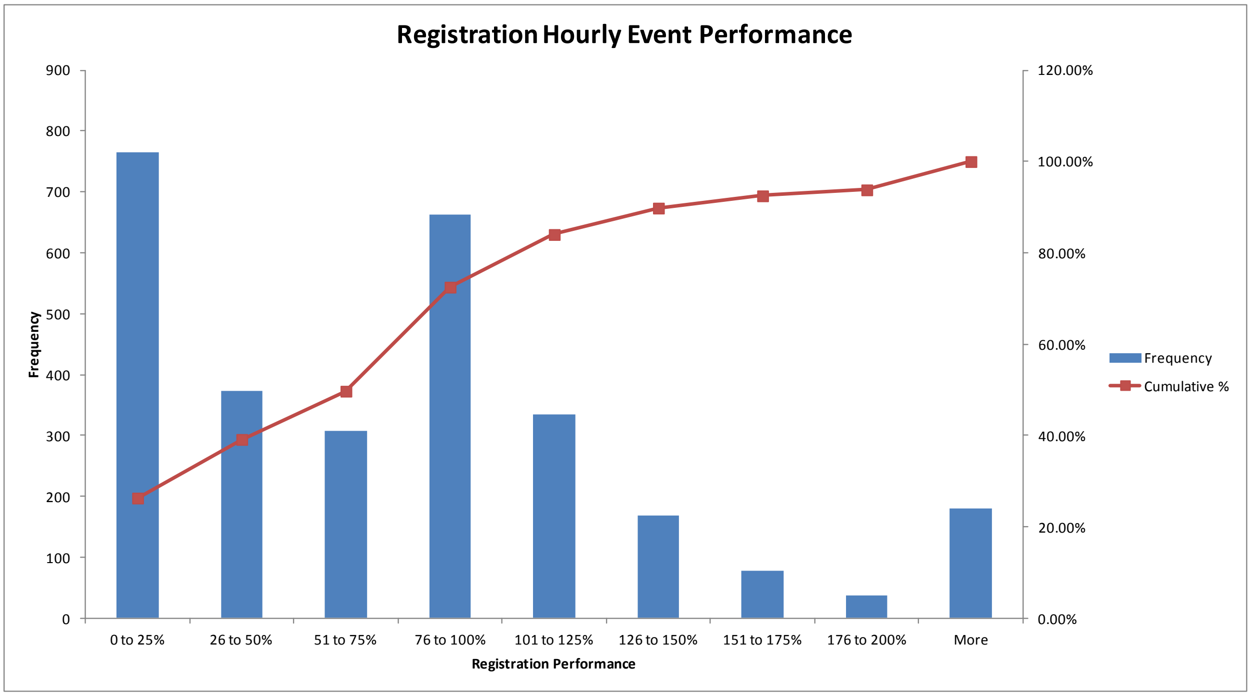
Registration Events Performance

Although CSP compliance is aggregated to a zonal level, PJM initially calculates performance by registration by end use customer by event by hour. Figure 15 below depicts the individual hourly performance of each registration called on for the 2011 Load Management events. Unlike the CSP performance above, the registration performance does not exhibit a normal distribution. Rather, the distribution has significant amount of activity in each "tail" which represents more extreme hourly resource event under and over performance. These tails represent large numbers of registrations with low performance values (less than 25%) and another group with high performance values (greater than 200%) which offset through the aggregation of overall portfolio performance.

This effect is when, within a CSPs portfolio of registrations, some registrations over perform for the benefit of those that under perform yielding an aggregate performance that is satisfactory. The high performance can come from two possible situations. First, a site with a relatively high PLC may conservatively register with a reduction commitment that is much lower than the PLC and when called on to perform, would provide a reduction well in excess of its' registered commitment. The second situation is when a site with a relatively low PLC (i.e. a site that makes an effort to lower its load on days likely to be peak load days in order to avoid a high capacity cost) registers with a low reduction commitment because it is limited by its low PLC. However, when this site is called on to perform, it will provide a reduction well in excess of its registered commitment. In both situations the excess reductions are applied to the CSP's portfolio and can offset under-performers[10].

[10] This second situation raises both a compliance and policy issue and was discussed at length in the Load Management Task Force, Markets Implementation Committee and reviewed at the Markets and Reliability Committee. Namely, should reductions achieved by registrations whose load was above its PLC (high reduction to PLC ratio registrations) at the time of the event be available to offset underperformance of other registrations. The "high reduction to PLC ratio" registrations have already received a benefit for the reductions through a reduced PLC and the resultant low capacity cost. The FERC has issued an order disallowing these reductions in the future. The order has a provision to allow a three year transition period.

Figure 15: Registration Hourly Event Performance



Event Performance Penalties

Load Management Event Penalties are assessed by CSP and zone and then disbursed to CSPs that over-perform and where necessary to LSEs. However, to preserve confidentiality, the results are reported on an aggregated basis. Load Management Event Penalties and Credits are currently billed as an annual lump sum. Figure 16 summarizes the annual charges and credits by Event. The total amount of Load Management Event Penalties assessed for the 2011 events is $5.6 million/year. To put this value into context it is important to note that total CSP revenues for ILR and DR are approximately $420 million per year. The penalty charges are about 1.3% of the total revenue. The Load Management Event Charges collected from CSPs are first allocated on a pro-rata basis to those CSPs that provided load reductions in excess of the amount obligated. Any Load Management Event Charges not allocated to over-performing CSPs are further allocated to all LSEs in the RTO pro-rata based on Load Contribution.

Figure 16: Load Management Event Penalties and Credits

	Annual Penalties	Annual Credits to Overperformers	Annual Credits to LSEs
May 26, 2011 LM Event	$ -	$ -	$ -
May 31, 2011 LM Event	$ -	$ -	$ -
July 22, 2011 LM Event	$ 5,609,918.94	$ 622,275.77	$ 4,987,643.17
Total	**$ 5,609,918.94**	**$ 622,275.77**	**$ 4,987,643.17**

Emergency Energy Settlements

For emergency events, Full Emergency type registrations are entitled to submit settlements for the energy reductions provided. The compensation is based on each registration's strike price and the LMPs during the event. Unlike economic settlements, emergency energy settlements do not subtract the retail rate. Figure 17 shows the settlement values for each of the 2011 Load Management Events.

Figure 17: Emergency Energy Settlements for 2011 Events

Load Management Events	Emergency Energy Settlements
5/26/2011	$167,895
5/31/2011	$4,064,090
7/22/2011	$10,601,309
Total	$14,833,294

Reductions for Compliance and Emergency Energy Settlements

Load reductions during emergency events are calculated separately for purposes of compliance and emergency energy settlements. When calculating the reduction values used for compliance, the specific methodology depends on the type selected by the CSP during the registration: GLD, FSL or DLC. For GLD a CSP further determines the specific baseline calculation that results in the best estimate of what the facility's load would have been absent the reduction made for the Load Management event[11]. The CSP has five different calculation methods available to achieve the best estimate. For FSL the CSP simply reports the load level of the facility during the hours of the event

[11] The CSP may also use meter data from a back up generation resource to determine the net metered load reduction at the site.

and that value is subtracted from the PLC. Finally, for DLC the CSP reports exactly when the signal was sent to the end use customers to control the specific switches. Compliance reductions are calculated for all participants of an event.

When calculating reduction values for emergency energy settlements the procedure is different. For GLD and FSL the CSP calculates hourly reductions during events by subtracting the load at the facility during each hour from the load of the facility prior to the start of the event. For DLC, the CSP reports the load reduction from its approved estimation technique. Emergency energy settlements are only available to Full Emergency registrations. In order to receive a payment for an energy reduction the CSP must submit accurate data within the prescribed timeframe (60 days from the event). Not all CSPs submit settlement data and if a facility had already fully reduced its load prior to the event, it cannot receive an emergency energy payment. Further, Emergency Capacity Only registrations by definition do not receive an emergency energy payment.

PJM analyzed compliance and emergency settlement data for the July 7th event for resources registered as Full Emergency to get an understanding of the difference in the measurement of load reduction based on capacity compliance rules compared to emergency energy rules. Average hourly load reductions based on capacity compliance rules were 1,856 MW while average hourly load reductions based on emergency energy settlements for the same hours[12] were 1,724 MW. The 3 primary reasons for the difference are: 1) customers that may have reduced load earlier for the specific day, 2) the fundamental difference in how the load reductions are measured and 3) participants that did not submit the appropriate data for either capacity compliance or energy settlements.

2011 Load Management Tests

The implementation of the forward capacity market, RPM, has incented an increase in capacity-based demand response which has been beneficial to the region. Given the increasing dependence on demand response to maintain reliability, PJM has implemented annual Load Management Tests as a means to assess performance of Load Management resources that had not been called on to participate in an actual emergency event.

The Load Management Test is initiated by a Curtailment Service Provider (CSP) that has a capacity commitment. The CSP must simultaneously test all Resources in a Zone if PJM has not called an event in that Zone by August 15th of a given Delivery Year. If a PJM-initiated Load Management Event is called in a Zone between June 1st and September 30th there is no test requirement and no Test Failure Charges would be assessed to a CSP for that Zone.

The timing of a Load Management Test is intended to represent the conditions when a PJM-initiated Load Management event might occur in order to assess performance during a relative period. Therefore, a Load Management Test may occur from June 1st through September 30th on a non-holiday weekday during any hour from 12 noon until 8 PM EPT. All of a CSP's committed DR and certified ILR resources in the same Zone are required to

[12] Note when evaluating all of the emergency energy settlement hours, which can include hours before and after the hours in the compliance window, the results differ. Reductions based on compliance rules are the same at 1,856 MW, but the average emergency energy settlement value was 1,485 MW.

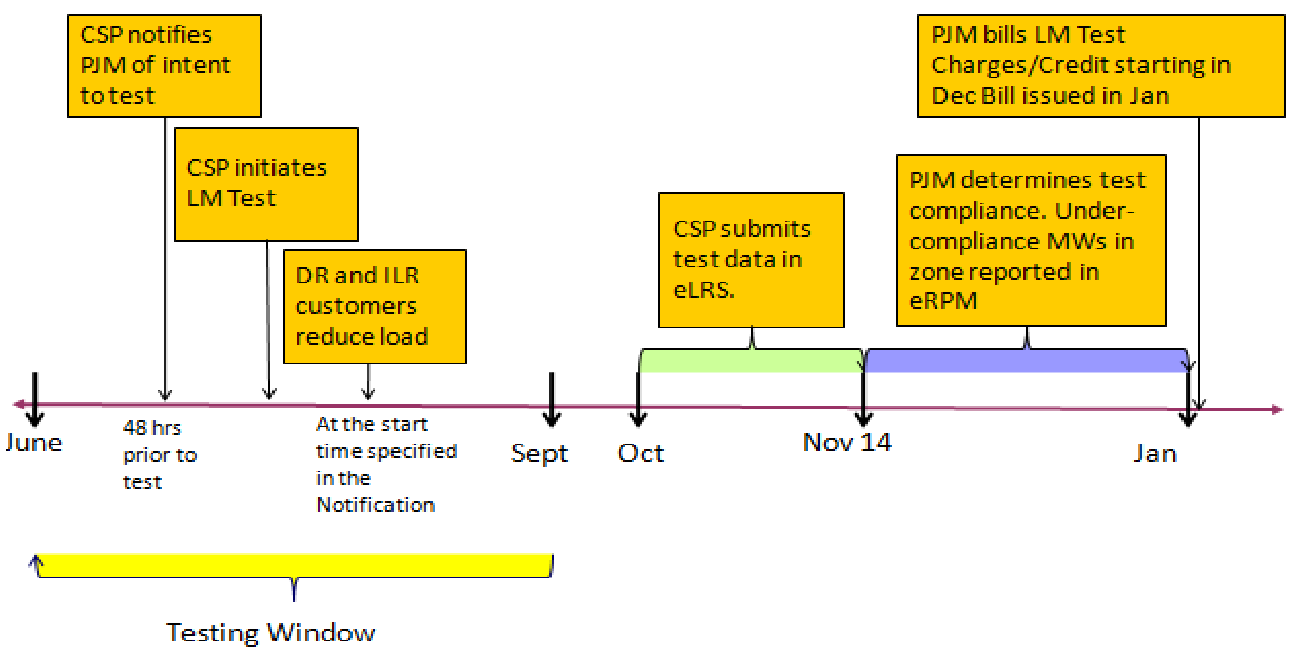
test at the same time for a one hour period. The requirement to test all resources in a zone simultaneously is necessary to ensure that test conditions are as close to realistic as possible. It is requested that the CSP notify PJM of intent to test 48 hours in advance to allow coordination with PJM dispatch.

There is not a limit on the number of tests a CSP can perform. However, a CSP may only submit data for one test to be used by PJM to measure compliance. If the CSP's Zonal Resources collectively achieve a reduction greater than 75% of the CSP's committed MW volume during the test, the CSP may choose to retest the Resources in that Zone that failed to meet their individual nominated value.

New for 2011/2012, CSPs made notification and confirmation of their tests and retests to PJM via eLRS. In previous years the notification process was done via email and confirmation was inferred based on data submissions. The new eLRS functions improved the test/retest administration efficiency by reducing both the number of missed tests and unclear date and times of tests and retests.

CSPs must submit their test data using PJM's Load Response System (eLRS). For the 2011/2012 Delivery Year, the test data deadline was November 14, 2011. PJM reviews the information and contacts the CSP for additional supporting information where necessary. PJM determines test compliance and reports the information in PJM's RPM system (eRPM) during December. Any Load Management charges or credits are normally issued in January on the December bill.

Figure 18: Load Management Test Timeline



Load Management Resources are assessed a Test Failure Charge if their test data demonstrates that they did not meet their commitment level. The Test Failure Charge is calculated based on the CSP's Weighted Daily Revenue Rate which is the amount the CSP is paid for their RPM commitments in each Zone. The Weighted Daily Revenue Rate takes into consideration the different prices DR and ILR can be paid in the same Zone. For example, a CSP can clear DR in the Base Residual and/or Incremental Auctions and/or register ILR in the same Zone, all of which are paid different rates. The penalty rate for under-compliance is the greater of 1.2 times the CSP's Weighted Daily Revenue Rate or $20 plus the Weighted Daily Revenue Rate. If a CSP didn't clear in a RPM auction or certify ILR resources in a Zone, the CSP-specific Revenue Rate will be replaced by the PJM Weighted Daily Revenue Rate for such Zone.

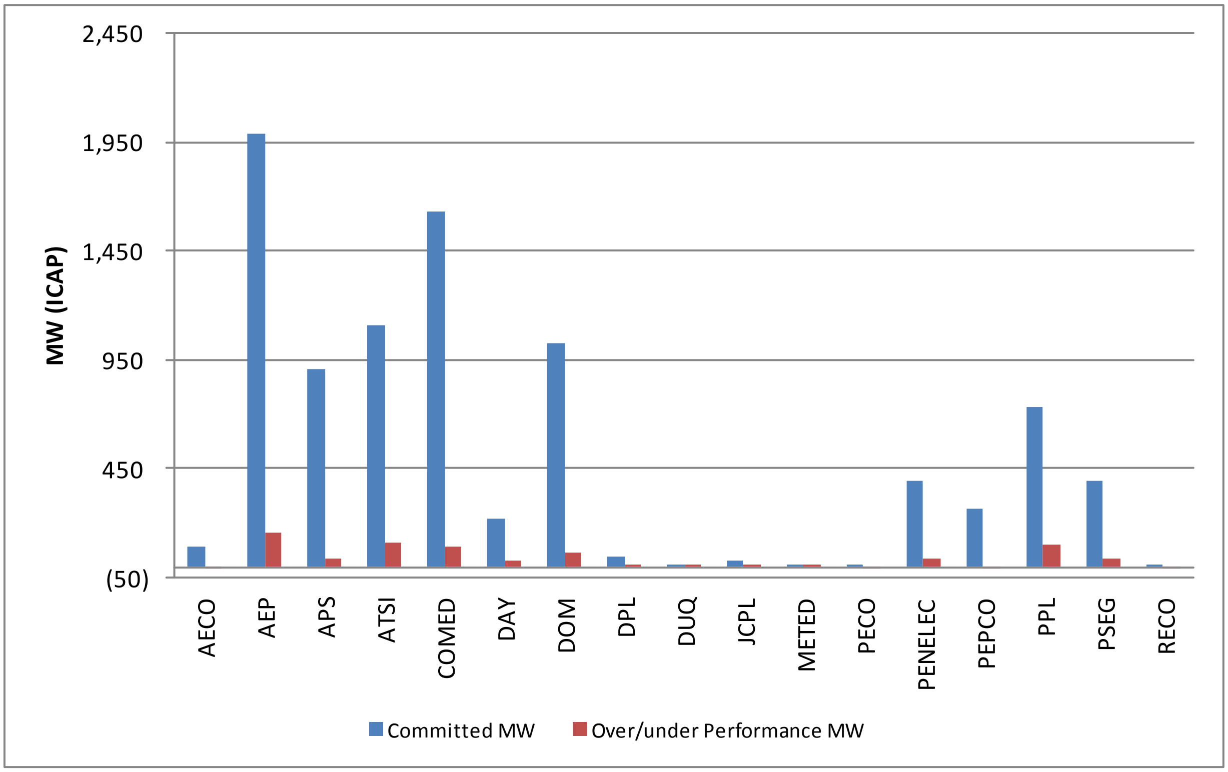
Load Management Test Results

There were 8,860 MW in ICAP of committed Load Management Resources that were not called upon to participate in the 2011/2012 Delivery Year emergency event. As a result, these resources were required to perform a test to assess their performance capability. Testing was performed by 83 CSPs in 17 Zones which resulted in a total of 260 CSP/Zone combinations. The over-compliance across all Zones and CSPs totaled 660 MW which equates to a performance level of 107%. Of the 8,860 MW of committed MWs, 234 MW were retested. Those 234 MW that were retested resulted in zero MW of over-compliance after the retest. In tabular form, the Zonal results are as follows:

Figure 19: Load Management Commitments, Compliance, and Test Performance (ICAP)

Test Results				
Zone	Committed MW	Reduction MW	Over/under Performance MW	Performance Percentage
AECO	90	90	0	100%
AEP	1,991	2,148	157	108%
APS	908	943	35	104%
ATSI	1,107	1,220	113	110%
COMED	1,633	1,729	96	106%
DAY	219	243	25	111%
DOM	1,025	1,088	63	106%
DPL	49	49	0	100%
DUQ	5.9	7.5	1.6	127%
JCPL	27	27	0	100%
METED	3.8	5.2	1.4	136%
PECO	1.4	1.2	-0.2	86%
PENELEC	393	433	40	110%
PEPCO	268	260	-9	97%
PPL	734	837	103	114%
PSEG	398	436	38	110%
RECO	6.4	4.6	-1.8	72%
Total	**8,860**	**9,521**	**660**	**107%**

Figure 20: Load Management Test Obligations and Compliance (ICAP)



The performance on an individual CSP/Zone basis varied. Overall, 191 CSP/Zone combinations complied or over-complied in their Load Management Tests for the 2011/2012 Delivery Year. The over-compliance averaged just over 4 MW per CSP/Zone combination and totaled 792 MW of over-compliance. There were 69 CSP/Zone combinations that under-complied. The under-compliance averaged just over 2 MW per CSP/Zone combination for a total of 132 MW of under-compliance.

Test Failure Charges for the 2011/2012 Delivery Year are applied on an individual CSP/Zone basis for settlement purposes. However, the Test Failure Charges are reported on an aggregate basis here to preserve confidentiality. The average Penalty Rate for the 2011/2012 Delivery Year is $127.87/MW-day. This Penalty Rate is an average of $130.37/day when weighted by the under-compliance amounts. The annual penalties for under-compliance total just over $6.4 million which will be allocated to RPM LSEs pro-rata based on their Daily Load Obligation Ratio. To better understand the order of magnitude, the under-compliance penalties compare to the total Load Management annual credits of just over $420 million. Therefore, the under-compliance penalties are about 1.5% of the Load Management credits in the RPM.

Postings

Postings (/ep/pages/dashboard.jsf) | Message Definitions (/ep/pages/messagedefinitions.jsf) | Message Priorities (/ep/pages/priorities.jsf) | PAH Guidance Matrix (/ep/pages/pahguidances.jsf) | PAH Active Guidance (/ep/pages/activepahguidance.jsf) | Regions (/ep/pages/regions.jsf) | Emergency Bid Form (/ep/pages/bidform.jsf)

Effective From * 07/22/2011 Effective To * 07/22/2011 Regions Message Types PJM Drill Exclude Active Only PAH Only Reset

Last Updated: 05.19.2017 14:22:16 Filters: 07/22/2011 to 07/22/2011; Exclude PJM Drill

Records Per Page: 100 (1 of 1)

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
		All					
	70493 (/ep/pages/\ id=70493)	Alert	Hot Weather Alert	07.18.2011 09:19	PJM-RTO	As of 09:15 hours, a Hot Weather Alert has been issued for 07/21/11 Additional Comments: Forecasted temperature in Philadelphia is 97 degrees.Forecasted temperature in Chicago is 94 degrees.Forecasted temperature in Richmond is 98 degrees.	07.22.2011 14:00
	70494 (/ep/pages/\ id=70494)	Alert	Hot Weather Alert	07.18.2011 09:20	PJM-RTO	As of 09:15 hours, a Hot Weather Alert has been issued for 07/22/11 Additional Comments: Forecasted temperature in Philadelphia is 99 degrees. Forecasted temperature in Chicago is 93 degrees. Forecasted temperature in Richmond is 99 degrees.	07.23.2011 00:05
	70495 (/ep/pages/\ id=70495)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.18.2011 09:40	AEP	As of 09:38 hours, a Non-Market Post Contingency Local Load Relief Warning of 20 MW in the PIPERSGAP/HUFFMAN 138KV area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-contingency low voltage violation at Huffman, Pipersgap, Austinvil and Jubalear(as applicable) 138kv facilities l/o Jacksons Ferry - Huffman 138kv line. No other solution available.	08.05.2011 02:08
	70499 (/ep/pages/\ id=70499)	Informational	Special Notice	07.18.2011 15:26	PJM-RTO	As of 15:00 As of PJM is planning on implementing eDART application upgrades on Wednesday, July 27 starting at 19:00 and ending Thursday, July 28 at 02:00. During the release there will be a few brief 10 minute interruptions to Emergency Procedures. EDART will be unavailable throughout the release. We apologize for any inconvenience this may cause.	07.26.2011 10:50
	70539 (/ep/pages/\ id=70539)	Alert	Maximum Generation Emergency/Load Management Alert	07.20.2011 18:03	MIDATL	As of 18:00 hours, a Maximum Emergency Generation Alert has been issued for 07/21/2011 Maximum Emergency Generation has been called into the operating capacity. Additional Comments: For the day and evening operating period of Thursday July 21, 2011 the PJM Mid-Atlantic control zone estimated operating reserve capacity is 3219 MW and the operating reserve requirement is 4260 MW.	07.22.2011 23:46
	70557 (/ep/pages/\ id=70557)	Warning	Post Contingency Local Load Relief Warning	07.21.2011 10:09	PJM-RTO	As of 10:10 hours, a Post Contingency Local Load Relief Warning of 10MW's MW in the 221 N.Huntly area of ComEd has been issued for Transmission Contingency Control. Additional Comments: 12204 - 141 Pleasant Valley 138kv for the l/o 15616 Cherry Valley-Silver Lake 345kv.	07.22.2011 01:34
	70560 (/ep/pages/\ id=70560)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.21.2011 10:53	AEP	As of 10:50 hours, a Non-Market Post Contingency Local Load Relief Warning of 40 MW in the NWALDO/SHARPROAD/MTVERNON area of AEP has been issued for Transmission Contingency Control. This also covers post-cont low voltages at FULTON, NWALDO, HEDDINGR, SKENTON, WTRINWAY, MILLWOOD, APPLEVAL and ACADEMIA. Additional Comments: Post-cont thermal over LD on NLEXINGT-HOWARD2 l/o ELIMA-SKENTON 138kv.	07.22.2011 00:38
	70564 (/ep/pages/\ id=70564)	Warning	Post Contingency Local Load Relief Warning	07.21.2011 11:50	AEP	As of 11:46 hours, a Post Contingency Local Load Relief Warning of 20 MW in the ENEWCONC/WCAMBRI2 area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on MUSKING2-ENEWCONC l/o KAMMER - S CANTON 765kv line.	07.22.2011 00:38
	70576 (/ep/pages/\ id=70576)	Informational	NERC EEA 1 retired	07.21.2011 21:33	PJMCA	As of 21:30 a NERC EEA 1 has been issued. NERC Energy Emergency Alert (EEA) 1 is issued concurrent with a Max Emergency Generation Alert and is posted on the NERC Reliability Coordinator Information System (RCIS). Additional Comments: For Friday 22-July-2011 for the Mid-Atlantic Control Zone ONLY. Mid-Atlantic Reserve Objective is 4,354 MWs and the Estimated Mid-Atlantic Reserves are 3,744 MWs.	07.22.2011 23:46
	70578 (/ep/pages/\ id=70578)	Informational	TLR Level 1	07.21.2011 22:30	PJM-RTO	As of 22:30 hours, a TLR Level 1 has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 10:44

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
		All					
	70579 (/ep/pages/\ id=70579)	Warning	Post Contingency Local Load Relief Warning	07.21.2011 23:02	BGE	As of 22:58 hours, a Post Contingency Local Load Relief Warning of 15 MW in the Dolefield, Finksburg&Westminster area of BGE has been issued for Transmission Contingency Control. Additional Comments: Issued for 15mw for the Granite-Harrison 110560-A for l/o Northwest 230-3 xfrm	07.22.2011 00:43
	70591 (/ep/pages/\ id=70591)	Warning	HLV Warning	07.22.2011 07:25	PJM-RTO	As of 07:13 a Heavy Load Voltage Schedule Warning has been issued.	07.22.2011 20:00
	70592 (/ep/pages/\ id=70592)	Alert	Hot Weather Alert	07.22.2011 07:26	PJM-RTO	As of 07:20 hours, a Hot Weather Alert has been issued for 07/23/2011 Additional Comments: Forecasted temperatures 103 and THI 87	07.22.2011 23:46
	70593 (/ep/pages/\ id=70593)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 09:10	MIDATL	As of 09:02 hours, a Post Contingency Local Load Relief Warning of 10 MW in the area of FE (PN) has been issued for Transmission Contingency Control. Additional Comments: Hooversville-Scalp Level l/o Johnstown #2 TX	07.22.2011 22:44
	70594 (/ep/pages/\ id=70594)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 09:28	PJM-RTO	As of 09:21 hours, a Non-Market Post Contingency Local Load Relief Warning of 10 MW in the 12th and Irving area of PEPCO has been issued for Transmission Contingency Control. Additional Comments: 12th St-Benning 69048R loss of 12th St-Benning 69049R & 12th St-Benning 69049R loss of 12th St-Benning 69048R	07.22.2011 21:42
	70595 (/ep/pages/\ id=70595)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 09:38	MIDATL	As of 09:36 hours, a Post Contingency Local Load Relief Warning of 20 MW in the area of FE (PN) has been issued for Transmission Contingency Control. Additional Comments: Buffalo-Erie S l/o GESG Tap	07.22.2011 22:44
	70596 (/ep/pages/\ id=70596)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 09:39	PJM-RTO	As of 11:09 hours, a Post Contingency Local Load Relief Warning of 80 MW in the Harrisonville, Dolfield, Plesant Hill, White Rock area of BGE has been issued for Transmission Contingency Control. Additional Comments: Granite to Harrisonville 110-560A l/o Northwest 230-3 XF.	07.22.2011 14:57
	70597 (/ep/pages/\ id=70597)	Informational	Emerg Mndtry Load Mgmt Long Lead 1-2Hrs retired	07.22.2011 09:57	BGE	As of 10:00 hours (Alert Time), Emergency Mandatory Load Management with Long Lead Time has been issued. Load reduction is expected to be fully implemented within 2 hours of this Alert Time (or 12:00) and should remain off for 6 hours unless released earlier by PJM. Emergency Mandatory Load Management with Long Lead Time is in effect for the BGE Control Zone(s) only. Additional Comments: BGE zone only.	07.22.2011 18:00
	70598 (/ep/pages/\ id=70598)	Informational	Emerg Mndtry Load Mgmt Long Lead 1-2Hrs retired	07.22.2011 10:04	BGE	As of 10:00 hours (Alert Time), Emergency Mandatory Load Management with Long Lead Time has been issued. Load reduction is expected to be fully implemented within 2 hours of this Alert Time (or 12:00) and should remain off for 6 hours unless released earlier by PJM. Emergency Mandatory Load Management with Long Lead Time is in effect for the BGE Control Zone(s) only. Additional Comments: 12:00 - 18:00	07.22.2011 18:00
	70599 (/ep/pages/\ id=70599)	Informational	NERC EEA 2 retired	07.22.2011 10:07	BGE	As of 10:00 hours, a NERC EEA 2 has been issued. NERC Energy Emergency Alert (EEA) 2 is issued concurrent with the implementation of Emergency Mandatory Load Management Long Lead Time and/or Short Lead Time and is posted on the NERC Reliability Coordinator Information System (RCIS). Additional Comments: ACTIVATED LOAD MGT	07.22.2011 20:04
	70600 (/ep/pages/\ id=70600)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 10:26	MIDATL	As of 10:24 hours, a Post Contingency Local Load Relief Warning of 10 MW in the area of FE (PN) has been issued for Transmission Contingency Control. Additional Comments: Edgewood-Shelocta l/o Colver Power TX	07.22.2011 22:44
	70601 (/ep/pages/\ id=70601)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 10:27	PJM-RTO	As of 10:20 hours, a Post Contingency Local Load Relief Warning of 25 MW in the Leside area of ATSI has been issued for Transmission Contingency Control. Additional Comments: Galion-Leside l/o Galion-GM	07.22.2011 20:37
	70602 (/ep/pages/\ id=70602)	Action	HLV Action	07.22.2011 10:27	PJM-RTO	As of 10:20 a Heavy Load Voltage Schedule Action has been issued.	07.22.2011 20:00
	70603 (/ep/pages/\ id=70603)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 10:33	AEP	As of 10:31 hours, a Post Contingency Local Load Relief Warning of 10 MW in the ENEWCONC/WCAMBRI2 area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on MUSKING2-ENEWCONC l/o KAMMER - SOUTH CANTON.	07.22.2011 18:25

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
	70604 (/ep/pages/\ id=70604)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 10:35	AEP	As of 10:33 hours, a Post Contingency Local Load Relief Warning of 30 MW in the CARBOND2/MONTGOMR area of AEP has been issued for Transmission Contingency Control. Post-cont switching to relieve actual overload agreed to be APS: open 138kv Durbin CB @ Pickens and 138kv CB at Powell Mountain. Additional Comments: Post-cont thermal violation on CARBOND2-KANAWHAR l/o KAMMER-BELMONT-MOUNTAINEER.	07.22.2011 18:25
	70605 (/ep/pages/\ id=70605)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 10:41	AEP	As of 10:36 hours, a Non-Market Post Contingency Local Load Relief Warning of 50 MW in the MWBLOOMF/FULTON/ACADEMIA area of AEP has been issued for Transmission Contingency Control. Also covers LYNNST-SKENTON and ELIMA-WNEWTON. Additional Comments: Post-cont thermal on LYNNST-WNEWTON l/o ACADEMIA-HOWARD circuit.	07.22.2011 12:44
	70606 (/ep/pages/\ id=70606)	Informational	TLR Level 3a	07.22.2011 10:44	PJM-RTO	As of 10:44 hours, a TLR Level 3A has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 20:27
	70607 (/ep/pages/\ id=70607)	Informational	Emerg Mndtry Load Mgmt Short Lead < 1Hr retired	07.22.2011 10:52	BGE	As of 11:00 hours (Alert Time), Emergency Mandatory Load Management with Short Lead Time has been issued. Load reduction is expected to be fully implemented within 1 hour of this Alert Time (or 12:00) and should remain off for 6 hours unless released earlier by PJM. Emergency Mandatory Load Management with Short Lead Time is in effect for the BGE Control Zone(s) only. Additional Comments: BGE zone only.	07.22.2011 17:30
	70608 (/ep/pages/\ id=70608)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 10:56	PJM-RTO	As of 10:55 hours, a Post Contingency Local Load Relief Warning of 40 MW in the Crescent area of DLCO (Duquesne) has been issued for Transmission Contingency Control. Additional Comments: Crescent Tx#1 l/o Tx#2.	07.22.2011 22:16
	70609 (/ep/pages/\ id=70609)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 10:59	AEP	As of 10:55 hours, a Non-Market Post Contingency Local Load Relief Warning of 30 MW in the FULTON/ACADEMIA/SHARPROAD/SKENTON area of N/A has been issued for Transmission Contingency Control. Additional Comments: Post-cont low voltage over load dump for the areas listed below l/o ACADEMIA-HOWARD 138kv circuit. AREAS: HEDDINGR, FULTON, SHARPROAD, ACADEMIA, NWALDO, SKENTON.	07.22.2011 12:26
	70610 (/ep/pages/\ id=70610)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 11:13	PJM-RTO	As of 11:09 hours, a Post Contingency Local Load Relief Warning of 50 MW in the Riverside, Gray Manor, Riverside area of BGE has been issued for Transmission Contingency Control. Additional Comments: Riverside 115 kV SD1 for the loss of the Riverside #2 230/115 kV transformer.	07.22.2011 21:46
	70611 (/ep/pages/\ id=70611)	Informational	Emerg Mndtry Load Mgmt Long Lead 1-2Hrs retired	07.22.2011 11:32	PJM-RTO	As of 11:30 hours (Alert Time), Emergency Mandatory Load Management with Long Lead Time has been issued. Load reduction is expected to be fully implemented within 2 hours of this Alert Time (or 13:30) and should remain off for 6 hours unless released earlier by PJM. Emergency Mandatory Load Management with Long Lead Time is in effect for the following Control Zone(s) only. Additional Comments: DPL, DUQ, JCPL, ME, PECO zones only.	07.22.2011 19:37
	70612 (/ep/pages/\ id=70612)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 11:33	PJM-RTO	As of 11:30 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Highland area of DLCO (Duquesne) has been issued for Transmission Contingency Control. Additional Comments: Arsenal-Highland Z68 l/o Dravosburg T1 Tx	07.23.2011 00:03
	70613 (/ep/pages/\ id=70613)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 11:39	PJM-RTO	As of 11:38 hours, a Post Contingency Local Load Relief Warning of 10 MW in the North area of DLCO (Duquesne) has been issued for Transmission Contingency Control. Additional Comments: Crescent-North Z20 l/o Cres.-Mt.Nebo Z21	07.22.2011 22:15
	70614 (/ep/pages/\ id=70614)	Action	Maximum Generation Emergency Action Trans retired	07.22.2011 11:47	BGE	As of 11:27 hours, a Maximum Emergency Generation Action has been issued in BGE area of BGE for Transmission Contingency Control. Additional Comments: BGE zone only. DO NOT LOAD. PJM will call to load units on an individual basis	07.22.2011 20:00
	70615 (/ep/pages/\ id=70615)	Action	Maximum Generation Emergency Action Trans retired	07.22.2011 11:51	MIDATL	As of 11:45 hours, a Maximum Emergency Generation Action has been issued in MID ATLANTIC ZONE area of PSEG for Transmission Contingency Control. Additional Comments: For the entire MID ATLANTIC ZONE. DO NOT LOAD. PJM will call to load on an individual basis	07.22.2011 20:00
	70616 (/ep/pages/\ id=70616)	Action	Maximum Generation Emergency Action Trans retired	07.22.2011 11:53	DUQ	As of 11:45 hours, a Maximum Emergency Generation Action has been issued in DUQ area of DLCO (Duquesne) for Transmission Contingency Control. Additional Comments: DO NOT LOAD. PJM will call to load on an individual basis	07.22.2011 20:00

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
		All					
	70617 (/ep/pages/\ id=70617)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 11:57	PJM-RTO	As of 11:52 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Harrington area of DPL (Delmarva) has been issued for Transmission Contingency Control. Additional Comments: Bridgeville - Taylor 6737-1 l/o South Harrington 138/69kv transformer. DPL will open T-2 @ Harrington to alleviate overload post contingency.	07.22.2011 13:04
	70618 (/ep/pages/\ id=70618)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:16	PJM-RTO	As of 12:15 hours, a Post Contingency Local Load Relief Warning of 25 MW in the Riverside, Gray Manor area of BGE has been issued for Transmission Contingency Control. Additional Comments: Riverside SD2 l/o Brandon Shore - Riverside 2344 and #1 XF.	07.22.2011 21:46
	70619 (/ep/pages/\ id=70619)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:34	PJM-RTO	As of 12:00 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Carbon Center area of APS has been issued for Transmission Contingency Control. Additional Comments: Carbon-Center-Elko l/o Elko T1 Tx	07.23.2011 00:05
	70620 (/ep/pages/\ id=70620)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:38	PJM-RTO	As of 12:00 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Kingwood area of APS has been issued for Transmission Contingency Control. Additional Comments: Kingwood-Pruntytown l/o Hatfield- Ronco. Post contingency switching solution; Open N-S 138kv B.T. @ Albright.	07.22.2011 21:03
	70621 (/ep/pages/\ id=70621)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:39	AEP	As of 12:36 hours, a Post Contingency Local Load Relief Warning of 50 MW in the RUTH/CHESTER2 area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal overload on Ruth-Turner l/o Kanawha River transformer.	07.22.2011 18:25
	70622 (/ep/pages/\ id=70622)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 12:55	PJM-RTO	As of 13:52 hours, a Non-Market Post Contingency Local Load Relief Warning of 25 MW in the Atco area of AE (Atlantic Elec) has been issued for Transmission Contingency Control. Additional Comments: Atco-Tansboro 6707 l/o Cox Corner - Lumberton & Lumberton transformer. Added Atco - Tabernacle @ 13:52.	07.22.2011 21:48
	70623 (/ep/pages/\ id=70623)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:55	AEP	As of 12:48 hours, a Post Contingency Local Load Relief Warning of 0 MW in the WBELAI2 area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-contigency, and actual overload, switching for TILTONSVILLE-WINDSOR l/o HATFIELD-RONCO or actual overload. Open WEST BELLAIR 345/138kv trans opening low side 138kv E and E2 CBs.	07.22.2011 18:25
	70624 (/ep/pages/\ id=70624)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:56	PJM-RTO	As of 12:00 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Kittanning area of APS has been issued for Transmission Contingency Control. Additional Comments: Alldam-Kittanning l/o Erie W.-Ashtabula-Perry. Post contingency switching solution;Open Burma breaker @ Armstrong.	07.22.2011 22:19
	70625 (/ep/pages/\ id=70625)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 12:58	AEP	As of 12:55 hours, a Post Contingency Local Load Relief Warning of 50 MW in the OHIOCENT/WTRINWAY area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on CONEPREP-CONESVILLE and OHIOCENT-CONEPREP l/o MUSKRIV - OHIO CENTRAL 345kv.	07.22.2011 18:25
	70626 (/ep/pages/\ id=70626)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:05	AEP	As of 13:03 hours, a Post Contingency Local Load Relief Warning of 30 MW in the WOLFCREE/LAYMAN area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on WOLFCREE T2 transformer and MUSKINGU-WOLFCREE l/o KAMMER-BELMONT-MOUNTAIEER 765kv.	07.22.2011 18:25
	70627 (/ep/pages/\ id=70627)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:12	AEP	As of 13:11 hours, a Post Contingency Local Load Relief Warning of 15 MW in the HEATH area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on HEATH-WMILLER l/o MUSKINGU-OHIOCENTRAL.	07.22.2011 18:25
	70628 (/ep/pages/\ id=70628)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:21	AEP	As of 13:16 hours, a Post Contingency Local Load Relief Warning of 15 MW in the MILLSPRI/WAKEFIELD area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on MARQUIS2 XF3 l/o MARQUIS and MARQUIS2-DOEX53.	07.22.2011 18:25
	70629 (/ep/pages/\ id=70629)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 13:30	MIDATL	As of 13:25 hours, a Non-Market Post Contingency Local Load Relief Warning of 25 MW in the area of PECO has been issued for Transmission Contingency Control. Additional Comments: NPhiladephia-Waneeta 220-49 l/o 220-17	07.22.2011 14:22

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
		All					
	70630 (/ep/pages/v id=70630)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:31	AEP	As of 13:28 hours, a Post Contingency Local Load Relief Warning of 10 MW in the IVYHILL/REUSENS area of AEP has been issued for Transmission Contingency Control. Additional Comments: Post-cont thermal violation on CLOVERDALE-IVHILL l/o JOSHUA FALLS XF.	07.22.2011 21:09
	70631 (/ep/pages/v id=70631)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:41	PSEG	As of 13:36 hours, a Post Contingency Local Load Relief Warning of 25 MW in the Lumberton area of PSEG has been issued for Transmission Contingency Control. Additional Comments: For Cox's Corner - Lumberton on L/O Smithburg - East Windsor Post Contingency Switching available	07.22.2011 17:35
	70632 (/ep/pages/v id=70632)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:41	PJM-RTO	As of 13:20 hours, a Post Contingency Local Load Relief Warning of 15 MW in the Windsor area of APS has been issued for Transmission Contingency Control. Additional Comments: Tiltonsville-Windsor l/o Hatfield-Ronco	07.22.2011 21:01
	70633 (/ep/pages/v id=70633)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:43	GPU	As of 13:37 hours, a Post Contingency Local Load Relief Warning of 25 MW in the Smithburg area of FE (JC) has been issued for Transmission Contingency Control. Additional Comments: For East Windsor - Smithburg on L/O Oyster Creek 1 Post Contingency Switching available	07.22.2011 17:33
	70634 (/ep/pages/v id=70634)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:54	PJM-RTO	As of 13:49 hours, a Post Contingency Local Load Relief Warning of 12mws MW in the Corson area of AE (Atlantic Elec) has been issued for Transmission Contingency Control. Additional Comments: Corson #1 XF l/o Corson #2 XF.	07.22.2011 23:46
	70635 (/ep/pages/v id=70635)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 13:58	PJM-RTO	As of 13:52 hours, a Post Contingency Local Load Relief Warning of 20 MW in the Williamstown, Washington Twp area of AE (Atlantic Elec) has been issued for Transmission Contingency Control. Additional Comments: Monroe #6 XF l/o Monroe #5 XF.	07.22.2011 21:51
	70636 (/ep/pages/v id=70636)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 14:06	PJM-RTO	As of 13:20 hours, a Post Contingency Local Load Relief Warning of 20 MW in the Limekiln area of APS has been issued for Transmission Contingency Control. Additional Comments: Doubs-Limekiln #207 l/o Doubs-Limekiln #231 line.	07.22.2011 21:03
	70637 (/ep/pages/v id=70637)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 14:21	PECO	As of 13:25 hours, a Post Contingency Local Load Relief Warning of 25 MW in the area of PECO has been issued for Transmission Contingency Control. Additional Comments: As of 13:25 hours, a Post Contingency Local Load Relief Warning of 25 MW in the area of PECO has been issued for Transmission Contingency Control. Additional Comments: NPhiladephia-Waneeta 220-49 l/o 220-17	07.22.2011 17:33
	70638 (/ep/pages/v id=70638)	Warning	Post Contingency Local Load Relief Warning	07.22.2011 15:22	GPU	As of 15:21 hours, a Post Contingency Local Load Relief Warning of 10 MW in the Belfast, Glendon, N Bangor area of FE (ME) has been issued for Transmission Contingency Control. Additional Comments: Issued a 10 MW PCLLRW for Northwood 6 bank on loss of Martins Creek Portland 230KV line.	07.22.2011 15:48
	70639 (/ep/pages/v id=70639)	Warning	Non-Market Post Contingency Local Load Relief Warn	07.22.2011 16:05	AEP	As of 16:00 hours, a Non-Market Post Contingency Local Load Relief Warning of 26 MW in the Brooksville area of AEP has been issued for Transmission Contingency Control. Additional Comments: Non-Market PCLLRW issued @ 16:00 for 26MW's in Brooksville area for L/O Reusens-Monel-Gomingo-Joshua Falls 138kv Line. No Post contingency switching available at this time.	07.22.2011 20:02
	70640 (/ep/pages/v id=70640)	Informational	Special Notice	07.22.2011 18:30	MIDATL	As of 18:30 Additional Comments: As of 18:30 hours, Long Lead Time, Emergency Mandatory Load Management has been cancelled in the JCPL and ME Zones only.	07.23.2011 00:03
	70641 (/ep/pages/v id=70641)	Informational	Special Notice	07.22.2011 19:00	MIDATL	As of 19:00 Additional Comments: As of 19:00 hours, Long Lead Time, Emergency Mandatory Load Management has been cancelled in the PECO Zone only.	07.23.2011 00:03
	70642 (/ep/pages/v id=70642)	Informational	Special Notice	07.22.2011 19:30	PJM-RTO	As of 19:30 Additional Comments: As of 19:30 hours, Long Lead Time, Emergency Mandatory Load Management has been cancelled in the DPL and DUQ Zones only.	07.23.2011 00:03
	70643 (/ep/pages/v id=70643)	Informational	TLR Level 1	07.22.2011 20:27	PJM-RTO	As of 20:27 hours, a TLR Level 1 has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 21:20
	70644 (/ep/pages/v id=70644)	Informational	TLR Level 3a	07.22.2011 21:20	PJM-RTO	As of 21:20 hours, a TLR Level 3A has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 22:00

History	Msg ID	Priority	Message Type	Effective Start Time	Regions	Emergency Message	Effective End Time
		All					
	70645 (/ep/pages/\ id=70645)	Informational	TLR Level 1	07.22.2011 22:00	PJM-RTO	As of 22:00 hours, a TLR Level 1 has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 22:55
	70646 (/ep/pages/\ id=70646)	Informational	TLR Level 0	07.22.2011 22:55	PJM-RTO	As of 22:55 hours, a TLR Level 0 has been issued for control of flowgate 310 , Person-Halifax 230 for L/O CARSON-WAKE 500 and 0 Not Applicable and 0 Not Applicable	07.22.2011 22:55

Records Per Page: 100 (1 of 1)

All times are in EPT

 Legal and Privacy (http://pjm.com/about-pjm/legal.aspx) Feedback (http://survey.qualtrics.com/SE/?SID=SV_d6fuIl3F0Cnou5D)

Nonroad Compression-Ignition Engines: Exhaust Emission Standards

	Rated Power (kW)	Tier	Model Year	NMHC (g/kW-hr)	NMHC + NOx (g/kW-hr)	NOx (g/kW-hr)	PM (g/kW-hr)	CO (g/kW-hr)	Smoke [a] (Percentage)	Useful Life (hours /years) [b]	Warranty Period (hours /years) [b]
Federal	kW < 8	1	2000-2004	-	10.5	-	1.0	8.0	20/15/50	3,000/5	1,500/2
		2	2005-2007	-	7.5	-	0.80	8.0			
		4	2008+	-	7.5	-	0.40 [c]	8.0			
	8 ≤ kW < 19	1	2000-2004	-	9.5	-	0.80	6.6		3,000/5	1,500/2
		2	2005-2007	-	7.5	-	0.80	6.6			
		4	2008+	-	7.5	-	0.40	6.6			
	19 ≤ kW < 37	1	1999-2003	-	9.5	-	0.80	5.5		5,000/7 [d]	3,000/5 [e]
		2	2004-2007	-	7.5	-	0.60	5.5			
		4	2008-2012	-	7.5	-	0.30	5.5			
			2013+	-	4.7	-	0.03	5.5			
	37 ≤ kW < 56	1	1998-2003	-	-	9.2	-	-		8,000/10	3,000/5
		2	2004-2007	-	7.5	-	0.40	5.0			
		3 [f]	2008-2011	-	4.7	-	0.40	5.0			
		4 (Option 1) [g]	2008-2012	-	4.7	-	0.30	5.0			
		4 (Option 2) [g]	2012	-	4.7	-	0.03	5.0			
		4	2013+	-	4.7	-	0.03	5.0			
	56 ≤ kW < 75	1	1998-2003	-	-	9.2	-	-			
		2	2004-2007	-	7.5	-	0.40	5.0			
		3	2008-2011	-	4.7	-	0.40	5.0			
		4	2012-2013 [h]	-	4.7	-	0.02	5.0			
			2014+ [i]	0.19	-	0.40	0.02	5.0			
	75 ≤ kW < 130	1	1997-2002	-	-	9.2	-	-			
		2	2003-2006	-	6.6	-	0.30	5.0			
		3	2007-2011	-	4.0	-	0.30	5.0			
		4	2012-2013 [h]	-	4.0	-	0.02	5.0			
			2014+	0.19	-	0.40	0.02	5.0			

Continued

	Rated Power (kW)	Tier	Model Year	NMHC (g/kW-hr)	NMHC + NOx (g/kW-hr	NOx (g/kW-hr	PM (g/kW-hr	CO (g/kW-hr)	Smoke [a] (Percentage)	Useful Life (hours /years) [b]	Warranty Period (hours /years) [b]
Federal	130 ≤ kW < 225	1	1996-2002	1.3 [j]	-	9.2	0.54	11.4	20/15/50	8,000/10	3,000/5
		2	2003-2005	-	6.6	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	225 ≤ kW < 450	1	1996-2000	1.3 [j]	-	9.2	0.54	11.4			
		2	2001-2005	-	6.4	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	450 ≤ kW < 560	1	1996-2001	1.3 [j]	-	9.2	0.54	11.4			
		2	2002-2005	-	6.4	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	560 ≤ kW < 900	1	2000-2005	1.3 [j]	-	9.2	0.54	11.4			
		2	2006-2010	-	6.4	-	0.20	3.5			
		4	2011-2014	0.40	-	3.5	0.10	3.5			
			2015+ [i]	0.19	-	3.5 [k]	0.04 [l]	3.5			
	kW > 900	1	2000-2005	1.3 [j]	-	9.2	0.54	11.4			
		2	2006-2010	-	6.4	-	0.20	3.5			
		4	2011-2014	0.40	-	3.5 [k]	0.10	3.5			
			2015+ [i]	0.19	-	3.5 [k]	0.04 [l]	3.5			

Notes on following page.

Notes:

- For Tier 1, 2, and 3 standards, exhaust emissions of nitrogen oxides (NOx), carbon monoxide (CO), hydrocarbons (HC), and non-methane hydrocarbons (NMHC) are measured using the procedures in 40 Code of Federal Regulations (CFR) Part 89 Subpart E. For Tier 1, 2, and 3 standards, particulate matter (PM) exhaust emissions are measured using the California Regulations for New 1996 and Later Heavy-Duty Off-Road Diesel Cycle Engines.
- For Tier 4 standards, engines are tested for transient and steady-state exhaust emissions using the procedures in 40 CFR Part 1039 Subpart F. Transient standards do not apply to engines below 37 kilowatts (kW) before the 2013 model year, constant-speed engines, engines certified to Option 1, and engines above 560 kW.
- Tier 2 and later model naturally aspirated nonroad engines shall not discharge crankcase emissions into the atmosphere unless these emissions are permanently routed into the exhaust. This prohibition does not apply to engines using turbochargers, pumps, blowers, or superchargers.
- In lieu of the Tier 1, 2, and 3 standards for NOX, NMHC + NOX, and PM, manufacturers may elect to participate in the averaging, banking, and trading (ABT) program described in 40 CFR Part 89 Subpart C.

a Smoke emissions may not exceed 20 percent during the acceleration mode, 15 percent during the lugging mode, and 50 percent during the peaks in either mode. Smoke emission standards do not apply to single-cylinder engines, constant-speed engines, or engines certified to a PM emission standard of 0.07 grams per kilowatt-hour (g/kW-hr) or lower. Smoke emissions are measured using procedures in 40 CFR Part 86 Subpart I.

b Useful life and warranty period are expressed hours and years, whichever comes first.

c Hand-startable air-cooled direct injection engines may optionally meet a PM standard of 0.60 g/kW-hr. These engines may optionally meet Tier 2 standards through the 2009 model years. In 2010 these engines are required to meet a PM standard of 0.60 g/kW-hr.

d Useful life for constant speed engines with rated speed 3,000 revolutions per minute (rpm) or higher is 5 years or 3,000 hours, whichever comes first.

e Warranty period for constant speed engines with rated speed 3,000 rpm or higher is 2 years or 1,500 hours, whichever comes first.

f These Tier 3 standards apply only to manufacturers selecting Tier 4 Option 2. Manufacturers selecting Tier 4 Option 1 will be meeting those standards in lieu of Tier 3 standards.

g A manufacturer may certify all their engines to either Option 1 or Option 2 sets of standards starting in the indicated model year. Manufacturers selecting Option 2 must meet Tier 3 standards in the 2008-2011 model years.

h These standards are phase-out standards. Not more than 50 percent of a manufacturer's engine production is allowed to meet these standards in each model year of the phase out period. Engines not meeting these standards must meet the final Tier 4 standards.

i These standards are phased in during the indicated years. At least 50 percent of a manufacturer's engine production must meet these standards during each year of the phase in. Engines not meeting these standards must meet the applicable phase-out standards.

