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
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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,

JOHN C. CRUDEN
Assistant Attorney General
Environment & Natural Resources Division

/s/ Austin D. Saylor
AUSTIN D. SAYLOR
United States Department of Justice
Environment & Natural Resources Div.
Environmental Defense Section
P.O. Box 7611
Washington D.C. 20044
Tel: (202) 514-1880
Fax: (202) 514-8865

Counsel for Respondent EPA

OF COUNSEL:

SHEILA IGOE
Office of General Counsel
U.S. Environmental Protection Agency
Ariel Rios Building,
1200 Pennsylvania Avenue, N.W.
Mail Code: 2344A
Washington, D.C. 20460

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

REGULATORY ADDENDUM

TABLE OF CONTENTS

CODE OF FEDERAL REGULATIONS

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or 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.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

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§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NOX and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NOX and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a

way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

****

§60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in §60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in §60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4233(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

Exhibit 1

American
Public Power
Association

Ph: 202.467.2900
Fax: 202.467.2910
www.APPAnet.org

1875 Connecticut Avenue, NW
Suite 1200
Washington, DC 20009-5715

Comments of
The American Public Power Association (APPA)

on

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines
Notice of Reconsideration of Final Rule; Request for Public Comment; Notice of Public Meeting

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February 14, 2011

example, under the new RICE rules distribution voltage support does *not* constitute an "emergency" use, yet many utilities in rural communities must use these units to keep distribution system voltage at acceptable levels. **Low voltage levels can damage customer equipment and violate rules as well as standards.**

EPA Should Expand Its Definition of Emergency to Include Local Distribution System Voltage Support

There are many industry standards that compel many utilities to maintain distribution system reliability. Reliability includes providing a supply of electricity at a steady state, or normal expected voltage. At a utility, providing normal voltage that continuously meets the manufacturer specifications is often referred to as power quality. Accordingly, power quality is a key component of local electric system reliability. Institute of Electrical and Electronics Engineers[7] (IEEE) standard 1250 establishes a guide for providing electric distribution service to all types of power quality sensitive equipment. This equipment, including computers and computer-like products, will rapidly fail if subjected to power quality phenomena, such as low voltage disturbances. In the case of these comments, the terms "voltage sag" and "low voltage" refer to a percentage drop in voltage relative to normal system voltage. IEEE 1250 defines voltage sag, and relative to normal system voltage, gives acceptable voltage sag through the American National Standards Institute (ANSI) standard C84.1-1989.

[7] The IEEE Standards Association is defined on their website (http://standards.ieee.org/) as a leading consensus building organization that nurtures, develops and advances global technologies. IEEE standards drive the functionality, capabilities and interoperability of a wide range of products and services that transform the way people live, work and communicate. IEEE Standards Association promotes innovation and helps protect health and public safety.

System voltage is defined by ANSI 84.1 as the root-mean-square phase-to-phase voltage of a portion of an alternating-current electric system. Across a utility, there can be different system voltages, but each system voltage is defined by the portion of the system in question as bounded by transformers or utilization equipment and is designed to be within specified normal voltage ranges. Relative to the system voltage, ANSI C84.1 sets the maximum allowable voltage sag at the point of acceptance by a utility at -5%. However, in certain instances the allowable sag can be even less. RICE units are one utility solution that can be used to correct local system voltage disturbances during emergencies that are outside of the local utility's control.

IEEE 1159, a standard used by utilities in reporting outages and interruptions to their customers, states that an under-voltage of greater than 10% for greater than one minute should be counted as an electrical service interruption. An under-voltage incident of 10% can be described as a brownout. However, since the term "brownout" is not defined, it is not appropriate for use in any standard created by the EPA. In the event of a distribution system low voltage, or under-voltage condition, utilities adhering to IEEE standards would have operational reason to employ RICE units to preserve normal voltage levels. At the distribution system level, a utility is acting to prevent equipment damage when it responds to low voltage conditions. In the case of increased electrical demand, or constrained transmission to a geographically isolated area, voltage will tend to sag as the system is loaded to its maximum capacity. The utility can act by engaging its RICE unit(s) as needed to return distribution voltage to required levels.

For example, during summer peak conditions, there may be times when the primary transmission feed may become overloaded. **To prevent low voltage on the distribution system, which would adversely affect power services to the community, there are times when public power systems must operate their RICE units.**

The city of Waterloo, Illinois, an APPA member with an approximate population of 10,000 people, has dealt with low voltage issues for a number of years. Although a variety of third party transmission projects have helped, under peak conditions, voltage can still drop to unacceptable levels. During these times, the city has to operate some RICE units to avoid equipment damage or the risk of protective relays tripping their primary transmission feed due to under-voltage. Waterloo's RICE units are being operated to prevent an interruption of power to the community where the main transmission line cannot adequately support the needs of the city. **The power generated by this system's RICE units is not sent to the BES, but rather utilized by the community's <u>own citizens</u>.**

APPA members in Kansas also have insufficient transmission to serve their native load. All of APPA's members in the Kansas Power Pool (KPP) are within the Southwest Power Pool (SPP) footprint. However, all of KPP's RICE generation is considered by SPP to be outside of its authority, as all are either deemed to be "behind-the-meter" generation or connected to voltages below SPP's opinion of what is actually transmission.[8]

[8] In "behind-the-meter" use cases a utility operates the RICE unit to avoid voltage drops, which prevents outages before they occur. Since the situation is handled effectively at a local level, the conditions do not spread to the larger electric system and are not "seen" by the RTO. This districting of responsibility greatly simplifies the process of responding to system conditions by both entities.

Eighteen cities in the KPP currently do not have, or are not connected to, sufficient transmission to serve their native load and are not notified by SPP when they need to generate. The monitoring of voltage determines the need to generate. When distribution voltages in these cities drop below acceptable levels, they have to bring on their generation. **This decision is made locally, not by the RTO or the host transmission owner. KPP member cities receive no guidance from SPP on this issue, nor do they receive compensation for running their units.**

Beyond voltage emergencies, EPA should be clear that utilities can use their emergency RICE units to ensure essential public services are available during severe weather events.

EPA Should Increase Non-Emergency Hours in Consideration for Distribution System Maintenance and Local System Reliability

Public power systems also use RICE units for support during critical transmission and sub-transmission