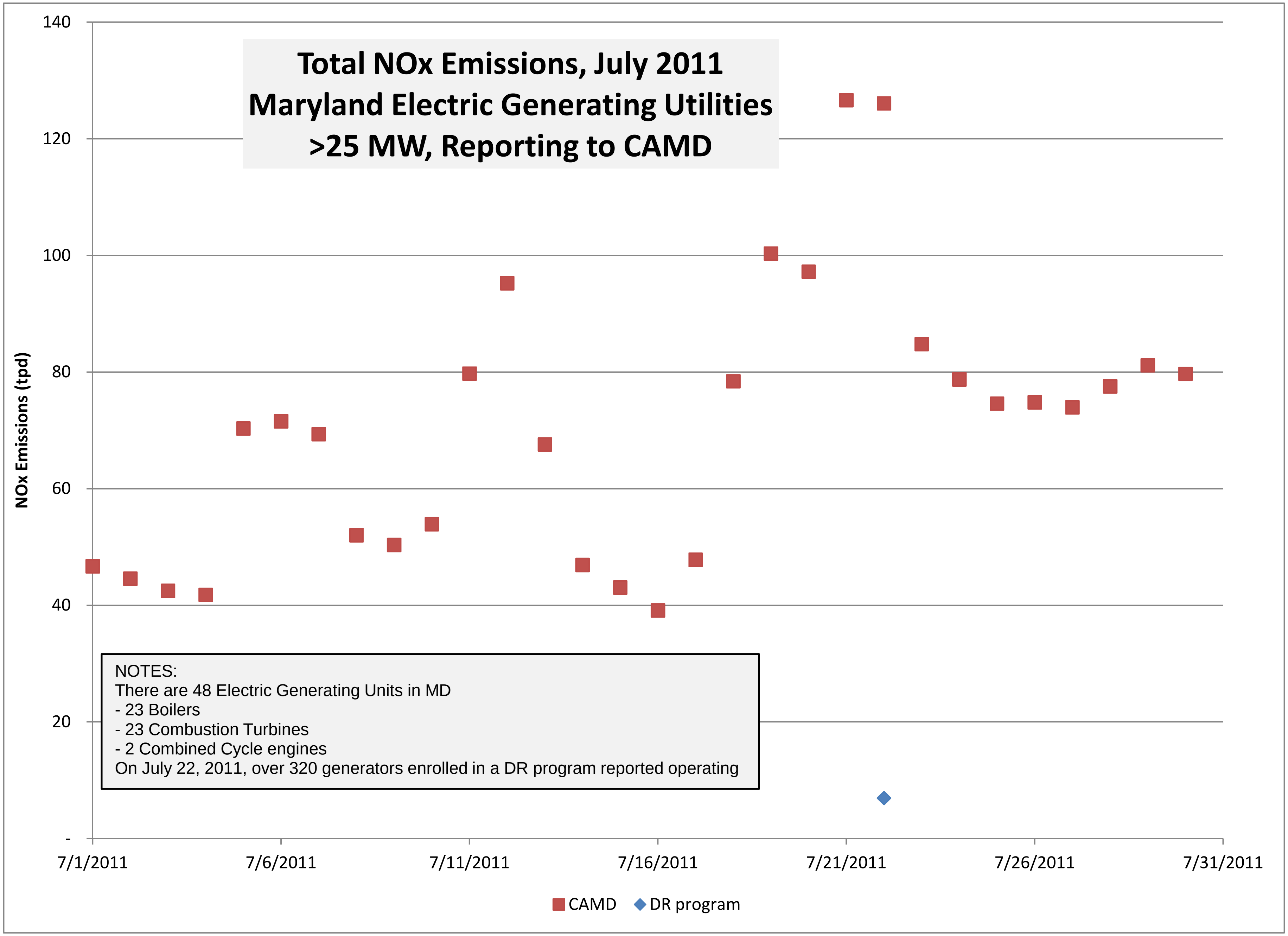
j For Tier 1 engines the standard is for total hydrocarbons.

k The NOx standard for generator sets is 0.67 g/kW-hr.

l The PM standard for generator sets is 0.03 g/kW-hr.

Citations: Code of Federal Regulations (CFR) citations:

- 40 CFR 89.112 = Exhaust emission standards
- 40 CFR 1039.101 = Exhaust emission standards for after 2014 model year
- 40 CFR 1039.102 = Exhaust emission standards for model year 2014 and earlier
- 40 CFR 1039 Subpart F = Exhaust emissions transient and steady state test procedures
- 40 CFR 86 Subpart I = Smoke emission test procedures
- 40 CFR 1065 = Test equipment and emissions measurement procedures


Total NOx Emissions, July 2011
Maryland Electric Generating Utilities
>25 MW, Reporting to CAMD
NOx Emissions (tpd)
140
120
100
80
60
40
20
-
7/1/2011
7/6/2011
7/11/2011
7/16/2011
7/21/2011
7/26/2011
7/31/2011
NOTES:
There are 48 Electric Generating Units in MD
- 23 Boilers
- 23 Combustion Turbines
- 2 Combined Cycle engines
On July 22, 2011, over 320 generators enrolled in a DR program reported operating
CAMD
DR program

2011											
Daily peak 8-hour ozone concentration (ppb) recorded in MD[1]		Demand response		PJM Emergnecy procedure posting - for MIDATL, PJM RTO and BGE only							
			hours, total	emergency voluntary energy only demand response	max emerg gen	max emerg gen/ load management alert	emerg mndtry load mgmt short lead < 1 hr	emerg mndtry load mgmt long lead 1-2 hrs	NERC EEA 1	NERC EEA 2	max emerg gen action trans
		05/01/11	0.35								
		05/24/11									
05/26/11	76	05/26/11	0.33								
05/30/11	76										
05/31/11	85	05/31/11	562.6								
06/01/11	92										
06/02/11	77										
06/07/11	89										
06/08/11	114										
06/09/11	106										
06/10/11	98										
06/18/11	76										
		06/26/11	0.17								
06/28/11	76										
07/01/11	81										
07/02/11	107										
07/03/11	84										
07/05/11	98										
07/06/11	90										
07/07/11	94										
07/12/11	79										
07/18/11	88										
07/19/11	76										
07/20/11	86										
07/21/11	83										
07/22/11	97	07/22/11	4981								
07/23/11	91										
07/26/11	78										
07/28/11	79	07/28/11	0.2								
07/29/11	88										
07/31/11	78										
08/01/11	94										
		08/04/11	6								
		08/17/11	170								
		09/14/11	15								
		09/16/11	55								
		09/24/11	0.15								
		09/27/11	0.5								
			5791.3								

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

2012

PJM Emergnecy procedure posting - for MIDATL, PJM RTO and BGE only

Daily peak 8-hour ozone concentration (ppb)		Demand response	hours, total	emergency voluntary energy only demand response	max emerg gen	max emerg gen/ load management alert	emerg mndtry load mgmt short lead < 1 hr	emerg mndtry load mgmt long lead 1-2 hrs	NERC EEA 1	NERC EEA 2	max emerg gen action trans
05/31/12	80										
		06/03/12	1								
06/09/12	81										
06/10/12	89										
06/19/12	79										
06/20/12	89										
06/21/12	99										
06/22/12	84										
		06/26/12	0.35								
		06/27/12	19								
06/28/12	90										
06/29/12	113	06/29/12	0.2								
06/30/12	83										
07/01/12	83										
		07/02/12	3.5								
07/03/12	88										
07/04/12	82										
07/05/12	91										
07/06/12	84										
07/07/12	101										
07/08/12	86										
07/17/12	95	07/17/12	2								
07/18/12	86	07/18/12	1680								
07/19/12	87										
07/23/12	78	07/23/12	0.6								
07/26/12	83										
08/02/12	77										
08/03/12	79										
08/08/12	83										
08/09/12	77										
		08/16/12	2								
08/23/12	76										
08/24/12	86										
08/31/12	80										
		09/08/12		synchronized reserve event							
		09/13/12	20								
		09/27/12	0.47								

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

2013

PJM Emergnecy procedure posting - for MIDATL, PJM RTO and BGE only

	Daily peak 8-hour ozone concentration (ppb)	Demand response	emergency voluntary energy only demand response	max emerg gen	max emerg gen/ load management alert	emerg mndtry load mgmt short lead < 1 hr	emerg mndtry load mgmt long lead 1-2 hrs	NERC EEA 1	NERC EEA 2	max emerg gen action trans
		hours, total								
05/15/13	77									
05/29/13	80									
05/31/13	76									
06/05/13	76									
06/25/13	78									
06/26/13	76									
		07/15/13								
		07/16/16								
07/17/13	76	07/17/13								
07/18/13	80									
07/19/13	83									
		09/11/13	special notice							

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

2014

PJM Emergnecy procedure posting - for MIDATL, PJM RTO and BGE only

	Daily peak 8-hour ozone concentration (ppb)	Demand response	hours, total gen	hours, total curt	emergency voluntary energy only demand response	max emerg gen	max emerg gen/ load management alert	emerg mndtry load mgmt short lead < 1 hr	emerg mndtry load mgmt long lead 1-2 hrs	NERC EEA 1	NERC EEA 2	max emerg gen action trans
		05/01/14	0.433									
		05/03/14	0.433									
		05/13/14	0.167									
06/16/14	81											
06/17/14	80											
07/11/14	79											
		07/26/14	6									
		07/28/15										
08/06/14	77											
		08/13/14	21									
		08/14/14	17									
		08/19/14	2									
08/27/14	85											
		09/16/14	20	21								
		09/17/14	16	31								
		09/18/14	2	28								
		09/20/14	0.233									
		09/26/14	4									

[1] the maximum of all monitors in Maryland is reported; the actual monitor can be identifed through other references

PJM initiated load management event, BGE, MIDATL

Demand Response as a result of CSP Load Management Event, total >17 hours

Demand Response Load management event called by CSPs, with event reported to MDE annually

75 ppb < Ozone value < 95 ppb

Ozone value > 95 ppb

Appendix B
PJM Interconnection Supporting Documents for Demand Response Events

1. Summary of PJM-Initiated Load Management Events, 1991 – Present
2. PJM Top 10 All Time Summer/Winter Peak Load Days
3. 2016 Demand Response Operations Markets Activity Report: May 2017. *PJM Demand Side Response Operations, May 11, 2017*
4. New Air Quality Rules have Dramatically Changed the Demand Response Resource Mix. *Greentechmedia.com, November 3, 2016*

Summary of PJM-Initiated Load Management Events

					OPERATIONS INFORMATION				Running Total:		
									# of Events		LM Capacity
Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Step 1	Step 2	Committed/Expected MW**
1	1991/92	1991	Sep 16 (Mon)	1, 2, 3, and 4	14:33	14:33	20:09	Members could choose to use this as a compliance event			
2	1992/93	1992	Jul 14 (Tue)	1, 2, and 3	15:10	15:10	16:31	Members could choose to use this as a compliance event			
3	1993/94	1994	Jan 19 (Wed.)	1, 2, 3, and 4	5:06	6:00	22:32	5% voltage reduction 6:45 - 20:28. Manual load shed 7:05 - 7:41 and 9:22 - 13:07 (max. 1500 MW). Event occurred outside ALM period.			
4	1993/94	1994	Jan 20 (Thur.)	1, 2, 3, and 4	7:40	7:40	0:00	Event occurred outside ALM compliance period			
5	1993/94	1994	Jan 21 (Fri.)	1 and 2		0:01	11:51	Event occurred outside ALM compliance period			
6	1995/96	1995	Aug 3 (Thur)	2	12:00	12:00	18:00				
7	1995/96	1996	May 20 (Mon)		15:06	15:06	18:32	5% voltage reduction. Event occurred outside ALM compliance period			
8	1995/96	1996	May 21 (Tue)	3 and 4	11:17	11:17	16:00	Event occurred outside ALM compliance period			
				2	11:17	11:17	16:17				
				1	11:17	11:17	16:28				
9	1998/99	1998	Jun 26 (Fri)	2	10:10	13:00	14:15				
10	1999/2000	1999	Jun 8 (Tue)	2 and 4	9:31	12:00	18:00		0	1	
11	1999/2000	1999	Jul 6 (Tue)	2 and 4	9:18	13:00	19:00	5% voltage reduction 13:58 - 18:10			
				1 and 3	12:50	12:50	19:00		1	2	
12	1999/2000	1999	Jul 19 (Mon)	1 and 3	12:55	12:55	16:25	5% volt. red. 12:55 - 14:06 (East only)			
				2 and 4	13:12	13:12	16:25	No compliance report needed for Step 2	2	3	
13	1999/2000	1999	Jul 23 (Fri)	2 and 4	9:50	12:00	17:00		2	4	
14	1999/2000	1999	Jul 28 (Wed)	2 and 4	9:00	12:00	17:13	PP&L (EDC) customers excluded		4 PL	
				1 and 3	14:38	14:38	17:13		3	5 non-PL	
15	1999/2000	1999	Jul 30 (Fri)	2 and 4	9:28	12:00	17:58			5 PL	
				1 and 3	13:45	13:45	17:58		4	6 non-PL	
16	1999/2000	2000	May 8 (Mon)	1, 2, 3, and 4	13:30	13:30	18:40	5% volt. red. 15:45 - 18:04. Event occurred outside ALM compliance period	5	6 / 7	
17	1999/2000	2000	May 9 (Tue)	1, 2, 3, and 4	9:03	12:30	18:30	Event occurred outside ALM compliance period	6	7 / 8	
18	2001/02	2001	Jul 25 (Wed)	1, 2, 3, and 4	13:29	13:29	17:25	LRPP Emergency: 14:08 - 17:25	1	1	
19	2001/02	2001	Aug 8 (Wed)	2 and 4	10:30	13:00	18:30	LRPP Emergency: 12:40 - 18:00		2	
				1 and 3	12:40	13:30	18:00		2		
20	2001/02	2001	Aug 9 (Thu)	2 and 4	10:00	12:30	19:00	5% volt. red.: 14:40 - 18:15 (East), 15:10 - 17:09 West		3	
				1 and 3	11:04	12:00	18:30	LRPP Emergency: 11:20 - 19:00	3		
21	2001/02	2001	Aug 10 (Fri)	2 and 4	8:30	11:00	14:40			4	
				1 and 3	10:54	12:00	13:10		4		
22	2002/03	2002	Jul 3 (Wed)	1, 2, 3, and 4	9:35	12:00	18:00	Demand Side Response Emergency: 12:00 - 17:00	1	1	
23	2002/03	2002	Jul 29 (Mon)	2 and 4	11:10	13:10	18:00		1	2	
24	2002/03	2002	Jul 30 (Tue)	2 and 4	10:00	12:00	18:00		1	3	
25*	2005/06	2005	Jul 27 (Wed)	2 and 4	11:00	13:00	18:10	Mid-Atlantic and Dominion only.		1	
				1 and 3	11:00	14:00	18:10	5% volt. red.: 13:39 - 17:30 (BC, DOM, PEP, PED)	1		
								5% volt. red.: 14:21 - 17:30 (PE, JC, PS, Eastern PL)			
26	2005/06	2005	Aug 4 (Thu)	2 and 4	12:30	14:30	17:15	Mid-Atlantic only	1	2	

OPERATIONS INFORMATION

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Running Total: # of Events Step 1	Running Total: # of Events Step 2	LM Capacity Committed/Expected MW**
27	2006/07	2006	Aug 2 (Wed)	2 and 4	12:34	13:00	19:33	Mid-Atlantic only		1	
				1 and 3	15:11	15:30	19:33		1		
28	2006/07	2006	Aug 3 (Thu)	2	12:15	14:15	19:00	Mid-Atlantic only		2	
				1	13:00	14:00	19:00		2		
29	2007/08	2007	Aug 8 (Wed)	2 and 4	11:44	13:44	18:35	BGE and PEPCO zones		1	
				2 and 4	12:08	14:08	17:50	Mid-Atlantic region		1	
				2 and 4	12:08	14:08	18:35	DOM zone		1	
				1 and 3	12:20	13:20	18:35	BGE and PEPCO zones	1		
				1 and 3	15:30	16:30	17:50	Mid-Atlantic and DOM	1		
					15:55	15:55	17:09	5% voltage reduction. Mid-Atlantic only			
					17:09	17:09	17:59	5% volt. red. continued for BGE and PEPCO zones only			LM Capacity
											Committed/Expected MW**
30	2009/10	2010	May 26 (Wed)	2	15:15	17:15	19:59	DC portion of PEPCO zone only. Event occurred outside compliance period		1	47
31	2010/11	2010	Jun 11 (Fri)	2	13:58	15:58	20:12	DC portion of PEPCO zone only		1	137
32	2010/11	2010	Jul 7 (Wed)	2	11:37	13:37	19:07	DOM zone		1	
				2	12:30	14:30	18:32	AE, BGE, DPL, JCPL, PECO, PS, RECO zones		1	2,725
				2	12:30	14:30	18:32	PEPCO zone		2	
33	2010/11	2010	Aug 11 (Wed)	2	11:15	13:15	19:15	DC portion of PEPCO zone only		3	60
34	2010/11	2010	Sep 23 (Thu)	1	11:00	12:00	18:00	MD, VA and WV portions of APS zone only	1		
				2	11:00	13:00	19:00	MD, VA and WV portions of APS zone only		1	849
				2	12:30	14:30	20:00	BGE zone		2	
35	2010/11	2010	Sep 24 (Fri)	2	10:30	12:30	18:30	BGE zone		3	
								PEPCO zone		4	967
								MD, VA and WV portions of APS zone only		2	
36	2010/11	2011	May 26 (Thu)	2	14:20	16:20	18:20	Norfolk portion of DOM zone only. Event occurred outside compliance period		2	253
37	2010/11	2011	May 31 (Tue)	2	15:05	17:05	19:05	Event occurred outside compliance period.			
								METED, PENLC, PL, RECO zones		1	
								AE, DPL, JCPL, PECO, PS zones		2	3,450
								DOM zone		3	
								BGE zone		4	
								PEPCO zone		5	
38	2011/12	2011	Jul 22 (Fri)	2	10:00	12:00	18:00	BGE zone		1	
				1	11:00	12:00	17:30	BGE zone	1		
				2	11:30	13:30	18:30	JCPL, METED zones		1	2,296
				2	11:30	13:30	19:00	PECO zone		1	
				2	11:30	13:30	19:30	DPL, DLCO zones		1	
39	2012/13	2012	Jul 17 (Tue)	2	13:08	15:08	19:05	AEP, DOM zones		1	1,670
40	2012/13	2012	Jul 18 (Wed)	2	13:22	15:22	17:23	BGE, JCPL, PECO, PENLC, PEPCO zones		1	
				2	13:38	15:38	17:29	DPL zone		1	2,135
				1	14:28	15:28	17:34	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	1		
41	2013/14	2013	Jul 15 (Mon)	2	13:50	15:50	18:22	ATSI zone		1	690
42	2013/14	2013	Jul 16 (Tue)	2	11:30	13:30	16:30	ATSI zone		2	690
43	2013/14	2013	Jul 18 (Thu)	2	12:40	14:40	18:00	ATSI zone		3	
				2	12:40	14:40	17:00	PECO, PL zones		1	1,791
				2	13:00	15:00	18:00	Canton portion of AEP zone only		1	

OPERATIONS INFORMATION

Running Total: # of Events | LM Capacity

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Step 1	Step 2	Committed/Expected MW**
44	2013/14	2013	Sep 10 (Tue)	2	13:50	15:50	21:30	ATSI zone		4	798
				2	14:45	16:45	21:30	Canton portion of AEP zone only		2	
45	2013/14	2013	Sep 11 (Wed)	2	11:30	13:30	19:30	AEP zone Note: 3rd event for Canton portion of AEP zone		1	6,048
				2	12:00	14:00	20:00	ATSI zone		5	
				2	12:30	14:30	18:30	DOM zone		1	
				2	13:00	15:00	17:00	AE, JCPL, PS, RECO zones		1	
				2	13:00	15:00	17:30	METED zone		1	
				2	13:00	15:00	17:30	PECO, PL zones		2	
				2	13:00	15:00	18:00	BGE, DPL, PEPCO zones		1	
				2	13:00	15:00	18:30	PENLC zone		1	
				1	13:00	14:00	17:15	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	1		
				2	13:00	15:00	18:30	DLCO zone		1	
	2013/14	2014	Jan 6 (Mon)					5% voltage reduction: 19:52 - 20:45			
46	2013/14	2014	Jan 7 (Tue)	1	4:30	5:30	11:00	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	1		1,887
				1	4:30	5:30	11:00	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	2		
				2	4:30	6:30	11:00	APS,COMED,DAYTON,DEOK,EKPC zones		1	
				2	4:30	6:30	11:00	AEP zone Note: 4th event for Canton portion of AEP zone		2	
				2	4:30	6:30	11:00	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		2	
				2	4:30	6:30	11:00	PECO, PL zones		3	
				2	4:30	6:30	11:00	ATSI zone		6	
								Event occurred outside compliance period.			
47	2013/14	2014	Jan 7 (Tue)	1	15:00	16:00	18:15	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	2		3,042
				1	15:00	16:00	18:15	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	3		
				2	15:00	17:00	18:15	APS,COMED,DAYTON,DEOK,EKPC zones		2	
				2	15:00	17:00	18:15	AEP zone Note: 5th event for Canton portion of AEP zone		3	
				2	15:00	17:00	18:15	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		3	
				2	15:00	17:00	18:15	PECO, PL zones		4	
				2	15:00	17:00	18:15	ATSI zone		7	
								Event occurred outside compliance period.			
48	2013/14	2014	Jan 8 (Wed)	1	5:00	6:00	7:00	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	3		Cancelled prior to start time
				1	5:00	6:00	7:00	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	4		
				2	5:00	7:00	7:00	APS,COMED,DAYTON,DEOK,EKPC zones		3	
				2	5:00	7:00	7:00	AEP zone Note: 6th event for Canton portion of AEP zone		4	
				2	5:00	7:00	7:00	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		4	
				2	5:00	7:00	7:00	PECO, PL zones		5	
				2	5:00	7:00	7:00	ATSI zone		8	
								Event occurred outside compliance period.			
49	2013/14	2014	Jan 22 (Wed)	1	14:00	15:00	21:00	BGE, PEPCO zones	5		140
				2	14:00	16:00	21:00	BGE, PEPCO zones		5	
								Event occurred outside compliance period.			
50	2013/14	2014	Jan 23 (Thu)	1	4:30	5:30	8:30	APS, DOM zones	4		633
				1	4:30	5:30	8:30	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	5		
				1	4:30	5:30	8:30	BGE, PEPCO zones	6		
				2	4:30	6:30	8:30	APS zone		4	
				2	4:30	6:30	8:30	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		5	
				2	4:30	6:30	8:30	BGE, PECO, PEPCO, PL zones		6	
								Event occurred outside compliance period.			

OPERATIONS INFORMATION

Running Total:

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	# of Events Step 1	# of Events Step 2	LM Capacity Committed/Expected MW**
51	2013/14	2014	Jan 23 (Thu)	1	14:00	15:00	19:00	APS, DOM zones	5		
				1	14:00	15:00	19:00	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	6		
				1	14:00	15:00	19:00	BGE, PEPCO zones	7		
				2	14:00	16:00	19:00	APS zone		5	1,266
				2	14:00	16:00	19:00	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		6	
				2	14:00	16:00	19:00	BGE, PECO, PEPCO, PL zones		7	
								Event occurred outside compliance period.			
52	2013/14	2014	Jan 24 (Fri)	1	4:30	5:30	8:45	APS, DOM zones	6		
				1	4:30	5:30	8:45	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	7		
				1	4:30	5:30	8:45	BGE, PEPCO zones	8		
				2	4:30	6:30	8:45	APS zone		6	706
				2	4:30	6:30	8:45	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		7	
				2	4:30	6:30	8:45	BGE, PECO, PEPCO, PL zones		8	
								Event occurred outside compliance period.			
53	2013/14	2014	Mar 4 (Tue)	1	4:30	5:30	8:30	AEP,ATSI,COMED,DAYTON,DEOK,DLCO,EKPC zones	4		
				1	4:30	5:30	8:30	APS, DOM zones	7		
				1	4:30	5:30	8:30	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	8		
				1	4:30	5:30	8:30	BGE, PEPCO zones	9		
				2	4:30	6:30	8:30	COMED,DAYTON,DEOK,EKPC zones		4	1,592
				2	4:30	6:30	8:30	AEP, DLCO zones Note: 7th event for Canton portion of AEP zone		5	
				2	4:30	6:30	8:30	APS zone		7	
				2	4:30	6:30	8:30	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		8	
				2	4:30	6:30	8:30	ATSI, BGE, PECO, PEPCO, PL zones		9	
								Event occurred outside compliance period.			

*** Prior to Event #25, all events were Mid-Atlantic only.**

**** Average committed capacity reduction when event occurs in a capacity compliance period. Average expected energy reduction, as reported by CSPs, when event is outside of capacity compliance period.**

LM Step Definitions:
Step 1: PJM-dispatchable, Short Lead Time (<= 1 hour)
Step 2: PJM-dispatchable, Long Lead Time (> 1 hour)
Step 3: Company-dispatchable, Short Lead Time (<= 1 hour)
Step 4: Company-dispatchable, Long Lead Time (> 1 hour)

Eastern PJM = AE, DPL, JCPL, PECO, and PS zones
LRPP: Load Response Pilot Program
Mid-Atlantic = AE, BGE, DPL, JCPL, METED, PECO, PEPCP, PENLC, PL, PS, RECO (effective 2002/03) zones

Summary of PJM-Initiated Load Management Events***

OPERATIONS INFORMATION

Event #	Delivery Year	Year	Date	Type(s) Invoked	Notification Period Invoked	Product(s) Invoked	Time of Notification	Start Time	Time Released	Zone(s) Dispatched	Notes	LM Capacity Committed/Expected MW**
54	2014/15	2015	Apr 21 (Tue.)	Pre-Emergency	Long_120	L, E	18:20	20:20	21:30	PENLC		
					Short_60	L	18:20	19:20	21:30			99
				Emergency	Long_120	L, E	18:20	20:20	21:30			
55	2014/15	2015	Apr 22 (Wed.)	Pre-Emergency	Long_120	L, E	5:30	7:30	12:30	PENLC		
					Short_60	L	5:30	6:30	12:30			113
				Emergency	Long_120	L, E	5:30	7:30	12:30			

*** Prior to Event #25, all events were Mid-Atlantic only.**
**** Average committed capacity reduction when event occurs in a capacity compliance period. Average expected energy reduction, as reported by CSPs, when event is outside of capacity compliance period.**
***** Beginning with Event #54, the report was restructured to reflect new options for Type, Notification Period, and Products.**

Definitions:
Step 1: PJM-dispatchable, Short Lead Time (<= 1 hour)
Step 2: PJM-dispatchable, Long Lead Time (> 1 hour)
Step 3: Company-dispatchable, Short Lead Time (<= 1 hour)
Step 4: Company-dispatchable, Long Lead Time (> 1 hour)
Pre-Emergency: Load management that can be invoked prior to the declaration of a system emegency
Emergency: Load management that can be invoked susequent to the declaration of a system emegency
L (Limited): Committed to providing up to 10 load reductions of 6 hours duration in the months Jun-Sep
E (Extended Summer): Committed to providing an unlimited number of interruptions of 10 hours durarion during a period of Jun-Oct and the following May
A (Annual): Committed to providing an unlimited number of interruptions of 10 hours duration
Long_120: Full load reduction must be implemented within 120 minutes of the notification time
Short_60: Full load reduction must be implemented within 60 minutes of the notification time
Quick_30: Full load reduction must be implemented within 30 minutes of the notification time

Eastern PJM = AE, DPL, JCPL, PECO, and PS zones
LRPP: Load Response Pilot Program
Mid-Atlantic = AE, BGE, DPL, JCPL, METED, PECO, PEPCP, PENLC, PL, PS, RECO (effective 2002/03) zones

PJM Top 10 All Time Summer/Winter Peak Load Days

Top 10 Summer Peak Days

Rank	Date	Load MWh
1	7/21/2011	158,043
2	7/18/2013	157,509
3	7/19/2013	156,077
4	7/17/2012	154,339
5	7/17/2013	154,044
6	7/18/2012	152,758
7	7/6/2012	151,966
8	7/16/2013	151,421
9	7/22/2011	151,366
10	7/15/2013	150,315

*Load MWh do not include coincident load or Demand Response

Top 10 Winter Peak Days

Rank	Date	Load MWh
1	2/20/2015	143,086
2	1/7/2014	140,510
3	2/19/2015	140,344
4	1/28/2014	137,336
5	1/24/2014	136,982
6	1/30/2014	136,215
7	1/8/2015	136,185
8	1/29/2014	136,020
9	1/7/2015	135,649
10	1/22/2014	135,061

*Load MWh do not include coincident load or Demand Response

http://www.pjm.com/markets-and-operations/data-dictionary.aspx

2016 Demand Response Operations Markets Activity Report: May 2017

James McAnany

PJM Demand Side Response Operations

May 11, 2017

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Figure 1: DY 16/17 Active Participants in Economic, Load Management DR, and Capacity Performance Programs

			Economic		Load Management		Capacity Performance		Unique	
State	Zone	EDC	Locations	MW	Locations	MW	Locations	MW	Locations	MW
DC	PEPCO	PEPCO	17	23.0	308	95.3			314	96.6
DE	DPL	DEMEC	2	5.8	28	15.7			28	15.7
DE	DPL	DOVDE			16	3.8			16	3.8
DE	DPL	DPL	8	197.9	241	216.0			242	219.4
DE	DPL	ODEC			12	4.5			12	4.5
IL	COMED	BATAV			1	1.9			1	1.9
IL	COMED	COMED	1,139	304.5	2,173	1,033.7	69	122.6	3,330	1,325.7
IL	COMED	GENEVA	1	1.0						
IL	COMED	IMEAA1	1	0.3	1	32.7	1	6.0	2	38.7
IN	AEP	AEPIMP			112	219.1			112	219.1
IN	AEP	HEREC	1	39.0			1	21.3	1	21.3
IN	AEP	WVPA			68	2.0			68	2.0
IN	AEP	WVSDI			1	23.3			1	23.3
KY	AEP	AEPKPT			1	1.5			1	1.5
KY	DEOK	DEK			54	28.3			54	28.3
KY	EKPC	EKPC			6	27.5	5	114.2	11	141.7
MD	APS	AETSAP	21	16.3	162	72.7			163	79.5
MD	APS	AETSHG	3	2.2	3	0.2			3	0.2
MD	APS	AETSTH			1	0.1			1	0.1
MD	BGE	BC	91	566.6	743	726.6	1	1.6	748	728.4
MD	DPL	DPL	8	95.9	180	115.6			180	115.6
MD	DPL	EASTON			7	3.1			7	3.1
MD	DPL	ODEC	1	1.5	18	10.8			18	10.8
MD	PEPCO	PEPCO	11	309.5	337	404.7			339	405.0
MD	PEPCO	SMECO	11	2.7	113	50.5			113	50.5
MI	AEP	COSEDC					1	5.2	1	5.2
NJ	AECO	AE	16	56.7	251	109.4	1	0.9	255	111.3
NJ	AECO	VMEU			23	6.3			23	6.3
NJ	JCPL	AECI			1	0.2			1	0.2
NJ	JCPL	BSHNJ	1	2.0	1	2.0			1	2.0
NJ	JCPL	JCBGS	14	53.6	454	134.8			460	180.6
NJ	PSEG	PSEG	33	44.1	1,057	345.2			1,061	366.7
NJ	RECO	RECO			17	4.3			17	4.3
NY	PENELEC	PaElec			2	2.0			2	2.0
OH	AEP	AEPOPT	42	58.5	779	450.5	28	77.0	810	539.4
OH	AEP	AMPO			36	50.0	3	1.0	39	51.0
OH	AEP	BUCK			2	20.1			2	20.1
OH	ATSI	AMPO			17	45.7			17	45.7
OH	ATSI	BUCK			2	5.6			2	5.6
OH	ATSI	CPP	1	0.9	11	4.1			11	4.1
OH	ATSI	OEEDC	26	53.9	942	733.6	2	2.2	949	757.9
OH	DAY	AMPO	1	7.0	9	28.8			9	28.8
OH	DAY	BUCK			2	4.0			2	4.0
OH	DAY	DAYEDC	7	8.3	189	146.5	1	6.0	190	152.5
OH	DEOK	AMPO			3	1.4			3	1.4
OH	DEOK	BUCK			2	2.0			2	2.0

State	Zone	EDC	Economic Locations	Economic MW	Load Management Locations	Load Management MW	Capacity Performance Locations	Capacity Performance MW	Unique Locations	Unique MW
OH	DEOK	DEOEDC	18	75.2	381	156.1	2	94.7	384	252.2
PA	APS	AECI			1	0.3			1	0.3
PA	APS	AETSAP	12	104.2	622	334.4	5	57.3	628	396.1
PA	APS	CHBDTE	0	0.0	1	0.3			1	0.3
PA	ATSI	PAPWR	2	0.3	83	57.2			84	57.4
PA	DUQ	DLCO	53	17.5	338	148.8	5	1.0	344	164.8
PA	METED	AECI			1	1.9			1	1.9
PA	METED	MetEd	36	44.4	487	227.5			488	228.5
PA	PECO	PE	124	75.9	1,230	330.2	2	0.8	1,238	339.8
PA	PENELEC	AECI			22	10.7			22	10.7
PA	PENELEC	PaElec	7	13.0	508	238.6	1	12.1	513	258.7
PA	PENELEC	WELLSB			1	1.1			1	1.1
PA	PPL	AMPO			8	2.2			8	2.2
PA	PPL	CTZECL			4	3.4			4	3.4
PA	PPL	PPL	238	159.1	1,768	617.2	1	0.7	1,773	692.4
PA	PPL	UGI-UI			15	4.1			15	4.1
TN	AEP	AEPAPT			11	6.6			11	6.6
VA	AEP	AEPAPT	1	0.1	210	283.8	1	1.4	211	285.2
VA	AEP	AMPO	3	0.1	12	5.3			12	5.3
VA	AEP	RADFRD			1	1.5			1	1.5
VA	AEP	SALEM			1	0.1			1	0.1
VA	AEP	VATECH			1	7.8			1	7.8
VA	APS	ODEC	3	0.9	52	37.2			52	37.2
VA	DOM	CVEC			6	6.9			6	6.9
VA	DOM	DOMEDC	40	143.9	862	398.1	10	37.5	873	515.7
VA	DOM	DOMVME	2	0.4	19	94.0			19	94.0
VA	DOM	NVEC	2	14.6	49	27.9			51	42.5
VA	DOM	ODEC	3	47.4	33	48.3			33	48.3
VA	DPL	ODEC			19	6.2			19	6.2
WV	AEP	AEPAPT	32	2.1	320	303.4			320	303.4
WV	AEP	APWVP			4	0.5			4	0.5
WV	APS	AETSAP	134	46.2	292	200.9	4	31.7	296	232.6
Total			**2,166**	**2,597**	**15,748**	**8,749**	**144**	**595**	**17,037**	**9,836**

Note:
1) Data as of 5/8/2017.
2) Load Management and Capacity Performance MW are in ICAP.
3) Economic MW are CSP reported Load Reduction values.
4) Residential Locations reported as one location not a total number of end use customers in that program.
5) Unique MW: represents total estimated demand reduction assuming full Load Management, Capacity Performance, and Economic reductions.
6) As of May 2, 2017, DY16/17 RPM Committed Values are 7,762 MW for Load Management, and 574 MW for Capacity Performance.
7) No Emergency Energy Only registrations to report.

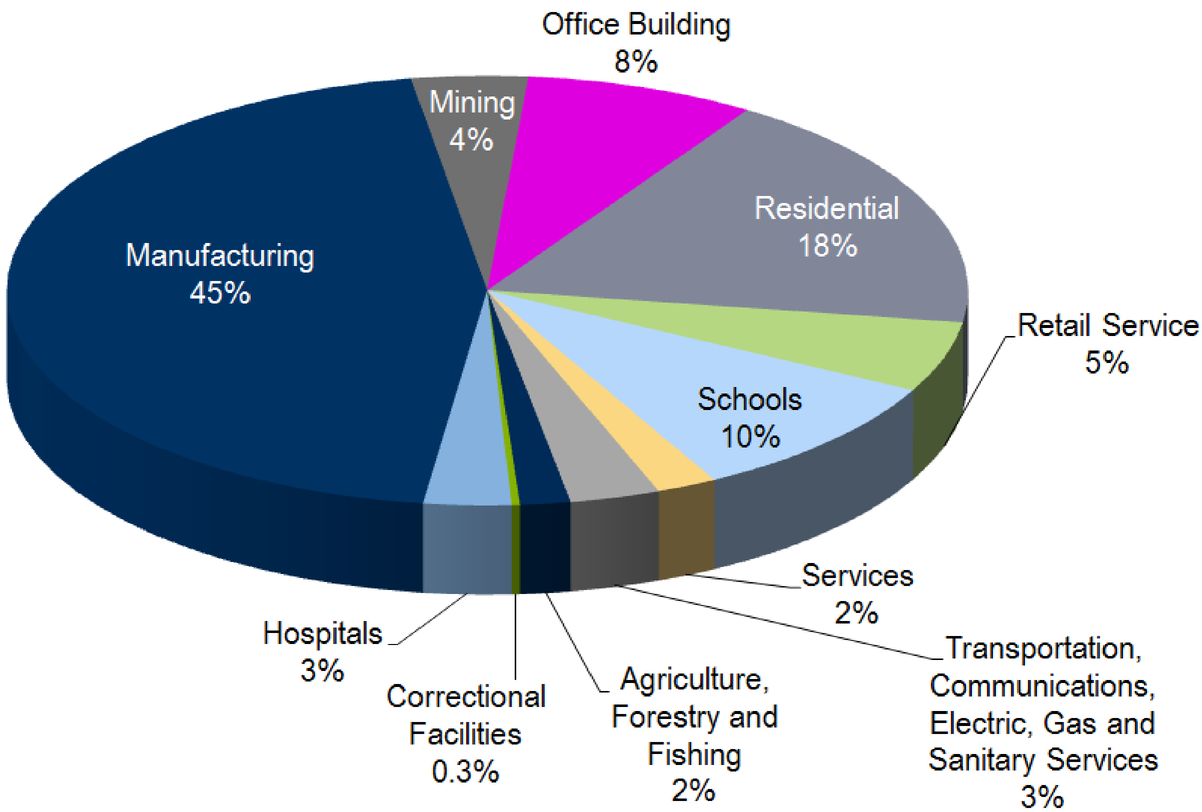
Figure 2: DY 16/17 MWs in Load Management DR by Resource, Product, and Lead Times

Zone		DR Product			Lead Times (Minutes)			Total DR	Committed
		Limited	Extended	Annual	30	60	120	MWs	MWs
AECO									
	Pre-Emergency	52.7	54.9	7.9	103.1	4.1	8.2	115.5	
	Emergency	0.2	0.0	0.0	0.2	0.0	0.0	0.2	
	Total	52.9	54.9	7.9	103.3	4.1	8.2	115.7	109.7
AEP									
	Pre-Emergency	1,332.6	5.4	0.0	698.4	37.4	602.1	1,337.9	
	Emergency	37.7	0.0	0.0	28.8	0.8	8.0	37.7	
	Total	1,370.2	5.4	0.0	727.3	38.2	610.2	1,375.6	1,323.7
APS									
	Pre-Emergency	617.4	5.2	2.0	339.4	11.5	273.7	624.6	
	Emergency	21.5	0.0	0.0	14.0	0.0	7.5	21.5	
	Total	638.9	5.2	2.0	353.4	11.5	281.3	646.1	587.3
ATSI									
	Pre-Emergency	657.2	90.1	73.9	380.3	44.1	396.8	821.2	
	Emergency	25.0	0.0	0.0	20.2	0.3	4.5	25.0	
	Total	682.2	90.1	73.9	400.5	44.4	401.3	846.2	488.5
BGE									
	Pre-Emergency	700.8	0.3	3.9	659.3	4.0	41.7	705.0	
	Emergency	21.5	0.0	0.0	12.3	0.0	9.3	21.5	
	Total	722.3	0.3	3.9	671.6	4.0	50.9	726.6	653.9
COMED									
	Pre-Emergency	998.0	52.2	0.0	793.3	29.9	227.0	1,050.2	
	Emergency	18.1	0.0	0.0	4.2	0.0	14.0	18.1	
	Total	1,016.2	52.2	0.0	797.5	29.9	240.9	1,068.4	1,034.5
DAY									
	Pre-Emergency	174.1	0.6	0.0	116.0	0.5	58.2	174.7	
	Emergency	4.6	0.0	0.0	4.6	0.0	0.0	4.6	
	Total	178.7	0.6	0.0	120.6	0.5	58.2	179.3	165.3
DEOK									
	Pre-Emergency	168.0	16.9	0.0	84.2	70.2	30.5	184.9	
	Emergency	2.8	0.0	0.0	2.8	0.0	0.0	2.8	
	Total	170.8	16.9	0.0	87.0	70.2	30.5	187.7	169.4
DOM									
	Pre-Emergency	455.6	64.8	0.0	232.7	33.0	254.6	520.3	
	Emergency	54.5	0.0	0.3	46.6	6.2	2.1	54.8	
	Total	510.1	64.8	0.3	279.3	39.2	256.7	575.2	504.9
DPL									
	Pre-Emergency	157.4	211.0	1.0	176.9	19.8	172.7	369.4	
	Emergency	6.4	0.0	0.0	3.4	1.9	1.1	6.4	
	Total	163.7	211.0	1.0	180.3	21.7	173.8	375.8	328.3
DUQ									
	Pre-Emergency	145.6	2.3	0.0	72.6	6.8	68.5	147.9	
	Emergency	0.9	0.0	0.0	0.9	0.0	0.0	0.9	
	Total	146.5	2.3	0.0	73.5	6.8	68.5	148.8	132.5
EKPC									
	Pre-Emergency	27.5	0.0	0.0	27.5	0.0	0.0	27.5	
	Emergency	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Total	27.5	0.0	0.0	27.5	0.0	0.0	27.5	26.9

Zone		DR Product Limited	Extended	Annual	Lead Times (Minutes) 30	60	120	Total DR MWs	Committed MWs
JCPL									
	Pre-Emergency	120.1	0.3	11.4	95.2	1.4	35.3	131.8	
	Emergency	5.2	0.0	0.0	5.2	0.0	0.0	5.2	
	Total	125.3	0.3	11.4	100.3	1.4	35.3	137.0	120.3
METED									
	Pre-Emergency	212.8	0.0	4.3	138.3	15.9	62.9	217.1	
	Emergency	12.3	0.0	0.0	0.4	3.5	8.3	12.3	
	Total	225.1	0.0	4.3	138.7	19.5	71.2	229.4	211.0
PECO									
	Pre-Emergency	269.9	6.9	18.8	202.5	29.6	63.5	295.6	
	Emergency	34.6	0.0	0.0	31.3	3.2	0.0	34.6	
	Total	304.4	6.9	18.8	233.8	32.8	63.5	330.2	297.1
PENELEC									
	Pre-Emergency	246.5	1.0	4.4	135.1	6.6	110.0	251.8	
	Emergency	0.5	0.0	0.0	0.5	0.0	0.0	0.5	
	Total	247.0	1.0	4.4	135.7	6.6	110.0	252.3	232.9
PEPCO									
	Pre-Emergency	186.0	355.1	2.1	344.1	0.9	198.1	543.2	
	Emergency	7.3	0.0	0.0	6.7	0.0	0.6	7.3	
	Total	193.3	355.1	2.1	350.8	0.9	198.7	550.5	510.0
PPL									
	Pre-Emergency	603.9	0.3	17.4	333.2	64.0	224.3	621.5	
	Emergency	5.3	0.0	0.0	3.1	0.0	2.2	5.3	
	Total	609.2	0.3	17.4	336.3	64.0	226.5	626.8	549.0
PSEG									
	Pre-Emergency	317.3	1.5	23.1	303.1	7.8	31.0	341.9	
	Emergency	3.3	0.0	0.0	0.2	0.0	3.2	3.3	
	Total	320.7	1.5	23.1	303.2	7.8	34.1	345.2	313.2
RECO									
	Pre-Emergency	4.0	0.0	0.3	4.2	0.0	0.1	4.3	
	Emergency	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Total	4.0	0.0	0.3	4.2	0.0	0.1	4.3	3.6
TOTAL									
	Pre-Emergency	7,447.4	868.7	170.4	5,239.7	387.7	2,859.2	8,486.5	
	Emergency	261.8	0.0	0.3	185.3	16.0	60.7	262.1	
	Total	7,709.2	868.7	170.7	5,425.0	403.7	2,919.9	8,748.5	7,762.0

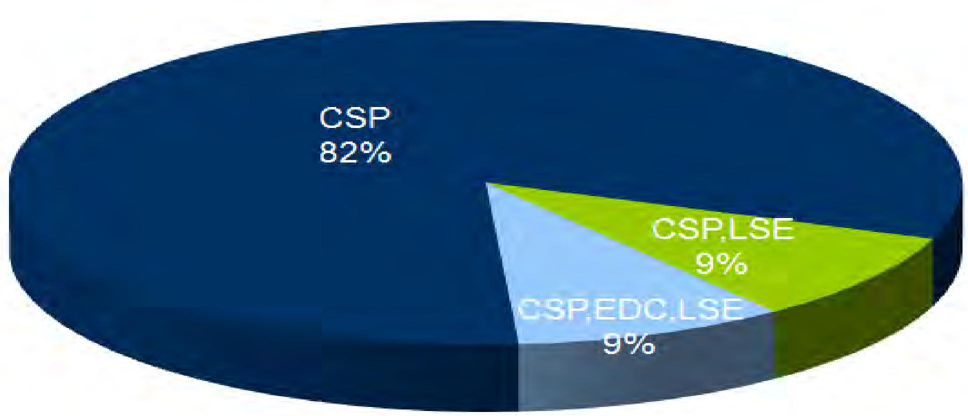
Note: MWs are Nominated Capacity (MWs)

Figure 3: DY 16/17 Confirmed Load Management DR Registrations Business Segments



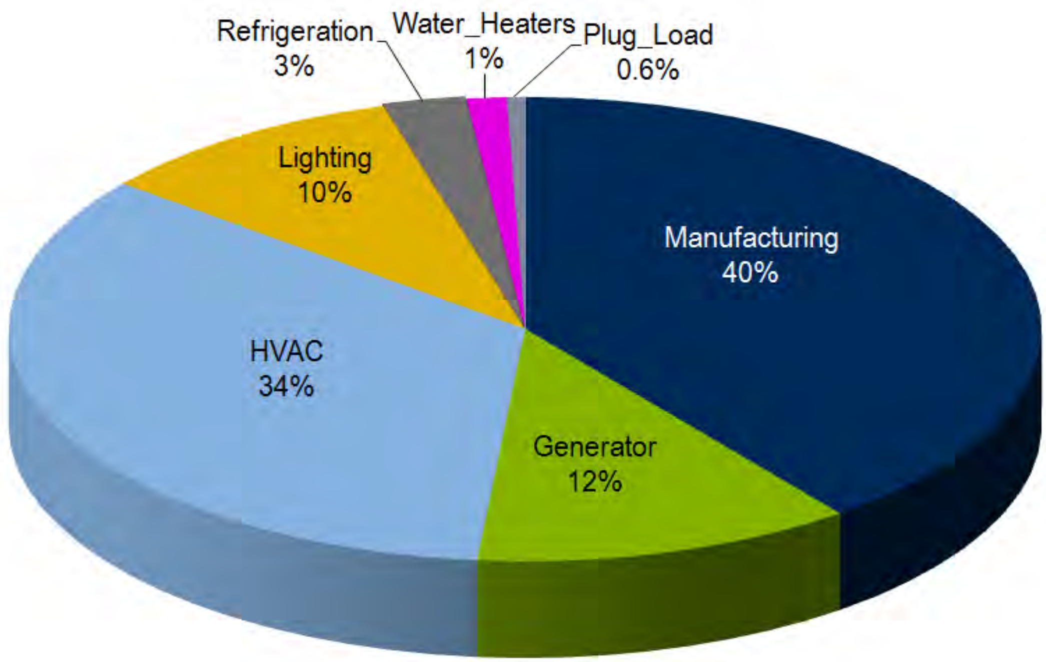
Note: Percent of Nominated Capacity (MWs)

Figure 4: DY 16/17 Confirmed Load Management DR Registrations Owner/Company Type



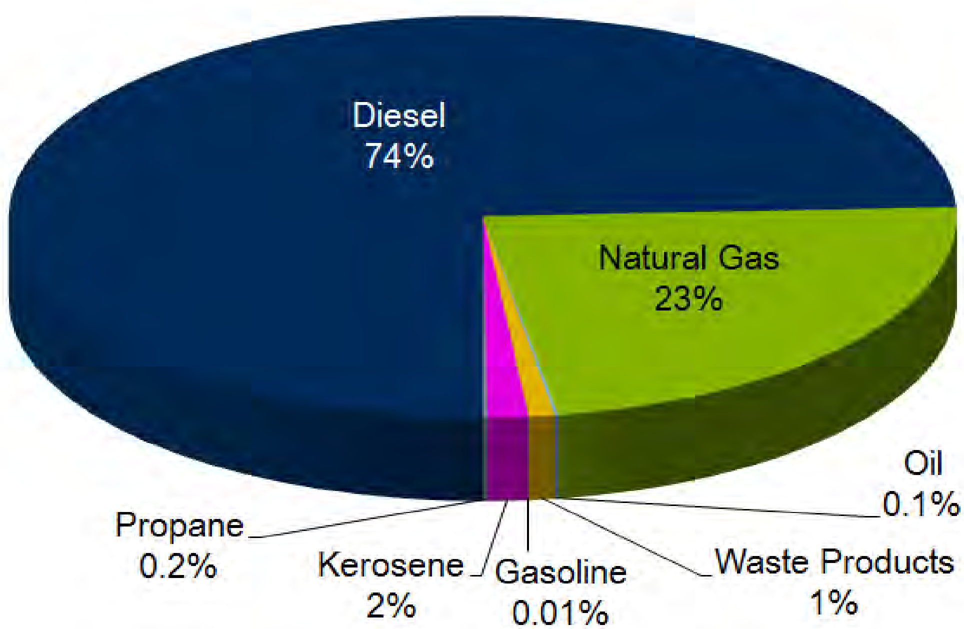
Note: Percent of Nominated Capacity (MWs)

Figure 5: DY 16/17 Confirmed Load Management DR Registrations Customer Load Reduction Methods



Note: Percent of Nominated Capacity (MWs)

Figure 6: DY 16/17 Confirmed Load Management DR Registrations Fuel Mix with Behind the Meter Generation



Note: Percent of Nominated Capacity (MWs)

Figure 7: DY 16/17 Confirmed Load Management DR Registrations Generator and Permit Type

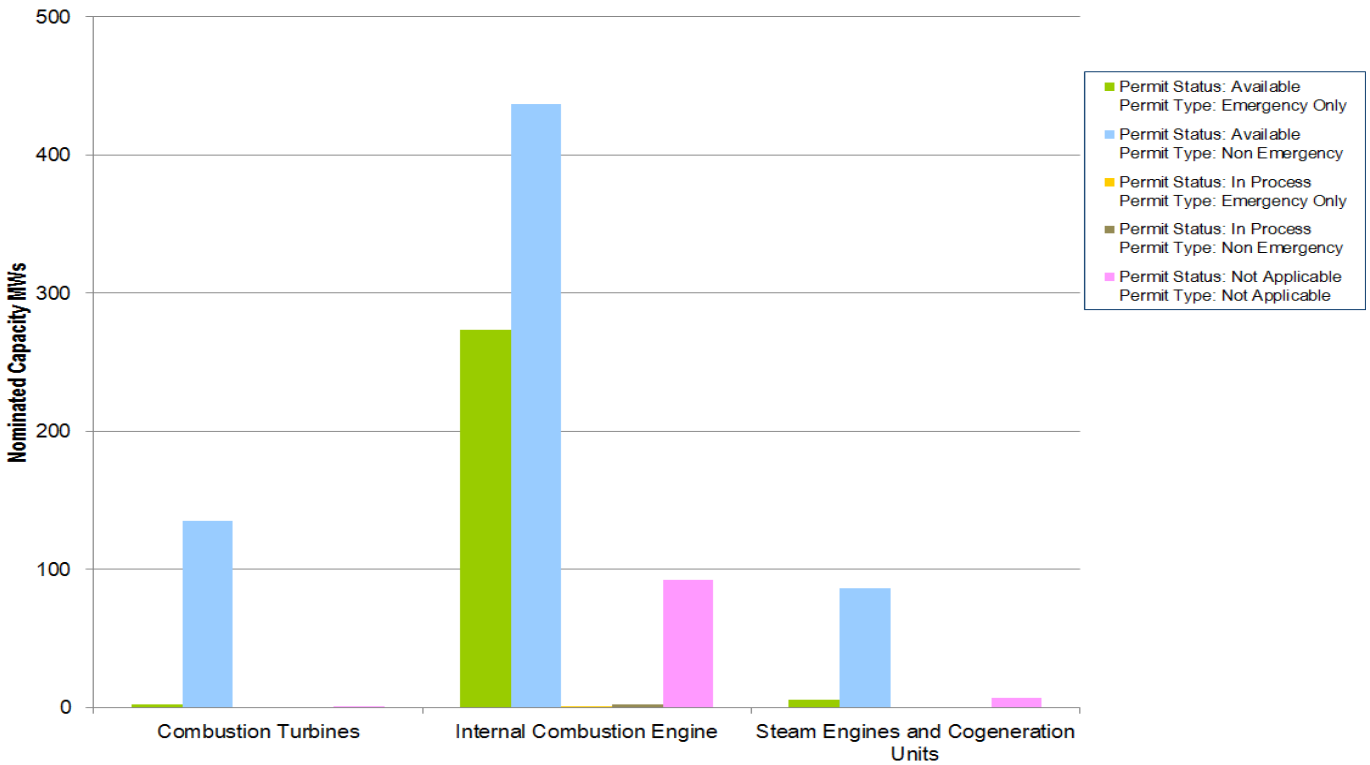


Figure 8: DY 16/17 Confirmed Load Management DR Registrations Fuel Mix with Behind the Meter Generation

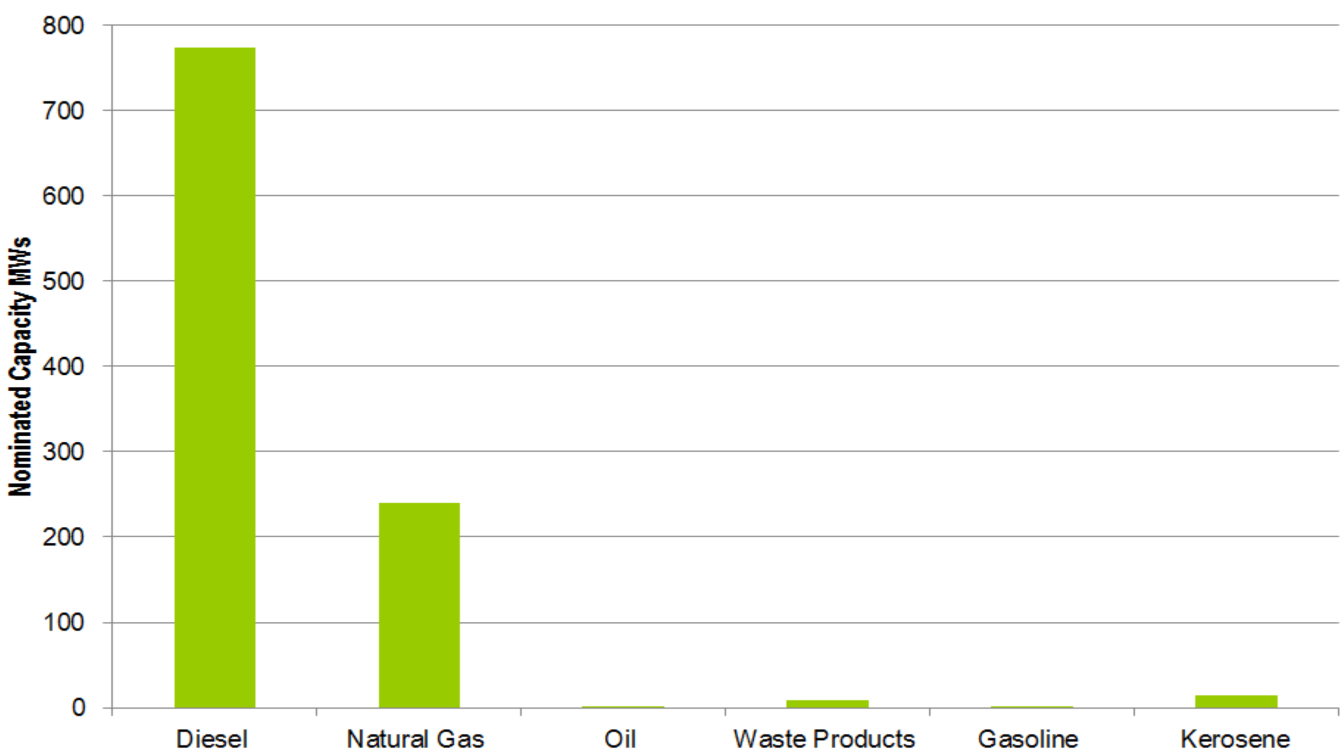


Figure 9: DY 16/17 Confirmed Load Management Full DR Registrations Energy Supply Curve:

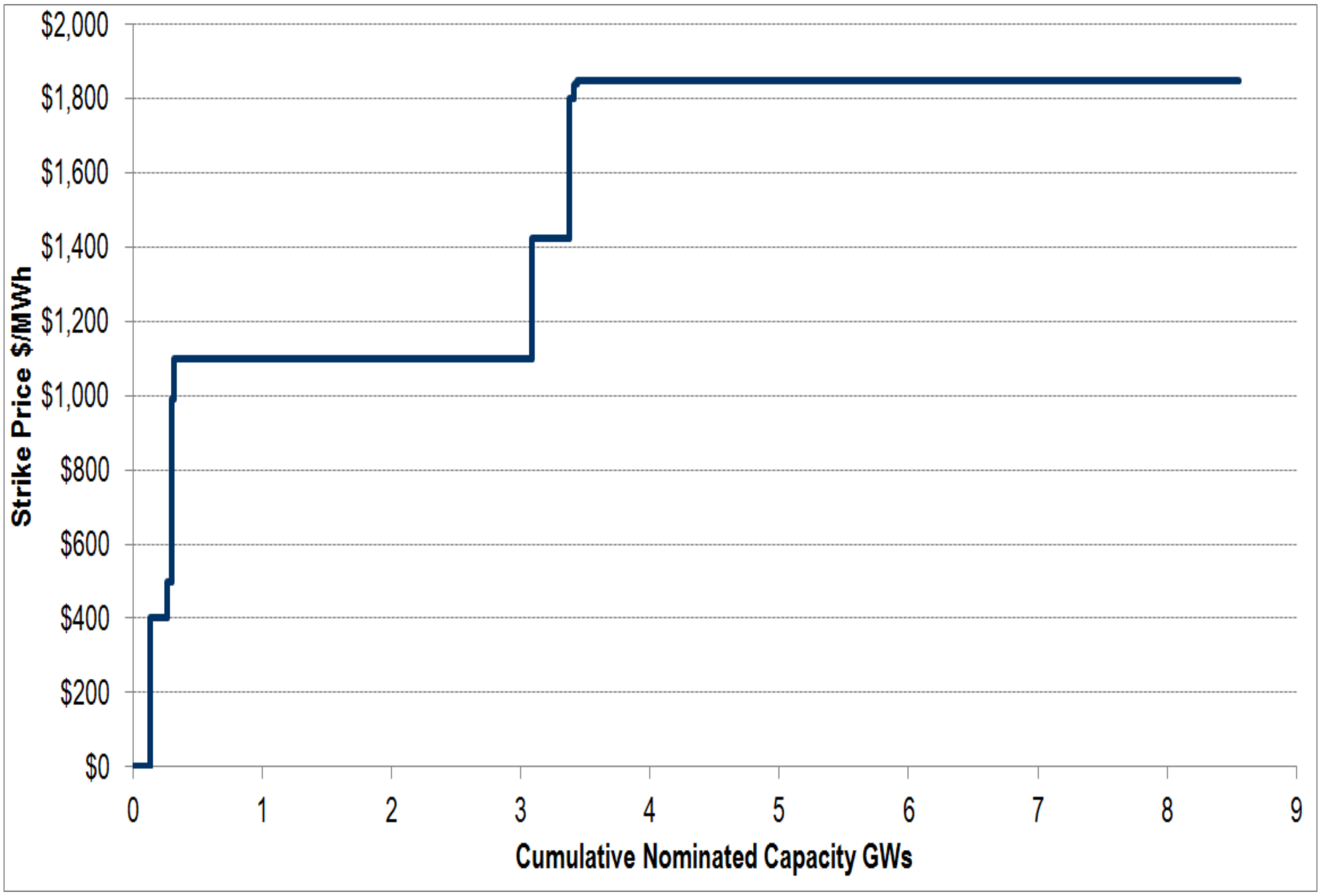


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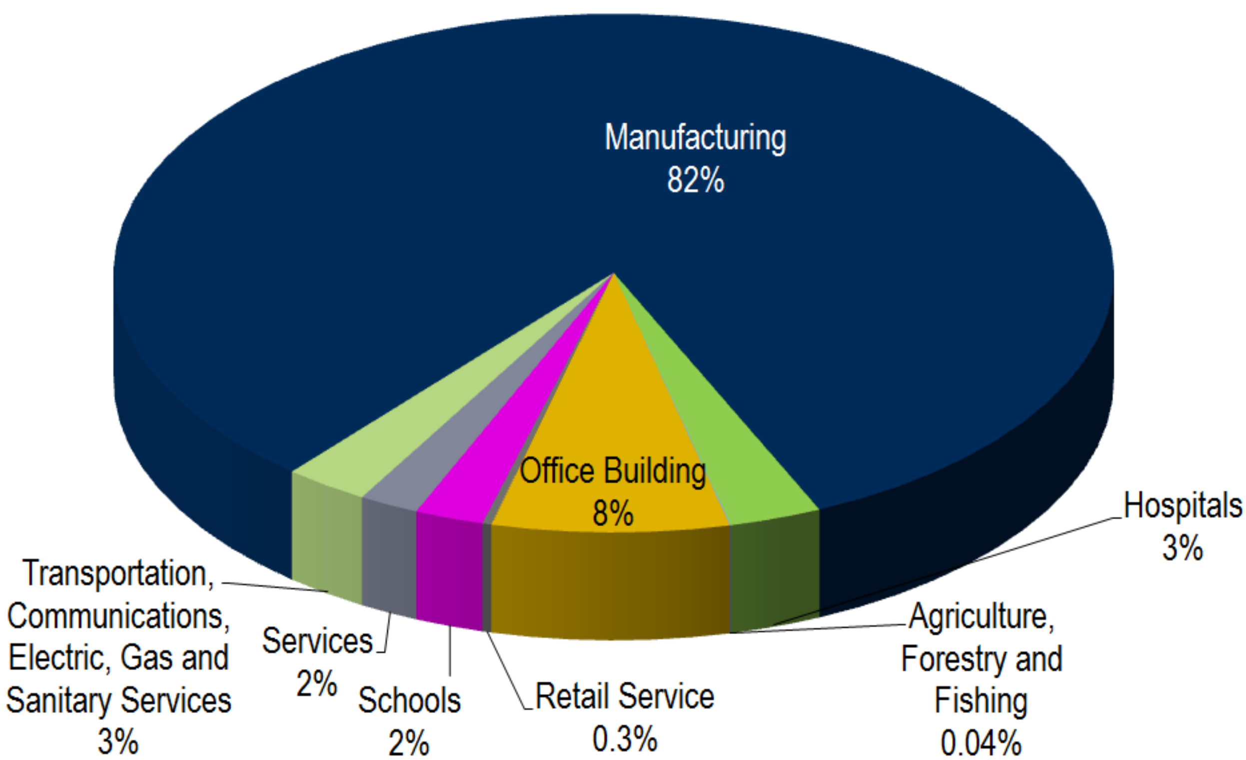
Figure 10: DY 16/17 MWs in PJM Capacity Performance by Resource and Lead Times

Zone		Lead Times (Minutes) 30	60	120	Total MWs	Committed MWs
AECO						
	Pre-Emergency	0.9	0.0	0.0	0.9	
	Emergency	0.0	0.0	0.0	0.0	
	Total	0.9	0.0	0.0	0.9	0.9
AEP						
	Pre-Emergency	68.5	0.0	12.3	80.8	
	Emergency	14.7	0.0	10.3	25.0	
	Total	83.2	0.0	22.7	105.8	104.0
APS						
	Pre-Emergency	64.1	6.5	18.3	88.9	
	Emergency	0.0	0.0	0.0	0.0	
	Total	64.1	6.5	18.3	88.9	84.1
ATSI						
	Pre-Emergency	2.2	0.0	0.0	2.2	
	Emergency	0.0	0.0	0.0	0.0	
	Total	2.2	0.0	0.0	2.2	2.3
BGE						
	Pre-Emergency	1.6	0.0	0.0	1.6	
	Emergency	0.0	0.0	0.0	0.0	
	Total	1.6	0.0	0.0	1.6	1.0
COMED						
	Pre-Emergency	112.3	5.4	9.5	127.2	
	Emergency	1.4	0.0	0.0	1.4	
	Total	113.6	5.4	9.5	128.6	123.5
DAY						
	Pre-Emergency	6.0	0.0	0.0	6.0	
	Emergency	0.0	0.0	0.0	0.0	
	Total	6.0	0.0	0.0	6.0	6.0
DEOK						
	Pre-Emergency	8.0	0.0	86.7	94.7	
	Emergency	0.0	0.0	0.0	0.0	
	Total	8.0	0.0	86.7	94.7	93.5
DOM						
	Pre-Emergency	27.2	0.0	5.3	32.6	
	Emergency	5.0	0.0	0.0	5.0	
	Total	32.2	0.0	5.3	37.5	30.5
DUQ						
	Pre-Emergency	1.0	0.0	0.0	1.0	
	Emergency	0.0	0.0	0.0	0.0	
	Total	1.0	0.0	0.0	1.0	1.0
EKPC						
	Pre-Emergency	10.2	7.2	95.1	112.4	
	Emergency	1.7	0.0	0.0	1.7	
	Total	11.9	7.2	95.1	114.2	113.9
PECO						
	Pre-Emergency	0.0	0.0	0.8	0.8	
	Emergency	0.0	0.0	0.0	0.0	
	Total	0.0	0.0	0.8	0.8	0.8
PENELEC						
	Pre-Emergency	0.0	0.0	12.1	12.1	
	Emergency	0.0	0.0	0.0	0.0	
	Total	0.0	0.0	12.1	12.1	12.1

Zone		Lead Times (Minutes) 30	60	120	Total MWs	Committed MWs
PPL						
	Pre-Emergency	0.7	0.0	0.0	0.7	
	Emergency	0.0	0.0	0.0	0.0	
	Total	0.7	0.0	0.0	0.7	0.7
TOTAL						
	Pre-Emergency	302.8	19.2	240.2	562.1	
	Emergency	22.7	0.0	10.3	33.1	
	Total	325.5	19.2	250.6	595.2	574.3

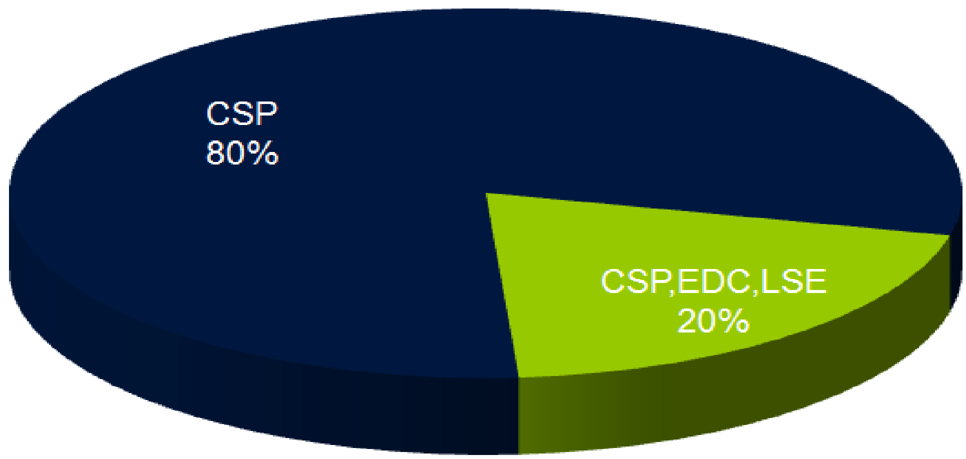
Note: MWs are Nominated Capacity (MWs)

Figure 11: DY 16/17 Confirmed Capacity Performance Registrations Business Segments



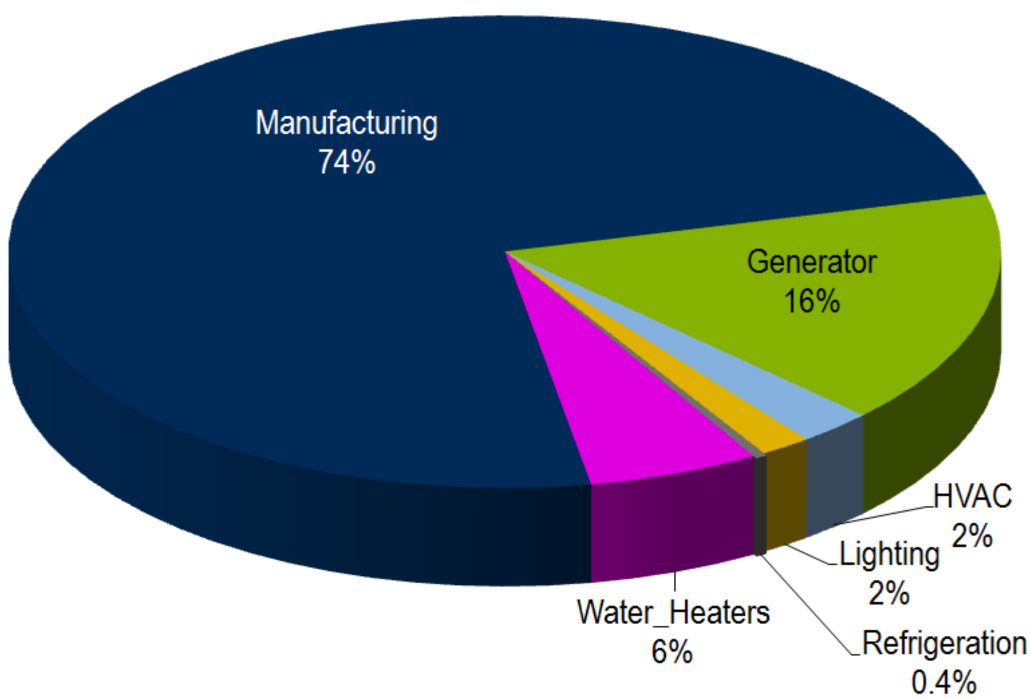
Note: Percent of Nominated Capacity (MWs)

Figure 12: DY 16/17 Confirmed Capacity Performance Registrations Owner/Company Type



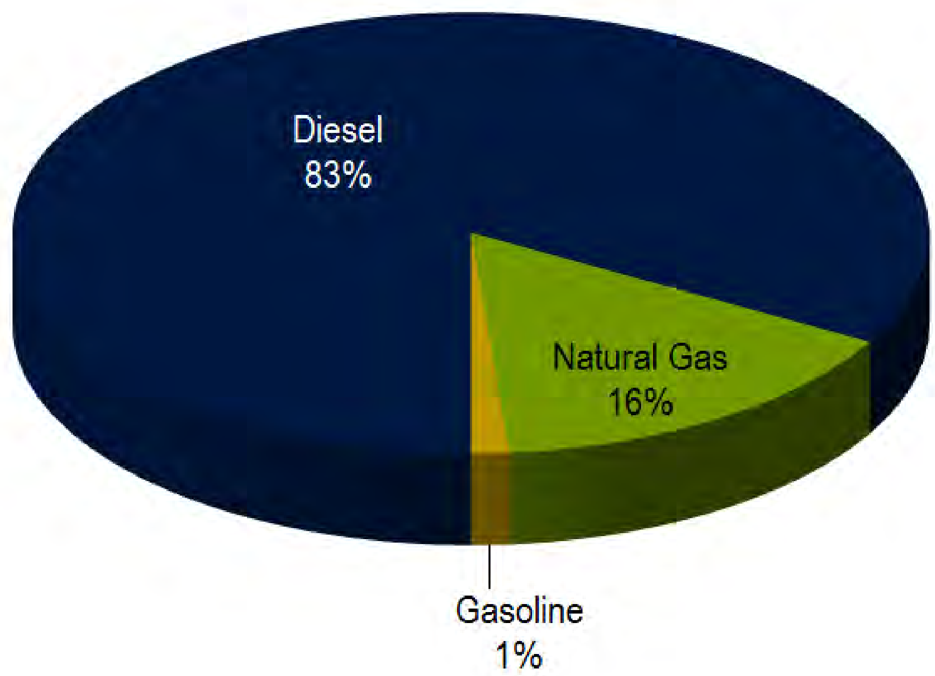
Note: Percent of Nominated Capacity (MWs)

Figure 13: DY 16/17 Confirmed Capacity Performance Registrations Load Reduction Methods



Note: Percent of Nominated Capacity (MWs)

Figure 14: DY 16/17 Confirmed Capacity Performance Registrations Fuel Mix with Behind the Meter Generation



Note: Percent of Nominated Capacity (MWs)

Figure 15: DY 16/17 Confirmed Capacity Performance Registrations Generator and Permit Type

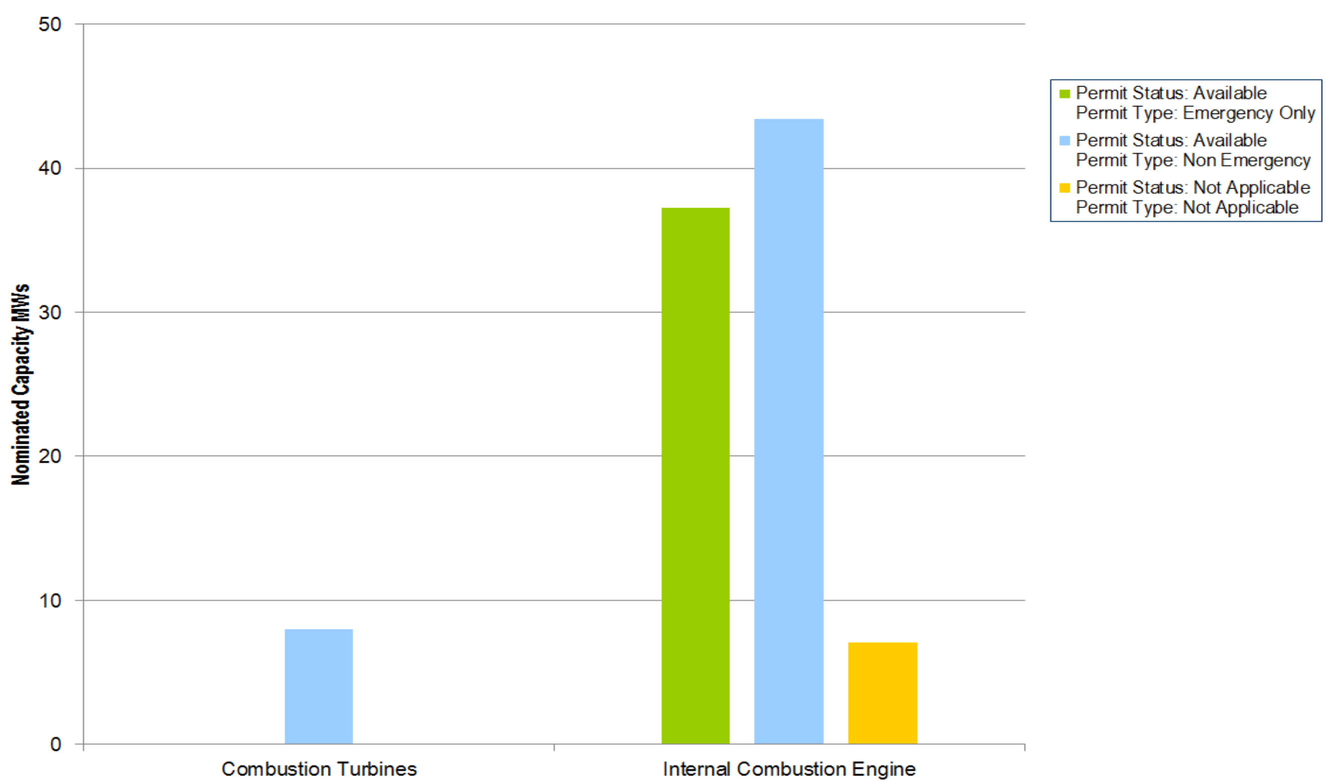


Figure 16: DY 16/17 Confirmed Capacity Performance Registrations Fuel Mix with Behind the Meter Generation

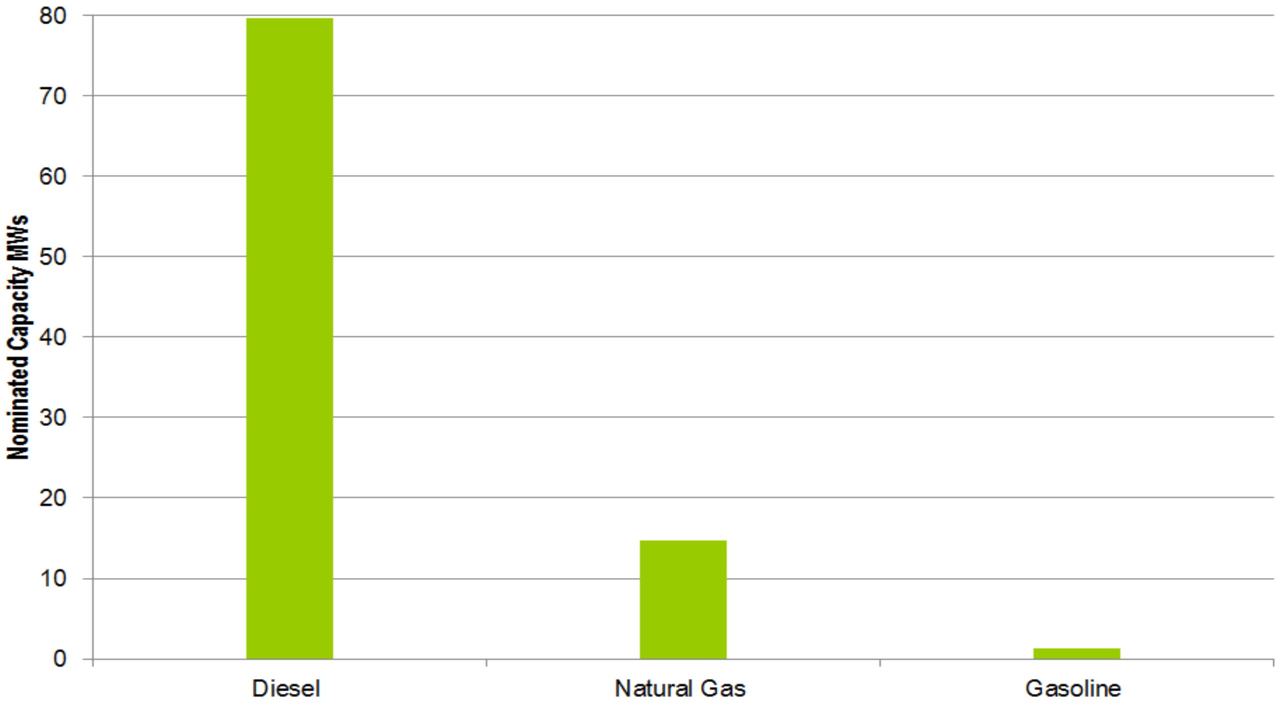


Figure 17: DY 16/17 Confirmed Capacity Performance Registrations Energy Supply Curve

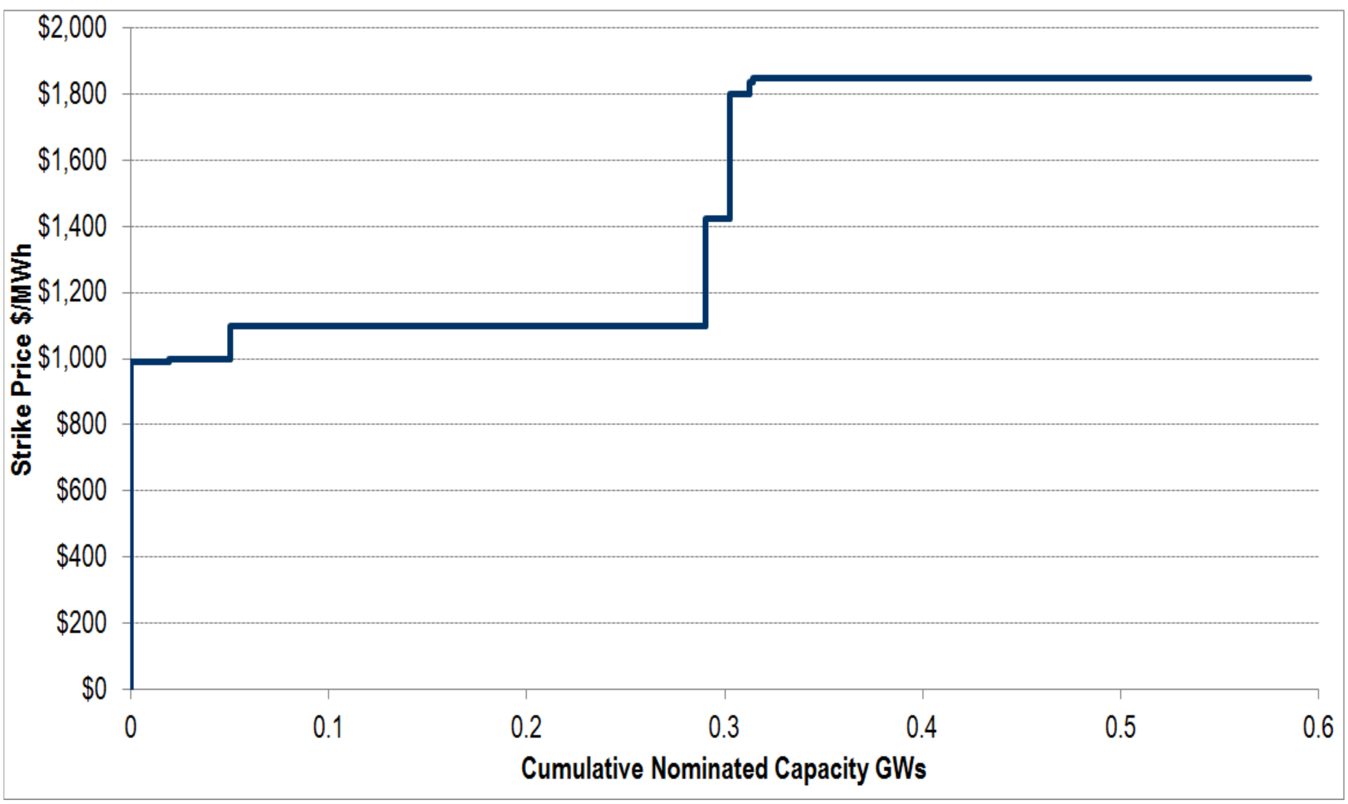


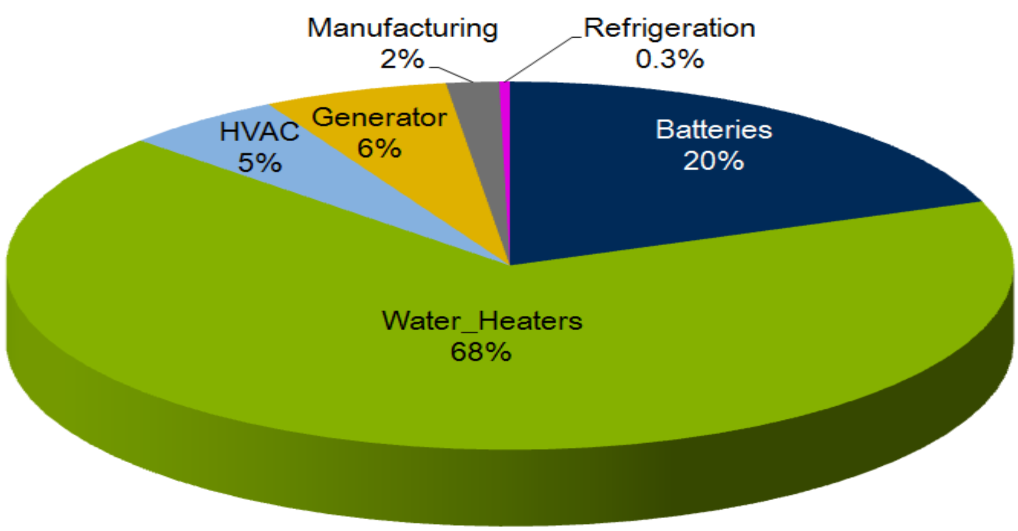
Figure 18: 2016 Economic Demand Response Capability in the Ancillary Service Markets

Synch Reserves	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Locations	MAD	135	136	136	136	136	146	140	139	140	139	141	158
	Non-MAD	10	10	12	12	12	11	11	11	12	12	13	15
	RTO	145	146	148	148	148	157	151	150	152	151	154	173
Average Number of Unique Participating Locations per Month:					152								
MWs	MAD	375	375	375	375	370	360	360	344	347	349	349	360
	Non-MAD	198	198	202	202	202	149	149	149	149	150	150	150
	RTO	573	573	576	576	571	509	509	492	496	499	499	510
	Average MWs per Month:				532								

Regulation	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Locations	RTO	293	292	277	331	338	302	302	391	396	400	397	407
Average Number of Unique Participating Locations per Month:					344								
MWs	RTO	24	24	25	33	36	36	36	42	47	56	57	59
	Average MWs per Month:				39								

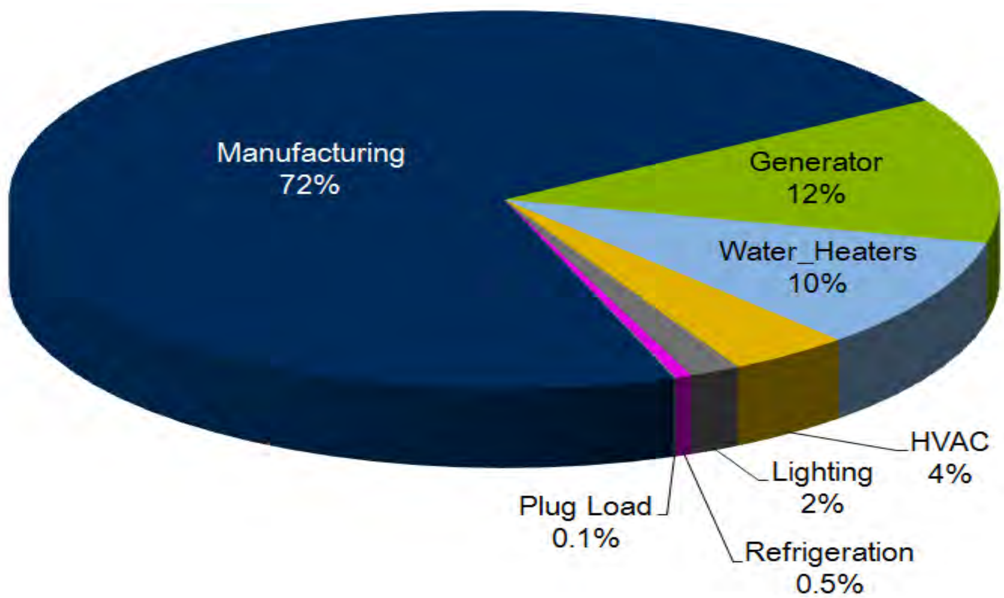
Capability represents total amount that may be offered. Actual offered and cleared volume may be significantly lower and is represented in subsequent figures/tables in report

Figure 19: 2016 PJM Demand Response Confirmed Regulation Registrations Load Reduction Methods



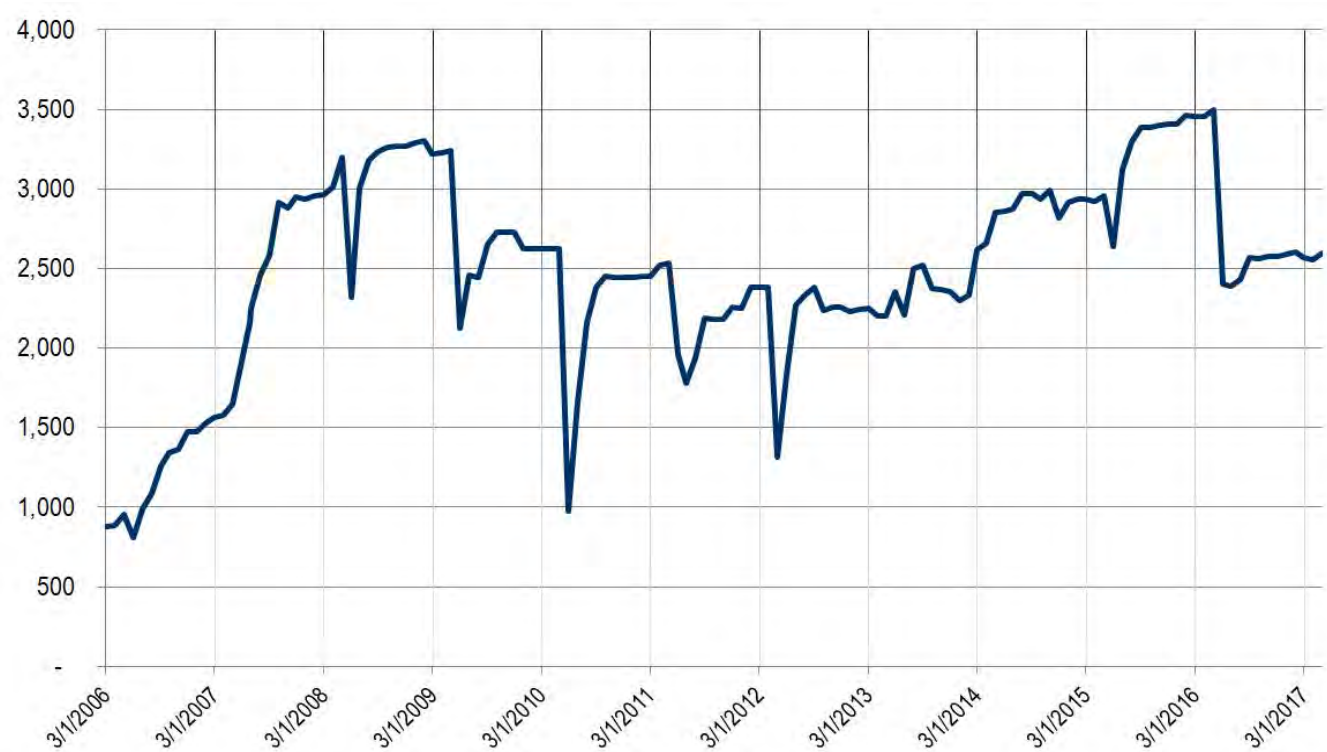
Note: Percent of CSP Reported Load Reduction MWs

Figure 20: 2016 PJM Demand Response Confirmed Synch Reserve Registrations Load Reduction Methods:



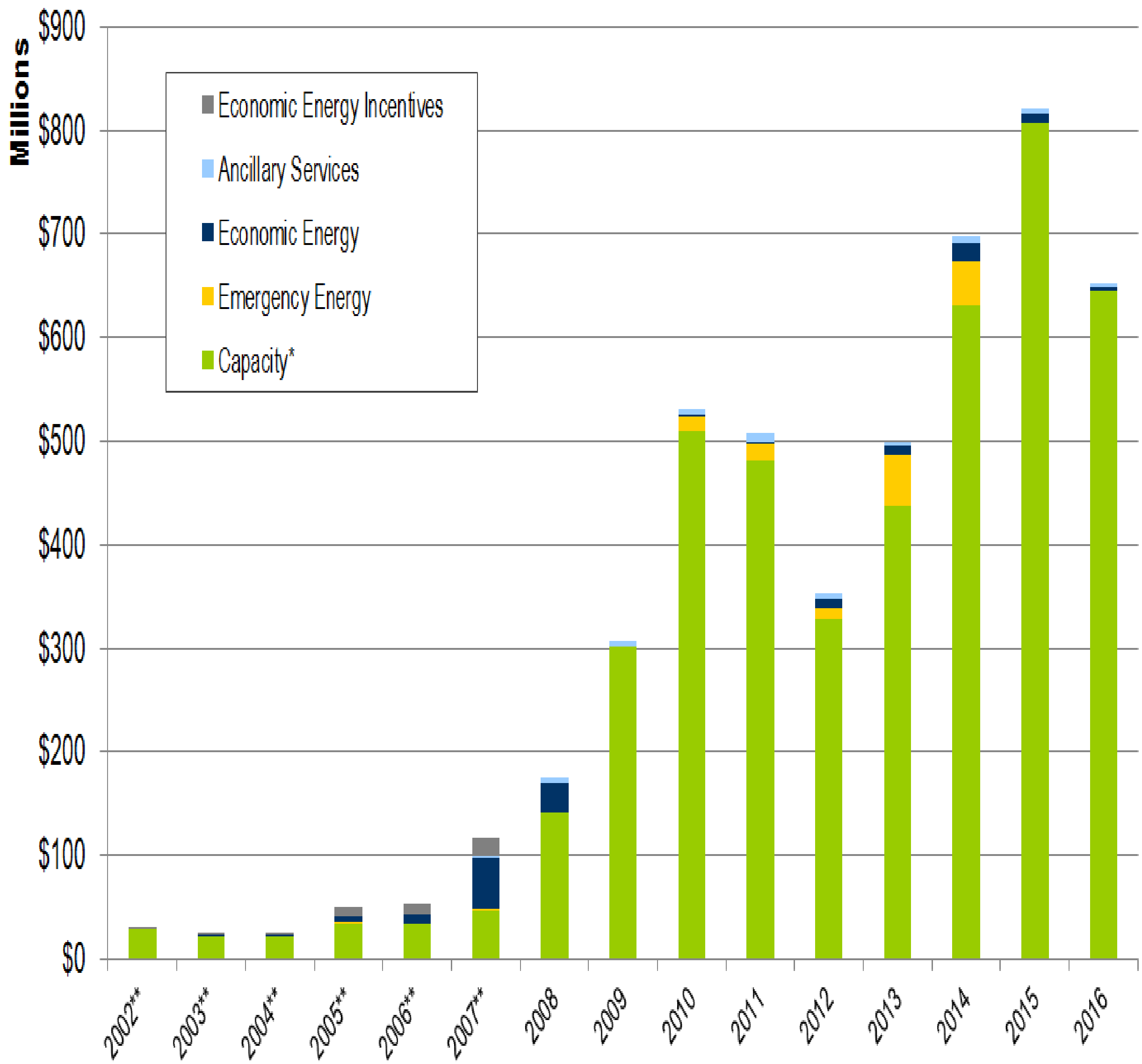
Note: Percent of CSP Reported Load Reduction MWs

Figure 21: PJM Economic Demand Response Capability in Energy Market (3/1/2006-05/10/2017)



Capability represents total amount that may be offered. Actual offered and cleared volume may be significantly lower and is represented in subsequent figures/tables in report.

Figure 22: PJM Estimated Revenue for Economic and Load Management DR Markets



*Capacity Net Revenue inclusive of Capacity Credits and Charges.
**PJM assumes capacity value at $50 MW Day (PJM does not know the value of capacity credits in the forward market prior to RPM; only a portion of capacity was purchased through the daily capacity market at the time).

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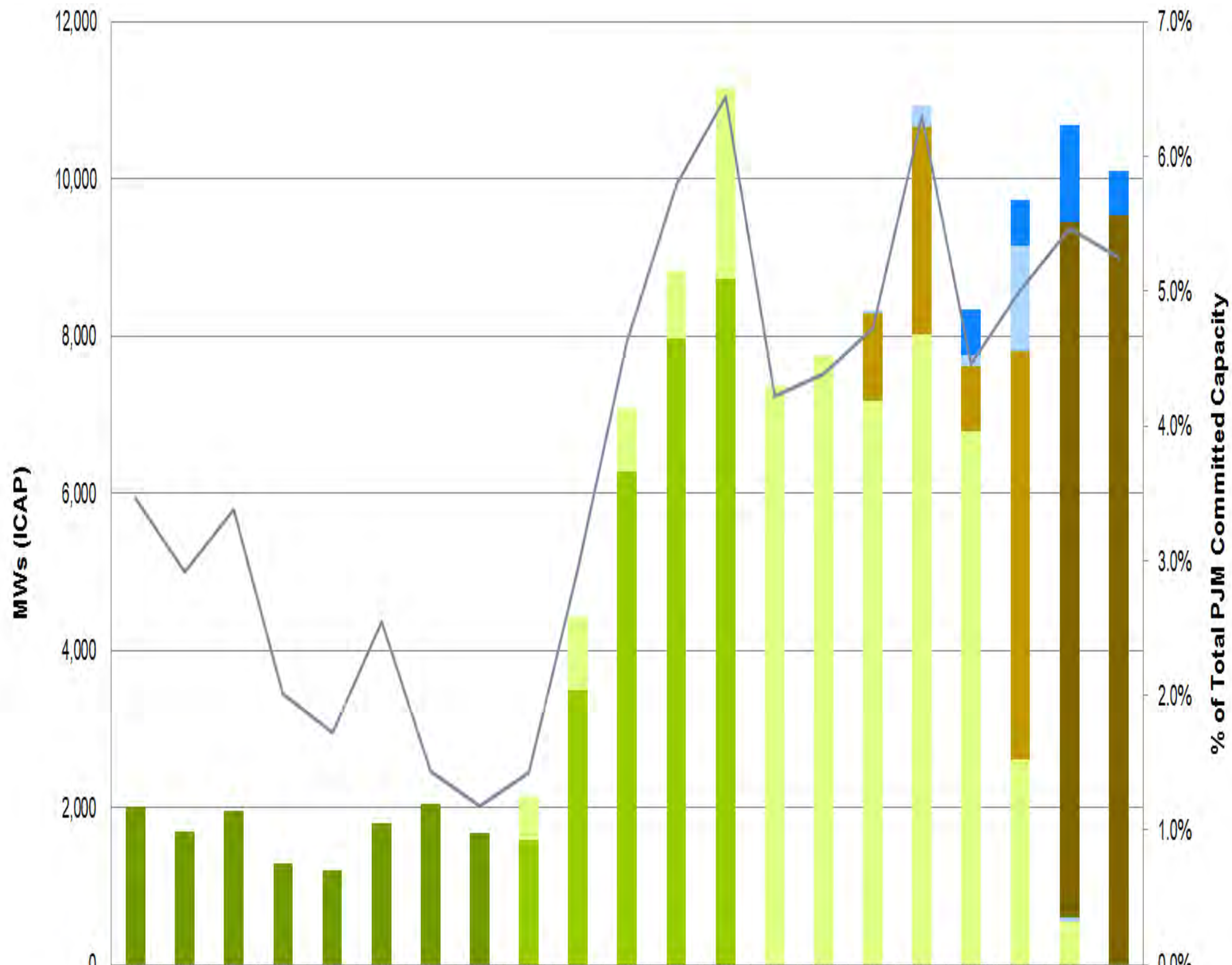
Figure 23: PJM Demand Response Committed MWs by Delivery Year



	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
Annual - CP																		574	589	1,225	564
Base - CP																				8,854	9,537
Annual - DR																22	266	144	1,333	44	
Extended Summer - DR																1,126	2,635	836	5,199	1	
Limited - DR									555	940	815	869	2,425	7,361	7,753	7,166	8,027	6,783	2,609	555	
Limited - ILR									1,585	3,489	6,274	7,961	8,731								
Limited - ALM	2,005	1,693	1,962	1,292	1,207	1,806	2,042	1,677													
DR as % of Total PJM Committed Capacity	3.5%	2.9%	3.4%	2.0%	1.7%	2.5%	1.4%	1.2%	1.4%	2.9%	4.6%	5.8%	6.4%	4.2%	4.4%	4.7%	6.3%	4.5%	5.0%	5.5%	5.3%

Notes:
1) Data as of 5/8/2017.
2) RPM was implemented DY 07/08.
3) DY 17/18 MWs include results from Base, First, Second, and Third Incremental Auctions.
4) DY 18/19 MWs include results from Base and First Incremental Auction.
5) DY 19/20 MWs include results from Base Residual Auction.
6) ALM MWs are seasonal averages for Delivery Years before 07/08.

Figure 24: 2016 Economic Demand Response Monthly Registration Participation

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							1		1			
DE	DPL							4	1	2			
IL	COMED	2	2	2	4	3	4	6	7	6	5	3	3
MD	BGE							8	1				
	DPL							2		2			
	PEPCO							2		2			
NJ	AECO					1	1	2	1	1	1		1
	JCPL		1					2	2				
	PSEG	10	7	7	8	6	7	10	9	8	8	6	7
OH	ATSI	1	1	1	1	1	1	1	1	1	1	1	1
	DEOK							8	8	8			
PA	METED							1	2	2	2	2	2
	PECO	2	2	1		1	1	7	3	3			2
	PENELEC	2	2	2	2	2	2	3	2	2	2	2	2
	PPL	1					1	3	2			1	1
VA	DOM	2	3	1	1	2	3	3	3	3	2	1	1
WV	APS	1		1		1	1		1	1	1	1	1
Total		**21**	**18**	**15**	**16**	**17**	**21**	**63**	**43**	**42**	**22**	**17**	**21**

Average Unique Participating Registrations per Month: 26

Figure 25: 2016 Economic Demand Response Monthly Registration Participation Day-Ahead Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO												
DE	DPL							1	1				
IL	COMED												
MD	BGE												
	DPL												
	PEPCO												
NJ	AECO												
	JCPL							1	1				
	PSEG	5	5	5	5	4	3	5	4	3	4	3	4
OH	ATSI												
	DEOK							8	8	8			
PA	METED								1	1	1	1	1
	PECO		1					1		1			1
	PENELEC	1	1	1	1	1	1	1	1	1	1	1	1
	PPL							2	1				1
VA	DOM	1	1			1	1		1		1		
WV	APS												
Total		**7**	**8**	**6**	**6**	**6**	**5**	**19**	**18**	**14**	**7**	**5**	**8**

Average Unique Participating Registrations per Month (Day-Ahead): 9

Figure 26: 2016 Economic Demand Response Monthly Registration Participation Real-Time Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							1		1			
DE	DPL							3		2			
IL	COMED	2	2	2	4	3	4	6	7	6	5	3	3
MD	BGE							8	1				
	DPL							2		2			
	PEPCO							2		2			
NJ	AECO					1	1	2	1	1	1		1
	JCPL		1					1	1				
	PSEG	5	2	2	3	2	4	5	5	5	4	3	3
OH	ATSI	1	1	1	1	1	1	1	1	1	1	1	1
	DEOK												
PA	METED							1	1	1	1	1	1
	PECO	2	1	1		1	1	6	3	2			1
	PENELEC	1	1	1	1	1	1	2	1	1	1	1	1
	PPL	1					1	1	1			1	
VA	DOM	1	2	1	1	1	2	3	2	3	1	1	1
WV	APS	1		1		1	1		1	1	1	1	1
Total		**14**	**10**	**9**	**10**	**11**	**16**	**44**	**25**	**28**	**15**	**12**	**13**

Average Unique Participating Registrations per Month (Real-Time): 17

Figure 27: 2016 Economic Demand Response Monthly MWh Reductions

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							44		16			
DE	DPL							210	4	0			
IL	COMED	193	6	20	143	458	514	1,092	1,575	1,082	647	62	572
MD	BGE							8,607	2				
	DPL							165		31			
	PEPCO							798		150			
NJ	AECO					8	1	42	40	19	0		0
	JCPL		5					2,307	739				
	PSEG	2,156	1,011	143	2,236	1,142	919	974	891	601	723	916	2,211
OH	ATSI	1,009	667	610	1,190	328	1,105	1,442	1,883	1,066	1,076	78	159
	DEOK							211	46	29			
PA	METED							30	12	37	31	8	19
	PECO	5	4	0		0	1	353	31	97			4
	PENELEC	1,185	534	493	1,208	815	1,335	1,084	1,222	1,077	959	1,058	622
	PPL	1					1	770	122			16	854
VA	DOM	3,374	2,311	2,059	3,445	2,413	1,935	215	1,374	827	1,569	852	1,875
WV	APS	205		47		111	212		334	303	81	0	0
Total		**8,128**	**4,538**	**3,373**	**8,222**	**5,275**	**6,024**	**18,345**	**8,275**	**5,336**	**5,087**	**2,990**	**6,315**

Total MWh: **81,908**

Figure 28: 2016 Economic Demand Response Monthly MWh Reductions Day-Ahead Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO												
DE	DPL							30	4				
IL	COMED												
MD	BGE												
	DPL												
	PEPCO												
NJ	AECO												
	JCPL							2,189	668				
	PSEG	2,050	918	126	2,014	1,067	632	842	204	305	194	298	1,560
OH	ATSI												
	DEOK							211	46	29			
PA	METED								9	32	14	3	16
	PECO		0					274		64			4
	PENELEC	1,005	522	372	1,142	533	1,231	1,003	685	827	496	755	538
	PPL							763	120				854
VA	DOM	912	464			824	434		542		399		
WV	APS												
Total		**3,967**	**1,905**	**498**	**3,157**	**2,424**	**2,298**	**5,314**	**2,278**	**1,257**	**1,104**	**1,056**	**2,972**

Total Day-Ahead MWh: **28,230**

Figure 29: 2016 Economic Demand Response Monthly MWh Reductions Real-Time Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							44		16			
DE	DPL							180		0			
IL	COMED	193	6	20	143	458	514	1,092	1,575	1,082	647	62	572
MD	BGE							8,607	2				
	DPL							165		31			
	PEPCO							798		150			
NJ	AECO					8	1	42	40	19	0		0
	JCPL		5					118	71				
	PSEG	105	93	17	221	75	287	131	688	296	529	618	651
OH	ATSI	1,009	667	610	1,190	328	1,105	1,442	1,883	1,066	1,076	78	159
	DEOK												
PA	METED							30	3	5	17	5	2
	PECO	5	4	0		0	1	79	31	33			0
	PENELEC	181	12	121	65	282	103	81	538	250	463	302	84
	PPL	1					1	7	1			16	
VA	DOM	2,461	1,847	2,059	3,445	1,589	1,500	215	832	827	1,170	852	1,875
WV	APS	205		47		111	212		334	303	81	0	0
Total		**4,160**	**2,633**	**2,875**	**5,065**	**2,851**	**3,726**	**13,031**	**5,997**	**4,079**	**3,983**	**1,934**	**3,343**

Total Real-Time MWh: **53,678**

Figure 30: 2016 Economic Demand Response Monthly Energy Market Revenue

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							$1,606		$522			
DE	DPL							$13,825	$490	$1,609			
IL	COMED	$6,380	$194	$231	$4,265	$10,461	$16,621	$38,588	$73,779	$50,558	$22,085	$980	$22,974
MD	BGE							$487,806	$241				
	DPL							$6,535		$977			
	PEPCO							$29,309		$4,630			
NJ	AECO					$563	$37	$1,747	$2,776	$777	$0		$0
	JCPL		$308					$137,272	$38,619				
	PSEG	$90,115	$40,477	$3,490	$61,433	$26,640	$28,710	$50,813	$32,678	$24,707	$20,467	$13,429	$85,500
OH	ATSI	$38,068	$22,026	$18,985	$46,867	$12,725	$45,699	$58,848	$90,484	$47,383	$35,208	$2,365	$5,509
	DEOK							$21,996	$4,213	$2,115			
PA	METED							$1,534	$485	$1,658	$900	$244	$790
	PECO	$247	($2,391)	$0		$0	$40	$33,071	$4,424	$8,982			$322
	PENELEC	$39,606	$15,657	$13,765	$41,646	$28,204	$44,737	$47,432	$50,959	$48,924	$24,833	$21,227	$20,395
	PPL	$38					$23	$40,749	$10,793			($16)	$34,308
VA	DOM	$203,643	$105,347	$67,538	$163,066	$94,672	$72,093	$9,586	$77,272	$55,069	$71,575	$21,630	$111,757
WV	APS	$7,823		$960		$3,031	$7,935		$24,096	$10,128	$2,015	$0	$0
Total		**$385,920**	**$181,618**	**$104,969**	**$317,277**	**$176,295**	**$215,893**	**$980,718**	**$411,310**	**$258,040**	**$177,082**	**$59,858**	**$281,555**

Total CSP Credits: $3,550,535

Figure 31: 2016 Economic Demand Response Monthly Energy Market Revenue Day-Ahead Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO												
DE	DPL							$2,671	$490				
IL	COMED												
MD	BGE												
	DPL												
	PEPCO												
NJ	AECO												
	JCPL							$129,260	$35,861				
	PSEG	$86,509	$36,686	$3,080	$54,614	$23,318	$19,707	$44,978	$1,747	$13,291	$6,013	$6,607	$67,969
OH	ATSI												
	DEOK							$21,996	$4,213	$2,115			
PA	METED								$352	$1,433	$487	$100	$685
	PECO		($2,581)					$26,903		$6,053			$322
	PENELEC	$33,647	$15,394	$11,540	$39,649	$17,671	$41,730	$44,297	$27,715	$35,750	$16,713	$17,331	$19,197
	PPL							$40,462	$10,766				$34,308
VA	DOM	$43,482	$14,732			$23,468	$9,726		$17,350		$17,655		
WV	APS												
Total		**$163,639**	**$64,230**	**$14,620**	**$94,264**	**$64,456**	**$71,162**	**$310,567**	**$98,494**	**$58,644**	**$40,868**	**$24,038**	**$122,480**

Total Day-Ahead CSP Credits: $1,127,462

Figure 32: 2016 Economic Demand Response Monthly Energy Market Revenue Real-Time Activity

State	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DC	PEPCO							$1,606		$522			
DE	DPL							$11,154		$1,609			
IL	COMED	$6,380	$194	$231	$4,265	$10,461	$16,621	$38,588	$73,779	$50,558	$22,085	$980	$22,974
MD	BGE							$487,806	$241				
	DPL							$6,535		$977			
	PEPCO							$29,309		$4,630			
NJ	AECO					$563	$37	$1,747	$2,776	$777	$0		$0
	JCPL		$308					$8,012	$2,758				
	PSEG	$3,606	$3,790	$410	$6,819	$3,322	$9,003	$5,834	$30,931	$11,415	$14,454	$6,822	$17,531
OH	ATSI	$38,068	$22,026	$18,985	$46,867	$12,725	$45,699	$58,848	$90,484	$47,383	$35,208	$2,365	$5,509
	DEOK												
PA	METED							$1,534	$134	$225	$413	$144	$105
	PECO	$247	$190	$0		$0	$40	$6,168	$4,424	$2,929			$0
	PENELEC	$5,959	$263	$2,225	$1,997	$10,533	$3,007	$3,135	$23,244	$13,174	$8,119	$3,896	$1,198
	PPL	$38					$23	$287	$27			($16)	
VA	DOM	$160,161	$90,616	$67,538	$163,066	$71,204	$62,367	$9,586	$59,922	$55,069	$53,921	$21,630	$111,757
WV	APS	$7,823		$960		$3,031	$7,935		$24,096	$10,128	$2,015	$0	$0
Total		**$222,281**	**$117,388**	**$90,349**	**$223,013**	**$111,839**	**$144,731**	**$670,150**	**$312,815**	**$199,396**	**$136,214**	**$35,821**	**$159,075**

Total Real-Time CSP Credits: $2,423,073

Figure 33: 2016 Economic Demand Response Energy Market Cost Allocation by Zone

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AECO	$3,909	$2,797	$572	$2,699	$2,006	$2,590	$15,701	$5,781	$2,893	$921	$404	$3,101
AEP	$61,507	$26,701	$19,772	$55,451	$28,377	$33,758	$138,190	$61,304	$39,715	$30,234	$7,819	$42,102
APS	$25,411	$12,526	$7,495	$21,191	$10,641	$12,386	$53,344	$23,249	$15,531	$11,412	$3,116	$16,731
ATSI	$30,433	$14,082	$10,414	$29,156	$15,424	$18,108	$78,490	$34,379	$20,837	$16,268	$4,488	$21,987
BGE	$17,843	$13,378	$4,900	$13,129	$6,937	$8,588	$40,535	$17,640	$11,992	$8,594	$3,448	$11,547
COMED	$35,941	$9,206	$12,101	$33,432	$22,093	$27,308	$122,641	$50,969	$31,707	$23,258	$5,155	$28,212
DAY	$8,580	$3,505	$2,662	$7,589	$3,972	$4,887	$19,909	$9,015	$5,800	$4,508	$1,129	$5,860
DEOK	$12,263	$3,982	$3,881	$11,534	$6,103	$7,889	$31,911	$14,246	$9,178	$6,222	$1,557	$8,411
DOM	$52,633	$27,376	$14,607	$40,297	$21,615	$27,008	$122,961	$52,343	$35,851	$26,544	$8,263	$33,606
DPL	$9,111	$4,489	$2,439	$5,439	$3,756	$4,013	$24,867	$9,392	$5,387	$1,800	$1,069	$6,572
DUQ	$5,960	$2,557	$1,998	$5,790	$3,173	$3,984	$17,404	$7,392	$4,610	$3,174	$840	$4,123
EKPC	$6,939	$2,164	$1,809	$5,275	$2,592	$3,415	$12,875	$5,979	$3,773	$2,483	$753	$4,619
JCPL	$9,635	$4,081	$1,611	$7,346	$4,909	$5,862	$34,202	$12,963	$6,776	$2,241	$916	$6,819
METED	$6,844	$2,967	$1,194	$5,165	$3,115	$3,592	$17,925	$6,836	$3,859	$1,700	$648	$4,628
PECO	$17,023	$6,772	$2,922	$12,132	$8,122	$9,217	$51,727	$18,914	$10,613	$3,963	$1,652	$12,466
PENELEC	$7,961	$4,042	$2,449	$7,667	$3,807	$4,123	$17,681	$7,592	$4,217	$3,251	$980	$5,590
PEPCO	$16,299	$8,753	$4,662	$12,682	$7,016	$8,677	$40,162	$17,283	$11,562	$8,534	$2,920	$10,511
PPL	$19,654	$8,344	$3,307	$14,971	$8,129	$9,380	$44,500	$17,174	$9,703	$4,213	$1,686	$13,688
PSEG	$18,650	$8,019	$3,191	$14,874	$9,273	$10,817	$59,053	$22,599	$12,521	$5,101	$1,887	$13,659
RECO	$665	$223	$118	$515	$345	$422	$2,310	$886	$480	$225	$69	$456
Exports	$18,659	$15,654	$2,865	$10,943	$4,891	$9,868	$34,331	$15,373	$11,032	$12,435	$11,058	$26,868
TOTAL	**$385,920**	**$181,618**	**$104,969**	**$317,277**	**$176,295**	**$215,893**	**$980,718**	**$411,310**	**$258,040**	**$177,082**	**$59,858**	**$281,555**

Total Zonal Charges: **$3,550,535**

Figure 34: 2016 Economic Demand Response Day-Ahead Energy Market Cost Allocation by Zone

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AECO	$1,359	$1,239	$55	$527	$701	$591	$5,135	$2,041	$435	$97	$60	$972
AEP	$21,817	$5,322	$1,636	$10,509	$9,412	$7,828	$45,539	$19,743	$6,133	$4,793	$784	$13,319
APS	$8,886	$2,918	$639	$3,961	$3,507	$2,879	$17,320	$7,611	$2,333	$1,679	$353	$5,224
ATSI	$11,196	$3,467	$878	$5,644	$5,118	$4,174	$26,176	$11,116	$3,195	$2,628	$513	$7,051
BGE	$6,643	$5,484	$444	$2,450	$2,230	$2,024	$13,323	$6,070	$1,798	$1,235	$573	$3,662
COMED	$14,264	$1,643	$1,147	$7,295	$6,957	$6,144	$40,805	$15,880	$5,022	$4,068	$480	$8,741
DAY	$3,203	$764	$224	$1,470	$1,316	$1,148	$6,547	$2,932	$930	$710	$111	$1,865
DEOK	$4,435	$740	$320	$2,246	$2,001	$1,815	$10,434	$4,550	$1,429	$1,066	$143	$2,596
DOM	$17,275	$5,706	$1,257	$7,495	$6,875	$6,237	$40,327	$17,782	$5,184	$3,695	$837	$10,402
DPL	$3,128	$1,039	$294	$1,012	$1,265	$936	$8,093	$3,281	$839	$184	$244	$1,986
DUQ	$2,162	$622	$172	$1,135	$1,041	$925	$5,652	$2,441	$731	$527	$94	$1,297
EKPC	$2,382	$381	$148	$946	$838	$765	$4,405	$1,924	$561	$416	$71	$1,403
JCPL	$3,459	$1,071	$152	$1,432	$1,681	$1,342	$11,377	$4,555	$1,007	$234	$142	$2,106
METED	$2,400	$1,004	$122	$1,029	$1,120	$822	$5,916	$2,360	$606	$180	$91	$1,636
PECO	$5,902	$1,972	$406	$2,353	$2,921	$2,153	$16,941	$6,648	$1,569	$403	$226	$3,878
PENELEC	$2,896	$1,225	$201	$1,482	$1,319	$972	$5,874	$2,509	$713	$539	$116	$1,726
PEPCO	$5,850	$2,269	$426	$2,429	$2,271	$2,056	$13,070	$5,941	$1,699	$1,211	$420	$3,326
PPL	$6,815	$2,101	$323	$3,030	$2,956	$2,277	$14,763	$5,887	$1,520	$432	$240	$4,428
PSEG	$7,111	$2,084	$289	$3,126	$3,246	$2,587	$19,662	$7,851	$1,862	$802	$254	$4,215
RECO	$275	$61	$10	$112	$116	$100	$775	$306	$72	$35	$11	$143
Exports	$10,210	$9,301	$346	$2,094	$1,454	$1,968	$11,949	$5,058	$1,447	$1,880	$2,133	$10,588
TOTAL	**$141,668**	**$50,414**	**$9,490**	**$61,778**	**$58,346**	**$49,744**	**$324,084**	**$136,487**	**$39,085**	**$26,813**	**$7,897**	**$90,566**

Total Day-Ahead Zonal Charges: **$996,371**

Figure 35: 2016 Economic Demand Response Real-Time Energy Market Cost Allocation by Zone

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AECO	$2,549	$1,558	$517	$2,172	$1,305	$1,999	$10,566	$3,740	$2,459	$824	$344	$2,128
AEP	$39,691	$21,379	$18,136	$44,942	$18,965	$25,930	$92,651	$41,561	$33,582	$25,441	$7,035	$28,783
APS	$16,525	$9,608	$6,855	$17,230	$7,134	$9,508	$36,024	$15,638	$13,198	$9,733	$2,764	$11,507
ATSI	$19,237	$10,615	$9,536	$23,513	$10,306	$13,934	$52,314	$23,262	$17,643	$13,641	$3,975	$14,936
BGE	$11,199	$7,894	$4,456	$10,679	$4,706	$6,564	$27,212	$11,570	$10,194	$7,359	$2,875	$7,884
COMED	$21,676	$7,563	$10,954	$26,137	$15,137	$21,164	$81,836	$35,089	$26,686	$19,191	$4,675	$19,471
DAY	$5,377	$2,742	$2,438	$6,119	$2,655	$3,739	$13,361	$6,083	$4,870	$3,798	$1,017	$3,994
DEOK	$7,828	$3,242	$3,560	$9,288	$4,102	$6,074	$21,477	$9,696	$7,749	$5,156	$1,414	$5,815
DOM	$35,358	$21,670	$13,349	$32,801	$14,740	$20,771	$82,634	$34,561	$30,667	$22,849	$7,426	$23,204
DPL	$5,983	$3,450	$2,145	$4,426	$2,491	$3,077	$16,773	$6,110	$4,549	$1,616	$824	$4,587
DUQ	$3,799	$1,935	$1,826	$4,655	$2,131	$3,060	$11,753	$4,951	$3,879	$2,647	$746	$2,826
EKPC	$4,557	$1,783	$1,661	$4,329	$1,754	$2,650	$8,471	$4,054	$3,212	$2,066	$682	$3,216
JCPL	$6,176	$3,009	$1,460	$5,914	$3,227	$4,519	$22,825	$8,409	$5,769	$2,007	$775	$4,713
METED	$4,444	$1,963	$1,071	$4,136	$1,996	$2,770	$12,009	$4,476	$3,253	$1,520	$557	$2,992
PECO	$11,121	$4,800	$2,516	$9,780	$5,201	$7,064	$34,785	$12,267	$9,044	$3,559	$1,426	$8,588
PENELEC	$5,065	$2,816	$2,248	$6,185	$2,488	$3,152	$11,808	$5,083	$3,504	$2,712	$864	$3,864
PEPCO	$10,448	$6,484	$4,236	$10,253	$4,745	$6,621	$27,091	$11,342	$9,864	$7,323	$2,500	$7,185
PPL	$12,839	$6,243	$2,984	$11,941	$5,173	$7,103	$29,736	$11,286	$8,183	$3,781	$1,446	$9,260
PSEG	$11,539	$5,935	$2,902	$11,748	$6,027	$8,230	$39,391	$14,748	$10,659	$4,298	$1,634	$9,443
RECO	$390	$162	$108	$403	$230	$322	$1,535	$580	$408	$190	$58	$313
Exports	$8,449	$6,354	$2,519	$8,849	$3,436	$7,900	$22,382	$10,315	$9,585	$10,555	$8,925	$16,279
TOTAL	**$244,251**	**$131,205**	**$95,478**	**$255,499**	**$117,950**	**$166,149**	**$656,634**	**$274,823**	**$218,955**	**$150,269**	**$51,962**	**$190,989**

Total Real-Time Zonal Charges: **$2,554,163**

Figure 36: 2016 Load Managment Demand Response Monthly Capacity Revenue from RPM

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AECO	$1,018,226	$952,534	$1,018,226	$985,380	$1,018,226	$618,278	$638,888	$638,888	$618,278	$638,888	$618,278	$638,888
AEP	$6,833,359	$6,392,497	$6,833,359	$6,612,928	$6,833,359	$2,787,543	$2,880,461	$2,880,461	$2,787,543	$2,880,461	$2,787,543	$2,880,461
APS	$3,279,835	$3,068,232	$3,279,835	$3,174,034	$3,279,835	$1,613,157	$1,666,929	$1,666,929	$1,613,157	$1,666,929	$1,613,157	$1,666,929
ATSI	$19,097,783	$17,865,668	$19,097,783	$18,481,726	$19,097,783	$5,701,661	$5,891,717	$5,891,717	$5,701,661	$5,891,717	$5,701,661	$5,891,717
BGE	$5,546,155	$5,188,338	$5,546,155	$5,367,247	$5,546,155	$3,355,267	$3,467,109	$3,467,109	$3,355,267	$3,467,109	$3,355,267	$3,467,109
COMED	$6,679,174	$6,248,259	$6,679,174	$6,463,717	$6,679,174	$2,980,466	$3,079,815	$3,079,815	$2,980,466	$3,079,815	$2,980,466	$3,079,815
DAY	$760,832	$711,746	$760,832	$736,289	$760,832	$448,489	$463,438	$463,438	$448,489	$463,438	$448,489	$463,438
DEOK	$1,319,812	$1,234,663	$1,319,812	$1,277,237	$1,319,812	$577,029	$596,264	$596,264	$577,029	$596,264	$577,029	$596,264
DOM	$5,235,719	$4,897,930	$5,235,719	$5,066,825	$5,235,719	$2,395,261	$2,475,103	$2,475,103	$2,395,261	$2,475,103	$2,395,261	$2,475,103
DPL	$2,201,083	$2,059,077	$2,201,083	$2,130,080	$2,201,083	$1,572,292	$1,624,702	$1,624,702	$1,572,292	$1,624,702	$1,572,292	$1,624,702
DUQ	$878,296	$821,632	$878,296	$849,964	$878,296	$388,781	$401,741	$401,741	$388,781	$401,741	$388,781	$401,741
EKPC	$47,787	$44,704	$47,787	$46,245	$47,787	$504,721	$521,545	$521,545	$504,721	$521,545	$504,721	$521,545
JCPL	$1,720,510	$1,609,510	$1,720,510	$1,665,010	$1,720,510	$797,471	$824,053	$824,053	$797,471	$824,053	$797,470	$824,053
METED	$1,667,231	$1,559,668	$1,667,231	$1,613,449	$1,667,231	$1,120,926	$1,158,290	$1,158,290	$1,120,926	$1,158,290	$1,120,926	$1,158,290
PECO	$3,824,221	$3,577,497	$3,824,221	$3,700,859	$3,824,221	$1,898,249	$1,961,524	$1,961,524	$1,898,249	$1,961,524	$1,898,249	$1,961,524
PENELEC	$2,625,490	$2,456,104	$2,625,490	$2,540,797	$2,625,490	$1,545,027	$1,596,528	$1,596,528	$1,545,027	$1,596,528	$1,545,027	$1,596,528
PEPCO	$4,232,745	$3,959,665	$4,232,745	$4,096,205	$4,232,745	$2,379,380	$2,458,692	$2,458,692	$2,379,380	$2,458,692	$2,379,380	$2,458,692
PPL	$5,591,452	$5,230,713	$5,591,452	$5,411,083	$5,591,452	$3,571,436	$3,690,484	$3,690,484	$3,571,436	$3,690,484	$3,571,436	$3,690,484
PSEG	$3,862,880	$3,613,662	$3,862,880	$3,738,271	$3,862,880	$4,088,123	$4,224,394	$4,224,394	$4,088,123	$4,224,394	$4,088,123	$4,224,394
RECO	$103,031	$96,384	$103,031	$99,707	$103,031	$36,097	$37,300	$37,300	$36,097	$37,300	$36,097	$37,300
Total	**$76,525,621**	**$71,588,484**	**$76,525,621**	**$74,057,052**	**$76,525,621**	**$38,379,653**	**$39,658,975**	**$39,658,975**	**$38,379,653**	**$39,658,975**	**$38,379,653**	**$39,658,975**

Total Capacity Credits: **$648,997,257**

Figure 37: 2016 Economic Demand Response Dispatched vs Settled Real-Time Energy Market Summary

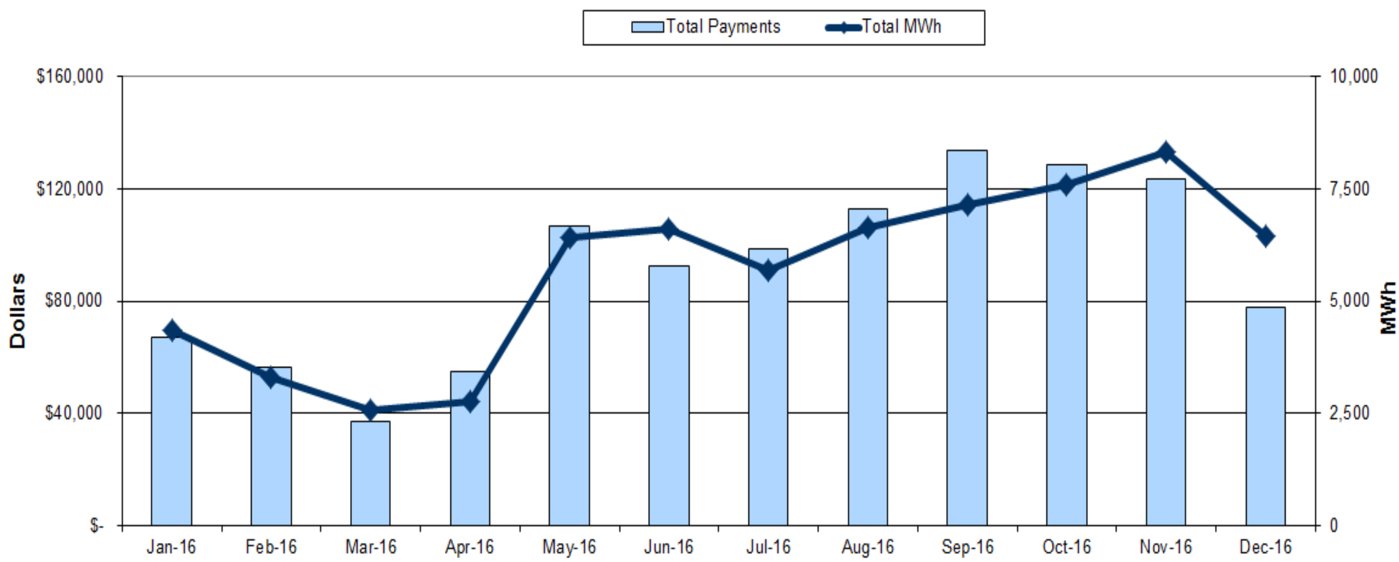
Time		CSPs		Zone		Registrations			MWh			Registration Hours		
Year	Month	Dispatched	Settled	Dispatched	Settled	Dispatched	Settled	%	Dispatched	Settled	%	Dispatched	Settled	%
2016	1	4	4	8	8	14	14	100%	3,621	4,160	115%	610	610	100%
2016	2	4	4	7	7	10	10	100%	2,204	2,633	119%	288	288	100%
2016	3	4	4	7	7	9	9	100%	2,372	2,875	121%	272	272	100%
2016	4	4	4	5	5	10	10	100%	3,888	5,065	130%	622	622	100%
2016	5	5	5	8	8	11	11	100%	2,652	2,851	108%	763	763	100%
2016	6	4	4	9	9	16	16	100%	4,103	3,726	91%	996	996	100%
2016	7	11	11	13	13	44	44	100%	15,588	13,031	84%	2,115	2,115	100%
2016	8	7	7	12	12	25	25	100%	6,046	5,997	99%	2,081	2,081	100%
2016	9	7	7	11	11	28	28	100%	4,607	4,079	89%	1,352	1,352	100%
2016	10	4	4	8	8	15	15	100%	3,250	3,983	123%	1,226	1,226	100%
2016	11	4	4	8	8	12	12	100%	1,388	1,934	139%	513	513	100%
2016	12	4	4	9	9	13	13	100%	2,683	3,343	125%	849	849	100%
YTD Totals						207	207	100%	52,402	53,678	102%	11,687	11,687	100%
YTD Average		5	5	9	9									

Figure 38: 2016 Economic Demand Response Cleared vs Settled Day-Ahead Energy Market Summary

Time		CSPs		Zone		Registrations			MWh			Registration Hours		
Year	Month	Cleared	Settled	Cleared	Settled	Cleared	Settled	%	Cleared	Settled	%	Cleared	Settled	%
2016	1	3	3	3	3	7	7	100%	3,557	3,967	112%	872	872	100%
2016	2	3	3	4	4	8	8	100%	1,568	1,905	121%	401	401	100%
2016	3	2	2	2	2	6	6	100%	349	498	143%	109	109	100%
2016	4	2	2	2	2	6	6	100%	2,168	3,157	146%	764	764	100%
2016	5	3	3	3	3	6	6	100%	2,148	2,424	113%	592	592	100%
2016	6	2	2	3	3	5	5	100%	1,609	2,298	143%	506	506	100%
2016	7	6	6	7	7	19	19	100%	5,423	5,314	98%	1,177	1,177	100%
2016	8	5	5	8	8	18	18	100%	2,491	2,278	91%	467	467	100%
2016	9	4	4	5	5	14	14	100%	791	1,257	159%	402	402	100%
2016	10	2	2	4	4	7	7	100%	706	1,104	156%	177	177	100%
2016	11	3	3	3	3	5	5	100%	545	1,056	194%	225	225	100%
2016	12	5	5	5	5	8	8	100%	2,286	2,972	130%	848	848	100%
YTD Totals						109	109	100%	23,639	28,230	119%	6,540	6,540	100%
YTD Average		3	3	4	4									

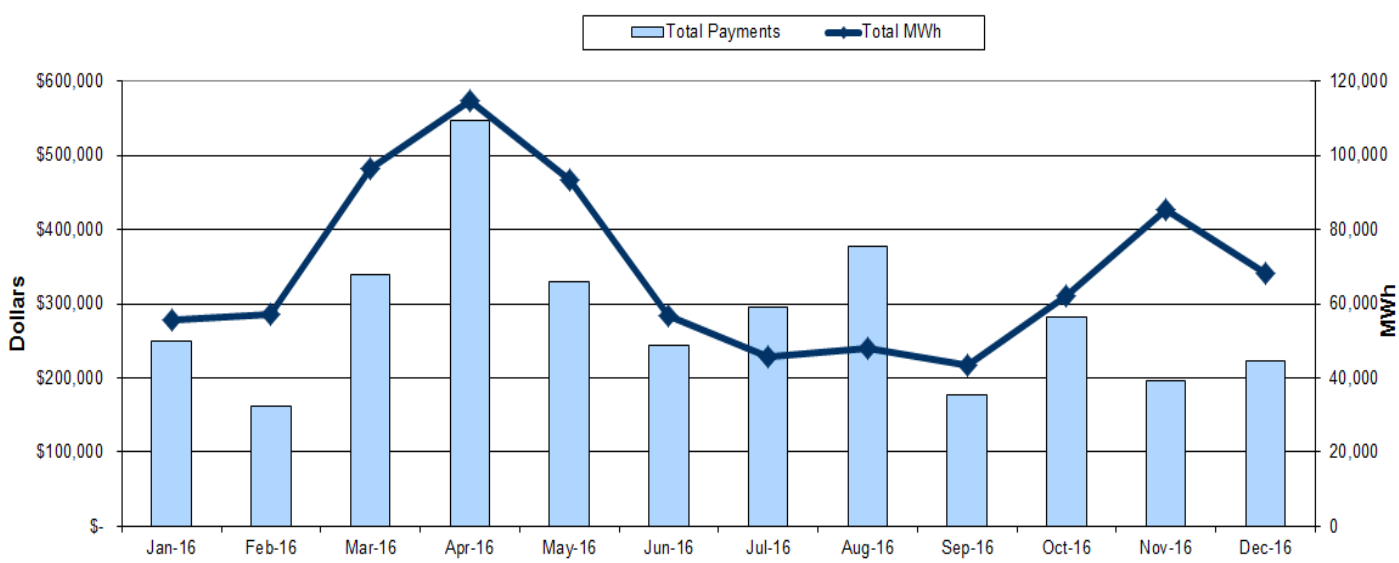
Note: For Figures 37 and 38 above, Settlement information submitted up to 60 days after the event. Therefore, YTD performance reflected in these reports for the current 2 months is artificially low due to incomplete information at the time of report preparation.

Figure 39: 2016 Economic Demand Response Regulation Market Participation



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Total MWh	4,349	3,295	2,565	2,756	6,407	6,617	5,670	6,640	7,135	7,592	8,334	6,440	67,801
Total Payments	$66,904	$56,484	$36,874	$54,895	$106,759	$92,492	$98,730	$113,058	$133,866	$128,788	$123,357	$77,866	$1,090,074
$ / MWh	$15.38	$17.14	$14.37	$19.92	$16.66	$13.98	$17.41	$17.03	$18.76	$16.96	$14.80	$12.09	$16.08

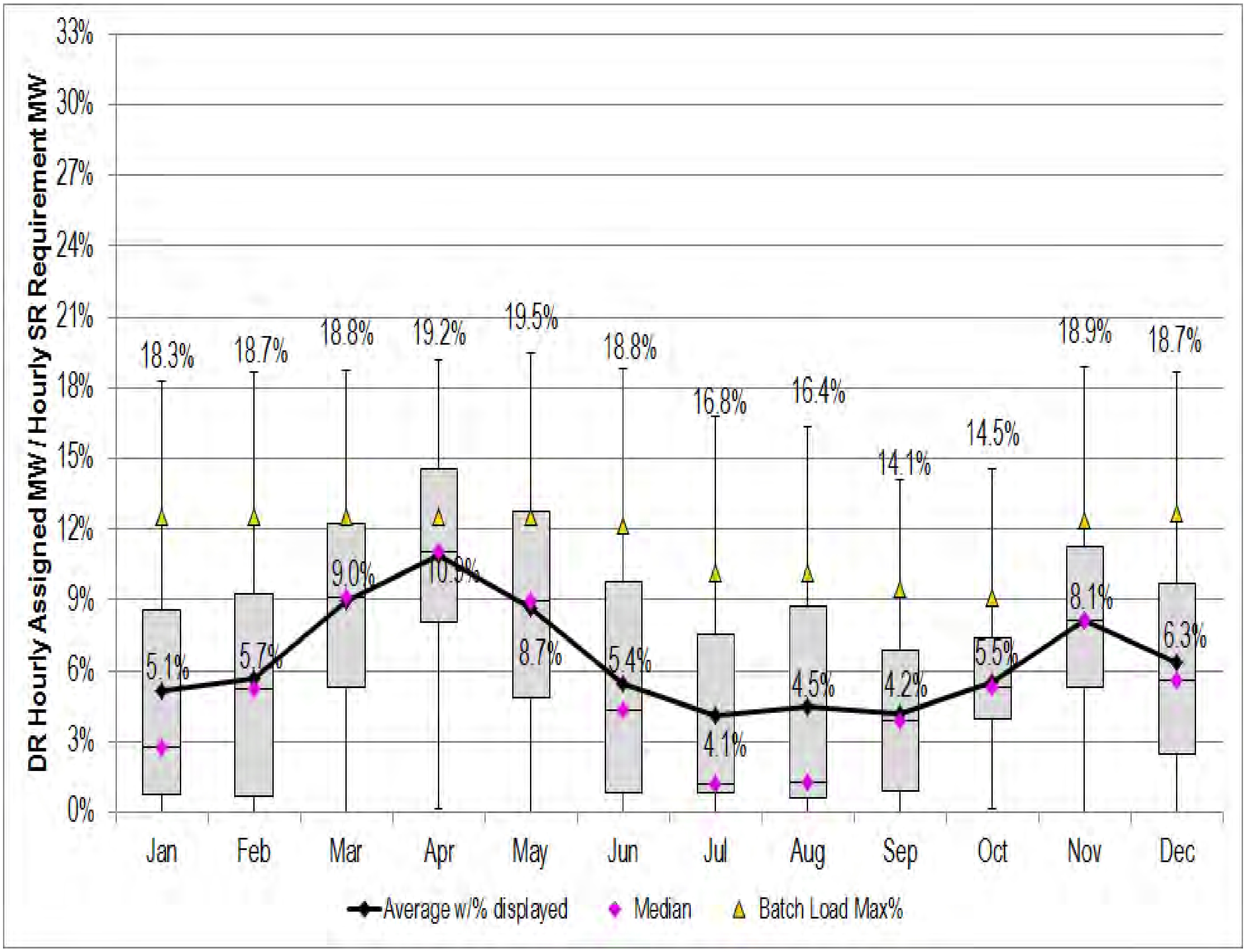
Figure 40: 2016 Economic Demand Response Synchronous Reserve Market Participation



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Total MWh	55,640	57,085	96,640	114,593	93,471	56,760	45,592	47,897	43,603	62,209	85,451	68,149	827,091
Total Payments	$249,849	$161,092	$339,892	$547,426	$328,966	$244,619	$295,094	$377,998	$176,723	$281,843	$196,854	$222,382	$3,422,739
$ / MWh	$4.49	$2.82	$3.52	$4.78	$3.52	$4.31	$6.47	$7.89	$4.05	$4.53	$2.30	$3.26	$4.14

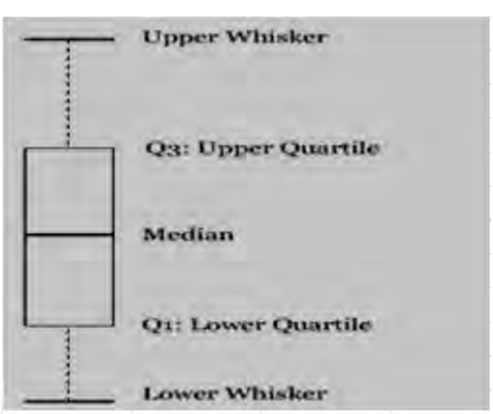
Note: For Figures 39 and 40 above, MWh=sum of the settled MW. Example: 1 MW load available for 12 hours = 12 MWh.

Figure 41: Economic DR Synchronous Reserve Penetration Distribution (Box-plot) for 2016



Notes:

1) Economic Demand Response are Tier2 resources.
2) Percents shown on upper whisker are maximum hourly DR percentage of Total SR Requirement.
3) The Box-plot depicts the distribution of DR hourly assigned (as a percentage of the Total requirement) for a month:



The upper whisker is the maximum value

The box top is the Upper Quartile (75%) value

The line inside the box is the median (50%) value

The box bottom is the Lower Quartile (25%) value

The lower whisker is the minimum value

DEMAND RESPONSE

New Air Quality Rules Have Dramatically Changed the Demand Response Resource Mix

A GTM Research report indicates that backup generation participation in DR has fallen by 25%.

by Olivia Chen
(https://www.greentechmedia.com/authors/Olivia+Ch
November 03, 2016

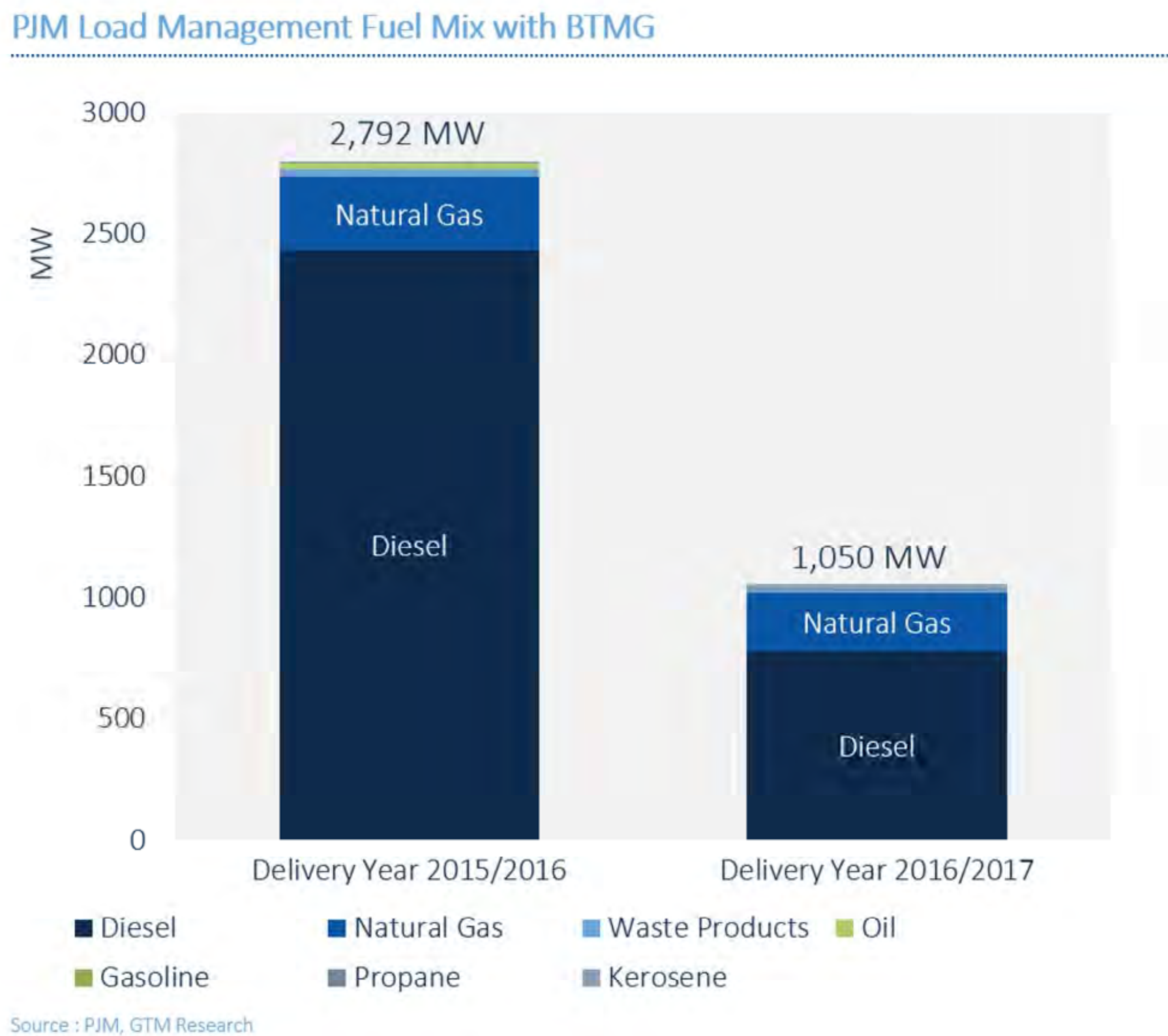
The use of behind-the-meter generation for demand response programs is declining as a result of recent regulation favoring greener emergency demand response resources, according to GTM Research's third-quarter edition of the *U.S. Wholesale DER Aggregation* report (https://www.greentechmedia.com/research/report/us-wholesale-der-aggregation-q3-2016).

In May 2016, the Environmental Protection Agency (EPA) cracked down on the use of stationary reciprocating internal combustion engines (RICE) that are unable to meet new emissions standards.The provision went into effect as PJM and MISO entered their 2016/2017 delivery year.

GTM Research found this led to a 1.7-gigawatt drop in behind-the-meter participation in PJM and MISO. "Past participation of non-complying RICE generators is not clear; however, the declining numbers show a clear shift in resource mix," said Elta Kolo, a GTM Research grid edge analyst and author of the report.

As delivery year 2016/2017 commenced, MISO cleared 500 fewer megawatts of behind-the-meter resources -- a decline attributed to the EPA ruling. In PJM, the percentage of behind-the-meter resources providing load management demand response has contracted by 50 percent.

The fuel mix has traditionally been dominated by diesel generators; however, in delivery year 2016/2017, diesel's dominance shrunk while the provision from natural gas remained stable.



EPA regulations are impacting the provision of emergency demand response across the country. On the West Coast, declining participation in demand response programs is an effect of broader decarbonization goals. The California Public Utilities Commission has adopted a ban on backup generators that use diesel, natural gas, gasoline, propane, or liquefied petroleum gas acting as demand response resources in CAISO that will go into effect in January 2018.

"For more than a decade, California has demonstrated a vigorous push for a carbon-free energy system. Over the years, the California Public Utilities Commission has asserted that using fossil-fueled backup generators as a demand response resource goes against the greater purpose of DR: offsetting carbon-intensive peaking generation," said Kolo.

While territories differ in their development of demand response or distributed energy resource programs, there is a clear signal that EPA regulations are impacting electricity markets across the country.

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Demand response resources are continuously changing as policy and regulation make headway into greener pastures. To dive deeper into the evolving electricity market landscape for distributed energy resources, please download the report brochure, or contact subscribe@gtmresearch.com (mailto:subscribe@gtmresearch.com).

Olivia Chen

Senior Marketing Associate
GTM Research

Appendix C
Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines

Portions of the federal regulations for stationary engines were vacated by the D.C. Circuit Court of Appeals in Delaware v. EPA, 785 F. 3d1 (2015). As a result, operation of emergency engines up to 100 hours per year in response to an Energy Emergency Alert Level 2 as defined in the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, or when there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency is no longer permissible. The court decision, as modified on rehearing, vacated paragraphs 40 CFR 60.4211 (f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii).

1. EPA Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines, April 15, 2016
2. RICE NESHAP Requirements for Stationary Engines at Area Sources of Hazardous Air Pollutants, September 19, 2013
3. Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration, OAR-2008-0708, April 1, 2013
4. Delaware Department of Natural Resources and Environmental Control v. EPA, 785 F. 3d1 (2015). Argued September 26, 2014. Decided May 1, 2015.
5. Delaware Department of Natural Resources and Environmental Control, et al., v. United States Environmental Protection Agency. USCA Case #13-1093, Document #1562706, Filed: 07/15/2015
6. United States Court of Appeals for the District of Columbia Circuit, No. 13-1093, Issued 05/04/2016
7. United States Court of Appeals for the District of Columbia Circuit, USCA Case #13-1233, Document #1574665, Filed: 09/23/2015
8. DC Circuit Vacates Portions of EPA's Emergency Generator Rule. *www.Taftlaw.com, September 4, 2015*
9. DC Circuit Reverses 100-hour Exemption for Backup Generators. *Lexology. May 11, 2015.*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

April 15, 2016

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines

FROM: Peter Tsirigotis P. Tsirigotis
Director, Sector Policies and Programs Division
Office of Air Quality Planning and Standards

TO: EPA Regional Air Enforcement Managers
EPA Regional Air Directors

The U.S. Environmental Protection Agency is issuing this guidance to explain how the EPA intends to implement certain regulatory requirements after the U.S. Court of Appeals for the District of Columbia Circuit issues the mandate effectuating the vacatur in *Delaware v. EPA*.[1] The statutory provisions and EPA regulations, as impacted by the impending issuance by the court of its mandate and described in this document, are themselves legally binding requirements. This document does not substitute for those provisions or regulations or modify them, nor is it a regulation itself. As such, this document does not impose legally binding requirements on the EPA, states, or the regulated community and may not apply to a particular situation based upon the circumstances. In appropriate circumstances, individual EPA decision makers may adopt approaches that differ from this guidance.

Background

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision[2] granting in part and denying in part petitions for review of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE), 40 CFR part 63 subpart ZZZZ, and the New Source Performance Standards (NSPS) for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, 40 CFR part 60 subparts IIII and JJJJ. The court decision, as modified on rehearing, vacated paragraphs 40 CFR 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii). The vacated paragraphs specified that emergency engines may operate for a limited number of hours per year in two situations: (1) emergency demand response when the Reliability Coordinator has declared an Energy Emergency Alert Level 2, and (2) when there is a deviation of voltage or frequency of five percent or greater below standard voltage or frequency.[3]

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[1] *Delaware v. EPA*, 785 F.3d 1 (D.C. Cir. 2015).

[2] *Ibid.*

[3] In a different case (*Conservation Law Foundation, et. al. v. EPA*, No. 13-1233 (DC. Cir.)), the EPA requested and received a voluntary remand without vacatur of the provisions in 40 CFR 60.4211(f)(3)(i), 60.4243(d)(3)(i), and 63.6640(f)(4)(ii), which allow emergency engines to operate for up to 50 hours per year if certain conditions are met. Those provisions are not affected by the vacatur in *Delaware v. EPA* and engines can continue to operate for the purpose specified in those paragraphs

The EPA requested and received a stay of the court's mandate effectuating the vacatur until May 1, 2016. May 1, 2016, falls on a Sunday, so we expect the court to issue the mandate on Monday, May 2, 2016.

Impact of the Vacatur

Upon issuance of the court's mandate vacating 40 CFR 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii), these provisions will cease to have any legal effect. It is the EPA's view that this change will mean that an engine may not operate in circumstances described in the vacated provisions for any number of hours per year unless it is in compliance with the emission standards and other applicable requirements for a non-emergency engine.[4] After issuance of the mandate, operation of emergency engines will be limited to emergency situations as specified in 40 CFR 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1); maintenance checks and readiness testing for a limited number of hours per year as specified in 40 CFR 60.4211(f)(2)(i), 60.4243(d)(2)(i), and 63.6640(f)(2)(i); and certain non-emergency situations for a limited number of hours per year as specified in 40 CFR 60.4211(f)(3), 60.4243(d)(3), and 63.6640(f)(3)-(4).[5]

For an emergency engine that was operating for the purposes specified in paragraphs 40 CFR 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii) before the vacatur mandate that becomes a non-emergency engine after the vacatur mandate solely as a result of the operation for those purposes after the vacatur mandate, regulatory requirements including numerical emission limits or work practice standards, notifications, and performance testing may apply. The applicability of regulatory requirements to a particular engine depends on criteria including the engine's type, horsepower, and age, and not every such engine will become subject to notification and testing requirements. The EPA's Regulation Navigation tools for the RICE NESHAP and NSPS can assist engine owners/operators in determining the applicable criteria and requirements for a specific engine. The tools can be found at https://www3.epa.gov/ttn/atw/icengines/imp.html#regnav.

Engines that are subject to initial performance testing requirements should conduct the initial performance test within 180 days of the date of the mandate (or by October 29, 2016, assuming the court issues the mandate on May 2, 2016). If an initial notification is required for the engine per 40 CFR 63.6645, notifications should be submitted no later than 120 days after the date of the mandate. If an initial notification is required for the engine according to 40 CFR 60.4214(a) or 60.4245(c), then such notification should be submitted no later than 30 days after the date of the mandate.[6] The timelines for performance testing and initial notifications are specified in 40 CFR 60.7(a)(1), 60.8(a), 60.4214(a), 60.4245(c), 63.9(b), 63.6610, 63.6611, 63.6612, and 63.6645.

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while the EPA addresses the *Conservation Law Foundation, et. al. v. EPA* remand. This guidance does not further address those remanded provisions.

[4] In the EPA's motion asking the D.C. Circuit Court to stay the mandate, the EPA explained its understanding that the court's vacatur did not reinstate the provisions within the prior 2010 regulation that had previously allowed up to 15 hours per year of emergency demand response or mean that engines may operate for unlimited periods for emergency demand response and still qualify as emergency engines. See footnote 2 of the EPA's "Motion for Stay of the Mandate" in *Delaware v. EPA* which can be found at https://www3.epa.gov/ttn/atw/icengines/tech.html.

[5] See footnote 3 regarding the voluntary remand without vacatur of the provisions in 40 CFR 60.4211(f)(3)(i), 60.4243(d)(3)(i), and 63.6640(f)(4)(ii).

[6] This guidance with respect to notice and performance testing obligations only applies to the limited universe of engines that operate for the purposes specified in paragraphs 40 CFR 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), and 63.6640(f)(2)(ii)-(iii) before and after the issuance of the vacatur mandate and for which the issuance of the vacatur mandate is the sole reason for the engine's change in status from an emergency engine to a non-emergency engine.

Reporting for Emergency Engines

Paragraph 40 CFR 63.6650(h) specifies that owners/operators of emergency engines that are used or contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii)-(iii), which are the paragraphs that were vacated, must submit an annual report that includes the hours the engine operated for those purposes. These reporting regulations provide that the first report must cover operation during 2015 and must be submitted no later than March 31, 2016. The deadline for this report occurred before the court is scheduled to issue the mandate, and owners/operators were required to submit this report by March 31, 2016. The NSPS regulations also contain similar reporting requirements in 40 CFR 60.4214(d) and 60.4245(e), and owners/operators were also required to submit the reports required by the NSPS regulations by March 31, 2016. Owners and operators will not be required to submit a report by March 31, 2017, for any such operations in 2016.

cc: Sheila Igoe, OGC
Sara Ayres, OECA
Robert Klepp, OECA

RICE NESHAP Requirements for Stationary Engines at Area Sources of Hazardous Air Pollutants[1]

This document provides guidance on the requirements for stationary engines at area sources of hazardous air pollutants (HAP). An area source of HAP is any source that is not a major source of HAP. A major source is one that emits or has the potential to emit 10 tons or more per year of a single HAP or 25 tons or more per year of any combination of HAP. Refer to the rule at 40 CFR part 63 subpart ZZZZ for the requirements for stationary engines at major sources of HAP.

General Overview

What is the RICE NESHAP?
The National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines ("RICE NESHAP") limits emissions of toxic air pollutants from stationary reciprocating internal combustion engines. The pollutants emitted from stationary engines are known or suspected of causing cancer and other serious health effects.

What engines are affected by this rule?
The RICE NESHAP applies to stationary reciprocating internal combustion engines. Stationary engines are commonly used to generate electricity and to power pumps and compressors, and also in emergencies to produce electricity and pump water for flood and fire control. All sizes of stationary engines are covered by the rule.

The RICE NESHAP does not apply to engines used in motor vehicles and mobile nonroad equipment. Mobile nonroad engines are those that are:

- Self-propelled (such as tractors, bulldozers)
- Propelled while performing their function (such as lawnmowers)
- Portable or transportable (has wheels, skids, carrying handles, dolly, trailer, or platform) and do not remain in one location for more than 12 months, or full annual operating period of a seasonal source

What do I need to consider when determining compliance requirements?
The applicable RICE NESHAP requirements typically differ depending on whether the engine is a compression ignition (CI) or a spark ignition (SI) engine. Compression ignition engines are generally those that use diesel fuel. Spark ignition engines generally use gaseous fuels such as natural gas, gasoline, propane, or digester gas.

The RICE NESHAP requirements for an engine also depend on factors including the engine size and type, construction date, and application (non-emergency or emergency). The requirements also depend on whether the facility is a major source or an area source of HAP.

How do I determine if my engine is considered "existing" or "new"?
Engines located at an area source of HAP are considered "existing" if the original owner/operator of the engine entered into a contract for the on-site installation of the engine before June 12, 2006.

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[1] The content provided in this document is intended solely as assistance in determining requirements for compliance under the RICE NESHAP. Any variation between the rule and the information provided in this document is unintentional, and, in the case of such variations, the requirements of the rule govern.

Engines for which the original owner/operator of the engine entered into a contractual obligation for the on-site installation of the engine on or after June 12, 2006 are "new" engines. Note that relocating an existing engine to a new location (same facility or elsewhere) does not change the engine's status as an "existing" engine.

What do I have to do to comply with the rule?
The specific compliance requirements for emergency engines are found on p. 3-5 of this document. The specific compliance requirements for non-emergency engines are found on p. 6-8 of this document.

By what date must my engine(s) comply with the rule?
Existing CI engines must comply by May 3, 2013. Existing SI engines must comply by October 19, 2013. New engines must comply upon startup.

What if I was not aware of this rule? What happens?
Contact your EPA Regional Office. A list of RICE NESHAP contacts for each state can be found here: http://www.epa.gov/ttn/atw/icengines/docs/EPARegionalRICEcontacts.pdf

Where can I go for more information?
EPA RICE NESHAP website: http://www.epa.gov/ttn/atw/icengines/
EPA Region 1 RICE website: http://www.epa.gov/region1/rice/
EPA Region 10 RICE website: http://yosemite.epa.gov/R10/airpage.nsf/Enforcement/rice_rules
Electronic Code of Federal Regulations: http://www.ecfr.gov

Requirements for Emergency Engines

What are emergency engines?
Emergency engines are engines that are operated to provide electrical power or mechanical work during an emergency situation. Examples include engines used to produce power for critical networks or equipment when electric power from the local utility is interrupted, or engines used to pump water in the case of fire or flood.

Are there any stationary emergency engines that are not covered by the rule?
The RICE NESHAP does not apply to existing residential, commercial, and institutional emergency stationary engines located at an area source of HAP emissions, provided that the engines do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for emergency demand response or voltage/frequency deviations and the engines do not otherwise operate in non-emergency situations as part of a financial arrangement with another entity.

Residential emergency stationary engines include those used in residential establishments such as homes or apartment buildings. Commercial emergency stationary engines are used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities. Institutional emergency stationary engines are used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations. See this link for additional guidance regarding the types of facilities that are considered residential, commercial, or institutional:
http://www.epa.gov/ttn/atw/icengines/docs/guidance_emergency_engine_def.pdf.

What are the operational limitations for emergency engines?
In order to be considered an emergency engine, the engine must meet the RICE NESHAP operational requirements for emergency engines, which are as follows:

- There is no time limit on the use of the engine in emergency situations
- The engine may be used for up to 100 hours per calendar year for any combination of the following purposes:
    - Maintenance checks and readiness testing
    - Emergency demand response when an Energy Emergency Alert Level 2 has been declared by the Reliability Coordinator
    - Periods where the voltage or frequency deviates by 5 percent or more below standard
- The engine may be used for up to 50 hours per calendar year for any combination of the following purposes, but the operation counts as part of the 100 hours per calendar year for maintenance, testing, and emergency demand response:
    - Non-emergency situations, provided there is no financial arrangement with another entity
    - Peak shaving in local system operator program until May 3, 2014 if existing engine
    - Local reliability as part of a financial arrangement with another entity if all of the following conditions are met:
        - engine is an existing engine
        - engine is dispatched by local transmission/distribution system operator

- dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads
- dispatch follows reliability, emergency operation, or similar protocols that follow specific NERC, regional, state, public utility commission, or local standards or guidelines
- power is provided only to the facility or to support the local distribution system
- engine owner/operator identifies and records dispatch and standard that is being followed

What do I have to do to comply with this rule?

For Existing Emergency Engines, Owners and Operators Must:

- Change oil and filter every 500 hours of operation or annually, whichever comes first (you may use an oil analysis program to extend the oil change requirement)
- Inspect air cleaner for CI engines or spark plugs for SI engines every 1,000 hours of operation or annually, whichever comes first, and replace as necessary
- Inspect hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary
- Operate and maintain the engine per the manufacturer's instructions or your own maintenance plan
- Minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine
- Equip the engine with a non-resettable hour meter if one is not already installed
- Keep records of engine maintenance
- Keep records of the hours of operation recorded through the non-resettable hour meter, including how many hours are spent for emergency operation and what classified the operation as emergency

Emergency Engines in Emergency Demand Response or Local Reliability Programs:
In addition to meeting the requirements above, starting January 1, 2015, owners and operators of emergency engines meeting the below three (3) criteria must use ultra low sulfur diesel fuel (if the engine uses diesel fuel; existing diesel fuel obtained prior to January 1, 2015, may be used until depleted) and submit an annual report of the dates and times that the engine operated for emergency demand response or for local reliability.

1. Larger than 100 HP with a displacement less than 30 liters per cylinder, and either
2. Operated or contractually obligated to be available greater than 15 hours per year (up to the maximum of 100 hours per year) for emergency demand response or voltage/frequency deviation, or
3. Operated for local reliability (up to the maximum of 50 hours per year).

The annual report must contain the following information:

- Facility name and address
- Engine rating, model year, latitude/longitude
- Date, start time, and end time for operation for emergency demand response, voltage/frequency deviations, and local reliability

- Number of hours engine is contractually obligated for emergency demand response or voltage/frequency deviation
- Entity that dispatched engine for local reliability and situation that necessitated dispatch
- For CI engines, deviations from ultra low sulfur diesel fuel requirement

The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year. The annual report must be submitted through the Compliance and Emissions Data Reporting Interface that is accessed through EPA's Central Data Exchange (http://www.epa.gov/cdx).

New Emergency Engines

New emergency engines must meet the requirements of the New Source Performance Standards, 40 CFR part 60 subpart IIII for CI engines and 40 CFR part 60 subpart JJJJ for SI engines, if applicable. These engines have no further requirements under the RICE NESHAP.

Requirements for Non-Emergency Engines

What are non-emergency engines?[2]

Non-emergency engines are engines that are operated to provide electrical power or mechanical work primarily during non-emergency situations. Any engine that does not meet the RICE NESHAP definition of an emergency engine is considered to be a non-emergency engine. Emergency engines are generally operated during an emergency situation, such as when electric power from the local utility is interrupted, or to pump water in the case of fire or flood. A more detailed description of an emergency engine can be found in the previous section of this document.

What are the emission standards for existing non-emergency engines?

The emission standards for existing non-emergency engines are provided in the table below.

Emission Standards for Existing Non-Emergency Engines

<table>
<tr><th rowspan="2">HP</th><th colspan="5">Engine Subcategory</th></tr>
<tr><th>CI</th><th>SI 2-Stroke Lean Burn</th><th>SI 4-Stroke in remote areas</th><th>SI 4-Stroke not in remote areas</th><th>Landfill or Digester Gas</th></tr>
<tr><td>≤300</td><td>Change oil/filter[a] & inspect air cleaner every 1,000 hours or annually; inspect hoses/belts every 500 hours or annually, whichever comes first</td><td rowspan="3">Change oil/filter[a], inspect spark plugs, & inspect hoses/ belts every 4,320 hours or annually, whichever comes first</td><td colspan="2" rowspan="2">Change oil/ filter[a], inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually, whichever comes first</td><td rowspan="3">Change oil/ filter[a], inspect spark plugs, & inspect hoses/ belts every 1,440 hours of operation or annually, whichever comes first</td></tr>
<tr><td>300-500</td><td>49 ppm CO or 70% CO reduction</td></tr>
<tr><td>>500</td><td>23 ppm CO or 70% CO reduction</td><td>Change oil/ filter[a], inspect spark plugs, & inspect hoses/belts every 2,160 hours of operation or annually, whichever comes first</td><td>If engine used >24 hrs/yr[b]:
4SLB: Install oxidation catalyst
4SRB: Install non-selective catalytic reduction</td></tr>
</table>

[a] You may use an oil analysis program to extend the oil change requirement. See 40 CFR 63.6625(i)-(j).

[b] If engine used ≤24 hr/yr: change oil/filter & inspect air cleaner every 500 hours or annually; inspect hoses/belts every 500 hours or annually, whichever comes first.

[2] This guidance does not cover the requirements for non-emergency engines whose only purpose is to start up a combustion turbine, known as "black start" engines; certain non-emergency CI engines in remote areas of Alaska; certain non-emergency CI engines on offshore vessels that are Outer Continental Shelf sources; and certain non-emergency CI engines certified to the Tier 1, 2 or 3 standards in Table 1 of 40 CFR 89.112. Refer to the rule at 40 CFR part 63 subpart ZZZZ for the requirements for these engines.

What are the other compliance requirements for existing non-emergency engines?
In addition to meeting the emission standards, owners and operators must comply with the requirements listed below. Also, all engines that are subject to the rule must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply to the engine.

<u>Existing non-emergency CI engines of 300 horsepower (HP) or less and existing non-emergency SI engines of 500 HP or less</u>

- Operate and maintain the engine per the manufacturer's instructions or your own maintenance plan
- Keep records of engine maintenance

<u>Existing non-emergency CI engines larger than 300 HP</u>

- Initial performance test to demonstrate compliance with emission limit
- If larger than 500 HP:
    - o subsequent performance testing every 8,760 hours of operation or 3 years, whichever comes first (every 5 years if engine operates less than 100 hours per calendar year)
    - o keep catalyst pressure drop within 2 inches of water from pressure drop measured during initial performance test; measure and record catalyst pressure drop monthly
    - o keep catalyst inlet temperature between 450-1,350°F; continuously monitor and record catalyst inlet temperature
- Use ultra low sulfur diesel fuel
- Equip engine with closed crankcase ventilation system or open crankcase filtration system
- Submit required notifications
- Submit semiannual compliance reports (annual if engine operates less than 100 hours per calendar year)

<u>Existing non-emergency SI 4-stroke engines larger than 500 HP that are in remote areas</u>

- Operate and maintain the engine per the manufacturer's instructions or your own maintenance plan
- Keep records of engine maintenance

The engine must be in a remote area on the initial compliance date (October 19, 2013) to be considered a remote engine. An engine is in a remote area if it meets one of the following three criteria:

1. The engine is located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.
2. The engine is located on a pipeline segment that has 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards on either side of the centerline of any continuous 1-mile length of pipeline and does not lie within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period.

3. The engine is not located on a gas pipeline and has 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine.

Existing non-emergency SI 4-stroke engines larger than 500 HP that are not in remote areas

- Initial and annual catalyst activity checks to show that 4-stroke lean burn engine carbon monoxide (CO) emissions are reduced by at least 93 percent or more or limited to 47 parts per million (ppm), and 4-stroke rich burn engine CO emissions are reduced by at least 75 percent or more or limited to 270 ppm or total hydrocarbons is reduced by 30 percent or more
- Equip engine with high temperature engine shutdown or continuously monitor catalyst inlet temperature and maintain between 450-1,350°F for 4-stroke lean burn engines and 750-1,250°F for 4-stroke rich burn engines
- Submit required notifications
- Submit semiannual compliance reports (annual if engine operates less than 100 hours per calendar year)

What are the emission standards and other compliance requirements for new non-emergency engines?

New non-emergency engines must meet the requirements of the New Source Performance Standards, 40 CFR part 60 subpart IIII for CI engines and 40 CFR part 60 subpart JJJJ for SI engines, if applicable. These engines have no further requirements under the RICE NESHAP.

OAR-2008-0708

JOSEPH R. BIDEN, III
ATTORNEY GENERAL

DEPARTMENT OF JUSTICE
KENT COUNTY
102 WEST WATER STREET
DOVER, DELAWARE 19904

CIVIL DIVISION (302) 739-7641
FAX: (302) 739-7652
CRIMINAL DIVISION (302) 739-4211

Reply to: Civil Division

April 1, 2013

APR 01 2013

By Hand Delivery
Office of the Administrator
EPA Docket Center
EPA West Building, Room 3334
1301 Constitution Avenue, NW
Washington, DC 20004

Dear Administrator:

Enclosed for filing please find the Delaware Department of Natural Resources and Environmental Control's Petition for Reconsideration.

Please contact me if you require anything further.

Sincerely,

Valerie S. Edge
Deputy Attorney General

VSE/jrm/I/EPA/RICE

Enclosure

cc: Ali Mirzakhalili, Program Administrator

APR 01 2013

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Final Rule:

National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines (Jan. 30, 2013)

Petition for Administrative Reconsideration

Pursuant to §307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. §7607(d)(7)(B), the State of Delaware Department of Natural Resources & Environmental Control ("Delaware") respectfully asks EPA to reconsider the final rule issued Wednesday, January 30, 2013, at 78 Fed. Reg. 6674, et seq., entitled National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE NESHAP"); New Sources Performance Standards for Stationary Internal Combustion Engines ("NSPS"); Final Rule. Delaware stands by and incorporates all of its prior comments on the rulemaking into this submission.

Modification of the NSPS Without Regard to §111

Specifically, Delaware requests reconsideration of EPA's decision to modify the NSPS without considering the impacts of criteria pollutants from rulemaking. The CAA authorizes EPA in §111 to adopt NSPS for new sources to control criteria pollutants. In 2006, EPA adopted the Combustion Engine New Source Performance Standard ("NSPS") for Compression-Ignition ("CI") engines. In that 2006 rulemaking, pursuant to §111 of the CAA, EPA expressly addressed the definition of "emergency" use with pointed discussion of the issue in both the Federal Register and in the Response to Comments Document. At that time, EPA had been urged to conform the definition of emergency in the NSPS to the existing NESHAP, and EPA's refusal to make that change was based on the record.

In 2008, EPA adopted the Spark-Ignited ("SI") NSPS and amended the RICE NESHAP in a joint rulemaking. EPA modified the NESHAP as authorized by the CAA §112, which is related to the regulation of hazardous air pollutants. EPA did the same for the NSPS as authorized by the CAA §111, which is related to the regulation of criteria pollutants. The record shows EPA was concerned with emissions of both criteria pollutants and HAPS. In this dual proceeding in 2008, EPA amended the definition of "emergency" in the RICE NESHAP to be more similar to that of the CI and SI NSPS, which made it more stringent. EPA, in its discussion concerning changes to the definition of "emergency," stated that it was "true that EPA was adopting a more stringent emergency engine definition and requirements as compared to the existing RICE MACT emergency definition. * * * However, EPA has learned a lot since the ICCR process from 10 years ago and knows now that there are health consequences for failing to regulate emergency engines and for having a broad definition that allows engines that are used for more than emergencies to emit at higher levels... ." 73 FR 3568 at 3583 (January 18, 2008).

The record shows, therefore, that EPA's decisions were based in part of its knowledge of health consequences related to emissions from emergency use.

EPA's rulemaking records in 2006 (for the NSPS) and 2008 (for NSPS and NESHAP) demonstrate EPA adopted the NSPS pursuant to the authority contained in § 111 of the CAA, which is designed to reduce emissions of criteria pollutants. EPA also considered public comment and criteria pollutant concerns related to the definition of "emergency" in both of those rulemakings. Further, both records demonstrate EPA was aware that there were differences between the definition in the NSPS and in the NESHAP of the term "emergency."

Throughout the process of EPA's most recent changes to the RICE NESHAP (the 2010 and 2013 Rules), EPA has been repeatedly urged to consider the potential increases in criteria pollutants due to the proposed changes. EPA refused to do so when it adopted the 2010 NESHAP modifications. Even after EPA proposed to also amend the NSPS (after the settlement was signed of the lawsuit over the 2010 NESHAP), EPA specifically and repeatedly declined in its Response to Comments Document and in the new Rule in 2013 to consider potential increases in criteria pollutants due to the Rule. Throughout the proceeding, EPA stated that the authority for the rulemaking was CAA § 112 and that it was only required to base its decision on hazardous air pollutants and MACT/GACT standards. Delaware disagrees and believes EPA should not refuse to consider impacts on criteria pollutant when setting the NESHAP, and should not approach air pollutants in an isolated fashion, disregarding the impacts of choices it makes in one venue on other regulatory programs.

While EPA has been unable to date to remedy the air pollution transport afflicting downwind states including Delaware, this decision will exacerbate the current situation in which more than 90% of Delaware's ozone deriving from upwind, out-of-state sources by increasing emissions from hazardous and criteria pollutants. Delaware recorded 39 exceedances of the old ozone standard in 2012 with the highest observation (25 percent above the standard) made at an urban monitoring location just 8 kilometers away from its western border. EPA's reliance on the historical data regarding the use of these emergency generators to refute our legitimate concerns regarding air quality impacts of these units under the revised rules have been proven to be wrong. According to a recent PJM report[1], use of such resources is projected to be 2.5 to 4.5 times higher in the next year and the years to follow. The resulting emissions increases in ozone precursor emissions are not considered by EPA in this rule and unmitigated will add to Delaware's challenge to meet the NAAQS.

Nonetheless, Delaware believes that EPA exceeded its statutory authority in modifying the NSPS definition of "emergency" in the context of statutory proceeding undertaken to modify a NESHAP, based solely on considerations of impacts on hazardous air pollution. Since EPA has specifically declined to consider criteria pollutants, cited a lack of data related to such an analysis, and did not even consider §111 of the CAA, Delaware believes EPA's action does not fulfill the requirement of the Clean Air Act for a NSPS to regulate criteria pollutants. Indeed, the lack of "conformity" was not an error or oversight and resulted from proceedings that considered the relevant statutory criteria. In order to amend an action properly taken previously pursuant to

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[1] http://www.pjm.com/~/media/markets-ops/dsr/emergency-dr-load-management-performance-report-2012-2013.ashx (attached).

§111 of the CAA (modifying the NSPS definition of "emergency"), the CAA requires EPA to do so in a manner consistent with §111.

Delay of Fuel Requirements

Delaware also asks EPA to reconsider the delay and scope of its requirements for the use of ultra low sulfur diesel. Ultra low sulfur diesel is widely available and likely the only diesel fuel available in most areas. Thus, Delaware does not believe the delayed requirement for use of ultra low sulfur diesel fuel will add much value in reducing pollution impacts. EPA has further softened that requirement by allowing a sell-through provision to allow the continued use of other fuels until the supply on hand has been exhausted. Additionally, EPA delayed even that requirement until 2015. Given those factors, if there is to be any real value at all to this requirement, Delaware asks EPA to immediately adopt the requirement for its use. The sell-through provision should address any concerns about existing supply on hand, if, indeed, there are sources using the heavily polluting diesel fuels.

Delayed Recordkeeping

Finally, Delaware asks EPA to reconsider the delayed in recordkeeping, as the record lacks justification for delaying the implementation of those provisions. EPA has stated that it does not believe emergency use will increase based on its modifications. One concrete way EPA can acquire knowledge as to whether its prediction is correct is to adopt an immediate recordkeeping requirement which would provide a baseline as to current emergency use. In addition to the new study previously cited, attached is an email from EnerNOC, Inc., dated January 31, 2013, (the day after EPA's rule was published) offering an incentive of $2,000 per MW bonus payment for new demand response customers who enroll before February 15, 2013. As Delaware believed, this strongly suggests usage will increase since aggregators are offering bonuses to add additional users to their so called demand response programs. As Delaware has suggested previously, it believes emissions will increase because of the new rule modifications and that this type of so called emergency demand response generation is not necessary or helpful to the stability of the grid. Nonetheless, it is critical to have immediate recordkeeping and reporting, particularly with respect to the first date on which an entity signs an emergency use or aggregating contract with a provider to determine how the proposed changes increase the use of generators and increase emissions. Delaware asks EPA to reconsider its recordkeeping and reporting, and modify it to make the recordkeeping requirement to be immediate and to include the date on which any and all contracts are signed relating to demand response or emergency usage and to require the records and contracts be retained for at least 5 years. This data may be helpful in determining actual impacts from the rule changes.

Summary

As Delaware has stated numerous times in this proceeding, it is concerned about increases in emissions of hazardous air pollutants and criteria pollutants from the Rule changes. Delaware further believes that EPA must rectify its failure to address emissions of criteria pollutant before it can lawfully amend the NSPS. Thus, we urge EPA to expedite the requirement to use ultra low sulfur diesel to reduce the impacts and to require immediate recordkeeping to quantify the resulting emissions impacts of the rule. For these reasons, Delaware respectfully asks you to reconsider the above issues.

Respectfully submitted,

Dated: April 1, 2013

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Emergency Demand Response (Load Management) Performance Report 2012/2013

December 2012

APR 0 1 2013

pjm

PJM has made all efforts possible to accurately document all information in this report. However, PJM cannot warrant or guarantee that the information is complete or error free. The information seen here does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing: http://www.pjm.com/documents/agreements/pjm-agreements.aspx

For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing: http://www.pjm.com/documents/manuals.aspx

Table of Contents

Executive Summary

Emergency Demand Resources have the ability to participate as a capacity resource in the PJM capacity market (Reliability Pricing Model or RPM) or to support a Load Serving Entities Fixed Resource Requirement (FRR) plan. For the 2012/2013 Delivery Year the single Emergency DR (Load Management) product type available was available: Limited Demand Resources (LDR). The other type of resource, Interruptible Load for Reliability (ILR), was terminated after 2011/2012 Delivery Year and the two new products (Summer Extended DR and Annual DR) do not become available until the 2014/2015 Delivery Year. A Curtailment Service Provider (CSP) is the PJM member that nominates the end use customer location(s) as a capacity resource and is fully responsible for the performance of the resource. Emergency DR (Load Management) products are required to respond to PJM Emergency Load Management events which may occur from noon through 8pm on non-holiday weekdays from June through September during PJM system emergencies or receive a penalty. Emergency DR that is not dispatched during a system emergency must perform a mandatory test to demonstrate it can meet its capacity commitment or receive a penalty.

Figure 1 shows both the event and test performance values for the past 4 years. In the years where there was more than one event, the event performance is the event MW weighted average of all of the events.

Figure 1: Yearly Performance Summary

Performance Summary		
Year	Event Performance	Test Performance
2009	No Events	118%
2010	100%	111%
2011	91%	107%
2012	104%	116%

PJM dispatched Emergency DR two times during the 2012; July17th (Tuesday) and 18th (Wednesday). Figure 2 below shows a summary of the events where performance on July 17th was 103 percent and performance on July 18th was 104 percent. Summer 2012 performance was significantly higher than performance for the single event in July of 2011 (91 percent).

Figure 2: 2012 Emergency DR (Load Management) Events Summary

Event Date and Zones	Committed MW	Reduction MW	Performance
7/17, AEP, DOM	1,670	1,736	104%
7/18, AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL, PSEG	2,135	2,203	103%

The two summer 2012 events varied in size and length. The July 17th event was a long lead time event (resources have up to 2 hours to reduce) called in two zones (AEP and DOM), lasting for almost four hours, calling on 1,670 MW of DR resources. In comparison, the July 18th event was a combination of long and short lead times (short lead time resources respond in up to one hour) across 10 mid-Atlantic zones, lasting under two hours, calling on 2,135 MW of DR resources. The July 18th event had the potential to be a longer event, but storms developed and the associated drop in load shortened what would have otherwise been a longer event. The temperatures for both days, which were part of an extended heat wave, were in the mid to upper 90's°F across the PJM footprint. The load on the system was increasing beyond the forecasted amounts on both days. Not all CSPs responded with their committed amounts in all of the zones where they participate but performance improved over last year. In the 2012 events 51 percent of the CSP/zones did not respond with their committed amounts – compared to 55 percent last summer. Conversely, 49 percent met or exceeded their commitments (vs. 45 percent last year). Underperformance penalties totaled $2 million ($5.6 million last year) or about 0.7 percent (1.3 percent last year) of the total DR of $267.5 million ($420 million last year). CSP credits for energy reduced during the events totaled $10 million.

DR resources that were not dispatched during the July emergency events were required to perform a mandatory one hour test. Each CSP must test all of these DR resources located in a zone at the same time. The test results for the 2012/2013 Delivery Year demonstrate that in aggregate, committed Emergency Demand Resources performed at 116 percent of their committed capacity values. Test results in excess of committed capacity values totaled 585 MW for the 3,635 MW of Emergency DR required to test this year. Similar to performance during the events, individually not all CSPs tested to their committed zonal amounts, but that number was small. Test failure charges totaled $1.7 million ($6.4 million last year), about 0.6 percent (1.5 percent last year) of total revenue.

New measurement and verification rules (M&V) went in to effect for this delivery year. These new rules came about as the result of the resolution of the so called "double counting" issue. The new rules cap the reduction amount that any registration can provide at its peak load contribution (PLC). Because of the transition to the new M&V rules and their potential impact on the ability to comply with their commitments, CSPs were provided the opportunity, through RPM incremental auctions to liquate unviable MW based on the new rules through the DR Capacity Transition Credits (CTC) and DR Alternative Transition Credits (ATC). Since the price of the Incremental Auction was less than the price of the Base Residual Auction, no CTC or ATC was paid to CSPs.

Emergency DR (Load Management) Overview

PJM Interconnection, L.L.C. procures capacity for its system reliability through the Reliability Pricing Model (RPM). The sources for meeting system reliability are divided into four groups:

1) Generation Capacity

2) Transmission Upgrades

3) Emergency Demand Resources (Load Management)

4) Energy Efficiency

For the 2012/2013 Delivery Year[1], there was only one Emergency DR product type available: Limited DR. In prior years another registration type, Interruptible Load for Reliability (ILR) was also available. With stakeholder and FERC approval the ILR product was eliminated at the end of the 2011/2012 Delivery Year. DR resources offer into the RPM's Base Residual Auction, one of the Incremental Auctions, or may take on a capacity obligation through the bilateral market.

DR agrees to be interrupted up to ten times per Delivery Year by PJM. The interruptions may be up to six consecutive hours in duration on non-holiday weekdays from noon until 8 PM EPT in the months from May through September. The interruptions must be implemented within two hours of notification by PJM. Those resources that can be fully implemented within one hour of notification are considered Short Lead Time Resources, while those that require more than one hour but not more than two hours of notification are considered Long Lead Time Resources. This agreement by Emergency DR (Load Management) Resources to allow PJM to provide notice of the interruptions enables PJM to procure less generation capacity while maintaining the same level of reliability according to the current reliability criteria and practices within the PJM market.

DR compliance can be more complex to measure than compliance for generation resources meeting their capacity obligations. In order to ensure the reliability service for which a Resource is paid has actually been provided, PJM utilizes three different types of measurement and verification methodologies. DR Resources can choose to be measured using:

- Direct Load Control (DLC) – Emergency DR (Load Management) for non-interval metered customers which is initiated directly by a Curtailment Service Provider's (CSP) market operations center, employing a communication signal to cycle HVAC or water heating equipment. This is traditionally done for residential consumers and requires the necessary statistical study as outlined in PJM Manual 19.
- Firm Service Level (FSL) – Emergency DR (Load Management) achieved by a customer reducing its load to a pre-determined level upon the notification from the CSP's market operations center. Industrial customers with a high load factor normally use this approach because they understand the electricity usage for their

[1] The Delivery Year for the capacity construct corresponds to PJM's Planning Year which runs each year from June 1 until May 31 of the following year

base electrical equipment that must operate even during an emergency situation. This is one of the easiest to verify since the firm service level amount is simply compared to the metered load during an event or test.

- Guaranteed Load Drop (GLD) – Emergency DR (Load Management) achieved by a customer reducing its load below the peak load contribution when compared to what the load would have been absent the PJM emergency or test event. This is normally utilized by customers that have a variable load profile to capture the impact of the system relative to what it would have been during the time periods under review.

New measurement and verification rules (M&V) went in to effect for this delivery year. These new rules came about as the result of the resolution of the so called "double counting" issue. The new rules ensure that all load reductions occur below the peak load contribution (PLC). This means each customer that participates should consume less power than their PLC (ie: reliability requirement) during an emergency or test event to comply. One of the effects of this change is evident in the large increase in registrations using the Firm Service Level methodology. Over 70 percent of the committed MWs where registered as FSL (see Figure 5). This is up from 32 percent last year.

Because of the transition to the new M&V rules and their potential impact on the ability to comply with their commitments, CSPs were provided the opportunity, through RPM, to liquate any load reductions which could no longer be delivered. First, a DR Capacity Transition Credit is available that protects the CSP from purchasing more expensive replacement capacity in Incremental Auctions in relation to the BRA price. Second, CSPs with unavoidable contractual obligations to pay their end-use customer(s), may recoup such losses through the Alternative Transition Credit. Both of transition mechanism are only available for the 2012/2013 and 2014/2015 DYs.

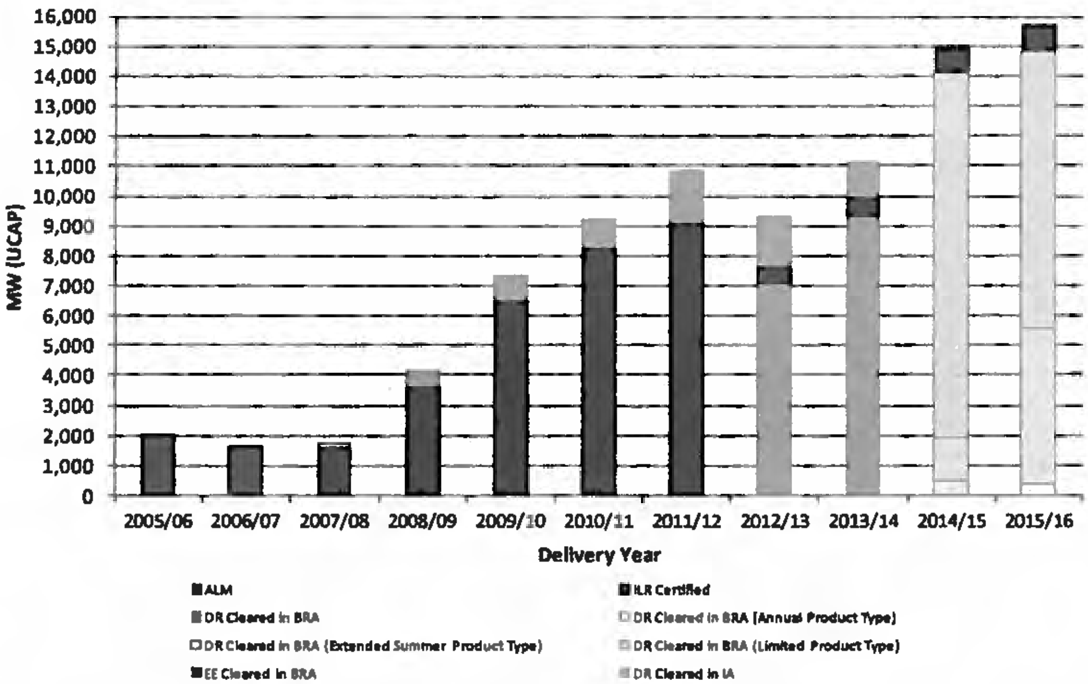
Emergency DR (Load Management) Participation Summary

The capacity numbers in this report are in terms of either Installed Capacity (ICAP) or Unforced Capacity (UCAP) depending upon which is most relevant. PJM calculates the Resource amounts required to meet the reliability standard in terms of UCAP which is also utilized to measure compliance with a RPM commitment. PJM determines the UCAP value of different types of Resources that are offered into the RPM auctions based on methods described in the PJM manuals.

For a conventional generation resource, ICAP value is the summer net dependable rating. The UCAP value is the ICAP value reduced by historical average forced outage and forced derating. Therefore, the UCAP value represents the average availability of capacity from a generating unit after forced outages and forced deratings. For a Emergency DR (Load Management) Resource, ICAP value is the nominated load reduction. The nominated load reduction for a Firm Service Level, Guaranteed Load Drop, or Direct Load Control resource is calculated in accordance with the PJM Capacity Market Manual, Manual 18. The UCAP value is calculated in two steps: First, the nominated load reduction is discounted to account for its reduced impact during higher load periods by multiplying by the Demand Resource Factor. Then, the value is increased to gross up the load reduction by the approved reserve margin.

Emergency DR (Load Management) participation in the PJM capacity construct has increased over time. ALM participation seven years ago in the 2006/2007 Delivery Year was under 1,700 Megawatts (MW). However, the Emergency DR (Load Management) commitments for the next three DYs average just under 13,000 MW each year and up to 14,800 MW by 2015/2016. This increase in participation by Emergency DR (Load Management) Resources reduces the need for generation capacity by providing reductions in demand at the system operator's request. Below is a graphical representation of the growth in Emergency DR (Load Management) participation at PJM in MWs of UCAP.

Figure 3: Emergency DR (Load Management) Participation History (UCAP)



In PJM, capacity is priced based on location to reflect the locational reliability requirements in various sub-regions of the market. The location of the capacity commitments are grouped by the Transmission Zones. Although capacity obligations are measured in UCAP, the most straightforward examination of Emergency DR (Load Management) participation by Zone is in MWs of ICAP. An ICAP value is converted to UCAP by applying a DR factor[2] and Forecast Pool Requirement (FPR) factor[3]. The DR factor accounts for load forecast uncertainty while the FPR is an adjustment for unforced reserve margin. For the 2012/2013 Delivery Year, Emergency DR (Load Management) Resources commitments represented 7,440 MW[4] of ICAP while total registered Emergency DR (Load Management) represented 8,548 MW. Registered Emergency DR (Load Management) may be in excess of the commitment if the CSP has indicated they have the potential to deliver an amount that is higher than their actual commitment[5].

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[2] See "Demand Resource (DR) Factor"; http://www.pjm.com/~/media/committees-groups/committees/cmec/20090805/20090805-item-07b-dr-factor.ashx

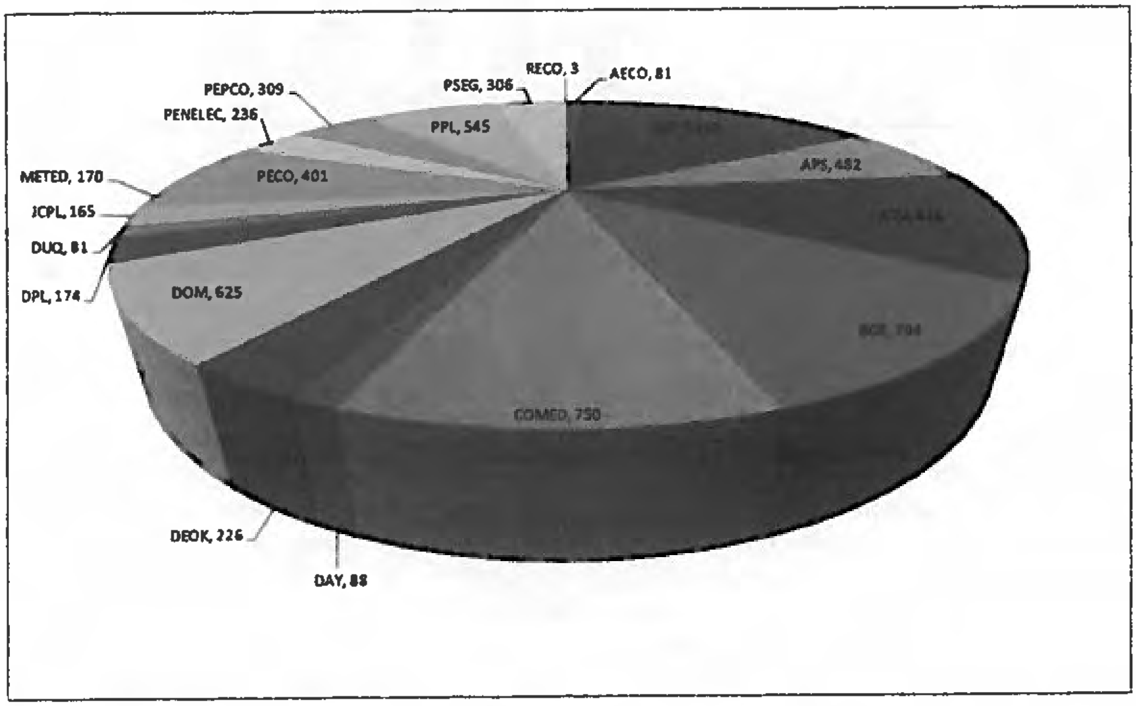
[3] The amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region

[4] Includes RPM auctions and FRR commitments

[5] For example, a CSP may clear 10 MW of resources in an RPM auction but register 11 MW load reduction capability by end use customers to fulfill such commitment.

Following is an illustration of how the registrations of Emergency DR Resources were spread across the 19 Zones for the 2012/2013 Delivery Year. Eighty-seven PJM members operate as a Curtailment Service Provider where over 1 million end use customers across almost every segment (residential, commercial, industrial, government, education, agricultural, etc.) participate as a Emergency DR (Load Management) resource

Figure 4: 2012/2013 Emergency DR Participation by Zone (MW ICAP)



Atlantic City Electric (AECO), American Electric Power (AEP), American Transmission Systems, Inc (ATSI), Allegheny Power (APS), Baltimore Gas and Electric (BGE), Commonwealth Edison (COMED), Dayton Power & Light (DAY), Dominion Virginia Power (DOM), Delmarva Power and Light (DPL), Duke Energy Ohio and Kentucky (DEOK), Duquesne Light (DUQ), Jersey Central Power & Light (JCPL), Metropolitan Edison (METED), PECO (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Co. (PEPCO), PPL Electric Utilities Corp. (PPL), Public Service Electric and Gas Co. (PSEG), Rockland Electric Company (RECO).

Figure 5 below illustrates the percentage of ICAP registered by the major methods where 71 percent represents Firm Service Level, 14 percent represent residential direct load control type resources, 8 percent represents Guaranteed Load Drop that is exclusively provided through a back up generation resource as measured through the output of the backup generator and 6 percent represents Guaranteed Load Drop that is not exclusively provided by a back up generation.[6] Note that although MWs from resources registered as Guaranteed Load Drop via Generation

[6] Firm Service Level and Guaranteed Load Drop (other) may include load reductions achieved with back up generation done in conjunction with another type of control within the facility. Guaranteed Load Drop (back up gen only) represents an estimate of facilities that substantiate load reduction based on meter data from the back up generator, exclusively.

account for 8 percent of the total committed load, event and test data submissions show that generator output accounts for 9 percet of the nominated total, just slightly more than the committed amount.

Figure 5: Percent of Committed ICAP

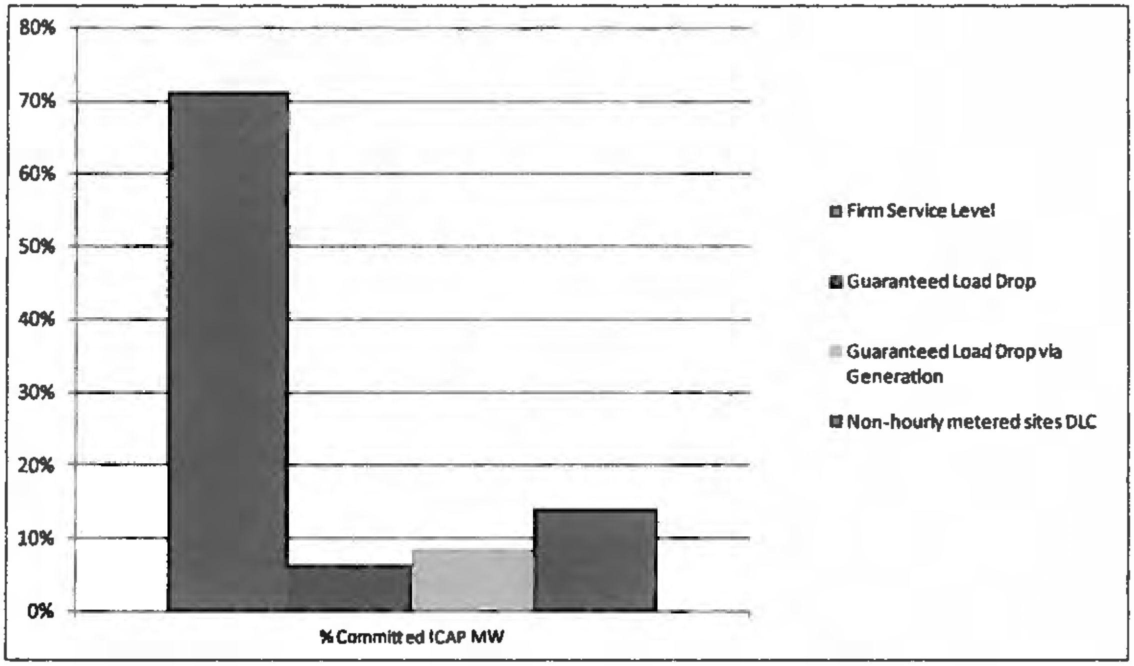
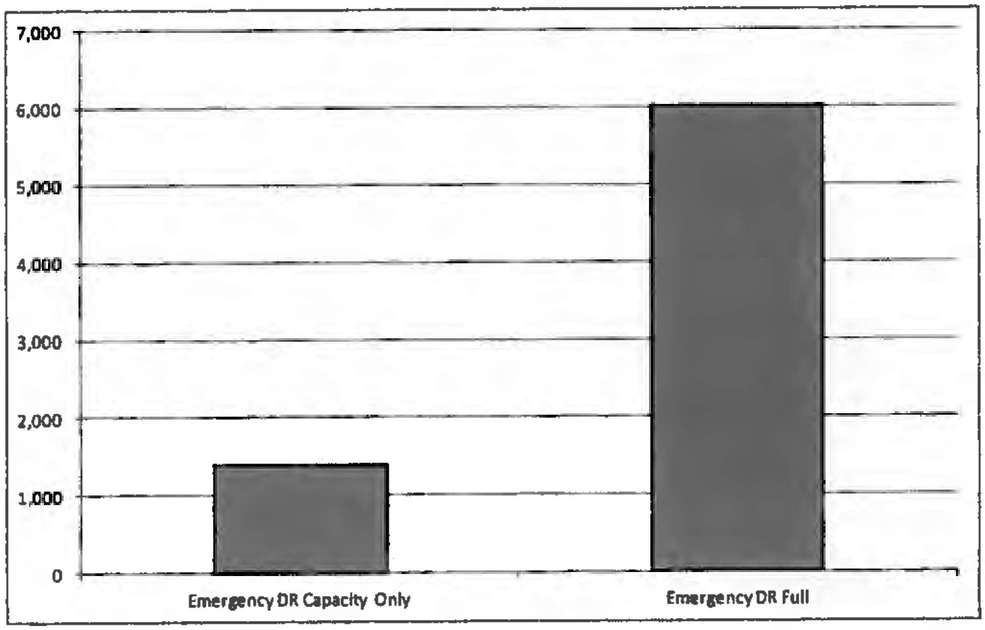


Figure 6 represents the current number of committed ICAP MWs for Emergency DR and is segmented to show the number of MWs registered as an Emergency Full resource (that receive both capacity revenue stream as well as an emergency energy revenue stream when there is an emergency DR (load management) event), compared to the number of MWs registered as Capacity Only (which indicates the CSP is not eligible for any emergency energy payments during an event). Approximately 19 percent of the total was registered as Capacity Only.

Figure 6: MW of Committed ICAP as Full or Capacity Only



2012 Emergency DR (Load Management) Events

Emergency DR is relied upon by PJM planning and PJM system operations to help maintain the safe and reliable operation of the PJM region. PJM had two Emergency DR (Load Management) events in 2012. Following is an overview of PJM Emergency DR (Load Management) events over the past 13 years.

Figure 7: Emergency DR (Load Management) Event History

Delivery Year	Event History
2012/2013	Tuesday, July 17, HE 1700[7] – 1900[8] Wednesday, July 18, HE 1700
2011/2012	Friday, July 22, HE 1300 – 1900
2010/2011	Tuesday, May 31, HE 1800 – 1900 Thursday, May 26, HE 1800 Friday, September 24, HE 1400 – 1800 Thursday, September 23, HE 1200 - 2000 Wednesday, August 11, HE 1500 – 1900 Wednesday, July 7, HE 1500 – 1900 Friday, June 11, HE 1700 – 2000
2009/2010	Wednesday, May 26, HE 1900 – 2000
2008/2009	No events

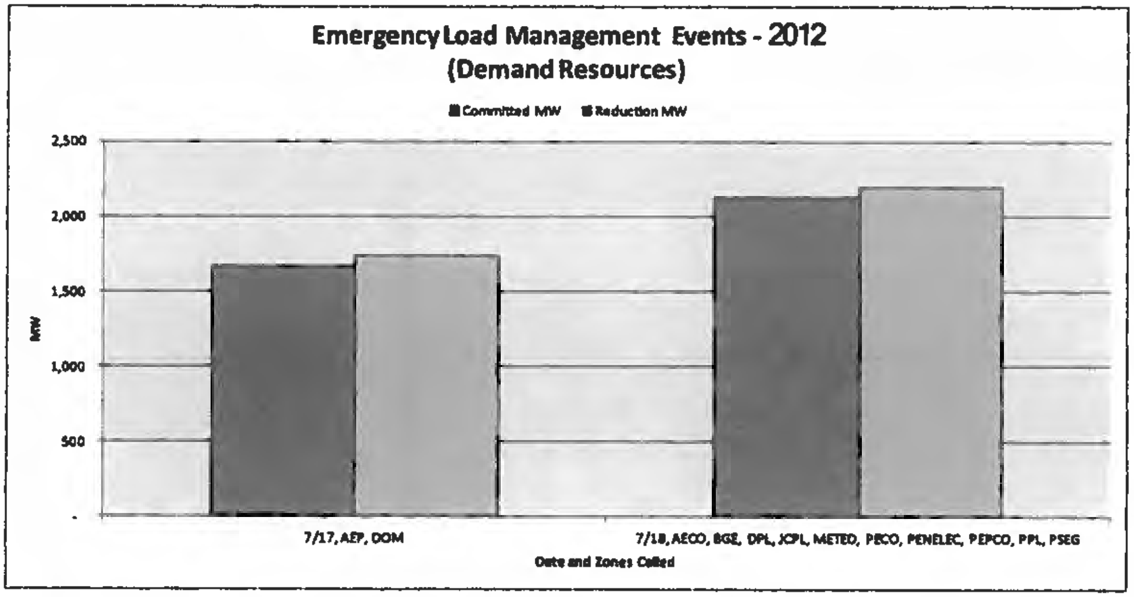
[7] HE in the table is an abbreviation for Hour Ending. For example, HE 1500 – 1800 is the same as the expression 2:00 PM until 6:00 PM.

[8] 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. The times shown are a summary of all Zones but the event may have been shorter or not even called in some Zones.

Delivery Year	Event History
2007/2008	Wednesday, August 8, HE 1500 - 1800
2006/2007	Thursday, August 3, HE 1500 – 1900 Wednesday, August 2, HE 1600 – 1900
2005/2006	Thursday, August 4, HE 1600 - 1700 Wednesday, July 27, HE 1400 - 1800
2004/2005	No events
2003/2004	No events
2002/2003	Tuesday, July 30, HE 1300 - 1800 Monday, July 29, HE 1500 - 1800 Wednesday, July 3, HE 1300 – 1800
2001/2002	Friday, August 10, HE 1300 - 1400 Thursday, August 9, HE 1300 - 1800 Wednesday, August 8, HE 1400 - 1800 Wednesday, July 25, HE 1600 - 1700
2000/2001	No events

PJM calls Emergency DR (Load Management) events by zone (or sub-zone) and by lead time. This allows PJM to address system conditions in a targeted, measured and phased manner. Figure 8 below depicts the overall performance for each of the 2012 Emergency DR (Load Management) events:

Figure 8: 2012 Emergency DR (Load Management) Events



Looking further into each event, the Figures 9 and 10 below show the hourly performance values for each event. As can be seen in both overall and hourly performance, the results are higher than anticipated. Review of the data shows that in all hours of the events the reductions provided by CSPs exceeded their committed values.

Figure 9: July 17, 2012 Hourly Performance

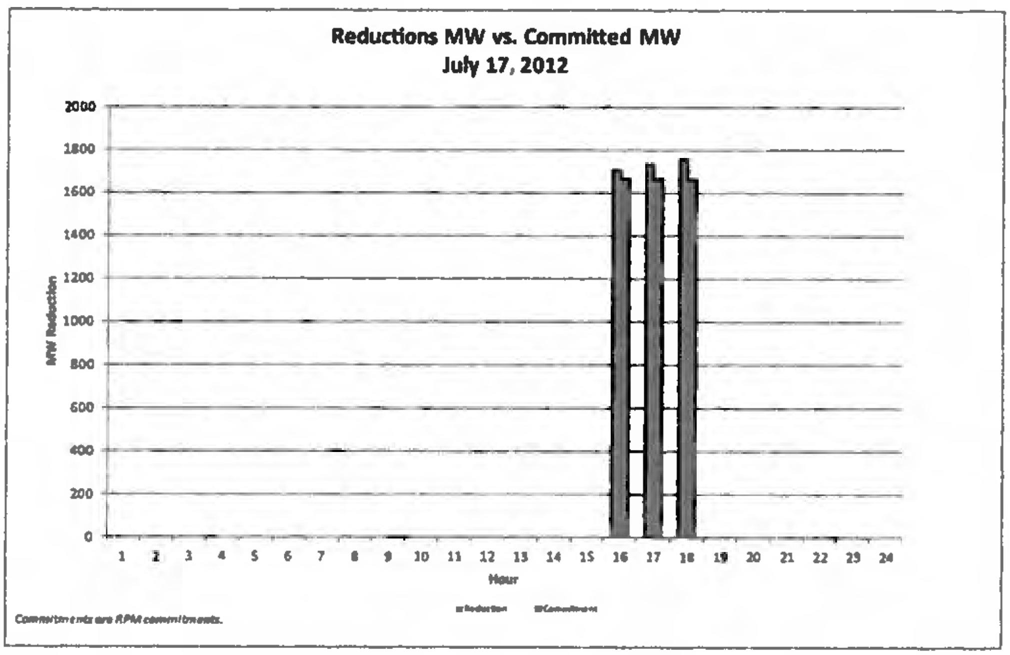
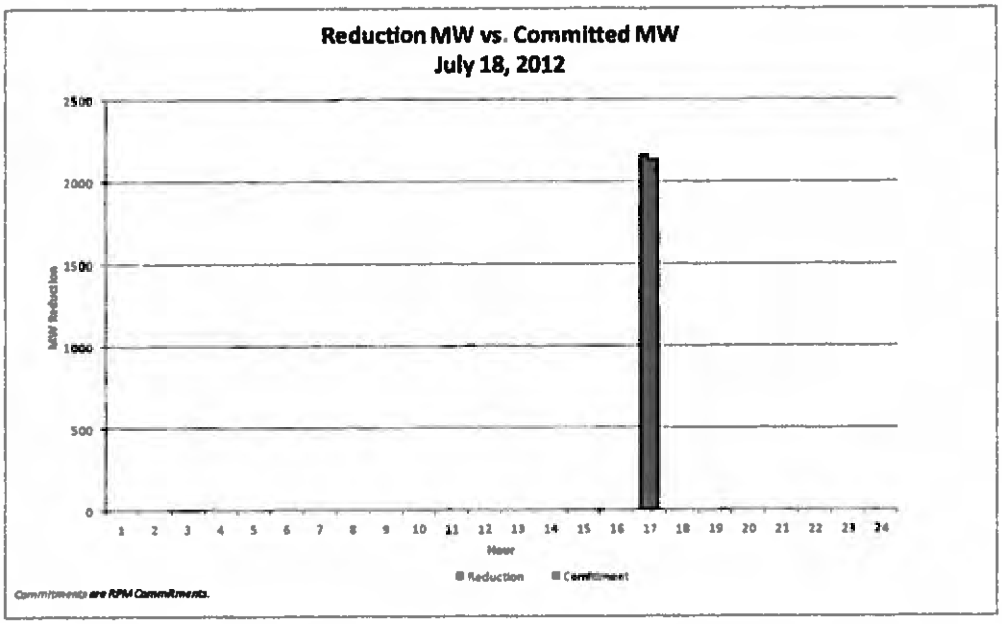


Figure 10: July 18, 2012 Hourly Performance



Event performance measurement can also be broken down by the specific zones called upon and the lead time of the resources. Only long lead time resources were called on for the July 17th event. The July 18th event was called in ten zones in a combination of long and short lead time resources. Performance for those Emergency DR (Load Management) events, by zone and lead time, is depicted in Figure 11 below. Zonal performance ranged from 11 percent to 141 percent.

Figure 11: 2012 Emergency DR (Load Management) Event Performance by Zone

EventDate	Committed MW	Reduction MW	Performance MW	Performance Percentage	Zone	Lead Time
7/17/2012	1046	1101	55	105%	AEP	Long
7/17/2012	624	635	11	102%	DOM	Long
7/18/2012	32	36	4	112%	AECO	Short
7/18/2012	705	727	22	103%	BGE	Long
7/18/2012	90	91	1	101%	BGE	Short
7/18/2012	127	113	-14	89%	DPL	Long
7/18/2012	47	48	2	103%	DPL	Short
7/18/2012	141	162	21	115%	JCPL	Long
7/18/2012	24	31	7	129%	JCPL	Short
7/18/2012	11	16	5	141%	METED	Short
7/18/2012	401	408	8	102%	PECO	Long
7/18/2012	0.7	0.4	-0.3	62%	PECO	Short
7/18/2012	236	238	2	101%	PENELEC	Long
7/18/2012	0.2	0.1	-0.1	26%	PENELEC	Short
7/18/2012	201	194	-7	96%	PEPCO	Long
7/18/2012	107	137	29	127%	PEPCO	Short
7/18/2012	1.9	1	-1	54%	PPL	Short
7/18/2012	10	1	-9	11%	PSEG	Short

CSP Event Performance

CSP performance is measured for each event by zone for all resources that were dispatched by PJM. The DR reductions made in a zone are compared to each CSP's reduction commitment. Under performance is penalized and over performance can be rewarded (within limits and to the extent that there were underperformance penalties paid, see Event Performance Penalties). Figures 12 and 13 below depict the performance of all CSP/zone combinations over each of the summer 2012/2013 DY Emergency DR (Load Management) events. It can be seen that performance is approximately normally distributed. In the July 17th event fifty-eight percent of CSPs zonal performance was within the 81 percent to 120 percent range while seventy-four percent feel into the wider range between 41 percent and 160 percent. For the July 18th event forty-seven percent of CSPs zonal performance was within the 81 percent to 120 percent range while eighty percent were between 41 percent and 160 percent. And, as expected, some performed better, others worse.

Figure 12: CSP Zonal Performance 7/17 Event

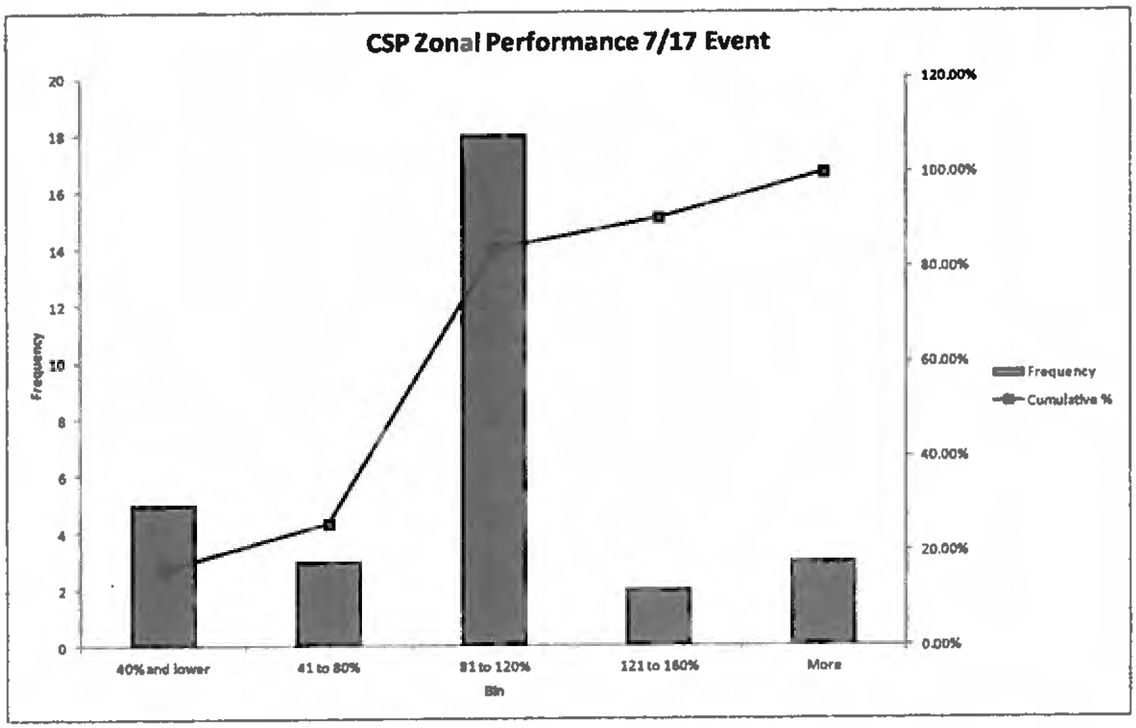
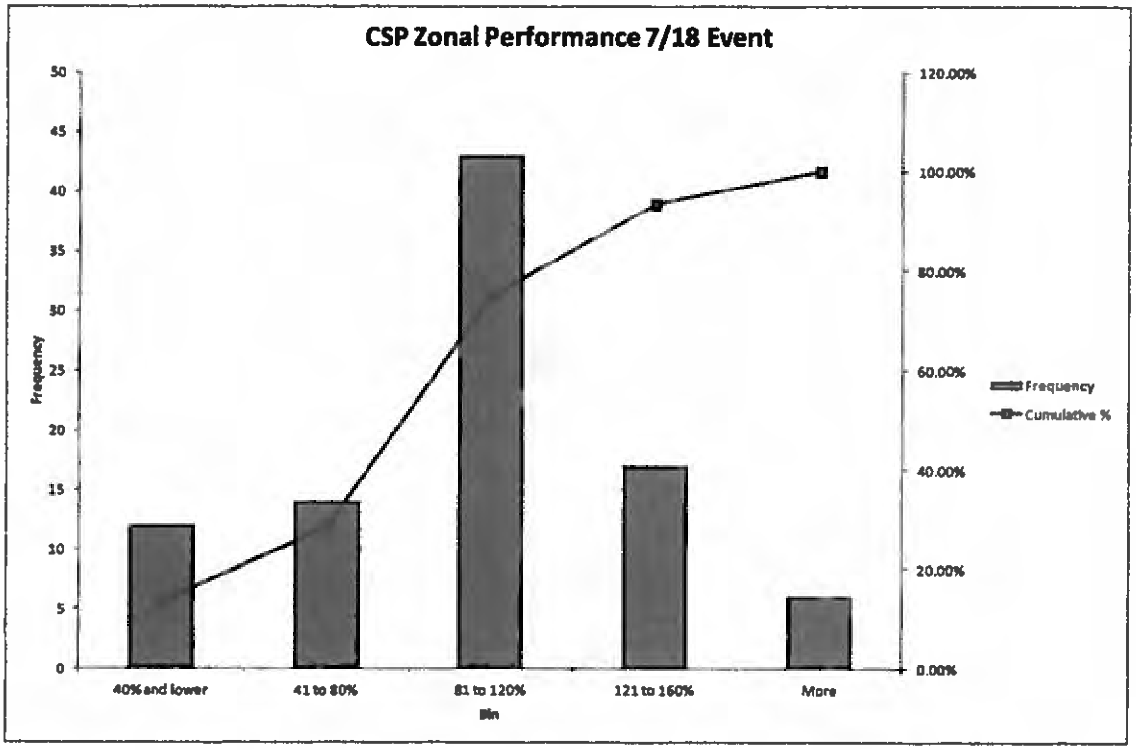


Figure 13: CSP Zonal Performance 7/18 Event



When comparing the event performance in 2012 with that of 2011 we see shifted results. In 2012 the CSP zonal performance shows a measurable shift out of the 41 percent to 80 percent category into the 0 to 40 percent and 121 to 160 percent ranges. The performance of the higher achieving group outweighed the under-performing group thus providing overall higher 2012 event performance results. The portion of CSP zonal performance at high tail of the distribution was similar year-over-year. Figure 14 below depicts the performance of all CSP/zone combinations over all of both the 2011 and 2012 Emergency DR (Load Management) events. It should be noted that there was only a single compliance event in 2011 as compared to two in 2012.

Figure 14: CSP Zonal Performance 2011 vs. 2012

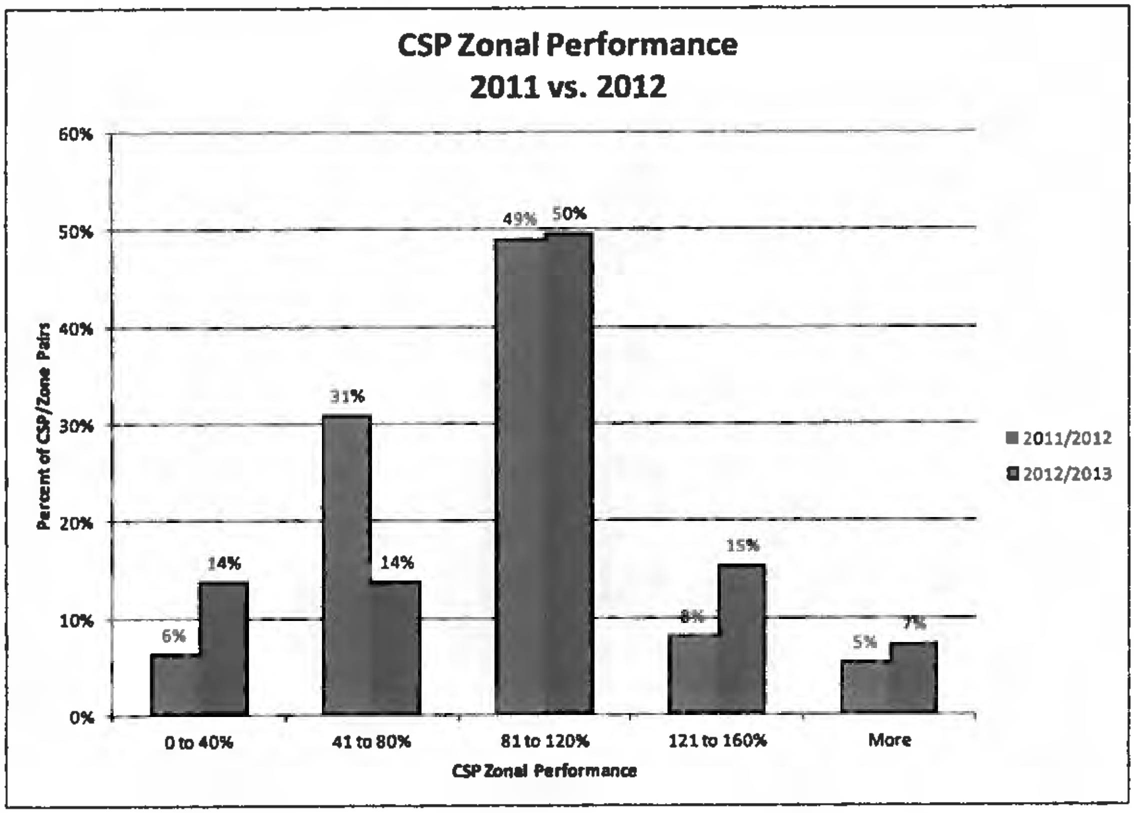
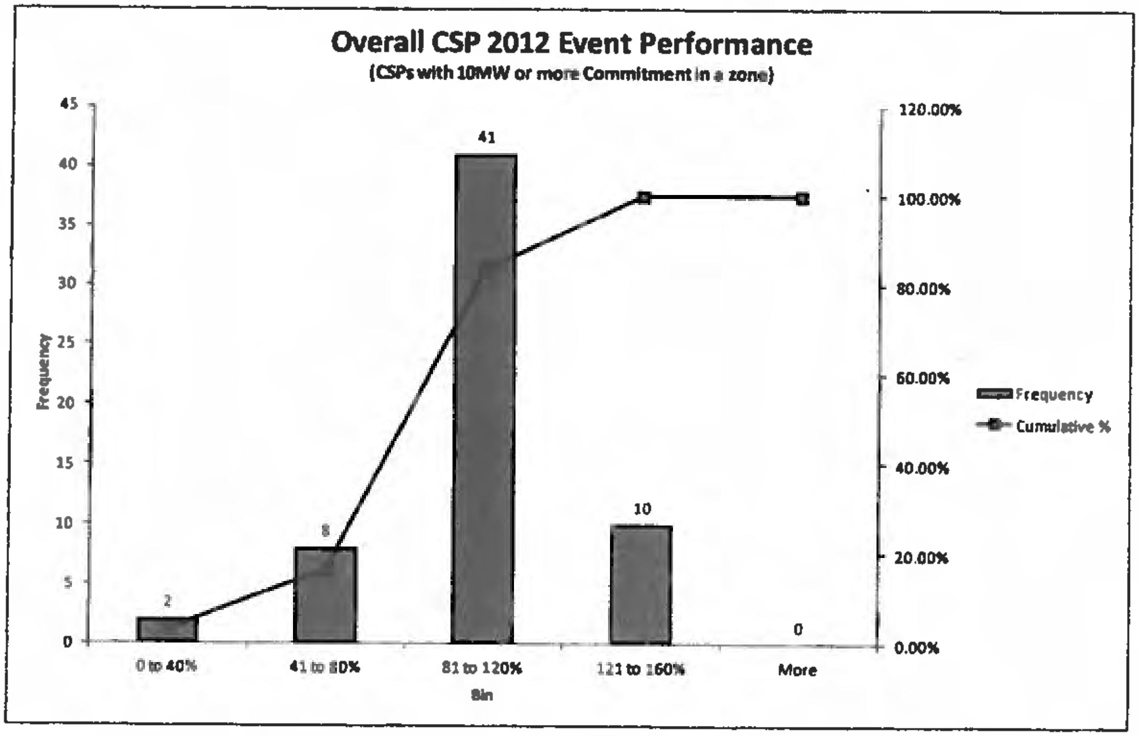


Figure 15 shows the combined – across zones and events – performance of large CSPs for 2012. There were 26 CSPs with commitments of at least 10MWs in a zone. For purposes of the analysis these are considered large CSPs. The previous three charts included the performance of all CSPs, including the very small ones. Removing the small CSPs from the analysis provides a look at performance of members providing most of the load reductions. The frequency distribution of this group is almost normally distributed with no CSP performance in the high tail and only 2 in the low tail. This is a change from last year when there was a more scattered distribution.

Figure 15: Overall Large CSP Event Performance

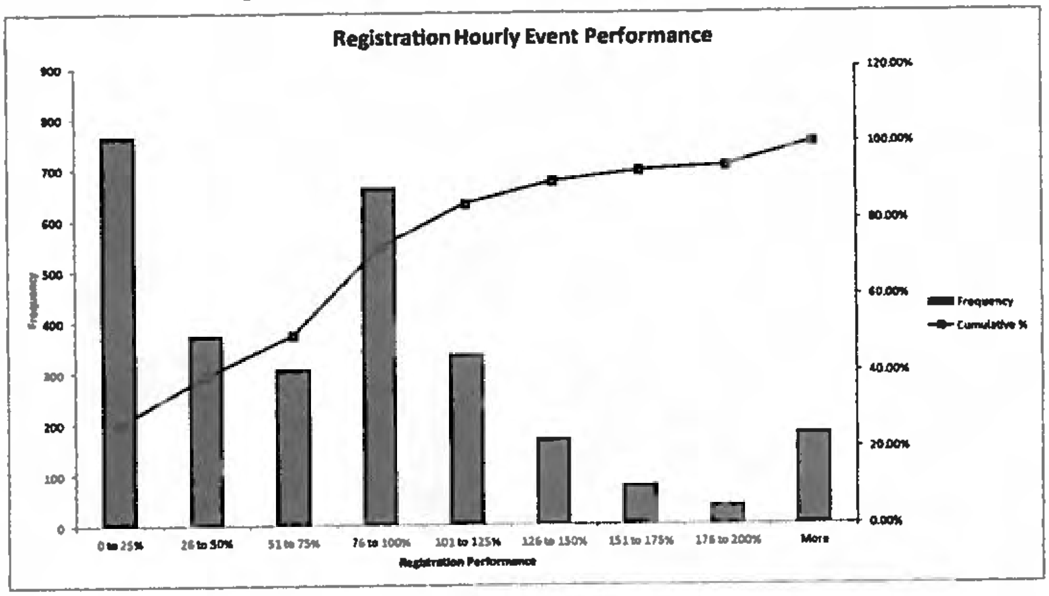


Registration Event Performance

Although CSP compliance is aggregated to a zonal level, PJM initially calculates performance by registration by end use customer by event by hour. Figure 16 below depicts the individual hourly performance of each registration called on for the 2012 Emergency DR (Load Management) events. Unlike the CSP performance above, the registration performance does not exhibit a normal distribution. Rather, the distribution has significant amount of activity in each "tail" which represents more extreme hourly resource event under and over performance. These tails represent significant numbers of registrations with low performance values (less than 25 percent) and another group with high performance values (greater than 200 percent) which offset through the aggregation of overall portfolio performance.

This effect is when, within a CSPs portfolio of registrations, some registrations over perform for the benefit of those that under perform yielding an aggregate performance that is satisfactory. The high performance can come from two possible situations. First, a site with a relatively high PLC may conservatively register with a reduction commitment that is much lower than the PLC and when called on to perform, would provide a reduction well in excess of its' registered commitment. The second situation is when a site with a relatively low PLC (i.e. a site that makes an effort to lower its load on days likely to be peak load days in order to avoid a high capacity cost) registers with a low reduction commitment because it is limited by its low PLC. However, when this site is called on to perform, it will provide a reduction well in excess of its registered commitment. This second situation does not occur this year due to the implementation of new M&V rules that limit the calculated reduction quantity to the PLC value[9].

Figure 16: Registration Hourly Event Performance



Event Performance Penalties

Emergency DR (Load Management) Event Penalties are assessed by CSP and zone and then disbursed to CSPs that over-perform and where necessary to LSEs. However, to preserve confidentiality, the results are reported on an aggregated basis. Emergency DR (Load Management) Event Penalties and Credits are currently billed as an annual lump sum. Figure 17 summarizes the annual charges and credits by Event. The total amount of Emergency DR (Load Management) Event Penalties assessed for the 2012 events is $2 million/year ($5.6 million last year). To put this value into context it is important to note that total CSP revenues for DR are approximately $267.5 million per year ($420 million last year). The penalty charges are about 0.7 percent of the total revenue (1.3 percent last year). The Emergency DR (Load Management) Event Charges collected from CSPs are first allocated on a pro-rata basis to those CSPs that provided load reductions in excess of the amount obligated. Any Emergency DR (Load Management) Event Charges not allocated to over-performing CSPs are further allocated to all LSEs in the RTO pro-rata based on Load Contribution.

[9] This second situation had raised both a compliance and policy issue and was discussed at length in the Load Management Task Force, Markets Implementation Committee and reviewed at the Markets and Reliability Committee. Namely, should reductions achieved by registrations whose load was above its PLC at the time of the event be available to offset underperformance of other registrations. The FERC issued an order disallowing these reductions.

Figure 17: Emergency DR (Load Management) Event Penalties and Credits

	Annual Penalties	Annual Credits to Over-Performers	Annual Credits to LSEs
July 17, 2012 LM Event	$ 202,520.25	$ 189,657.65	$ 12,862.60
July 18, 2012 LM Event	$ 1,835,179.85	$ 1,018,612.80	$ 816,567.05
Total	**$ 2,037,700.10**	**$ 1,208,270.45**	**$ 829,429.65**

Emergency Energy Settlements

For Emergency DR events, Full Emergency type registrations are entitled to submit settlements for the energy reductions provided. The compensation is based on each registration's strike price and the LMPs during the event. Figure 18 shows the settlement values for each of the 2012 Emergency DR (Load Management) Events.

Figure 18: Emergency Energy Settlements for 2012 Events

Load Management Events	Emergency Energy Settlements
7/17/2012	$4,762,053
7/18/2012	$5,719,281
Total	$10,481,333

Reductions for Compliance and Emergency Energy Settlements

Load reductions during emergency events are calculated separately for purposes of compliance and emergency energy settlements. When calculating the reduction values used for compliance, the specific methodology depends on the type selected by the CSP during the registration: GLD, FSL or DLC. For GLD a CSP further determines the specific baseline calculation that results in the best estimate of what the facility's load would have been absent the reduction made for the Emergency DR (Load Management) event[10]. The CSP has five different calculation methods available to achieve the best estimate. For FSL the CSP simply reports the load level of the facility during the hours of the event and that value is subtracted from the PLC. Finally, for DLC the CSP reports exactly when the signal was sent to the end use customers to control the specific switches. Compliance reductions are calculated for all participants of an event.

When calculating reduction values for emergency energy settlements the procedure is different. For GLD and FSL the CSP calculates hourly reductions during events by subtracting the load at the facility during each hour from the load of the facility prior to the start of the event. For DLC, the CSP reports the load reduction from its approved estimation technique. Emergency energy settlements are only available to Full Emergency registrations. In order to receive a payment for an energy reduction the CSP must submit accurate data within the prescribed timeframe (60

[10] The CSP may also use meter data from a back up generation resource to determine the net metered load reduction at the site.

days from the event). Not all CSPs submit settlement data and if a facility had already fully reduced its load prior to the event, it cannot receive an emergency energy payment. Further, Emergency Capacity Only registrations by definition do not receive an emergency energy payment.

PJM analyzed compliance and emergency settlement data for the July 17th and 18th events for resources registered as Full Emergency to get an understanding of the difference in the measurement of load reduction based on capacity compliance rules compared to emergency energy rules. Average hourly load reductions based on capacity compliance rules were 1,077 MW and 2,120 MW for the 17th and 18th respectively. The average hourly load reductions based on emergency energy settlements for the same hours were 1,085 MW and 1,817 MW respectively. The three primary reasons for the difference are: 1) customers that may have reduced load earlier for the specific day, 2) the fundamental difference in how the load reductions are measured and 3) participants that did not submit the appropriate data for either capacity compliance or energy settlements.

2012 Emergency DR (Load Management) Tests

The implementation of the forward capacity market, RPM, has incented an increase in capacity-based demand response which has been beneficial to the region. Given the increasing dependence on demand response to maintain reliability, PJM has implemented annual Emergency DR (Load Management) Tests as a means to assess performance of Emergency DR (Load Management) resources that had not been called on to participate in an actual emergency event.

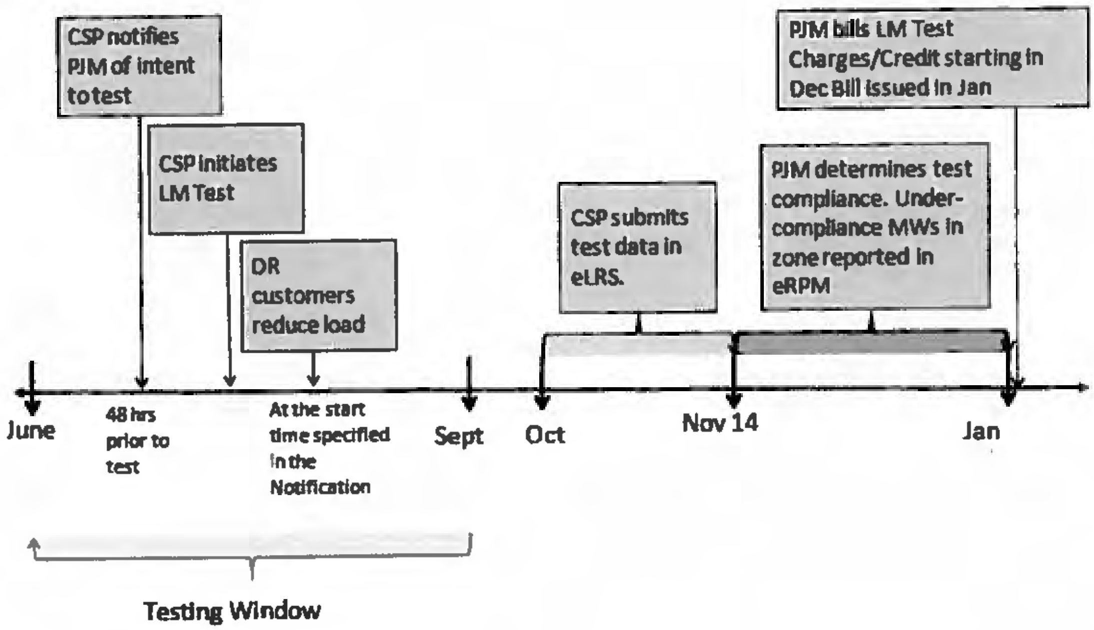
The Emergency DR (Load Management) Test is initiated by a Curtailment Service Provider (CSP) that has a capacity commitment. The CSP must simultaneously test all Resources in a Zone if PJM has not called an event in that Zone by August 15th of a given Delivery Year. If a PJM-initiated Emergency DR (Load Management) Event is called in a Zone between June 1st and September 30th there is no test requirement and no Test Failure Charges would be assessed to a CSP for that Zone.

The timing of a Emergency DR (Load Management) Test is intended to represent the conditions when a PJM-initiated Emergency DR (Load Management) event might occur in order to assess performance during a relative period. Therefore, a Emergency DR (Load Management) Test may occur from June 1st through September 30th on a non-holiday weekday during any hour from 12 noon until 8 PM EPT. All of a CSP's committed DR resources in the same Zone are required to test at the same time for a one hour period. The requirement to test all resources in a zone simultaneously is necessary to ensure that test conditions are as close to realistic as possible. It is requested that the CSP notify PJM of intent to test 48 hours in advance to allow coordination with PJM dispatch.

There is not a limit on the number of tests a CSP can perform. However, a CSP may only submit data for one test to be used by PJM to measure compliance. If the CSP's Zonal Resources collectively achieve a reduction greater than 75 percent of the CSP's committed MW volume during the test, the CSP may choose to retest the Resources in that Zone that failed to meet their individual nominated value.

CSPs must submit their test data using PJM's Load Response System (eLRS). For the 2012/2013 Delivery Year, the test data deadline was November 14, 2012. PJM reviews the information and contacts the CSP for additional supporting information where necessary. PJM determines test compliance and reports the information in PJM's RPM system (eRPM) during December. Any Emergency DR (Load Management) charges or credits are normally issued in January on the December bill.

Figure 19: Emergency DR (Load Management) Test Timeline



Emergency DR (Load Management) Resources are assessed a Test Failure Charge if their test data demonstrates that they did not meet their commitment level. The Test Failure Charge is calculated based on the CSP's Weighted Daily Revenue Rate which is the amount the CSP is paid for their RPM commitments in each Zone. The Weighted Daily Revenue Rate takes into consideration the different prices DR can be paid in the same Zone. For example, a CSP can clear DR in the Base Residual and/or Incremental Auctions in the same Zone, all of which are paid different rates. The penalty rate for under-compliance is the greater of 1.2 times the CSP's Weighted Daily Revenue Rate or $20 plus the Weighted Daily Revenue Rate. If a CSP didn't clear in a RPM auction in a Zone, the CSP-specific Revenue Rate will be replaced by the PJM Weighted Daily Revenue Rate for such Zone.

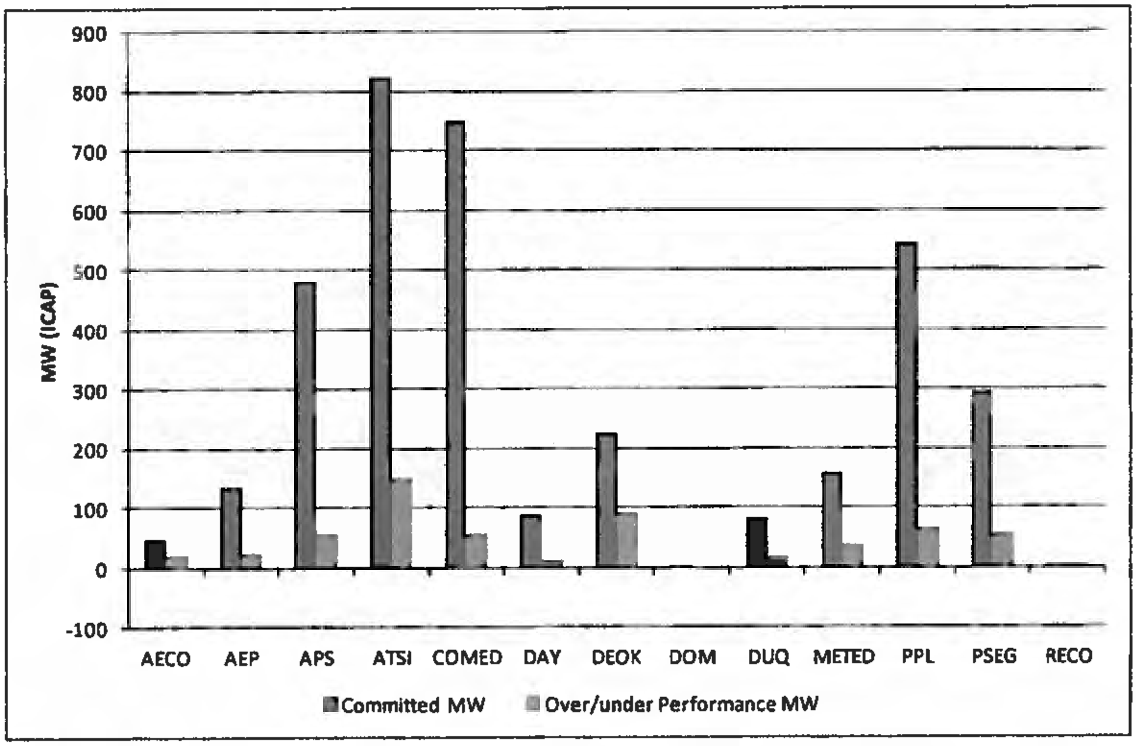
Emergency DR (Load Management) Test Results

There were 3,635 MW in ICAP of committed Emergency DR (Load Management) Resources that were not called upon to participate in any 2012/2013 Delivery Year emergency event. As a result, these resources were required to perform a test to assess their performance capability. Testing was performed by 51 CSPs in 12 Zones which resulted in a total of 133 CSP/Zone combinations. The over-compliance across all Zones and CSPs totaled 585 MW which equates to a performance level of 116 percent. Of the 3,635 MW of committed MWs, registrations with a combined commitment of 14 MW retested. The initial tests for these registrations showed a reduction value of 6 MW. After retesting, their reduction value was 16 MW, a 10 MW improvement. In tabular form, the Zonal results are as follows:

Figure 20: Emergency DR (Load Management) Commitments, Compliance, and Test Performance (ICAP)

Test Results				
Zone	Committed MW	Reduction MW	Over/under Performance MW	Performance Percentage
AECO	49	68	19	139%
AEP	134	158	24	118%
APS	482	538	56	112%
ATSI	824	973	149	118%
COMED	750	807	58	108%
DAY	88	99	11	112%
DEOK	226	316	90	140%
DOM	1.1	0.8	-0.3	70%
DUQ	81	98	18	122%
METED	159	196	37	123%
PPL	543	609	66	112%
PSEG	296	352	56	119%
RECO	3	5	2	164%
Total	3,635	4,220	585	116%

Figure 21: Emergency DR (Load Management) Test Obligations and Compliance (ICAP)



The performance on an individual CSP/Zone basis varied. Overall, 99 (74 percent) CSP/Zone combinations complied or over-complied in their Emergency DR (Load Management) Tests for the 2012/2013 Delivery Year. The over-compliance averaged 7 MW per CSP/Zone combination and totaled 660 MW of over-compliance. There were 34 (26 percent) CSP/Zone combinations that under-complied. The under-compliance averaged 2 MW per CSP/Zone combination for a total of 75 MW of under-compliance.

Test Failure Charges for the 2012/2013 Delivery Year are applied on an individual CSP/Zone basis for settlement purposes. However, the Test Failure Charges are reported on an aggregate basis here to preserve confidentiality. The average Penalty Rate for the 2012/2013 Delivery Year is $63.90/MW-day ($127.87 last year). This Penalty Rate is an average of $53.09/day when weighted by the under-compliance amounts ($130.37 last year). The annual penalties for under-compliance total just over $1.7 million which will be allocated to RPM LSEs pro-rata based on their Daily Load Obligation Ratio ($6.4 million last year). To better understand the order of magnitude, the under-compliance penalties compare to the total Emergency DR (Load Management) annual credits of just over $267.5 million ($420 million last year). Therefore, the under-compliance penalties are about 0.6 percent of the Emergency DR (Load Management) credits in the RPM (1.5 percent last year).

Edge, Valerie (DOJ)

To: Edge, Valerie (DOJ)
Subject: FW: DR bonus payment details

From: Nick Lake [mailto:nlake@enernoc.com]
Sent: [redacted] January 31, 2013 [redacted]
To: [redacted]
Subject: DR bonus payment details

ENERNOC

Problem viewing email? View in browser.

[redacted]

There has never been a better time to sign up for EnerNOC demand response. Payments for participating facilities in your geographical area are at their all-time high, meaning you will earn significantly more money for your participation than in past years.

Additionally, EnerNOC is offering a **$2,000 per MW bonus payment for new demand response customers who enroll before February 15th**. Early enrollment is beneficial to the electric grid, to demand response participants, and to EnerNOC, so we want to reward facilities who sign up early. This bonus payment is in addition to the ongoing revenues you would earn from EnerNOC.

Find out why thousands of Mid-Atlantic firms choose EnerNOC year after year. As always, EnerNOC demand response involves no risk for participants and no upfront or ongoing costs. You maintain control of your facility at all times, plus you get powerful tools to minimize your energy costs using our free, award-winning, energy management application, DemandSMART.

Would you be available for a meeting next week to discuss?

Best regards,
Nick

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United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued September 26, 2014 Decided May 1, 2015

No. 13-1093

DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL,
PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY,
RESPONDENT

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.,
INTERVENORS

Consolidated with 13-1102, 13-1104

On Petitions for Review of A Final Rule Promulgated by the United States Environmental Protection Agency

David W. DeBruin argued the cause for petitioners PSEG Power LLC, et al. With him on the briefs were *Matthew E. Price*, *Elizabeth C. Bullock*, *Shanna M. Cleveland*, and *Caitlin S. Peale*.

Valerie Satterfield Edge, Deputy Attorney General, Office of the Attorney General for the State of Delaware, argued the cause and filed the briefs for petitioner Delaware Department of Natural Resources and Environmental Control.

Ashley C. Parrish, *Karen Schoen*, *David G. Tewksbury*, and *Stephanie S. Lim* were on the brief for intervenor Electric Power Supply Association in support of petitioners.

Austin D. Saylor, Attorney, U.S. Department of Justice, argued the cause for respondent. With him on the brief were *Robert G. Dreher*, Acting Assistant Attorney General, U.S. Department of Justice, and *Michael Horowitz*, Attorney, U.S. Environmental Protection Agency.

William L. Wehrum Jr. argued the cause for intervenors-respondent. With him on the brief were *Lisa G. Dowden*, *Melissa E. Birchard*, *Leslie Ritts*, and *David M. Friedland.* *Aaron M. Flynn* entered an appearance.

Before: GARLAND, *Chief Judge*, WILLIAMS and RANDOLPH, *Senior Circuit Judges*.

Opinion for the Court filed by *Senior Circuit Judge* RANDOLPH.

RANDOLPH, *Senior Circuit Judge*: The State of Delaware, industry and environmental organizations, and an industry intervenor challenge a final rule of the Environmental Protection Agency governing the use of certain kinds of power generators. *See* National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, 78 Fed. Reg. 6,674 (Jan. 20, 2013). A group of trade associations and corporations intervened in support of EPA. The generators are known as Reciprocating Internal Combustion Engines. We refer to them here interchangeably as "backup generators" or "emergency engines." They typically run on diesel fuel and expel numerous pollutants. *See* National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 69 Fed Reg. 33,474, 33,499 (June 15, 2004).

Delaware raises three issues in its petition for judicial review. First, it argues that EPA acted arbitrarily and capriciously when it modified the National Emissions Standards for Hazardous Air Pollutants for the backup generators pursuant to Section 112 of the Clean Air Act. 42 U.S.C. § 7412. Second, it argues that, while modifying the National Emissions Standards, EPA improperly revised the definition of the same kind of generators in the New Source Performance Standards, violating Section 111 of the Act. *See* 42 U.S.C. § 7411. And, third, it argues that EPA unlawfully modified the National Emissions Standards to exempt from emissions controls certain non-emergency generators located in low-density areas.

All petitioners and the intervenor raise the first issue. Delaware alone raises the other two. Because we hold that Delaware lacks standing to challenge the exemption from emissions controls for backup generators in low-density areas, we need not address the third issue. For the reasons that follow, we hold that EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program.

I.

Congress enacted the Clean Air Act "to protect and enhance the quality of the Nation's air resources." 42 U.S.C. § 7401(b)(1). The Act governs the emissions of hazardous air pollutants that present "a threat of adverse human health effects . . . or adverse environmental effects." *Id.* § 7412(b)(2).

Section 112 requires EPA to promulgate national emissions standards for both "major sources" and "area sources" of hazardous air pollutants. *See id.* § 7412(d)(1). A "major source" is "any stationary source" that emits "10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." *Id.* § 7412(a)(1). An "area source" is "any stationary source . . . that is not a major source," *id.* § 7412(a)(2), which is to say, any stationary source that emits less than ten tons per year of any hazardous air pollutant or less than twenty-five tons per year of any combination of hazardous air pollutants. When promulgating such standards, EPA must consider "the known or anticipated adverse effects of such pollutants on public health and the environment." *Id.* § 7412(e)(2)(A).

Under Section 112, EPA "first sets emission floors for each pollutant and source category and then determines whether stricter standards, known as 'beyond-the-floor' limits, are achievable in light of the factors listed in section 7412(d)(2)." *Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855, 858 (D.C. Cir. 2001) (per curiam). Notably, these factors include the "consideration [of] the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." 42 U.S.C. § 7412(d)(2).

Section 111 directs EPA to set emissions standards for new and newly modified sources. *Id.* § 7411(d). A modified source is one that has undergone "any physical change in, or change in the method of operation[,] . . . which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." *Id.* § 7411(a)(4). Under Section 111, EPA must set standards for emissions that "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction." *Id.* § 7411(a)(1).

In rulemakings over the past decade, EPA has established National Emissions Standards and Performance Standards for pollutants emitted by backup generators.[1] Such pollutants include "[f]ormaldehyde, acrolein, methanol, and acetaldehyde." 69 Fed Reg. at 33,475. "[T]hese pollutants have been associated with several health-related concerns, including cancer, respiratory problems, and premature death." Emission Standards for Stationary Diesel Engines, 73 Fed. Reg. 4,136, 4,138 (Jan. 24, 2008).

Backup generators have traditionally been used in emergency situations "to produce power for critical networks or equipment . . . when electric power from the local utility is interrupted." 69 Fed. Reg. at 33,512. For years, they were not subject to the same level of regulation as larger generators. *See id.* at 33,477.

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[1] *See generally* National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 51,570 (Aug. 20, 2010), National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 75 Fed. Reg. 9,648 (Mar. 3, 2010), Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, 73 Fed. Reg. 3,568 (Jan. 18, 2008), Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 Fed. Reg. 39,154 (July 11, 2006), National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 69 Fed. Reg. 33,474 (June 15, 2004).

That began to change in 2004, when EPA promulgated a rule allowing backup generators to operate without emissions controls for unlimited periods "in emergency situations and for routine testing and maintenance." *Id.* at 33,512. It also allowed them to operate without emissions controls for "an additional 50 hours per year in non-emergency situations." *Id.* Four years later, EPA became "concerned that if stationary emergency engines are allowed to operate in non-emergency situations[,] they may be inappropriately used for peaking power" that is, to supply power to an energy grid during periods of high demand and, accordingly, EPA specified "that the 50 hours allowed for non-emergency situations cannot be used to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity." 73 Fed. Reg. at 3,583.

In two separate rules in 2010, EPA promulgated standards for hazardous air pollutant emissions from backup generators. The regulations allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." 75 Fed. Reg. 9,648, 9,667, 9,677 (Mar. 3, 2010) (rule for compression ignition engines); *see also* 75 Fed. Reg. 51,570, 51,591 (Aug. 20, 2010) (rule for spark ignition engines) (collectively, the "2010 Rule"). Demand response programs, which we discuss more below, are programs through which customers reduce their consumption of electric energy from the grid in response to high prices or other incentives. *See* 18 C.F.R. § 35.28(b)(4).

"Soon after the 2010 rule was final, the EPA received petitions for reconsideration of the 15-hour limitation for emergency demand response . . .." 78 Fed. Reg. at 6,679. On June 7, 2012, as a result of these petitions, EPA proposed amendments for National Emissions Standards for stationary backup generators and amendments to the Performance Standards for stationary internal combustion engines. *See* 40 C.F.R. Ch. I, Subch. C., Pt. 63, Subpt. ZZZZ (National Emission Standards); 40 C.F.R. Ch. I, Subch. C., Pt. 60, Subpt. IIII & JJJJ (Performance Standards).

EPA's final rule, issued on January 30, 2013, radically revised the fifteen-hour limit. The rule's preamble described its purpose as addressing the "use of existing engines for emergency demand response and system reliability" and noted that using such generators "as part of emergency demand response programs can help prevent grid failure or blackouts." 78 Fed. Reg. at 6,679. Under the new rule, backup generators are permitted to operate exempt from emissions controls for "emergency demand response" for up to 100 hours each year, in addition to actual emergency situations and maintenance. *Id.* at 6,679-80, 6,704-05; *see also id.* at 6,681, 6,695-97 (modifying Performance Standards for consistency). The rule limits emergency demand response operation to two circumstances: first, when a "Reliability Coordinator" (such as an independent electric grid operator) "has declared an Energy Emergency Alert Level 2," or, second, when "there is a deviation of voltage or frequency of [five] percent or greater below standard voltage or frequency." *Id.* at 6,705.[2]

Petitioners filed a timely petition for review on April 1, 2013. *See* 42 U.S.C. § 7607(b)(1); FED. R. APP. P. 15.

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[2] The 2013 Rule explains that, during a Level 2 alert, "there is insufficient energy supply and a true potential for electrical blackouts." 78 Fed. Reg. at 6,679. There is disagreement in the record whether the term "emergency demand response" is a misnomer. We do not resolve that issue here and understand "emergency" in this context to mean the circumstances during which the 2013 Rule allows backup generators to operate for up to 100 hours.

II.

Before turning to the merits of the case, we address the threshold issue of standing. *See Steel Co. v. Citizens for a Better Env't*, 523 U.S. 83, 101 (1998).

To establish standing under Article III of the Constitution, a petitioner "bears the burden of averring facts in its opening brief" that "demonstrate it has suffered a concrete and particularized injury that is imminent and not conjectural, that was caused by the challenged action, and that is likely to be redressed by a favorable judicial decision." *Texas v. EPA*, 726 F.3d 180, 198 (D.C. Cir. 2013) (citing *Sierra Club v. EPA*, 292 F.3d 895, 899-901 (D.C. Cir. 2002) and *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560-61 (1992)). When considering standing, we assume the validity of the petitioner's merits argument. *See Del. Dep't of Natural Res. & Envtl. Control v. FERC*, 558 F.3d 575, 578 (D.C. Cir. 2009).

Petitioner Conservation Law Foundation, "a private, nonprofit membership organization dedicated to the protection of public health and New England's environment," asserts that its "members live, work, and recreate in areas affected by emissions from diesel generators, particularly densely populated urban areas." Pet'r FirstEnergy, et al. Br. at 16. For an association to have standing, "it must demonstrate that at least one member would have standing under Article III to sue in his or her own right, that the interests it seeks to protect are germane to its purposes, and that neither the claim asserted nor the relief requested requires that an individual member participate in the lawsuit." *NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007) (citing *Hunt v. Wash. State Apple Adver. Comm'n*, 432 U.S. 333, 342-43 (1977)). Here, the Foundation claims that "the challenged rule will increase emissions of harmful air pollutants from [backup generators], threatening the health and welfare of CLF's members." Pet'r FirstEnergy, et al. Br. at 16 (citing Exs. A-C). The Foundation provided declarations from two of its members to that specific effect. Since these members assert harm traceable to the rise in backup generator emissions that would be redressable by government action, their interests in health are germane to the Foundation's purposes, and individual participation in the lawsuit is not required, the Foundation has standing. *See Sierra Club v. EPA*, 699 F.3d 530, 533 (D.C. Cir. 2012).

Petitioners FirstEnergy Solutions Corp., Calpine Corp., and PSEG Power LLC (collectively, the "Generator Petitioners") claim to have standing based on the alleged distorting impact the 2013 Rule has on organized capacity markets in which the Generator Petitioners compete. Intervenor Electric Power Supply Association asserts standing for the same reason. We need not address this argument, since the Generator Petitioners have submitted a joint brief with the Foundation, and the Association raises the same claims as raised in the joint brief. Because "constitutional and prudential standing can be shown for at least one plaintiff, we need not consider the standing of the other plaintiffs to raise that claim." *Mountain States Legal Found. v. Glickman*, 92 F.3d 1228, 1232 (D.C. Cir. 1996).[3]

Delaware asks us to vacate three portions of the 2013 Rule: the modified National Emissions Standards that allow for 100 hours of demand response, the similarly revised Performance Standards, and the exemption from emissions controls of certain non-emergency generators located in remote areas.

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[3] EPA concedes that the Foundation "does appear to have standing" and that the Electric Power Supply Association asserts the same issue raised in the Foundation's joint brief. Resp't Br. at 1 n.1.

EPA challenges Delaware's standing to bring any of these claims. It argues Delaware did not satisfy its burden of identifying "actual or imminent and concrete and particularized injury stemming from" EPA actions. Resp't Br. at 2-3 (internal quotation marks omitted). Indeed, Delaware's argument in favor of standing in its opening brief is thin. In a single paragraph, Delaware asserts that its standing is "self evident," Pet'r Del. Br. at 11 (citing *Sierra Club*, 292 F.3d at 900), arguing its "air quality is impacted by emissions from the engines covered by the [Performance Standards] and [National Emissions Standards] that originate upwind." *Id.* The added pollution will, so Delaware argues, negatively impact Delaware's ability to attain the National Ambient Air Quality Standards ("NAAQS") that Delaware has to maintain pursuant to the Clean Air Act. *Id.* In its opening brief, Delaware offers no specific evidence that the winds carry pollutants from backup generators into the state, or in what quantity, or with what frequency, or that backup generators in the remote-area subcategory are located near enough to Delaware to pose a threat to the state's air quality. Its brief also points to no specific place in the record, which extends for thousands of pages, where that information could be found. Its only additional authority is *Massachusetts v. EPA*, 549 U.S. 497, 516-25 (2007) (holding state petitioners had standing to challenge EPA order denying a petition for rulemaking to regulate greenhouse gas emissions from motor vehicles).

Typically the petitioner "bears the burden of averring facts in its opening brief" that establish standing. *Texas v. EPA*, 726 F.3d at 198; *see also* D.C. CIR. R. 28(a)(7) ("When the . . . petitioner's standing is not apparent from the administrative record, the brief must include arguments and evidence establishing the claim of standing."). Taken by themselves, the bare assertions in the opening brief may be insufficient to establish standing.

But our case law allows us the discretion to look beyond the opening brief and consider material submitted later if the petitioner "reasonably believed [its] standing [wa]s self-evident." *Am. Library Ass'n v. FCC*, 401 F.3d 489, 492 (D.C. Cir. 2005); *see also Ctr. for Sustainable Econ. v. Jewell*, 779 F.3d 588, 598-99 (D.C. Cir. 2015); *Ams. for Safe Access v. Drug Enforcement Admin.*, 706 F.3d 438, 444 (D.C. Cir. 2013).

We choose to exercise that discretion here for three reasons. First, Delaware is part of PJM Interconnection, LLC the regional transmission organization that operates the power grid for over 60 million customers in the mid-Atlantic region and the Midwest. *See* J.A. 1,790. As we will discuss below, part of EPA's motivation for this rule was to allow the use of emergency engines for demand response in the PJM region, and EPA explicitly sought to accommodate what it believed to be a PJM-specific sixty-hour availability requirement for emergency engines. *See* 78 Fed. Reg. at 6,679; National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, 77 Fed. Reg. 33,812, 33,817 (proposed June 7, 2012). There is evidence in the administrative record that backup generators represent nearly fifteen percent of demand response in the PJM region and that demand response use is growing therein. *See* J.A. 2,114. Second, the congressionally created Northeast Ozone Transport Region includes Delaware and other states in the mid-Atlantic and northeast regions, *see* 42 U.S.C. § 7511c, and we have previously noted that ozone pollution from these states contributes to pollution in each other. *See Virginia v. EPA*, 108 F.3d 1397, 1401 (D.C. Cir. 1997); *see also Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1036-37 (D.C. Cir. 2001) (per curiam) (describing EPA finding that stationary source emissions in upwind states contributed to ozone nonattainment in other states and "trigger[ed] direct federal regulation of stationary sources"). Third, parts of Delaware are in nonattainment, and its experts aver that most of the emissions that negatively impact its ability to attain the NAAQS come from out of state. *See* Addendum to Pet'r Del. Reply Br. at 4; *see also* EPA, *Current Nonattainment Counties for All Criteria Pollutants*, http://www.epa.gov/airquality/greenbook/ancl.html (last visited Apr. 22, 2015) (listing counties in nonattainment).

In light of these factors, it was reasonable for Delaware to believe that its standing was self-evident. Accordingly, we look beyond the opening brief to the reply brief to establish standing. *See Ams. for Safe Access*, 706 F.3d at 444; *Am. Library Ass'n*, 401 F.3d at 495-96; *see also Communities Against Runway Expansion, Inc. v. FAA*, 355 F.3d 678, 685 (D.C. Cir. 2004) (looking to supplemental declarations submitted with reply brief to establish injury and, thus, standing).

Delaware's reply brief and its accompanying addendum provide an explanation of the injuries that gave rise to Delaware's reasonable belief that its standing was self-evident. It cites a letter in the record sent by Ali Mirzakhalili, Director of Delaware's Department of Natural Resources and Environmental Control's Division of Air Quality, to EPA in August 2012, *see* J.A. 2,107-08, and provides in an addendum two affidavits, one from Mirzakhalili and another from Marty Prettyman, a Delaware environmental scientist, *see* Addendum to Pet'r Del. Reply Br. at 1-17, 20-29.

In his letter, Mirzakhalili argues that the EPA rule would have an "adverse" impact on air quality and that "[i]t is of vital importance not to increase emissions of oxides of nitrogen (NO_x), especially on high electricity demand days." J.A. 2,107. He also argues a lower ambient air quality standard is "looming" that "will require additional NO_x emission reductions," and EPA's proposed rule "increases rather than decreases NO_x

emissions that contribute to the formation of ozone." J.A. 2,107-08. In his affidavit, Mirzakhalili states that emissions from emergency demand response programs significantly impact ozone pollution in Delaware, Addendum to Pet'r Del. Reply Br. at 10, that at least 90 percent of the pollutants contributing to Delaware's failure to attain the NAAQS "come from pollutants transported from other states," *id.* at 3, that such pollution incurs medical costs that are borne by the state, *id.* at 4-5, and that stronger emissions controls on backup generators in other states would benefit Delaware, *id.* at 11-12. Prettyman charts the rising number of demand response incidents in the PJM regional power grid, *id.* at 23, and states that the remote area exemption for certain engines poses an environmental hazard, *id.* at 24-25, though it is unclear if such engines are within or proximate to Delaware.

This evidence suffices to establish that Delaware has suffered a concrete and imminent injury stemming from the portions of the 2013 Rule allowing backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program. *See Appalachian Power*, 249 F.3d at 1066-67; *see also Massachusetts v. EPA*, 549 U.S. at 521. Thus, Delaware's challenges to the modified National Emissions Standards and the related Performance Standards are properly before us.

But a petitioner "must demonstrate standing for each claim he seeks to press," *DaimlerChrysler Corp. v. Cuno*, 547 U.S. 332, 352 (2006), and Delaware's challenge to the exemption from emissions controls of certain non-emergency generators located in remote areas is another matter.

In both its opening brief and its reply brief, Delaware offers no evidence that backup generators in the remote-area subcategory are located near enough to Delaware to pose a threat to the state's air quality. To the contrary, the Mirzakhalili letter cited in Delaware's reply brief states that "[m]ost of these installations are in remote, unpopulated areas." J.A. 2,122. The only examples the letter offers of these remote locations are references to the Powder River Basin of Wyoming and "fields" of generators "visibly evident across Wyoming and Colorado, and . . . throughout Nebraska and California." J.A. 2,122-23. Nothing in Delaware's briefs or supplemental affidavits mentions a location in or near Delaware or even upwind of the state. Considered alongside Delaware's credible claims of injury from backup generators in upwind and contiguous states, its assertions regarding remote-area engines are strikingly weak. Accordingly, Delaware has failed to meet its burden of showing that it has standing to challenge the 2013 Rule's subcategorization of existing stationary spark ignition engines located at area sources in sparsely populated areas. *See Ass'n of Flight Attendants-CWA, AFL-CIO v. U.S. Dep't of Transp.*, 564 F.3d 462, 467 (D.C. Cir. 2009) (considering but rejecting standing arguments made in reply brief and accompanying submissions).

Accordingly, we address only EPA's modification of the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program, *see* 40 C.F.R. §§ 60.4211(f)(2), 60.4243(d)(2), 63.6640(f)(2), and we do not address the remote-area exemption, *see* 40 C.F.R. § 63.6675.

III.

We "may reverse" a final EPA rule if we find the agency's action "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). This language from the Clean Air Act differs from that of the

Administrative Procedure Act. Section 706 of the APA states that the "reviewing court shall" "hold unlawful and set aside agency action" the court finds to be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law," 5 U.S.C. § 706(2)(A). But "the standard we apply is essentially the same under either Act," the CAA or the APA. *Ethyl Corp. v. EPA*, 51 F.3d 1053, 1064 (D.C. Cir. 1995); *see also West Virginia v. EPA*, 362 F.3d 861, 867-68 (D.C. Cir. 2004).

To prevail, an "agency must 'examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.'" *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013) (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quotation marks omitted)). "To be regarded as rational, an agency must also consider significant alternatives to the course it ultimately chooses." *Allied Local & Reg'l Mfrs. Caucus v. EPA*, 215 F.3d 61, 80 (D.C. Cir. 2000). We will reverse when agency action is "based on speculation," *Jones*, 716 F.3d at 214, or when the agency did not "engage the arguments raised before it," *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (quoting *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992)).

IV.

To understand this case and petitioners' claims, we must discuss energy markets and capacity markets and their relationship to demand response.

Under the Federal Power Act, the Federal Energy Regulatory Commission ("FERC") has jurisdiction over the "transmission of electric energy in interstate commerce," 16 U.S.C. § 824(b)(1), and is responsible for maintaining the reliability of the electric grid, *see id.* § 824*o*(b)(1). FERC has certified the North American Electric Reliability Corporation ("NERC") as the nation's "electric reliability organization," and NERC has developed enforceable standards to ensure electric grid reliability. *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344-45 (D.C. Cir. 2009). FERC regulates electricity grid managers known as Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs") (collectively, "System Operators"), who are responsible for ensuring electric reliability within their regions of responsibility. *See Braintree Elec. Light Dep't v. FERC*, 550 F.3d 6, 8-9 (D.C. Cir. 2008) (describing history of RTOs).[4]

These System Operators are usually involved in both the energy and capacity markets. Energy "is the amount of electricity generators actually provide to the grid and is available to be used at any moment. Organized wholesale electricity markets buy and supply electricity instantaneously." Kennedy Maize, *Texas and the Capacity Market Debate*, Power Mag., Feb. 1, 2014.[5]

Capacity is different. "'Capacity' is not electricity itself but the ability to produce it when necessary. It amounts to a kind of call option that electricity transmitters purchase from

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[4] *See also* Michael H. Brown & Richard P. Sedano, Electricity Transmission: A Primer 53 (2004) (describing responsibilities of grid operators).

[5] *See also* Brown & Sedano, Electricity Transmission at 67 (defining the "wholesale power market" as "[t]he purchase and sale of electricity from generators to resellers . . . along with the ancillary services needed to maintain reliability and power quality at the transmission level"); J.A. 2,399 ("[A]ctual system load (real-time customer demand) is met via the energy and other daily markets.") (Analysis Group Report).

parties generally, generators who can either produce more or consume less when required." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009); *see also Me. Pub. Util. Comm'n v. FERC*, 520 F.3d 464, 467 (D.C. Cir. 2008) (per curiam), *rev'd in part sub nom. NRG Power Mktg., LLC v. Me. Pub. Util. Comm'n*, 558 U.S. 165 (2010). These sales may occur years in advance of when the capacity is actually needed; power generators are thus able to plan and build facilities to meet future demand. *See Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1284-85 (D.C. Cir. 2011) (per curiam).

ISOs and RTOs typically require local utilities delivering electricity to users (known as "load-serving entities," or LSEs) to purchase a certain amount of capacity to ensure reliability during periods of high demand. *See, e.g.*, *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1234 (D.C. Cir. 2005). "The goal is for [utilities] to purchase sufficient capacity to easily meet expected peaks in electricity demand on their transmission systems." *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 479.

"Payments for capacity provide a revenue stream to maintain and keep current resources operating and to develop new resources. Investors need sufficient long-term price signals to encourage the maintenance and development of generation, transmission and demand-side resources." PJM, *Reliability Pricing Model, Demand Response and Energy Efficiency* 1 (2009); *see also PJM Interconnection, LLC*, 128 FERC ¶ 61157 P 24 (Aug. 14, 2009) ("Since energy and ancillary services revenues in an export area are not sufficient by themselves to support new entry, capacity payments are needed to provide the proper incentives for new efficient entry in that area and to retain existing efficient generators over the long term.").

Capacity markets vary across the country, but "the primary goal of each of these markets is the same: ensure resource adequacy at just and reasonable rates through a market-based mechanism that is not unduly discriminatory or preferential as to the procurement of resources." FERC Staff, AD13-7-000, Centralized Capacity Market Design Elements 2 (2013); *see also N.E. Power Generators Ass'n v. FERC*, 707 F.3d 364, 367 (D.C. Cir. 2013). In some markets, System Operators administer auctions whereby LSEs procure capacity. *See Centralized Capacity Market Design* at 1-2.

We recently explained how the process works in New York. There, "[c]apacity suppliers bid a quantity of capacity into the auction, and the total amount of capacity bid creates a supply curve, which intersects with a predetermined demand curve." *TC Ravenswood, LLC v. FERC*, 741 F.3d 112, 114 (D.C. Cir. 2013). Supply and demand meet to set a price, which LSEs pay to purchase capacity. *Id.* "In theory, this market design encourages desirable investment by signaling the need for more generation and by enabling power generators to recoup their costs in the capacity market." *Id.*

Capacity auctions do "not differentiate among capacity resources based on any type of resource specific reliability criteria." J.A. 2,397 (Analysis Group Report). The capacity markets select resources almost exclusively on the basis of price they do not place a value on "fuel type, technology type, or resource flexibility." *Id.*; *see also TC Ravenswood*, 741 F.3d at 114; *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 479-80.

Capacity can be supplied by power plants, but it can also be supplied by demand-response resources. Traditionally, "demand response" simply referred to "a reduction in the consumption of electric energy by customers." *See* 18 C.F.R. § 35.28(b)(4).[6]

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[6] *See also* FERC Staff, National Action Plan on Demand Response, Docket No. AD09-10, at 3 (2010), *available at*

For example, a consumer may temporarily shut off air conditioning on a hot day.

Industry and environmental petitioners are concerned with what they consider a new phenomenon in demand response, whereby some consumers substitute the supply of capacity from traditional sources with backup generators. Consumers draw energy from the generators and not from the grid, "which reduces electricity consumption from the grid as measured at the customer's meter," according to a report in the administrative record. J.A. 2,142. By doing so, they "displace[] electricity that otherwise would be provided by the grid." J.A. 2,391 (Analysis Group Report). So-called "demand response 'aggregators' have adopted the practice of grouping backup generators together to form 'virtual power plants' of considerable size," according to comments presented to EPA by intervenor Electric Power Supply Association. J.A. 2,223-24.[7]

The performance obligations for these demand response providers and traditional generators differ; traditional generators have a "must-offer requirement" in accordance with which they

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http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf (FERC uses "'demand response' to refer to the ability of customers to respond to either a reliability trigger or a price trigger from their utility system operator, load-serving entity, regional transmission organization/independent system operator (RTO/ISO), or other demand response provider by lowering their power consumption.").

[7] Respondent-Intervenor EnerNOC, Inc.—a corporation that specializes in demand response and partly relies on the use of backup generators subject to the 2013 Rule—claims on its website that it is "rapidly building the world's largest virtual power plant." EnerNOC, *Our Impact*, http://www.enernoc.com/about/our-impact (last visited Apr. 22, 2015).

provide energy into the grid whenever "called upon," but "demand response capacity resources," like backup generators, "are not subject to the must-offer requirements," absent system emergencies. *Centralized Capacity Market Design* at 19.

Petitioners and the supporting intervenor argue that demand response in capacity markets based on backup generators is growing with negative effects on reliability and the environment. They argue there are four reasons why. First, because backup generators do not have to conform to emissions controls like regular power plants, their electricity costs less to produce and they can charge less and underbid conventional power suppliers in capacity markets. Second, as backup generators displace traditional power plants in capacity markets, demand for traditional power generation drops, and because traditional power generators rely on capacity markets to "recoup their costs," *TC Ravenswood*, 741 F.3d at 114 they under-invest in power plants that produce electricity for the energy markets. This reduction in supply undermines the reliability of the power grid. Third, as the power supply decreases and the grid becomes less stable, the number of power emergencies increases. And, fourth, as emergencies increase, the actual use of "dirty" backup generators correspondingly increases, causing greater pollution. In short, petitioners and the intervenor argue that instead of protecting the nation's air resources and improving grid reliability as EPA claims, the 2013 Rule has the opposite effect.

V.

During the notice and comment period, petitioners presented their concerns about the 2013 Rule's impact on the efficiency and reliability of the energy grid. They contend that EPA should have, but did not, respond properly to their well-founded concerns. *See Allied Local & Reg'l Mfrs. Caucus*, 215 F.3d at 80.

Petitioners are correct. EPA's action was arbitrary and capricious on that ground alone. In addition, EPA appears to have relied on faulty evidence when justifying the exemption increase from fifteen hours to 100 hours. EPA also did not consider the alternative of limiting the exception to parts of the country not served by organized capacity markets. We should further note that EPA did not obtain the views of FERC or NERC on the reliability considerations upon which EPA based the exemption.

1. Efficiency and Reliability

Several commenters explained how EPA's final rule threatens the efficiency and reliability of the energy markets by creating incentives for backup generators to enter the capacity markets and force out more efficient, traditional power generators.

For instance, at a hearing for public comments on the proposed rule in July 2012, Christina E. Simeone of the non-profit PennFuture Energy Center testified that the 2013 Rule would "create distortions in energy markets by making demand response from uncontrolled [backup] units artificially cheap." J.A. 1,697. She pointed to evidence showing that demand response programs were growing in the region overseen by PJM Interconnection. By making backup generators "artificially cheap, EPA is creating a rush to these resources," and, thus, harming reliability by diverting investment from power generation resources "needed to secure the grid." J.A. 1,699.

At the same hearing, Shannon Maher Banaga of Petitioner PSEG Power, LLC testified that demand response resources were not needed to ensure reliability. J.A. 1,703. Backup generators are "economic resource[s]" that "comp[]ete[] directly with other forms of capacity, most particularly generation," she said. J.A. 1,705. As backup generators play a larger role in capacity markets, "the number of so-called 'emergencies' is going to go up." J.A. 1,706.

In August 2012, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("IMM") for PJM, submitted comments to EPA objecting strongly to the reliability rationale of the proposed rule. "Some have asserted that an exemption for [backup] generators participating in demand side response [ ] programs provides benefits to the organized wholesale electricity markets," it wrote. J.A. 2,338. "Those arguments have no merit. On the contrary, providing the exemption will have negative consequences for efficiency and reliability." *Id.* It argued the 100-hour exemption "conflicts with and would undermine the development of the demand side of these markets" and is totally unnecessary to support reliability. *Id.* According to IMM, given the interplay between the capacity and energy markets, the exemption would distort both. *See* J.A. 2,340-41.

Petitioner Calpine Corporation submitted a letter to EPA in August 2012 echoing these concerns. The proposed rule "would incentivize the procurement of diesel-fired [behind-the-meter] generators masquerading as 'demand response' in electricity capacity markets and thereby displace clean generating resources . . .." J.A. 2,355. Backup generators are not necessary for reliability in organized competitive markets, since "the market will simply procure other resources instead of [a behind-the-meter generator] that has not had to internalize the costs of emissions controls." *Id.* Indeed, the increased reliance on demand-response resources available in capacity markets "may actually impair system reliability" since the traditional power generators they displace "operate more reliably" than the demand-response resources. J.A. 2,356. "Simply put, the Proposed Rule's exemption is nothing less than a subsidy for dirty generating sources." *Id.*

Nor were these concerns merely hypothetical. An August 2012 report submitted to EPA by Northeast States for Coordinated Air Use Management, a non-profit association of air quality agencies in the northeast, explained that "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." J.A. 2,142; *cf.* J.A. 1,711, 1,757 (comments showing an increase in demand-response resources offered into auction from 2009 to 2010).

EPA offered wan responses to these comments. EPA construed the concerns as arguments that the 2013 Rule "will encourage the use of backup generators in lieu of cleaner alternatives of energy" but "there is no guarantee that this would be the case." J.A. 2,579. EPA seems to have missed the forest for the trees: the overriding concern of these comments was the perverse effect the 100-hour exemption would have on the reliability and efficiency of the capacity and energy markets, not the specific clean energy alternatives that could supply the grid instead of backup generators. EPA essentially said that it was not its job to worry about those concerns: "The issues related [to] management of energy markets and competition between various forms of electric generation are far afield from EPA's responsibilities for setting standards under the CAA." J.A. 2,582; *see also* J.A. 2,592 ("Decisions about what units to allow to be bid into the capacity market and relied on for reliability are not under the EPA's purview and should be left to the entities that are responsible for maintaining the reliability of the electric grid.").[8]

But EPA cannot get away so easily from its obligations under the APA to respond to "relevant and significant" comments. *Cement Kiln Recycling Coal. v. EPA*, 493 F.3d 207, 225 (D.C. Cir. 2007) (quoting *Grand Canyon Air Tour Coal. v. FAA*, 154 F.3d 455, 468 (D.C. Cir. 1998)). Naturally, an agency need not "discuss every item of fact or opinion included in the submissions made to it." *Pub. Citizen, Inc. v. FAA*, 988 F.2d 186, 197 (D.C. Cir. 1993) (quoting *Auto. Parts & Accessories Ass'n v. Boyd*, 407 F.2d 330, 338 (D.C. Cir. 1968)). But an agency must respond sufficiently to "enable us to see what major issues of policy were ventilated . . . and why the agency reacted to them as it did." *Id.* (quoting *Auto. Parts*, 407 F.2d at 335) (ellipsis in original).

EPA did not even do that much. It refused to engage with the commenters' dynamic markets argument. At points, its later statements contradicted earlier responses; while the final rule placed reliability at the center of its reasoning, *see* 78 Fed. Reg. at 6,679, EPA's response to comments insisted it was not "justifying its regulation primarily on the reliability needs of the bulk power system." J.A. 2,592; *cf. Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1520 (D.C. Cir. 1984) ("Such self-contradictory, wandering logic does not constitute an adequate explanation" of agency action). EPA seeks to excuse its inadequate responses by passing the entire issue off onto a different agency. Administrative law does not permit such a

[8] EPA also responded to these comments by noting that areas of the country not served by organized capacity markets do rely on backup generators to protect the reliability of the grid. *See, e.g.*, J.A. 2,580. We find this response equally inadequate for the reasons explained in Part V.3.

dodge. *See Gen. Chem. Corp. v. United States*, 817 F.2d 844, 846 (D.C. Cir. 1987) (per curiam) (finding agency action arbitrary and capricious where agency analysis was "inadequately explained").

During oral argument, EPA's attorney told the court that EPA "heard" the commenters' concerns about the 2013 Rule. But merely hearing is not good enough EPA must respond to serious objections. *See Allied Local & Reg'l Mfrs. Caucus*, 215 F.3d at 80. By failing to do so here, its rulemaking was arbitrary and capricious. *See State Farm*, 463 U.S. at 43-44.

2. Backup Generator Aggregation

EPA's 100-hour exemption in the 2013 Rule was arbitrary and capricious for still another reason: EPA failed to respond to comments suggesting that the 100-hour limit was based on faulty evidence.

In support of its claim that the fifteen-hour cap was inadequate, EPA specifically relied on comments from a prior rulemaking, *see* J.A. 1,548 (PJM Comment from Feb. 14, 2011), indicating that resources were required to be available for a minimum of sixty hours per year to participate in PJM's "Emergency Load Response Program." *See* 78 Fed. Reg. at 6,679.

But, as PJM explained to EPA in comments written in August 2012 in response to this rule, the sixty-hour minimum does not apply to individual engines. J.A. 1791. Rather, these engines may be aggregated together to meet the sixty-hour availability requirement. *Id.* PJM explained that in 2012 "the environmental limitations on individual [backup] units . . . are not necessarily dispositive of the ability of demand response resources to participate in PJM's markets or to maintain bulk power system reliability." *Id.*; *see also* J.A. 2346-47 (IMM Comments); J.A. 2,104-05 (CLF Comments).

EPA seems to have either intentionally discounted PJM's later explanation of its requirement or simply confused the later comment for the earlier one. Another commenter brought the possible confusion to EPA's attention, but EPA did not specifically respond, saying it considered demand-resource needs "in all areas of the country, not just PJM." J.A. 2,596. And yet, EPA significantly grounded the 2013 Rule in a PJM requirement that does not exist for individual engines.

In light of PJM's 2012 comments, EPA failed to give an adequate reason for relying on the PJM availability requirement. *See* 78 Fed. Reg. at 6,679. EPA's action was thus arbitrary and capricious on this ground, as well. *See State Farm*, 463 U.S. at 43; *see also Nat'l Gypsum Co. v. EPA*, 968 F.2d 40, 41 (D.C. Cir. 1992) (vacating and remanding where EPA offered inadequate scientific evidence and failed to offer substantial evidence for decision).

3. Alternative Option

Petitioners argue that backup generator-based demand response resources "simply provide a reliability service that could and would be equally met by alternative resources" traditional energy generators that comply with emissions controls especially in organized capacity markets. Pet'r FirstEnergy, et al. Br. at 22 (citing Analysis Group Report).

EPA counters that petitioners "ignore[] that resources other than emergency engines are typically unavailable for emergency demand response purposes in those areas of the nation not served by organized capacity markets." Resp't Br. at 39-40.

EPA argues that by setting a nationwide annual limit of 100 hours, it "took into account the fact that emergency engines help to ensure reliable electric service not just in areas with organized capacity markets, but also in many rural communities and small municipal systems." *Id.* at 45.

This statement does not explain why EPA failed to limit the 100-hour exemption to areas of the country not served by organized markets. At least one commenter, the Electric Power Generation Association, proposed such an alternative. *See* J.A. 1,780-83. Tens of millions of Americans live in states served by organized markets.[9] Yes, EPA received comments that exempting backup generators from emissions controls would aid reliability "for small, rural municipalities," J.A. 2,556; *see also* J.A. 1,931-32, J.A. 1,944, but it did not adequately explain why it adopted a nationwide rule when such an allegedly overbroad action has the potential to distort organized markets. EPA asserts that it "was perfectly reasonable" for it "to promulgate a rule of nationwide applicability, rather than establish different limits on emergency demand response operation based on the specific (and not necessarily permanent) market conditions in a particular location." Resp't Br. at 48.

For support, EPA cites *National Telephone Co-Op Association v. FCC*, 563 F.3d 536 (D.C. Cir. 2009), in which we held that the Federal Communications Commission's explanation of its rejection of an alternative policy option "was reasonable and reasonably explained." *Id.* at 542; *see also* Resp't Br. at 48. But that case is instructive for exactly what is lacking in EPA's actions in the instant case. There, petitioner argued that the FCC could have created a "partial or blanket exemption" from an order requiring the portability of telephone

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[9] *See* FERC, Docket No. MO4-2-000, State of the Markets Report 5-6 (2004).

numbers for "small wireline carriers." *Id.* The FCC rejected the proposal after carefully articulating its reasons, noting the proposal "would harm consumers in small and rural areas across the country by preventing them from being able to port [or transfer their numbers] on a permanent basis" and discourage further competition that could help customers. *See id.*; *In re* Telephone Number Requirements for IP-Enabled Services Providers, 22 F.C.C.R. 19531, 19611 ¶16 2007 WL 3306343 (2007). In short, the FCC identified a specific harm of the alternative proposal.

Here, the only rationale provided for a national rule was a vague desire for uniformity.[10] While EPA emphasized in the administrative proceeding the benefits to rural areas of the rule, *see, e.g.*, J.A. 2,596, it did not address why a more limited rule would not achieve the same outcome without posing risks to organized energy markets.

We do not "broadly require an agency to consider all policy alternatives in reaching [a] decision." *State Farm*, 463 U.S. at 51. But "[a]t the very least this alternative way of achieving" EPA's objective, namely by limiting the 100-hour exemption to address the reliability needs of rural locations, "should have been addressed and adequate reasons given for its abandonment." *Id.* at 48. Because EPA too cavalierly sidestepped its responsibility to address reasonable alternatives, its action was not rational and must, therefore, be set aside. *See Allied Local*, 215 F.3d at 80; *see also Allentown Mack Sales & Serv., Inc. v. NLRB*, 522 U.S. 359, 374 (1998).

[10] We note that a concern for uniformity did not prevent EPA from establishing a subcategory of stationary engines located in sparsely populated areas. *See* 40 C.F.R. § 63.6675. Clearly, a desire for nationwide uniformity is not always dispositive.

4. FERC Input

An undercurrent coursing through this case has been that, while EPA justifies the 2013 Rule on the basis of supporting "system reliability," 78 Fed. Reg. at 6,679; *see also* Resp't Br. at 29, grid reliability is not a subject of the Clean Air Act and is not the province of EPA. There is no indication that either FERC, the federal entity responsible for the reliability of the electric grid, 16 U.S.C. § 824*o*(b)(1), or NERC, FERC's designated electric reliability organization, *see Alcoa*, 564 F.3d at 1345, was involved in this rulemaking or submitted their views to EPA.

During the comment period, when a commenter suggested EPA "work with FERC . . . to ensure grid reliability does not depend on stationary [backup generators]," J.A. 2,594, EPA responded that the rulemaking's purpose was to address emissions from the emergency engines "and to minimize such pollutants within the Agency's authority under the CAA. It is not within the scope of this rulemaking to determine which resources are used for grid reliability, nor is it the responsibility of the EPA to decide which type of power is used to address emergency situations." J.A. 2,595. Such responsibility was "within the hands of the power authorities and not" EPA. *Id.* In the preamble to the 2013 Rule, EPA similarly stated that concerns about the impact of demand response in capacity markets "are comments more appropriately directed towards the FERC." 78 Fed. Reg. at 6,685.

But EPA cannot have it both ways it cannot simultaneously rely on reliability concerns and then brush off comments about those concerns as beyond its purview. EPA's response to comments suggests that its 100-hour rule, to the extent that it impacts system reliability, is not "the product of agency expertise." *State Farm*, 463 U.S. at 43.

When asked at oral argument where EPA rooted its authority to regulate engines on the basis of grid reliability, EPA's attorney cited 42 U.S.C. § 7412(d), which instructs EPA to "consider[]" the cost of achieving emission reductions. *Id.* § 7412(d)(2). "Costs" can mean many different things, including the cost associated with increased risk, but it is unclear from the record how EPA weighed those costs here, when it suggested that system reliability was the responsibility of other specialized agencies but then did not seek input from them. On remand, we encourage EPA to solicit input from FERC, as necessary. *Cf. Williams Natural Gas Co. v. FERC*, 872 F.2d 438, 450-51 (D.C. Cir. 1989) (suggesting agency, on remand, solicit new comments to obtain needed information).

VI.

We reverse the challenged rules that contain the 100-hour exemption for emergency engines under the National Emissions Standards, 40 C.F.R. § 63.6640(f)(2), and the Performance Standards, 40 C.F.R. §§ 60.4211(f)(2), 60.4243(d)(2). We remand them to EPA for further action. *See* 42 U.S.C. § 7607(d)(9); *West Virginia*, 362 F.3d at 867. The rest of the 2013 Rule remains in effect.

If vacating these portions of the 2013 Rule will cause administrative or other difficulties, "EPA (or any of the parties to this proceeding) may file a motion to delay issuance of the mandate to request either that the current standards remain in place or that EPA be allowed reasonable time to develop interim standards." *Cement Kiln Recycling Coal.*, 255 F.3d at 872; *see also Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 924 (D.C. Cir. 1998) ("If EPA wishes to promulgate an interim treatment standard, the Agency may file a motion in this court to delay issuance of this mandate in order to allow it a reasonable time to develop such a standard.").

So ordered.

ORAL ARGUMENT HELD SEPTEMBER 26, 2014
PANEL DECISION ISSUED MAY 1, 2015

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL, ET AL.,	)	
PETITIONERS,	)	
v.	)	NOS. 13-1093, 13-1102, 13-1104 (CONSOLIDATED)
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,	)	
RESPONDENT.	)	

RESPONDENT'S MOTION FOR STAY OF MANDATE

Respondent, the United States Environmental Protection Agency ("EPA"), pursuant to Federal Rules of Appellate Procedure and Circuit Rules 27 and 41, respectfully requests that the Court stay issuance of the mandate in this matter until May 1, 2016. Petitioners Conservation Law Foundation and the Delaware Department of Natural Resources and Environmental Control oppose the relief requested in this motion. At the time of filing, undersigned counsel had not been informed as to the positions of Petitioners PSEG Power, LLC, FirstEnergy Solutions Corp., Calpine Corp., or Petitioner-Intervenor Electric Power Supply Association. Intervenor-Respondents American Public Power Association and

Kansas Power Pool support the requested stay. Intervenor-Respondents National Rural Electric Cooperative Association ("NRECA") and Gas Processors ("GPA") take no position on this motion. Intervenor-Respondents EnerNOC, Inc., EnergyConnect, Inc., and Innoventive Power, LLC, support the requested stay (with the caveat that they "reserve the right to contest any legal theories expressed in EPA's motion"), and together with NRECA and GPA have filed a separate motion for a stay of issuance of the mandate.

BACKGROUND

These consolidated petitions for review challenge portions of an EPA rule entitled, "*National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines,*" which was promulgated on January 30, 2013, 78 Fed. Reg. 6674 (Jan. 30, 2013) ("2013 Rule"). The 2013 Rule revises requirements applicable to certain classes of stationary reciprocating internal combustion engines, including revision of a subcategory of "emergency engines" to include reciprocating internal combustion engines that operate for up to 100 hours per year for maintenance checks, readiness testing, emergency demand response, or to address voltage or frequency deviations of greater than five percent below standard.[1] 40 C.F.R. §§ 63.6640(f)(2)(i)-(iii), 60.4211(f)(2)(i)-(iii) and 60.4243(d)(2)(i)-(iii). The 2013 Rule specifies that emergency engines can be used for emergency demand response only if an Energy Emergency Alert Level 2 has been called under standards developed by the North American Electric Reliability Corporation. *See, e.g.*, 40 C.F.R. § 63.6640(f)(2)(ii).

On May 1, 2015, the Court issued a decision in this case concluding that the provisions containing a 100-hour allowance for emergency demand response were arbitrary and capricious. *See Delaware Dep't of Natural Resources & Envtl. Control v. EPA* ("*Delaware*"), 785 F.3d 1, 4–5 (D.C. Cir. 2015). The Court vacated the 100-hour provisions and remanded them to EPA for further action. *See id.* at 18. The Court left in place the remainder of the 2013 Rule. The Court further indicated that if vacatur of these portions of the 2013 Rule would cause "administrative or other difficulties," EPA or other parties to this proceeding could

[1] As relevant to this case, the term "emergency demand response" refers to operation of reciprocating internal combustion engines when called upon by electric grid operators to help alleviate demand on the grid. Previously, in 2010, EPA had modified the definition of "emergency engines" to enable certain engines to operate for up to 15 hours of emergency demand response while maintaining their status as emergency engines. *See* 75 Fed. Reg. 9648, 9677 (Mar. 3, 2010); 40 C.F.R. § 63.6640(f)(4) (2010). More specifically, the 2010 Rule had restricted emergency engines to 100 hours of operation per year for maintenance checks and readiness testing, of which 15 hours could be used for emergency demand response if specified authorities have "determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level." 75 Fed. Reg. at 9677.

"'file a motion to delay issuance of the mandate to request either that the current standards remain in place or that EPA be allowed reasonable time to develop interim standards.'" *Id.* at 18–19 (quoting *Cement Kiln Recycling Coal. v. EPA*, 255 F.3d 855, 872 (D.C. Cir. 2001)); *see also* Docket Entry 1550128 (Judgment).

The Court stayed issuance of the mandate until 7 days after disposition of any timely petition for rehearing or rehearing en banc. Docket Entry 1550130. On May 22, the Court granted EPA's motion for an extension of time until July 15, 2015, to file any petition for rehearing or motion to stay the mandate. Docket Entry 1553910. Simultaneously with this motion for a stay of issuance of the mandate, EPA is filing an unopposed petition for panel rehearing as to the scope of the Court's vacatur order. EPA's petition for panel rehearing seeks an amended Opinion and Judgment clarifying that the 100-hour annual allowances for maintenance checks and readiness testing are not vacated.

ARGUMENT

I. A STAY OF ISSUANCE OF THE MANDATE UNTIL MAY 1, 2016, IS APPROPRIATE TO ENSURE ELECTRIC GRID RELIABILITY, TO ALLOW ENGINES A REASONABLE TIME TO INSTALL CONTROLS, AND TO ALLOW EPA TIME TO EVALUATE THE NEED FOR (AND TO PROMULGATE) A LIMITED FOLLOW-UP RULEMAKING.

Vacatur of the 100-hour per year allowances (i.e., the provisions allowing up to 100 hours per year of emergency demand response operation during a grid operator-declared Energy Emergency Alert Level 2, or during periods when voltage or frequency deviate by five percent or more below standard, 40 C.F.R. §§ 63.6640(f)(2)(ii)-(iii), 60.4211(f)(2)(ii)-(iii) and 60.4243(d)(2)(ii)-(iii)), means that engines operating for purposes of emergency demand response or to address voltage or frequency deviations no longer qualify as "emergency engines" under EPA's regulations, absent further action by EPA on remand.[2] EPA respectfully

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[2] EPA does not interpret this Court's vacatur of the 100-hour provisions within the 2013 Rule to reinstate the provisions within EPA's prior 2010 regulation (see note 1, *supra*) that had previously allowed up to 15 hours per year of emergency demand response. *See, e.g.*, *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 545 (D.C. Cir. 1983) (holding that upon vacatur by the Court of an agency rule, "[t]he better course is generally to vacate the new rule without reinstating the old rule," because "[t]his avoids any problem of the court overstepping its authority, and leaves it to the agency to craft the best replacement for its own rule."); *but see Croplife Am. v. EPA*, 329 F.3d 876, 884–85 (D.C. Cir. 2003) (holding that "the agency's previous practice . . . is reinstated and remains in effect unless and until it is replaced by a lawfully promulgated regulation."). The 2010 15-hour allowance, which was promulgated without notice-and-comment, does not serve as a direct or full replacement for the 2013 Rule's differently-formulated 100-hour allowance. The 2010 allowance was codified in a different subsection of the regulations that has now been entirely replaced (40 C.F.R. § 63.6640(f)(4) (2010)), and was not included in regulations implementing the New Source Performance Standards. Nor does EPA interpret this Court's vacatur of the 100-hour provisions to mean that engines may operate for unlimited periods for emergency demand response and still qualify as emergency engines. Although pre-2010 definitions of "emergency engine" did not include any specific allowances for or prohibitions against emergency demand response operation, those earlier EPA rulemakings provided that emergency engines did not include engines "used to supply power to an electric grid *or that supply power as part of a financial arrangement with another entity*." *See, e.g.*, 71 Fed. Reg. 39,154, 39,180 (July 11, 2006) (New Source Performance Standards for certain stationary compression ignition engines) (emphasis added); 73 Fed. Reg. 3568, 3577 (Jan. 18, 2008) (New Source Performance Standards for certain stationary spark ignition

(continued on next page)

requests a stay of the mandate until May 1, 2016. As set forth below, such a stay is appropriate to ensure electric grid reliability, to allow affected engines a reasonable time to install necessary emission controls, and to allow EPA adequate time to evaluate the need for, and promulgate if appropriate, a follow-up rulemaking on remand.

A. Electric Grid Reliability Concerns Support A Stay of the Mandate Through at Least August 31, 2015.

Issuance of the mandate this summer could threaten electric grid reliability. Specifically, it would result in the likely unavailability of many reciprocating internal combustion engines that have already committed to operate if called upon for purposes of emergency demand response. Such engines would be unavailable because they presently lack the emissions controls required for non-emergency engines. A stay of issuance of the mandate through August 31, 2015, would help to facilitate an orderly transition for independent system operators ("ISOs") and regional transmission organizations ("RTOs") such as PJM Interconnection, LLC ("PJM") that are already relying on stationary reciprocating internal combustion engines to be available for emergency demand response.[3] EPA has conferred with

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engines, and National Emission Standards for Hazardous Air Pollutants for certain new and reconstructed engines).

[3] ISOs and RTOs are federally-regulated entities "responsible for ensuring electric reliability within their regions of responsibility." *Delaware*, 785 F.3d at 11. PJM
(continued on next page)

attorneys in the Office of the General Counsel for the Federal Energy Regulatory Commission ("FERC") regarding the below-described information provided by PJM. *See* Declaration of Melanie King ("King Dec.")) ¶ 21. FERC's Office of General Counsel has advised EPA that FERC supports a stay through August 31, 2015, to facilitate an orderly transition for ISOs and RTOs. *Id.* ¶ 22.

PJM has informed EPA it currently has 10,600 megawatts of demand response resources committed to be available between June 1, 2015, and May 31, 2016,[4] representing approximately six percent of its total available resources for that period. Exhibit ("Ex.") H to King Dec. (June 2, 2015 Letter from PJM) at 1. Of that number, PJM estimates that approximately fourteen percent (i.e., approximately 1,500 megawatts) are reciprocating internal combustion engines without the pollutant emission controls required of non-emergency engines. *Id.* PJM has further informed EPA that vacatur of the allowance for emergency

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coordinates the movement of wholesale electricity in all or parts of several Mid-Atlantic and Midwestern states.

[4] Capacity, which "is not electricity itself but the ability to produce it when necessary," *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009), is procured in PJM through a yearly auction, three years in advance of when it may be needed. As this Court has explained, capacity markets such as PJM's amount "to a kind of call option that electricity transmitters purchase from . . . generators who can either produce more or consume less when required." *Id.*

demand response in mid-summer[5] "would cause [it] to lose these demand response resources [i.e., approximately 1,500 megawatts] with no realistic means to replace that capacity in the midst of the summer months." *Id.* at 2. PJM further stated that it seeks "to avoid significant disruptions or new operating rules during the summer months as this is a period when all resources are needed should we see multiple days of hot weather in our footprint as we have seen in past years." *Id.* In light of these issues, PJM concluded that issuance of the mandate this summer would be "disruptive," *id.* at 3, and that "[i]ssuance of the mandate after the summer season and before winter (i.e., September 1-November 30) would allow for a more orderly transition" ahead of the winter portion of its 2015/2016 planning year, *id.* at 2.[6]

In addition, vacatur this summer of the allowances for emergency engines to operate in situations where frequency or voltage deviates by five percent or more from standard may adversely affect local grid reliability in some areas of the country. *See, e.g.*, Ex. I to King Dec. (June 19, 2015 Memorandum from Counsel for American Public Power Association) at 2 (summarizing comments from the

[5] PJM's letter refers to vacatur occurring "in the third week in June," the original deadline for any petitions for rehearing or motions to stay the mandate in this matter. The same considerations would apply to vacatur occurring the third week in July, still mid-summer.

[6] Although PJM also stated in its letter that demand response resources "were helpful to PJM in maintaining reliability during extreme weather events such as the Polar Vortex conditions experienced in the winter of 2014," Ex. H to King Dec. at 2, its primary focus was on the availability of emergency engines this summer.

Missouri Joint Municipal Electric Utility Commission that upon vacatur, "a number of communities will be in a position where they will watch voltages drop in the summer until the distribution system collapses," at which point they intend to operate reciprocating internal combustion engines "until their supplier can get the system stabilized"). Moreover, as described below, such local grid reliability concerns would extend beyond just the summer months, warranting an even longer stay.

In sum, electric grid reliability considerations alone support a stay of the issuance of the mandate through at least August 31, 2015. As discussed below, however, a longer stay is warranted in light of additional important considerations (i.e., the time needed for engines to install appropriate controls, and for EPA to consider potential follow-on rulemakings).

B. A Stay of Issuance of the Mandate Until May 1, 2016, Would Allow Operators of Affected Engines Electing to Install the Controls a Reasonable Amount of Time to Do So.

While a stay through August 31, 2015, would alleviate near-term threats to electric grid reliability resulting from the Court's vacatur order, a stay of only that duration would not allow sufficient time for installation of emissions controls on affected engines. *See* King Dec. ¶¶ 11, 19. In light of the Court's May 1, 2015 decision, operators of engines that are used for purposes of emergency demand response will need to determine whether to install the controls required of non-emergency engines so as to be able to continue such operation. Operators electing to install controls should be afforded a reasonable time to do so, particularly in view of the fact that operators participating in certain capacity markets have already committed for these engines to be available for such use. As set forth in detail in the attached Declaration of Melanie King, EPA has determined that installation time would vary widely according to a particular engine's location and owner, but in many cases could take up to a year or longer. King Dec. ¶¶ 11–19. For public entities such as municipalities, budget approval processes and other regulatory issues significantly lengthen the time needed to install controls. *Id.* ¶¶ 13–14, 16, 18. To afford engine operators a reasonable amount of time to install controls, EPA requests a stay of issuance of the mandate until May 1, 2016.

A stay until May 1, 2016, would be less than one-third of the time that EPA ordinarily allows for operators of these types of existing sources to come into compliance with newly-promulgated regulations. *See* 42 U.S.C. § 7412(i)(3) (authorizing EPA to establish compliance dates as expeditiously as practicable, but not more than three years after effective date the standard); *see, e.g.*, 75 Fed. Reg. 9648, 9675 (Mar. 3, 2010) (mandating that certain existing engines comply with the newly-promulgated emissions limitations within three years of the regulation's effective date). The allowances for emergency demand response and to address voltage or frequency deviations have now been in effect for more than two years, and the regulated community has reasonably relied on those provisions.

While the requested stay until May 1, 2016, will not be sufficient to allow operators of engines participating in three-year forward capacity markets such as PJM's to operate without required non-emergency engine controls if called upon during the entire three-year period during which they have already committed to be available, it will allow a reasonable amount of time for those and other operators to install the required controls if they so choose. The requested stay would also allow time for capacity resource markets to adjust to the potential loss of capacity resources represented by engines that choose not to install controls. Thus, EPA believes that it would be a reasonable exercise of the Court's equitable discretion to stay issuance of the mandate until May 1, 2016, to allow operators of affected engines a reasonable time to come into compliance with any newly-applicable requirements and for capacity markets to adjust to the potential loss of demand response resources.

This Court has previously recognized that a stay of the mandate may be appropriate where a transition period is required after existing regulations have been vacated. *Cement Kiln Recycling Coalition*, 255 F.3d at 872; *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 924 (D.C. Cir. 1998); *see also Natural Res. Defense Council v. EPA*, D.C. Cir. Case No. 98-1379, Docket Entry 1520402 (per curiam order granting EPA's motion, Docket Entry 1512351 (Sept. 15, 2014), for a six-month stay of mandate to allow time for facilities to come into compliance with Resource Conservation and Recovery Act and Clean Air Act requirements following the Court's vacatur of a regulatory exclusion). Here, delaying issuance of the mandate until May 1, 2016, would allow operators of engines a reasonable period of time within which to install the appropriate emissions controls.

Additionally, EPA does not believe that the requested stay will result in adverse impacts to the environment or public health. King. Dec. ¶ 24. A stay of issuance of the mandate for the requested period would not necessarily mean that any emergency engines would actually operate for emergency demand response or voltage/frequency deviation purposes. While an extension of time would allow for the *potential* operation of these engines if the criteria specified in EPA's regulations at 40 C.F.R. §§ 63.6640(f)(2)(ii)–(iii) are satisfied (i.e., an Energy Emergency Alert Level 2 declared by the grid operator, or when there is a "deviation of voltage or frequency of 5 percent or greater below standard"), any such operation would likely be of very limited duration (i.e., a matter of hours) and limited to specific geographic areas. *See* King Dec. ¶ 24; *see also* Docket Entry 1492405 (EPA Merits Brief) at 19–20 ("[o]n the infrequent occasions when emergency demand response resources are dispatched, it is usually only in specified areas and for relatively short periods of time"). Thus, for the reasons explained above, EPA believes it is in the public interest for the Court to grant a stay of issuance of the mandate until May 1, 2016.

C. A Stay of Issuance of the Mandate Until May 1, 2016, Would Allow EPA a Reasonable Time to Evaluate the Need For – and Potentially Promulgate – a Rule Allowing Operation of Emergency Engines to Address Voltage or Frequency Deviations.

A stay of issuance of the mandate until May 1, 2016, is also warranted to allow EPA a reasonable time to evaluate the need for – and potentially promulgate – a rule allowing operation of emergency engines to address voltage or frequency deviations. The Court's vacatur of the provisions allowing for operation of emergency engines in circumstances where voltage or frequency deviates five percent or more from standard could adversely impact local grid reliability in certain areas of the country. The requested stay of issuance of the mandate would allow EPA a reasonable time to evaluate the propriety of a rulemaking to reinstate an allowance for that type of operation, and, if warranted, to promulgate such a rule through the notice-and-comment process.[7]

The purpose of the voltage and frequency deviation provisions is to allow for use of emergency engines (particularly those operated by small municipalities or in geographically isolated areas) to stabilize the grid in the event of voltage or

[7] If the Court denies EPA's petition for panel rehearing as to the maintenance check and readiness testing provisions at subsections (i) of the regulations, the time needed for EPA to reinstate regulations allowing such operation would serve as an additional ground for the requested stay of issuance of the mandate.

frequency drops, typically caused by severe weather events. *See* Joint Appendix 1929 (Kansas Power Pool Comments, attached hereto as Ex. 1) at 1931–32 (explaining that in remote locations across Kansas, backup engines are the sole resources available to respond to voltage or frequency drops, since "there is no redundancy" in the form of larger or more efficient power plants); Joint Appendix 1453 (American Public Power Association Comments, excerpt attached hereto as Ex. 2) at 1474–77 ("[a]t the distribution system level, a utility is acting to prevent equipment damage when it responds to low voltage conditions"). Petitioners' capacity market-focused arguments were not addressed to such operation. Nor are the Court's stated grounds for reversal relevant to such operation. *See Delaware*, 785 F.3d at 13 (describing four capacity market-related issues as grounds for reversal). Leaving in place the voltage and frequency deviation provisions during the requested stay would help to ensure that rural communities and small municipal systems are able to address power quality issues and maintain system reliability during periods of severe grid instability, but will not have any adverse impacts on organized capacity markets.

In a recent letter to EPA, Intervenor-Respondent Kansas Power Pool reiterated that engines operated by its members are used to address unexpected voltage degradation resulting from stress on the grid. Ex. J to King Dec. (June 12, 2015 letter from counsel for Kansas Power Pool) at 2. Kansas Power Pool further stated in this letter that, if the voltage or frequency deviation provisions were vacated, the unavailability of these engines as resources for local reliability coordinators (due to a lack of the controls needed to operate non-emergency engines) would result in more frequent blackouts in the rural areas served by its members. *Id.* EPA understands that Kansas Power Pool intends to file a separate motion for stay of issuance of the mandate to elaborate on these issues. A stay of issuance of the mandate until May 1, 2016 would allow EPA a reasonable time to evaluate the need for further rulemaking to address these issues, while maintaining the status quo so as not to threaten local grid reliability.

CONCLUSION

EPA respectfully requests that the Court stay issuance of the mandate until May 1, 2016.

DATED: July 15, 2015

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing Respondent's Motion for Stay of Mandate was electronically filed with the Clerk of the Court using the CM/ECF system, which will send notification of said filing to the attorneys of record for Petitioners and all other parties who have registered with the Court's CM/ECF system.

Date: July 15, 2015

/s/ Austin D. Saylor
Austin D. Saylor
Counsel for Respondent

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 13-1093 | **September Term, 2014**

Filed: May 1, 2015
Amended: July 21, 2015

DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL,
PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY,
RESPONDENT

ELECTRIC POWER SUPPLY ASSOCIATION, ET AL.,
INTERVENORS

Consolidated with 13-1102, 13-1104

MANDATE
Fed. R. App. Pro.41
ISSUED: 05/04/2016
BY:
ATTACHED: Amending Order
Opinion
Order on Costs

On Petitions for Review of A Final Rule Promulgated
by the United States Environmental Protection Agency

Before: GARLAND, *Chief Judge*, WILLIAMS and RANDOLPH, *Senior Circuit Judges.*

AMENDED JUDGMENT

These causes came on to be heard on the petitions for review of a Final Rule Promulgated by the United States Environmental Protection Agency and were argued by counsel. On consideration thereof, and in accordance with the opinion of the court filed herein this date and amended on July 21, 2015, it is

ORDERED and **ADJUDGED** that the petitions for review be granted except that the portion of Delaware's petition for review in No. 13-1093, challenging the exemption from emissions controls for backup generators be dismissed for lack of standing. The challenged rules that contain the 100-hour exemption for operation of emergency engines for purposes of emergency demand response under the National Emissions Standards, 40 C.F.R. § 63.6640(f)(2)(ii)-(iii), and the Performance Standards, 40 C.F.R. §§ 60.4211(f)(2)(ii)-(iii), 60.4243(d)(2)(ii)-(iii), be reversed and remanded to EPA for further action. The rest of the 2013 Rule remains in effect. If vacatur of portions of the 2013 Rule cause administrative or other difficulties, EPA or the parties to this proceeding may file a motion to delay issuance of the mandate.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Ken Meadows
Deputy Clerk

Date: July 21, 2015

Opinion for the court by Senior Circuit Judge Randolph.

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 13-1233 **September Term, 2015**

EPA-78FR6674
EPA-79FR48072

Filed On: September 23, 2015

Conservation Law Foundation, et al.,

Petitioners

v.

Environmental Protection Agency,

Respondent

Electric Power Supply Association, et al.,
Intervenors

Consolidated with 14-1199

BEFORE: Henderson, Rogers, and Pillard, Circuit Judges

ORDER

Upon consideration of the motion for voluntary remand without vacatur, the responses thereto, the reply, and the motion for a stay of the briefing schedule pending the court's decision regarding EPA's motion for remand, it is

ORDERED that the motion for voluntary remand without vacatur be granted and that the record be remanded for further proceedings in light of Delaware Department of Natural Resources and Environmental Control v. EPA, 785 F.3d 1 (D.C. Cir. 2015). The parties are directed to file status reports within 90 days of the date of this order and at 90-day intervals thereafter. The parties are further directed to file motions to govern future proceedings within 30 days after completion of the proceedings on remand. It is

FURTHER ORDERED that the motion for a stay of the briefing schedule pending the court's decision regarding EPA's motion for remand be dismissed as moot.

Per Curiam

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« Back DC Circuit Vacates Portions of EPA's Emergency Generator Rule

September 4, 2015

Earlier this summer, the United States Court of Appeals for the District of Columbia Circuit issued a decision granting in part and denying in part petitions for review of a final rule promulgated by the United States Environmental Protection Agency (EPA) that set operating parameters for emergency generators. *Del. Dep't of Natural Res. & Envtl. Control v. EPA*, 785 F.3d 1 (D.C. Cir. 2015). The rules are titled "National Emissions Standards for Hazardous Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE)" and "New Source Performance Standards for Stationary Internal Combustion Engines." *See* 40 C.F.R. Pt. 63, Subpt. ZZZZ (National Emission Standards); 40 C.F.R. Ch. I, Subch. C., Pt. 60, Subpt. IIII & JJJJ (Performance Standards).

In general, the RICE standards permit existing emergency generators to operate without emissions controls, as long as they adhere to certain operational restrictions. For example, generators could operate for 100 hours per year for any combination of the following:

- Maintenance or testing.
- Emergency demand response in situations when a blackout is imminent, meaning that either the reliability coordinator has declared an Energy Emergency Alert Level 2 as defined in the North American Reliability Corporation (NERC) Reliability Standard or there is a deviation of voltage or frequency of 5% or greater below standard voltage or frequency.
- Fifty hours of this 100 hours per year allocation can be used for:
  - Non-emergency situations, as long as there is no financial arrangement calling for the operation.
  - Local reliability as part of a financial arrangement with another entity if specific criteria are met (existing RICE at area sources of HAP only).

- Peak shaving until May 3, 2014 (existing RICE at area sources of HAP only) if it is part of a peak shaving (load management) program with the local distribution system operator and the power is provided only to the facility or to support the local distribution system.

Soon after the EPA published the final rule, the Delaware Department of Natural Resources and Environmental Control challenged the regulations in United States Court of Appeals for the District of Columbia Circuit. A number of environmental groups and an industry organization intervened in support of Delaware's challenge, while a number of trade associations and corporations intervened in support of the EPA. Delaware's principle objection challenged the provisions of the National Emission Standards and the Performance Standards that would allow generators to run for up to 100 hours of "emergency demand-response" in situations where a blackout is imminent. The court agreed and held that the EPA's modification of these standards "to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program" was arbitrary and capricious. 785 F.3d at 10.

In overruling these provisions, the court was persuaded that the EPA's revisions, which raised emergency demand-response operating times from 15 to 100 hours, were "radical" and unwarranted for three reasons:

1. The court found that the EPA had not adequately addressed concerns raised during the regulatory comment period that the demand-response exemption would negatively impact overall grid reliability. Those comments argued the following points:
   - Backup generators cost considerably less than conventional power plants (known as "load-serving entities") because they are and would not be subject to the same strict and expensive pollution controls. This competitive advantage would enable these "dirtier" sources to underbid conventional power suppliers in capacity markets.
   - By permitting the increased use of backup generators, the demand for traditional power in capacity markets decreases. This forces traditional power generators to use backup generators themselves to recoup costs and to underinvest in the maintenance of existing units or the construction of new units. This chronic underinvestment would eventually undermine the reliability of the power grid.
   - As the reliability of the grid decreases, power emergencies will increase, requiring the increased use of "dirty" backup generators that will cause greater pollution.

   The court criticized the EPA for failing to adequately consider these comments, for relying on "faulty evidence" to increase the demand-response exemption and for failing to seek the input of the federal agencies responsible for maintaining the reliability of the electricity grid (i.e., FERC and NERC). According to the court, the EPA's failure to respond to these serious objections was arbitrary and capricious.

2. The court criticized the EPA's reliance on a comment submitted by a regional transmission organization — PJM Interconnection, LLC (PJM) — from a prior rulemaking in 2011. In the prior rulemaking, PJM stated that its demand-response program required engines to be available for a minimum of 60 hours per year and that the EPA's old 15-hour exemption would not allow generator owners to meet its program requirements. In 2012, PJM submitted additional comments to clarify its position and stated that its 60-hour minimum did not apply to individual engines but allowed for aggregation of engines to meet the availability requirement. The court found the EPA either "intentionally discounted" PJM's 2012 comments or confused PJM's later comments with those submitted in 2011. Either way, the court reasoned that the EPA's actions were arbitrary and capricious.

3. The court found that the EPA had not adequately responded to comments that the 100-hour exemption should be limited to areas of the country that were not served by capacity markets. According to the court, the EPA had brushed off these comments and provided only cursory justification dressed as a "vague desire for uniformity." This manner of addressing this comment "too cavalierly sidestepped its responsibility to address reasonable alternatives" and was again arbitrary and capricious.

After performing this analysis, the court reversed and remanded the rules containing the 100-hour exemption for emergency generators under the National Emission Standards and the Performance Standards. However, the court left the remainder of the 2013 rule in effect.

The saga does not end with the court's remand. Other provisions of the rule were also challenged — namely, the 50-hour exemption for non-emergency use. The EPA sought from the court and, on August 14, 2015, was granted until May 1, 2016, to conduct an administrative review of the 50-hour exemption. Some estimate that there are more than 12 million emergency generators. Thus, the court's decision, the impending mandate, and the EPA's reconsideration of its exemptions will have a far reaching impact on the operation of these units.

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D.C. Circuit reverses 100-hour exemption for backup generators

USA | May 11 2015

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit struck down the 100-hour exemption from air pollution controls that EPA granted to emergency backup generators in 2013. The unanimous decision in *Delaware Department of Natural Resources v. EPA* affects the use of backup generators, which often run on diesel fuel, to reduce consumption of electric energy from the grid during times of high pricing and heavy loading, but it leaves untouched the use of backup generators in remote, low density areas, during emergency situations, or for routine testing and maintenance. *See Delaware Department of Natural Resources v. EPA* No. 13-1093, (D.C. Cir. 2015).

The court found that EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards for stationary internal combustion engines to allow backup generators to operate for up to 100 hours per year without emissions controls as part of an emergency demand-response program. The court remanded the rule to EPA for further action, but the mandate will not take effect until seven days after the disposition of any petition for rehearing.

Rulemaking

The reciprocating internal combustion engine ("RICE") rule promulgated by EPA in 2013 allowed backup generators to operate without emissions controls for 100 hours per year as part of a demand-response program, whereby consumers use backup generators to reduce their consumption of electric energy from the grid during times of high demand and high pricing. EPA promulgated this rule in response to petitions for reconsideration following a 2010 rule that initially allowed for a 15-hour exemption. The larger exemption window was supported by aggregators of generator power who have, as the court explained, "adopted the practice of grouping backup generators together to form 'virtual power plants' of considerable size" that are not subject to costly emissions controls and are therefore able to produce electricity at cheaper rates. Electric generators and environmental groups, however, objected during the rule's notice and comment period and argued that the 100-hour exemption would incent "behind-the-meter generation," resulting in greater air emissions and threatening the reliability of power grid by distorting the capacity markets.

Arbitrary and Capricious

The court held that EPA's promulgation of the 100-hour exemption was arbitrary and capricious for four reasons. First, the agency failed to properly respond to petitioners' "well-founded concerns" regarding the negative consequences the exemption would have on the efficiency and reliability of the energy markets, with EPA giving only "wan responses" to such concerns. In fact, EPA's response to these comments focused on a perceived concern of the rule's potential to encourage the use of backup generators in place of cleaner alternative energy sources. In this regard, the Court stated that EPA "missed the forest for the trees: the overriding concern of these comments was the perverse effect the 100-hour exemption would have on the reliability and efficiency of the capacity and energy markets, not the specific clean energy alternatives that could supply the grid instead of backup generators." Second, EPA relied on faulty evidence when justifying the 100-hour exemption: it assumed that 100 hours were needed for backup generators to participate in demand-response programs, when the operator of the largest program—and the one that the exemption was designed to address—made clear that no individual engine needed to operate for that long to participate. Third, EPA did not consider an alternative to applying the rule nationwide, despite suggestions toward this end from various commenters on the draft rule, who suggested that EPA only apply the exemption where organized capacity markets were not available to otherwise assure that reliability would be maintained. And fourth, EPA did not consult with either the Federal Energy Regulatory Commission (FERC) or the North American Electric Reliability Corporation (NERC) regarding the grid reliability considerations, which was a source of justification for EPA's exemption, even though FERC is the federal entity actually responsible for reliability of the electric grid and NERC is FERC's designated electric reliability organization.

Who Will Be Affected

The reversal of the 100-hour exemption will most affect those using backup generators during peak times to provide demand response—including non-utilities like large commercial or industrial customers who have depended on the exemption to reduce their power costs—and aggregators who bid demand response as capacity resources in Base Residual Auctions based upon the presumed availability of backup generators. The decision will not affect the use of backup generators during emergencies or routine maintenance. It also will not affect those who operate backup generators pursuant to the 2013 rule's 50-hour exemption for "non-emergency" demand-response, a provision allowing backup generators to be used for 50 hours per year without emissions controls when such operation is deemed necessary to mitigate local transmission or distribution limitations that could lead to an interruption of power supply. This 50-hour exemption is currently being litigated separately in the D.C. Circuit (*Conservation Law Foundation v. EPA*, No. 13-1233 (D.C. Cir.)). Lastly, for now the Court left intact the operation of backup generators in remote, low density areas, such as engines located offshore or along remote oil and gas pipelines.

Within days of the issuance of this decision, the U.S. Supreme Court granted cert to hear a case that also significantly affects the future of demand-response programs and distributed generation. The Court will hear the appeal of a D.C. Circuit decision that struck down FERC Order No. 745, which established certain rules accepted by FERC that governed demand response in wholesale power markets, on the grounds that FERC lacked authority to regulate those transactions. Supporters of demand-response programs hailed the Supreme Court's action and have warned that the wholesale markets would be disrupted and distributed generation will be thwarted if the D.C. Circuit's decision rejecting FERC's rules was not overturned. The Supreme Court stated it will consider two issues: (i) whether FERC reasonably concluded that it has authority to regulate demand response in wholesale markets and (ii) whether the D.C. Circuit erred when it concluded that FERC acted arbitrarily and capriciously in requiring that demand-response providers be paid similarly to generators.

Timing of Reversal

In reversing the 100-hour exemption, the court instructed that "[i]f vacating these portions of the 2013 Rule will cause administrative or other difficulties, 'EPA (or any of the parties to this proceeding) may file a motion to delay issuance of the mandate to request either that the current standards remain in place or that EPA be allowed reasonable time to develop interim standards.'" The court also stayed the mandate until seven days after disposition of any petition for rehearing. Petitions for panel rehearing and rehearing *en banc* must be filed within 45 days of the court's judgment. Assuming such a petition were filed, then it could be several months before the reversal actually takes effect.

Paul Hastings LLP - Lisa K. Rushton, William D. DeGrandis and Daniel Liebowitz

Appendix D
Supporting Documents Associated with 40 CFR Part 60 Subpart IIII, 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ
Summary of Compliance Criteria for Stationary Engines

A request for a simple, precise summary of the minimum compliance requirements, specifically in regard to emission limits from a non-emergency engine, was made by the Council. Unfortunately, federal regulations on the operation of stationary internal combustion engines and stationary reciprocating internal combustion engines outlines are very complex, and are based on the engine's location, construction date, size, type/fuel type (compression ignition or spark ignition) and application (emergency, non-emergency or fire pump).[D1] In addition,[D2] the D.C. Circuit Court of Appeals found that the EPA acted arbitrarily and capriciously when it allowed the operation of emergency engines in DR programs for up to 100 hours per year[D3]. And finally, the issue surrounding the 50-hours of non-emergency operation in remote locations remains unresolved.[D4]

When taking this all into consideration: initial complexity of federal regulations, recent amendments, the court decision overturning the EPA's allowance of 100 hours of emergency engine operation in the DR program, and the unresolved issue of 50-hours of non-emergency operation, there is no simple summary which outlines the emissions criteria. The EPA provides a number of resources, including menu driven guidance, to be used in determining the specific compliance requirements and permit limitations for a specific engine.

https://www.epa.gov/stationary-engines/compliance-requirements-stationary-engines

1. EPA Compliance Requirements for Stationary Engines Links and Summary Tables.
2. EPA Guidance and Tools for Implementing Stationary Engine Requirements Links.
3. EPA Tier Emission Standards – titled "Nonroad Compression-Ignition Engines: Exhaust Emission Standards"
4. EPA Rule Link and Fact Sheet: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines.
5. EPA Implementation Tools Link: NESHAP for Reciprocating Internal Combustion Engines.
6. EPA Rule Link and Fact Sheet: New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines.
7. Implementation Tools: NSPS for Compression Ignition Internal Combustion Engines.
8. EPA Rule Link and Fact Sheet: New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines.
9. EPA Implementation Tools Link: NSPS for Spark Ignition Internal Combustion Engines.
10. EPA's Air Quality Regulations for Stationary Engines. Melanie King, U.S. Environmental Protection Agency. June 18, 2014.

[D1] https://www.epa.gov/stationary-engines/compliance-requirements-stationary-engines
[D2] https://www.regulations.gov/searchResults?rpp=25&po=0&s=epa%2Bhq%2Boar%2B2008%2B0708&fp=true&ns=true
[D3] http://www.lawandenvironment.com/wp-content/uploads/sites/5/2015/05/13-1093-1550129.pdf
[D4] https://www.courtlistener.com/docket/4155384/conservation-law-foundation-v-epa/

United States Environmental Protection Agency

Compliance Requirements for Stationary Engines

On this page:

RICE Rule requirements are complex – but they are similar for several groups of engines, as summarized in the tables below.

Key Definitions for Terms Used in Compliance Summary Tables

- **CI**: Compression Ignition (diesel)
- **SI**: Spark Ignition (gas including natural gas, landfill gas, gasoline, propane, etc.)
- **2SLB**: 2-stroke lean burn
- **4SLB**: 4-stroke lean burn
- **4SRB**: 4-stroke rich burn
- **4S**: 4-stroke
- **LFG/DG**: landfill gas/digester gas
- **ULSD**: Ultra Low Sulfur Diesel

Notes:

- 2-stroke: power cycle completed in 1 revolution of crankshaft
- 4-stroke: power cycle completed in 2 revolutions of crankshaft
- Lean burn: higher air/fuel ratio (fuel-lean)
- Rich burn: lower air/fuel ratio (fuel-rich)

Compliance Requirements by Engine Subcategory

Engine Subcategory	Compliance Requirements

<table>
<tr><td>Existing non-emergency:
CI ≥100 HP at major source
CI >300 HP at area source
SI 100-500 HP at major source</td><td>Initial emission performance test
Subsequent performance testing every 8,760 hours of operation or 3 years for engines >500 HP (5 years if limited use)
Operating limitations - catalyst pressure drop and inlet temperature for engines >500 HP
Notifications
Semiannual compliance reports (annual if limited use)
Existing non-emergency CI >300 HP:
Ultra low sulfur diesel (ULSD)
Crankcase emission control requirements</td></tr>
<tr><td>Existing non-emergency SI 4SLB/4SRB >500 HP at area source used >24 hours/year and not in remote area</td><td>Initial and annual catalyst activity checks
High temperature engine shutdown or continuously monitor catalyst inlet temperature
Notifications
Semiannual compliance reports</td></tr>
</table>

Engine Subcategory	**Compliance Requirements**

Existing emergency/black start: • <100 HP at major source • ≤500 HP at major source • All at area source Existing non-emergency: • <100 HP at major source • CI ≤300 HP at area source • SI ≤500 HP at area source • SI 2SLB >500 HP at area source • SI LFG/DG >500 HP at area source • SI 4SLB/4SRB >500 HP at area source used ≤24 hours/year or in remote area	• Operate/maintain engine & control device per manufacturer's instructions or owner-developed maintenance plan • May use oil analysis program instead of prescribed oil change frequency • Emergency engines must have hour meter and record hours of operation • Keep records of maintenance • Notifications not required • Reporting and ULSD for emergency engines used for local reliability

Engine Subcategory	**Compliance Requirements**

Existing non-emergency:
 	
• SI 4SRB >500 HP at major source
 	
New non-emergency:
 	
• SI 2SLB >500 HP at major source
• SI 4SLB >250 HP at major source
• SI 4SRB >500 HP at major source
• CI >500 HP at major source
	• Initial emission performance test
	  ◦ Subsequent performance testing semiannually (can reduce frequency to annual) (subsequent performance testing required for 4SRB engine complying with formaldehyde % reduction standard if engine is ≥5000 HP)
	  ◦ Operating limitations - catalyst pressure drop and inlet temperature
	  ◦ Notifications
	  ◦ Semiannual compliance reports

Engine Subcategory	Compliance Requirements
• New emergency/limited use >500 HP at major source	• Initial notification
• New non-emergency LFG/DG >500 HP at major source	• Initial notification • Monitor/record fuel usage daily • Annual report of fuel usage

Emission Standards: Existing RICE at Major Sources

HP	Engine Subcategory					
	Non-emergency					Emergency
	CI	SI 2SLB	SI 4SLB	SI 4SRB	SI LFG/DG	
<100	Change oil and filter and inspect cleaner (CI) or spark plugs (SI) every 1,000 hours of operation or annually; inspect hoses and belts every 500 hours of operation or annually					Change oil/filter & inspect hoses/belts every 500 hours or annually; inspect air cleaner (CI) or spark plugs (SI) every 1,000 hours or annually
100-300	230 ppm CO					
300-500	49 ppm CO or 70% CO reduction	225 ppm CO	47 ppm CO	10.3 ppm CH_2O	177 ppm CO	
>500	23 ppm CO or 70% CO reduction	No standards	No standards	350 ppb CH_2O or 76% CH_2O reduction	No standards	No standards

Note: Existing limited use engines >500 HP at major sources do not meet any emission standards. Existing black start engines ≤500 HP at major sources must meet work practice standards.

Emission Standards: Existing RICE Located at Area Sources

<table>
<tr><th rowspan="3">HP</th><th colspan="6">Engine Subcategory</th></tr>
<tr><td colspan="5">Non-emergency</td><td rowspan="2">Emergency or Black Start</td></tr>
<tr><td>CI</td><td>SI 2SLB</td><td>SI 4S in remote areas</td><td>SI 4S not in remote areas</td><td>SI LFG/DG</td></tr>
<tr><td>≤300</td><td>Change oil/filter & inspect air cleaner every 1,000 hours or annually; inspect hoses/belts every 500 hours or annually</td><td rowspan="2">Change oil/filter, inspect spark plugs, & inspect hoses/belts every 4,320 hours or annually</td><td rowspan="2">Change oil/filter, inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually</td><td rowspan="2">Change oil/filter, inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually</td><td rowspan="2">Change oil/filter, inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually</td><td rowspan="2">Change oil/filter & inspect hoses/belts every 500 hours or annually; inspect air cleaner (CI) or spark plugs (SI) every 1,000 hours or annually</td></tr>
<tr><td>300-500</td><td>49 ppm CO or 70% CO reduction*</td></tr>
</table>

<table>
<tr><td>>500</td><td>23 ppm CO or 70% CO reduction</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Emission Standards: New RICE Located at Major Sources

<table>
<tr><th rowspan="3">HP</th><th colspan="6">Engine Subcategory</th></tr>
<tr><td colspan="5">Non-emergency</td><td rowspan="2">Emergency</td></tr>
<tr><td>CI</td><td>SI 2SLB</td><td>SI 4SLB</td><td>SI 4SRB</td><td>SI LFG/DG</td></tr>
<tr><td><250</td><td rowspan="2">Comply with CI NSPS</td><td rowspan="2">Comply with SI NSPS</td><td>Comply with SI NSPS</td><td rowspan="2">Comply with SI NSPS</td><td rowspan="2">Comply with SI NSPS</td><td rowspan="2">Comply with CI/SI NSPS</td></tr>
<tr><td>250-500</td><td rowspan="2">14 ppm CH_2O or 93% CO reduction</td></tr>
<tr><td>>500</td><td>580 ppb CH_2O or 70% CO reduction</td><td>12 ppm CH_2O or 58% CO reduction</td><td>350 ppb CH_2O or 76% CH_2O reduction</td><td>No standards</td><td>No standards</td></tr>
<tr><td colspan="7">Note: New limited use engines >500 HP at major sources do not meet any emission standards under the NESHAP</td></tr>
</table>

<table>
<tr><th>New RICE Located at Area Sources: meet Stationary Engine NSPS</th></tr>
<tr><td>• CI: part 60 subpart IIII
• SI: part 60 subpart JJJJ</td></tr>
</table>

Determining RICE New Source Performance Standards (NSPS) Compliance Requirements

The NSPS rules include two alternative compliance approaches:

1. Operators comply by purchasing an engine certified by the manufacturer.
2. For spark ignition engines, operators comply by meeting emission limits for an engine not certified by the manufacturer.

If you own or operate a Compression Ignition engine you are subject to the NSPS at 40 CFR 60, Subpart IIII if the engine was*:*

- Constructed (ordered) after July 11, 2005, and manufactured after April 1, 2006 (July 1, 2006 for fire pump engines), or
- Modified or reconstructed after July 11, 2005.
- Except for engines > 30 liters per cylinder (l/cyl) displacement, performance testing is not required - you achieve compliance by:
  - purchasing a new engine that has been certified by EPA, and
  - installing, configuring, operating, and maintaining the engine per the manufacturer's instructions.

If you own or operate a Spark Ignition engine you are subject to the NSPS at 40 CFR 60, Subpart JJJJ if the engine was:

- Constructed (ordered) after 6/12/2006 and the engine is
  - >500 HP manufactured on/after 7/1/2007 (except lean burn 500≤HP<1,350)
  - lean burn 500≤HP<1,350 manufactured on/after 1/1/2008
  - <500 HP manufactured on/after 7/1/2008
  - emergency >25 HP manufactured on/after 1/1/2009
  - modified/reconstructed after 6/12/2006.
- For certain Spark Ignition engines manufactured on/after July 1, 2008, the engine manufacturer is required to certify that the engine meets emission limits. As the owner or operator of the engine you can comply by purchasing a certified engine, and operating it according to manufacturer's instructions. These SI engine types include:
  - ≤ 25 HP,
  - gasoline engines >25 HP, and
  - rich burn LPG engines >25 HP.
- For other Spark Ignition engines, EPA made it optional for the manufacturer to certify that their engines meet the applicable emission limits. Owners or operators can comply either by purchasing an engine that the manufacturer has voluntarily certified, or by conducting performance testing to demonstrate that the engine meets the applicable emission limits.

Related Information

- EPA Regional RICE NESHAP Contacts
- Regulatory Actions for Stationary Engines

- Tools to Help You Comply

LAST UPDATED ON OCTOBER 5, 2016

Guidance and Tools for Implementing Stationary Engine Requirements

Below are tools and guidance documents to help you comply with the stationary engines rules.

- **National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines**
  - Regulation Navigation Tool
  - Example Forms
  - Summary Tables
  - Webinars and Presentations
  - Videos
  - Other Guidance Documents

- **New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines**
  - Regulation Navigation Tool
  - Example Forms
  - Summary Tables
  - Videos
  - Other Guidance Documents

- **New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines**
  - Regulation Navigation Tool
  - Example Forms
  - Summary Tables
  - Videos
  - Other Guidance Documents

LAST UPDATED ON AUGUST 4, 2016

Nonroad Compression-Ignition Engines: Exhaust Emission Standards

	Rated Power (kW)	Tier	Model Year	NMHC (g/kW-hr)	NMHC + NOx (g/kW-hr)	NOx (g/kW-hr)	PM (g/kW-hr)	CO (g/kW-hr)	Smoke [a] (Percentage)	Useful Life (hours /years) [b]	Warranty Period (hours /years) [b]
Federal	kW < 8	1	2000-2004	-	10.5	-	1.0	8.0	20/15/50	3,000/5	1,500/2
		2	2005-2007	-	7.5	-	0.80	8.0			
		4	2008+	-	7.5	-	0.40 [c]	8.0			
	8 ≤ kW < 19	1	2000-2004	-	9.5	-	0.80	6.6		3,000/5	1,500/2
		2	2005-2007	-	7.5	-	0.80	6.6			
		4	2008+	-	7.5	-	0.40	6.6			
	19 ≤ kW < 37	1	1999-2003	-	9.5	-	0.80	5.5		5,000/7 [d]	3,000/5 [e]
		2	2004-2007	-	7.5	-	0.60	5.5			
		4	2008-2012	-	7.5	-	0.30	5.5			
			2013+	-	4.7	-	0.03	5.5			
	37 ≤ kW < 56	1	1998-2003	-	-	9.2	-	-		8,000/10	3,000/5
		2	2004-2007	-	7.5	-	0.40	5.0			
		3 [f]	2008-2011	-	4.7	-	0.40	5.0			
		4 (Option 1) [g]	2008-2012	-	4.7	-	0.30	5.0			
		4 (Option 2) [g]	2012	-	4.7	-	0.03	5.0			
		4	2013+	-	4.7	-	0.03	5.0			
	56 ≤ kW < 75	1	1998-2003	-	-	9.2	-	-			
		2	2004-2007	-	7.5	-	0.40	5.0			
		3	2008-2011	-	4.7	-	0.40	5.0			
		4	2012-2013 [h]	-	4.7	-	0.02	5.0			
			2014+ [i]	0.19	-	0.40	0.02	5.0			
	75 ≤ kW < 130	1	1997-2002	-	-	9.2	-	-			
		2	2003-2006	-	6.6	-	0.30	5.0			
		3	2007-2011	-	4.0	-	0.30	5.0			
		4	2012-2013 [h]	-	4.0	-	0.02	5.0			
			2014+	0.19	-	0.40	0.02	5.0			

Continued

	Rated Power (kW)	Tier	Model Year	NMHC (g/kW-hr)	NMHC + NOx (g/kW-hr	NOx (g/kW-hr	PM (g/kW-hr	CO (g/kW-hr)	Smoke [a] (Percentage)	Useful Life (hours /years) [b]	Warranty Period (hours /years) [b]
Federal	130 ≤ kW < 225	1	1996-2002	1.3 [j]	-	9.2	0.54	11.4	20/15/50	8,000/10	3,000/5
		2	2003-2005	-	6.6	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	225 ≤ kW < 450	1	1996-2000	1.3 [j]	-	9.2	0.54	11.4			
		2	2001-2005	-	6.4	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	450 ≤ kW < 560	1	1996-2001	1.3 [j]	-	9.2	0.54	11.4			
		2	2002-2005	-	6.4	-	0.20	3.5			
		3	2006-2010	-	4.0	-	0.20	3.5			
		4	2011-2013 [h]	-	4.0	-	0.02	3.5			
			2014+ [i]	0.19	-	0.40	0.02	3.5			
	560 ≤ kW < 900	1	2000-2005	1.3 [j]	-	9.2	0.54	11.4			
		2	2006-2010	-	6.4	-	0.20	3.5			
		4	2011-2014	0.40	-	3.5	0.10	3.5			
			2015+ [i]	0.19	-	3.5 [k]	0.04 [l]	3.5			
	kW > 900	1	2000-2005	1.3 [j]	-	9.2	0.54	11.4			
		2	2006-2010	-	6.4	-	0.20	3.5			
		4	2011-2014	0.40	-	3.5 [k]	0.10	3.5			
			2015+ [i]	0.19	-	3.5 [k]	0.04 [l]	3.5			

Notes on following page.

Notes:

- For Tier 1, 2, and 3 standards, exhaust emissions of nitrogen oxides (NOx), carbon monoxide (CO), hydrocarbons (HC), and non-methane hydrocarbons (NMHC) are measured using the procedures in 40 Code of Federal Regulations (CFR) Part 89 Subpart E. For Tier 1, 2, and 3 standards, particulate matter (PM) exhaust emissions are measured using the California Regulations for New 1996 and Later Heavy-Duty Off-Road Diesel Cycle Engines.
- For Tier 4 standards, engines are tested for transient and steady-state exhaust emissions using the procedures in 40 CFR Part 1039 Subpart F. Transient standards do not apply to engines below 37 kilowatts (kW) before the 2013 model year, constant-speed engines, engines certified to Option 1, and engines above 560 kW.
- Tier 2 and later model naturally aspirated nonroad engines shall not discharge crankcase emissions into the atmosphere unless these emissions are permanently routed into the exhaust. This prohibition does not apply to engines using turbochargers, pumps, blowers, or superchargers.
- In lieu of the Tier 1, 2, and 3 standards for NOX, NMHC + NOX, and PM, manufacturers may elect to participate in the averaging, banking, and trading (ABT) program described in 40 CFR Part 89 Subpart C.

a Smoke emissions may not exceed 20 percent during the acceleration mode, 15 percent during the lugging mode, and 50 percent during the peaks in either mode. Smoke emission standards do not apply to single-cylinder engines, constant-speed engines, or engines certified to a PM emission standard of 0.07 grams per kilowatt-hour (g/kW-hr) or lower. Smoke emissions are measured using procedures in 40 CFR Part 86 Subpart I.

b Useful life and warranty period are expressed hours and years, whichever comes first.

c Hand-startable air-cooled direct injection engines may optionally meet a PM standard of 0.60 g/kW-hr. These engines may optionally meet Tier 2 standards through the 2009 model years. In 2010 these engines are required to meet a PM standard of 0.60 g/kW-hr.

d Useful life for constant speed engines with rated speed 3,000 revolutions per minute (rpm) or higher is 5 years or 3,000 hours, whichever comes first.

e Warranty period for constant speed engines with rated speed 3,000 rpm or higher is 2 years or 1,500 hours, whichever comes first.

f These Tier 3 standards apply only to manufacturers selecting Tier 4 Option 2. Manufacturers selecting Tier 4 Option 1 will be meeting those standards in lieu of Tier 3 standards.

g A manufacturer may certify all their engines to either Option 1 or Option 2 sets of standards starting in the indicated model year. Manufacturers selecting Option 2 must meet Tier 3 standards in the 2008-2011 model years.

h These standards are phase-out standards. Not more than 50 percent of a manufacturer's engine production is allowed to meet these standards in each model year of the phase out period. Engines not meeting these standards must meet the final Tier 4 standards.

i These standards are phased in during the indicated years. At least 50 percent of a manufacturer's engine production must meet these standards during each year of the phase in. Engines not meeting these standards must meet the applicable phase-out standards.

j For Tier 1 engines the standard is for total hydrocarbons.

k The NOx standard for generator sets is 0.67 g/kW-hr.

l The PM standard for generator sets is 0.03 g/kW-hr.

Citations: Code of Federal Regulations (CFR) citations:

- 40 CFR 89.112 = Exhaust emission standards
- 40 CFR 1039.101 = Exhaust emission standards for after 2014 model year
- 40 CFR 1039.102 = Exhaust emission standards for model year 2014 and earlier
- 40 CFR 1039 Subpart F = Exhaust emissions transient and steady state test procedures
- 40 CFR 86 Subpart I = Smoke emission test procedures
- 40 CFR 1065 = Test equipment and emissions measurement procedures

EPA United States Environmental Protection Agency

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

- Rule Summary
- Rule History
- Additional Resources
- Compliance

Rule Summary

Stationary engines use pistons that alternately move back and forth to convert pressure into rotating motion. They are used in a variety of applications from generating electricity to powering pumps and compressors in power and manufacturing plants. They are also used in the event of an emergency such as fire or flood.

The key pollutants EPA regulates from these sources includes formaldehyde, acetaldehyde, acrolein, methanol, polycyclic aromatic hydrocarbon (PAH), volatile organic compounds (VOC), carbon monoxide (CO), nitrogen oxide (NO_x) and particulate matter (PM).

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE) are outlined in the Code of Federal Regulations under 40 CFR 63 Subpart ZZZZ.

Rule History

The following is a timeline of regulatory actions that have formed the current NESHAP for RICE, beginning with the most recent actions.

- August 15, 2014 - EPA issued a final decision on reconsideration of the final amendments to the regulations for existing SI RICE
    - Notice for Final Decision on Reconsideration - August 15, 2014
    - Reconsideration of Final Rule - September 5, 2013
- January 30, 2013- EPA finalized amendments to the regulations
    - Final Amendments - January 30, 2013
        - Final Rule Amendments Correction - March 6, 2013
    - Proposed Rule Amendments - June 7, 2012
        - Reopening the Comment Period - October 3, 2012
        - Notice of Public Hearing and Extension of Public Comment Period - June 21, 2012
- August 20, 2010 - EPA finalized regulations for exisiting stationary spark ignition (SI) RICE
    - Final Rule - August 20, 2010

- March 3, 2010 - EPA finalized regulation for the exisiting stationary compression ignition (CI) RICE
    - Final Rule - March 3, 2010
    - Final Rule Correction - June 30, 2010
    - Proposed Rule - March 5, 2009
        - Extension of Public Comment Period - April 14, 2010
    - Advanced Notice of proposed Rulemaking - January 24, 2008

- January 18, 2008 - EPA finalized regulations for new RICE less than or equal to 500 HP located at major sources and new RICE located at area sources
    - Final Rule - January 18, 2008
    - Proposed Rule -June 12, 2006
        - Proposed Rule Correction - June 26, 2006
        - Extension of Public Comment Period - July 27, 2006

- June 15, 2004 - EPA finalized the first regulation for stationary RICE greater than 500 horsepower (HP) located at major sources of HAP
    - Final Rule - June 15, 2004
    - Proposed Rule - December 19, 2002

Additional Resources

- Technical Documents
- Fact Sheets
- Implementation Tools

Compliance

- Compliance Summary Tables

LAST UPDATED ON AUGUST 1, 2016

EPA United States Environmental Protection Agency

Fact Sheets: NESHAP for Reciprocating Internal Combustion Engines

The following fact sheets summarize amendments made to the NESHAP for Reciprocating Internal Combustion Engines.

- August 29, 2013 - Fact Sheet: Reconsideration of Final Standards for Stationary Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Overview of the Final Amendments to the Emission Standards for Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Specifics about Provisions Related to Emergency Engines
- May 22, 2012 - Fact Sheet: Summary of Proposed Changes
- March 2, 2011 - Fact Sheet: Amendments to the Final Air Toxics Standards for Reciprocating Internal Combustion Engines
- August 10, 2010 - Fact Sheet: Final Air Toxics Standards (NESHAP) for Reciprocating Internal Combustion Engines
- February 17, 2010 - Fact Sheet: Final Air Toxics Standards (NESHAP) for Reciprocating Internal Combustion Engines
- February 26, 2004 - Fact Sheet: Final Rule to Reduce Toxic Air Emissions from Reciprocating Internal Combustion Engines
- November 26, 2002 - Fact Sheet: Proposed Rule to Reduce Toxic Air Emissions from Reciprocating Internal Combustion Engines
- January 18, 2008 - Fact Sheet: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines

LAST UPDATED ON AUGUST 1, 2016

United States Environmental Protection Agency

Implementation Tools: NESHAP for Reciprocating Internal Combustion Engines

Below are tools and guidance documents for implementing the NESHAP for Reciprocating Internal Combustion Engines.

- **Regulation Navigation Tool**
  - RICE NESHAP

- **Example Forms**
  - March 2015 - Example Semiannual Report (5 pp, 43 K)
    - PDF version
  - March 2015 - Optional Deviation/Malfunction Log (1 pg, 13 K)
    - PDF version
  - March 2015 - Example Annual Compliance Report for New or Reconstructed Non-Emergency Landfill or Digester Gas Engines (4 pp, 28 K)
    - PDF version
  - October 7, 2010 - Example Notification of Compliance Status Report: Due 60 days after completing a required performance test, or 30 days after completing a compliance demonstration which does not include a performance test (5 pp, 73 K)
  - July 2,2010 - Example Initial Notification for Stationary Reciprocating Internal Combustion Engines Area Source Rule - 40 CFR Part 63 Subpart ZZZZ (3 pp, 61 K)
  - Other Example Forms

- **Summary Tables**
  - March 17, 2016 - RICE Summary Table of Requirements (XLSX) (8 pp, 49 K)
  - November 4, 2010 - Stationary Reciprocating Internal Combustion Engines: Applicability Flowchart (2 pp, 202 K)
  - Other Summary Tables

- **Webinars & Presentations**
  - December 2011 - Stationary RICE NESHAP Webinar
  - June 2010 - NESHAP for Existing Stationary Reciprocating Internal Combustion Engines (RICE) - June 2010 Web Broadcast
  - March 2013 & June 2012 RICE Presentation Slides

- **Videos**
  - April 15, 2015 - Air Quality Regulations for Stationary Engines for the Agriculture Industry

- **Other Guidance Documents**

LAST UPDATED ON DECEMBER 5, 2016

EPA United States Environmental Protection Agency

New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines

Rule Summary

Stationary engines use pistons that alternately move back and forth to convert pressure into rotating motion. They are used in a variety of applications from generating electricity to powering pumps and compressors in power and manufacturing plants. They are also used in the event of an emergency such as fire or flood.

A compression ignition (CI) engine, or diesel engine, is a type of engine in which the fuel injected into the combustion chamber is ignited by a heat resulting from the compresssion of gases inside the cylinder.

The key pollutants EPA regulates from these sources includes nitrogen oxide (NOx), particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), and hydrocarbons (HC) .

The New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines is outlined in the Code of Federal Regulations under 40 CFR Part 60 Subpart IIII.

Rule History

The following is a time line of the regulatory actions that have formed the current regulations:

- July 7, 2016
  - Final rule
- November 6, 2015
  - Proposed rule
- August 15, 2014
  - Notice of final decision on reconsideration
- September 5, 2013
  - Notice of reconsideration

- January 30, 2013
  - Final amendments
- October 3, 2012
  - Reopening of comment period
- June 21, 2012
  - Notice of public hearing and extension of comment period
- June 7, 2012
  - Proposed rule
- June 28, 2011 - final amendments to the NSPS for CI internal comubsion engines
  - Final rule - June 28, 2011
  - Proposed rule - June 8, 2010
    - Extension of public comment period - August 6, 2010
- July 11, 2006 - NSPS for CI internal combustion engines
  - Final rule - July 11, 2006
  - Proposed rule - July 11, 2005

Additional Resources

- Technical Documents
- Fact Sheets
- Implementation Tools

Compliance

- Compliance Summary Tables

LAST UPDATED ON OCTOBER 5, 2016

United States Environmental Protection Agency

Fact Sheets: NSPS for Compression Ignition Internal Combustion Engines

The following fact sheets summarize amendments made to the NSPS for Compression Ignition Internal Combustion Engines.

- October 30, 2015 - Fact Sheet: Proposed Amendments to the Standards for Performance for Stationary Compression Ignition Internal Combustion Engines
- August 29, 2013 - Fact Sheet: Reconsideration of Final Standards for Stationary Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Overview of the Final Amendments to the Emission Standards for Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Specifics about Provisions Related to Emergency Engines
- June 30, 2005 - Fact sheet: Proposed Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

LAST UPDATED ON AUGUST 1, 2016

Implementation Tools: NSPS for Compression Ignition Internal Combustion Engines

Below are tools and guidance documents to help you comply with the New Source Performance Standards for Compression Ignition Internal Combustion Engines.

- **Regulation Navigation Tool**
  - IC NSPS
- **Summary Tables**
  - February 8, 2013 - Table of Requirements: Compression Ignition NSPS (2 pp, 17 K)
- **Webinars and Presentations**
  - March 2013 and June 2012 RICE Presentation Slides
- **Videos**
  - April 15, 2015 - Air Quality Regulations for Stationary Engines for the Agriculture Industry
- **Other Guidance Documents**

LAST UPDATED ON DECEMBER 5, 2016

EPA United States Environmental Protection Agency

New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines

- Rule Summary
- Rule History
- Additional Resources
- Compliance

Rule Summary

Stationary engines use pistons that alternately move back and forth to convert preassue inro rotating motion. They are used in a variety of applications from generating electricity to powering pumps and compressors in power and manufacturing plants. They are also used in the event of an emergency such as fire or flood.

A spark ignition (SI) engine, or gasoline engine, is a type of engine in which the fuel-air mixture in the combustion chamber is ignited by a spark from a spark plug.

The key pollutants EPA regulates from these sources includes nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOC).

The New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines is outlined in the Code of Federal Regulations under 40 CFR Part 60 Subpart JJJJ.

Rule History

The following is a timeline of regulatory actions that have formed the current regulation:

- August 15, 2014
  - Notice of final decision on reconsideration
- September 5, 2013
  - Notice of reconsideration
- January 30, 2013
  - Final amendments
- October 3, 2012
  - Reopening of comment period
- June 21, 2012
  - Notice of public hearing and extension of comment period

- June 7, 2012
    - Proposed rule
- June 28, 2011 - final amendments to the NSPS for CI and SI internal combustion engines
    - Final rule - June 28, 2011
    - Proposed rule - June 8, 2010
- January 18, 2008
    - Final rule
- June 12, 2006
    - Proposed rule

Additional Resources

- Technical Documents
- Fact Sheets
- Implementation Tools

Compliance

- Compliance Summary Tables

LAST UPDATED ON DECEMBER 6, 2016

Fact Sheets: NSPS for Spark Ignition Engines

The following fact sheets summarize amendments made to the NSPS for Spark Ignition Engines.

- October 30, 2015 - Fact Sheet: Proposed Amendments to the Standards for Performance for Stationary Compression Ignition Internal Combustion Engines
- August 29, 2013 - Fact Sheet: Reconsideration of Final Standards for Stationary Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Overview of the Final Amendments to the Emission Standards for Reciprocating Internal Combustion Engines
- January 14, 2013 - Fact Sheet: Specifics about Provisions Related to Emergency Engines
- January 18, 2008 - Fact Sheet: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combusion Engines

LAST UPDATED ON AUGUST 1, 2016

Implementation Tools: NSPS for Spark Ignition Internal Combustion Engines

Below are tools and guidance documents to help you comply with the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines.

- **Regulation Navigation Tool**
  - IC NSPS
- **Summary Tables**
  - February 8, 2013 - Table of Requirements: Spark Ignition NSPS (6 pp, 112 K)
- **Webinars and Presentations**
  - March 2013 and June 2012 RICE Presentation Slides
- **Videos**
  - April 15, 2015 - Air Quality Regulations for Stationary Engines for the Agriculture Industry
- **Other Guidance Documents**

LAST UPDATED ON DECEMBER 5, 2016

EPA's Air Quality Regulations for Stationary Engines

Melanie King
U.S. Environmental Protection Agency

June 18, 2014

EPA's Stationary Engine Regulations

- National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE)
  - 40 CFR part 63 subpart ZZZZ
- New Source Performance Standards (NSPS) for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
  - 40 CFR part 60 subpart IIII
- NSPS for Stationary Spark Ignition (SI) ICE
  - 40 CFR part 60 subpart JJJJ

2

These Rules Do Not Apply to:

- Engines used in motor vehicles and mobile nonroad equipment:
  - Mobile nonroad engines are:
    - Self-propelled (tractors, bulldozers)
    - Propelled while performing their function (lawnmowers)
    - Portable or transportable (has wheels, skids, carrying handles, dolly, trailer, or platform)
      - Portable nonroad becomes stationary if it stays in one location for more than 12 months, or full annual operating period if seasonal source

VS.

Timeline of Final Regulations

Date	Rule	Type of engines covered
June 2004	NESHAP	•Existing/new engines >500 HP at major sources
June 2006	NSPS	•New CI engines
January 2008	NSPS	•New SI engines
	NESHAP	•New engines •≤500 HP at major sources •all HP at area sources
March 2010	NESHAP	•Existing CI engines •≤500 HP at major sources •all HP at area sources •non-emergency CI >500 HP at major sources
August 2010	NESHAP	•Existing SI engines •≤500 HP at major sources •all HP at area sources
June 2011	NSPS	•Amendments for CI and SI engines
January 2013	NESHAP and NSPS	•Reconsideration of 2010 NESHAP •Minor amendments to NSPS for CI and SI engines

Applicability

RICE NESHAP 40 CFR part 63 subpart ZZZZ	• Applies to existing and new stationary compression ignition (CI) and spark ignition (SI) engines

CI ICE NSPS
40 CFR part 60 subpart IIII
	• Applies to stationary CI engines:
	  • Ordered after July 11, 2005 and manufactured after April 1, 2006
	  • Modified or reconstructed after July 11, 2005

SI ICE NSPS
40 CFR part 60 subpart JJJJ
	• Applies to stationary SI engines:
	  • Ordered after June 12, 2006 and manufactured on/after
	    • July 1, 2007 if ≥500 HP (except lean burn 500≤HP<1,350)
	    • January 1, 2008 if lean burn 500≤HP<1,350
	    • July 1, 2008 if <500 HP
	    • January 1, 2009 if emergency >25 HP
	• Modified or reconstructed after June 12, 2006

Poll Question #1 – True or False

A Compression Ignition ICE manufactured in 2010 is “new” according the NSPS

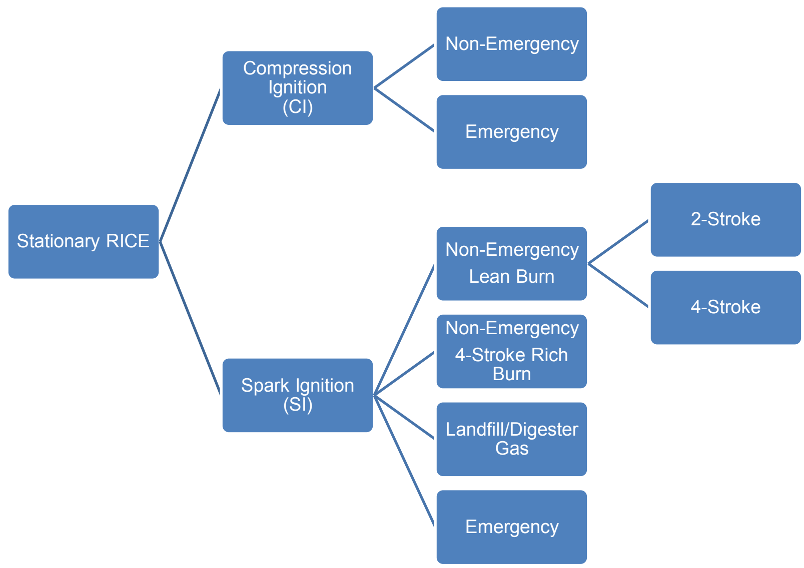
United States Environmental Protection Agency

Stationary Reciprocating Internal Combustion Engine NESHAP

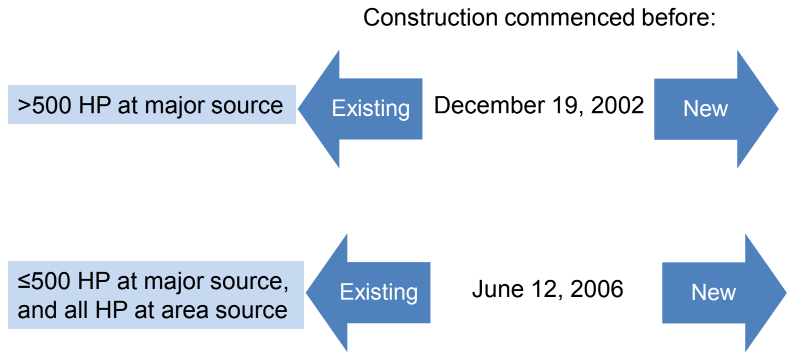
RICE NESHAP Background

- Regulates HAP emissions from stationary RICE at both major and area sources of HAP
  - Major: ≥10 tons/year single HAP or ≥25 tons/year total HAP
  - Area: not major
- **All sizes** of engines are covered
- **Only stationary engines not subject**: existing emergency engines located at residential, institutional, or commercial area sources used or obligated to be available ≤15 hr/yr for emergency demand response or voltage/frequency deviation, and not used for local reliability

General Subcategorization Approach



Existing vs. New



- <u>Determining construction date</u>: owner/operator has entered into a contractual obligation to undertake and complete, within a reasonable amount of time, a continuous program for the on-site installation of the engine
  - Does not include moving an engine to a new location, or a change in ownership of an existing engine

What is an Emergency Engine?

- "... operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment ... when electric power from the local utility ... is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc."
- Operates in non-emergency situations only as specified in the rule

Emergency Engine Operational Limitations

- Unlimited use for emergencies (e.g., power outage, fire, flood)
- 100 hr/yr for:
  - maintenance/testing
  - emergency demand response (EDR) when Energy Emergency Alert Level 2 has been declared by Reliability Coordinator
  - voltage or frequency deviates by 5% or more below standard
- 50 hr/yr of the 100 hr/yr allocation can be used for:
  - non-emergency situations if no financial arrangement
  - local reliability as part of a financial arrangement with another entity if:
    - existing RICE at area source
    - engine is dispatched by local transmission/distribution system operator
    - dispatch intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads
    - dispatch follows reliability, emergency operation, or similar protocols that follow specific NERC, regional, state, public utility commission, or local standards or guidelines
    - power provided only to facility or to support local distribution system
    - owner/operator identifies and records dispatch and standard that is being followed
  - peak shaving in local system operator program until May 3, 2014 if existing RICE at area source

Emission Standards: Existing RICE Located at Major Sources

HP	Engine Subcategory					
	Non-emergency					Emergency
	CI	SI 2SLB	SI 4SLB	SI 4SRB	SI LFG/DG	
<100	Change oil and filter and inspect air cleaner (CI) or spark plugs (SI) every 1,000 hours of operation or annually; inspect hoses and belts every 500 hours of operation or annually					Change oil/filter & inspect hoses/belts every 500 hours or annually; inspect air cleaner (CI) or spark plugs (SI) every 1,000 hours or annually
100-300	230 ppm CO	225 ppm CO	47 ppm CO	10.3 ppm CH_2O	177 ppm CO	
300-500	49 ppm CO or 70% CO reduction					
>500	23 ppm CO or 70% CO reduction	No standards	No standards	350 ppb CH_2O or 76% CH_2O reduction	No standards	No standards

Note: Existing limited use engines >500 HP at major sources do not have to meet any emission standards. Existing black start engines ≤500 HP at major sources must meet work practice standards.

Emission Standards: Existing RICE Located at Area Sources

HP	Engine Subcategory					
	Non-emergency					Emergency or Black start
	CI	SI 2SLB	SI 4S in remote areas	SI 4S not in remote areas	SI LFG/DG	
≤300	Change oil/filter & inspect air cleaner every 1,000 hours or annually; inspect hoses/belts every 500 hours or annually	Change oil/filter, inspect spark plugs, & inspect hoses/ belts every 4,320 hours or annually	Change oil/ filter, inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually	Change oil/ filter, inspect spark plugs, & inspect hoses/belts every 1,440 hours of operation or annually	Change oil/ filter, inspect spark plugs, & inspect hoses/ belts every 1,440 hours of operation or annually	Change oil/filter & inspect hoses/ belts every 500 hours or annually; inspect air cleaner (CI) or spark plugs (SI) every 1,000 hours or annually
300-500	49 ppm CO or 70% CO reduction					
>500	23 ppm CO or 70% CO reduction		Change oil/ filter, inspect spark plugs, & inspect hoses/belts every 2,160 hours of operation or annually	If engine used >24 hrs/yr: 4SLB: Install oxidation catalyst 4SRB: Install NSCR		

Poll Question #2 – True or False

Smaller existing CI engines (>300 HP) located at area sources have no numeric emission limits, they only need to maintain the engine. At major sources the threshold for "maintenance only" is 100 HP.

How is "Remote" Defined?

- Remote defined as:
  - Located in offshore area; or
  - Located on a pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with 4 or more stories within 220 yards on either side of a continuous 1-mile length of pipeline (DOT Class 1 area), and the pipeline segment is not within 100 yards of a building or small well-defined outside area (playground, etc.) occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period; or
  - Not located on a pipeline and having 5 or fewer buildings intended for human occupancy and no buildings with 4 or more stories within a 0.25 mile radius around the engine
- Engine must meet remote definition as of October 19, 2013

16

Emission Standards – New RICE

New RICE Located at Major Sources:

HP	Engine Subcategory					
	Non-emergency					Emergency
	CI	SI 2SLB	SI 4SLB	SI 4SRB	SI LFG/DG	
<250	Comply with CI NSPS	Comply with SI NSPS	Comply with SI NSPS	Comply with SI NSPS	Comply with SI NSPS	Comply with CI/SI NSPS
250-500			14 ppm CH_2O or 93% CO reduction			
>500	580 ppb CH_2O or 70% CO reduction	12 ppm CH_2O or 58% CO reduction		350 ppb CH_2O or 76% CH_2O reduction	No standards	No standards

Note: New limited use engines >500 HP at major sources do not have to meet any emission standards under the NESHAP. New RICE >500 HP at major sources may also have requirements under the NSPS.

New RICE Located at Area Sources: meet Stationary Engine NSPS
- •CI: part 60 subpart IIII
- •SI: part 60 subpart JJJJ

Compliance Requirements

Engine Subcategory	Compliance Requirements
Existing non-emergency: •CI ≥100 HP at major source •CI >300 HP at area source •SI 100-500 HP at major source	•Initial emission performance test •Subsequent performance testing every 8,760 hours of operation or 3 years for engines >500 HP (5 years if limited use) •Operating limitations - catalyst pressure drop and inlet temperature for engines >500 HP •Notifications •Semiannual compliance reports (annual if limited use) Existing non-emergency CI >300 HP: •Ultra low sulfur diesel (ULSD) fuel •Crankcase emission control requirements
•Existing non-emergency SI 4SLB/4SRB >500 HP at area source used >24 hours/year and not in remote area	•Initial and annual compliance demonstration •High temperature engine shutdown or continuously monitor catalyst inlet temperature •Notifications •Semiannual compliance reports

Compliance Requirements

Engine Subcategory	Compliance Requirements
<u>Existing emergency/black start</u>: •<100 HP at major source •≤500 HP at major source •All at area source <u>Existing non-emergency</u>: •<100 HP at major source •CI ≤300 HP at area source •SI ≤500 HP at area source •SI 2SLB >500 HP at area source •SI LFG/DG >500 HP at area source •SI 4SLB/4SRB >500 HP at area source used ≤24 hours/year or in remote area	•Operate/maintain engine & control device per manufacturer's instructions or owner-developed maintenance plan •May use oil analysis program instead of prescribed oil change frequency •Emergency engines must have hour meter and record hours of operation •Keep records of maintenance •Notifications not required •Reporting and ULSD for emergency engines used for emergency demand response or local reliability

Oil Analysis Programs

Parameter	Condemning Limits
Total Base Number (CI RICE only)	<30% of the TBN of the oil when new
Total Acid Number (SI RICE only)	Increases by more than 3.0 mg of potassium hydroxide per gram from TAN of the oil when new
Viscosity	Changed by more than 20% from the viscosity of the oil when new
% Water Content by volume	>0.5

- Oil analysis must be performed at same frequency specified for oil changes
- If condemned, change oil within 2 business days
  - Owner/operator must keep records of the analysis

Compliance Requirements

Engine Subcategory	Compliance Requirements
<u>Existing non-emergency:</u> •SI 4SRB >500 HP at major source <u>New non-emergency:</u> •SI 2SLB >500 HP at major source •SI 4SLB >250 HP at major source •SI 4SRB >500 HP at major source •CI>500 HP at major source	•Initial emission performance test •Subsequent performance testing semiannually (can reduce frequency to annual)* •Operating limitations - catalyst pressure drop and inlet temperature •Notifications •Semiannual compliance reports

*Subsequent testing required for 4SRB engine complying with formaldehyde % reduction standard only if engine is ≥5,000 HP

Compliance Requirements

Engine Subcategory	Compliance Requirements
•New emergency/limited use >500 HP at major source	•Initial notification •Reporting and ULSD for emergency engines used for emergency demand response
•New non-emergency LFG/DG >500 HP at major source	•Initial notification •Monitor/record fuel usage daily •Annual report of fuel usage

Fuel Requirements for Emergency Engines

- Requirements apply to emergency CI RICE >100 HP and displacement <30 liters/cylinder that are:
  - Operated or contractually obligated to be available >15 hr/yr (up to 100 hr/yr) for emergency demand response or voltage/frequency deviation, or
  - Operated for local reliability (up to 50 hr/yr)
- Beginning January 1, 2015, use ULSD fuel
  - Existing inventory may be depleted

Reporting Requirements for Emergency Engines

- Requirements apply to emergency RICE >100 HP that are:
  - Operated or contractually obligated to be available >15 hr/yr (up to 100 hr/yr) for emergency demand response or voltage/frequency deviation, or
  - Operated for local reliability (up to 50 hr/yr)
- Beginning with 2015 operation, report electronically by March 31 of following year:
  - Facility name/address
  - Engine rating, model year, lat/long
  - Date, start time, end time for operation for purposes above
  - Number of hours engine is contractually obligated for emergency demand response or voltage/frequency deviation
  - Entity that dispatched engine for local reliability and situation that necessitated dispatch
  - Deviations from fuel requirement
- Submit report electronically through the Compliance and Emissions Data Reporting Interface
  - Accessed through EPA's Central Data Exchange at http://www.epa.gov/cdx

Additional Changes in January 2013 Amendments

- THC compliance option:
  - Non-emergency 4SRB SI RICE >500 HP at major sources meeting the 76% formaldehyde reduction standard can show compliance by demonstrating through testing that THC is reduced by at least 30%
- Tier certified engines:
  - Existing non-emergency CI RICE >300 HP at area sources certified to Tier 1 or 2 and subject to enforceable state/local rule that requires replacement can comply with management practices until January 1, 2015, or 12 years after the installation date of the engine, but not later than June 1, 2018
  - Existing non-emergency CI RICE >300 HP at area sources certified to Tier 3* standards can comply with RICE NESHAP by complying with the CI ICE NSPS
- CI engines on vessels on the Outer Continental Shelf
  - Existing non-emergency CI RICE >300 HP on offshore vessels on the OCS that are area sources can meet the following management practices rather than numeric emission limits

*Tier 2 for engines ≥560 kW

Key Dates

- Compliance dates:
  - June 15, 2007
    - Existing RICE >500 HP at major sources (except non-emergency CI >500 HP at major sources)
  - **May 3, 2013**
    - Existing CI RICE (except emergency CI >500 HP at major sources)
  - **October 19, 2013**
    - Existing SI RICE ≤500 HP at major sources and all HP at area sources
  - Upon startup for new engines

United States Environmental Protection Agency

Stationary Compression Ignition Internal Combustion Engine NSPS

CI ICE NSPS Applicability

- CI Engines:
  - constructed (ordered) after July 11, 2005 **and** manufactured after April 1, 2006 (July 1, 2006 for fire pump engines)
  - modified/reconstructed after July 11, 2005

28

Engine Manufacturer Compliance Requirements

- Engine manufacturers must certify 2007 model year and later engines with a displacement <30 liters/cylinder
  - Certification = EPA Certificate of Conformity
    - http://www.epa.gov/otaq/certdata.htm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
2012 MODEL YEAR
CERTIFICATE OF CONFORMITY
WITH THE CLEAN AIR ACT OF 1990

OFFICE OF TRANSPORTATION AND AIR QUALITY
ANN ARBOR, MICHIGAN 48105

Certificate Issued To: Perkins Engines Co Ltd (U.S. Manufacturer or Importer)
Certificate Number: CPKXL04.4NJ1-007

Effective Date: 09/02/2011
Expiration Date: 12/31/2012

Karl J. Simon, Director
Compliance and Innovative Strategies Division

Issue Date: 09/02/2011
Revision Date: N/A

Model Year: 2012
Manufacturer Type: Original Engine Manufacturer
Engine Family: CPKXL04.4NJ1

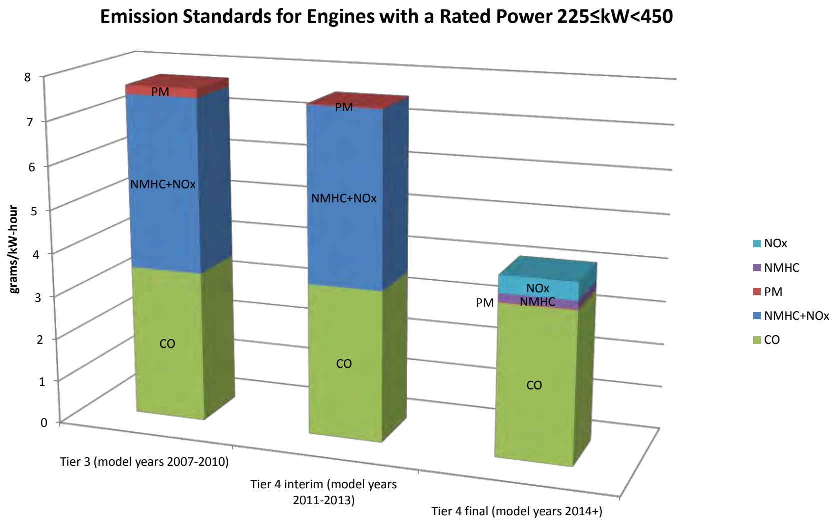
Mobile/Stationary Indicator: Stationary
Emissions Power Category: 75<=kW<130
Fuel Type: Non-Standard Fuel, Diesel
After Treatment Devices: No After Treatment Devices Installed
Non-after Treatment Devices: Electronic Control

Owner/Operator Compliance Requirements

- 2007 model year and later*
  - Purchase <u>certified</u> engine
    - Emission standards generally equivalent to "Tier" standards for nonroad engines
    - <10 l/cyl displacement: Tier 2/3 = part 89, Tier 4 = part 1039
    - 10-30 l/cyl displacement: Tier 1/2 = part 94, Tier 3/4 = part 1042
  - Install, configure, operate and maintain engine per manufacturer's instructions or manufacturer-approved procedures
    - Owner/operator performance testing not required
  - If operate differently than manufacturer's recommendations, must do performance test to show compliance
  - Use ultra low sulfur diesel fuel

*For CI fire pump engine, 2008-2011 model year and later (depending on engine size)

Example: 300 kilowatt (kW) non-emergency engine



31

United States Environmental Protection Agency

Poll Question #3 – Who needs to use ULSD per the NSPS? (Choose all that apply)

1. All engines immediately
2. CI engines manufactured after April 1, 2006

Monitoring/Recordkeeping/Reporting

Engine Type	Requirement
Emergency Engines	•Non-resettable hour meter and records of operation if engine does not meet non-emergency engine standards •If used for emergency demand response, voltage/frequency deviations, or local reliability, report operation (same as NESHAP)
Equipped with diesel particulate filter (DPF)	•Backpressure monitor and records of corrective actions
Non-emergency >3,000 HP or with displacement >10 liters/cylinder	•Submit initial notification •Keep records of notifications and engine maintenance •If certified, keep records of documentation of engine certification •If not certified, keep records of compliance demonstrations

33

EPA United States Environmental Protection Agency

Stationary Spark Ignition Internal Combustion Engine NSPS

SI ICE NSPS Applicability

- SI engines constructed (ordered) after June 12, 2006 **and**

Manufactured On/After	Engine Type
July 1, 2007	Non-emergency ≥500 HP (except lean burn 500≤HP<1,350)
January 1, 2008	Non-emergency lean burn 500≤HP<1,350
July 1, 2008	<500 HP (except emergency >25 HP)
January 1, 2009	Emergency >25 HP

- Modified/reconstructed after June 12, 2006

Note: engine manufacturers must certify stationary SI engines ≤25 HP and engines >25 HP that are gasoline or rich burn LPG

Emission Standards (In General)

Engine	Standards
≤25 HP (all engines)	Part 90 or part 1054 standards for new nonroad SI engines
Non-emergency gasoline and rich burn LPG	Part 1048 standards for new nonroad SI engines
Non-emergency natural gas and lean burn LPG 25<HP<100	Part 1048 standards for new nonroad SI engines (or other options)
≥100 HP and not gasoline or rich burn LPG	Standards in Table 1 of subpart JJJJ, part 1048 standards for some engines

Owners/operators of gasoline engines must use gasoline that meets the sulfur limit in 40 CFR 80.195 – cap of 80 ppm

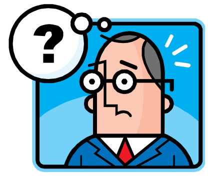
Compliance Requirements for Owners/Operators

- <u>Certified engines</u>
  - Install, configure, operate and maintain engine according to manufacturer's instructions
  - If you do not operate/maintain according to manufacturer's instructions:
    - keep maintenance plan and maintenance records
    - operate consistent with good air pollution control practices
    - 100≤HP≤500 – initial performance test
    - >500 HP – initial performance test and subsequent every 8,760 hours or 3 years, whichever is first

Compliance Requirements for Owners/Operators

- <u>Non-certified engines</u>:
  - Maintenance plan
  - Performance testing
    - 25<HP≤500 – initial test
    - >500 HP - initial test and subsequent every 8,760 hours or 3 years, whichever is first
    - Conduct within 10% of peak (or highest achievable) load
- Monitoring/recordkeeping/reporting includes:
  - Non-resettable hour meter and records of operation for emergency engines
  - If emergency engine used for emergency demand response, voltage/frequency deviations, or local reliability, report operation (same as NESHAP)
  - Documentation of certification
  - Records of engine maintenance
  - Initial notification for non-certified engines >500 HP
  - Results of performance testing within 60 days of test

Implementation Assistance



- EPA HQ RICE NESHAP/NSPS website
  - http://www.epa.gov/ttn/atw/icengines/
- EPA Regional Office RICE websites
  - Region 1: http://www.epa.gov/region1/rice
  - Region 10: http://yosemite.epa.gov/R10/airpage.nsf/Enforcement/rice_rules
- Electronic CFR
  - http://www.gpoaccess.gov/ecfr

39

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40

Questions

Questions

- Can you give an update on new, proposed and/or likely changes to the RICE Rule that have occurred in the last few months?
- Are any of these regulations likely to impact individuals who might be interested in employing CI engines to generate electricity for home use?
- Limited use engines are defined in the MACT as being used less than 100 hours of run time per year and are exempt from the MACT. Black start engines are used only to start-up turbines. I can't honestly think that a black start engine that would be used for more than a 100 hours per year for turbine start-ups. So why does EPA make them applicable to MACT Subpart ZZZZ and limited use engines not?

Questions

- § 60.4208(g) – does this apply to engines {with a displacement greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder} that have {a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP)} or does this apply to both engine classes, those engines {with a displacement greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder} AND engines that have {a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP)}?
- What does the statement "An emergency stationary RICE that does not meet the standards applicable to non-emergency engines" mean?

Questions

Remote SI RICE (NESHAP) issues/questions:

- Problems with stopping the remote determination at a point less than 1 mile from the engine, where applicable. For example, the engine discharges to a class 1 DOT pipeline for ½ mile then it changes to a class 2 DOT pipeline.
- Examples of continuing the determination at custody transfer points for 1 mile from the engine, where applicable. Companies have asked about pipelines that are not owned by the same company that owns the engine.
- Example of counting the occupied buildings on each pipeline segment. For example, if the engine discharges to 2 separate pipeline segments (one to the east and one to the west) do you total the occupied buildings from each segment to see if there are more than 10?
- Examples of what engines qualify for the ¼ mile radius criteria that are not on a pipeline.
- Is it a violation if the company did not complete the remote determination by 10-19-2013?
- If the remote determination was not made by 10-19-2013, is the company required to meet the non-remote standards even if the company believes the engine is remote? They did not do the determination so they do not know until it is completed.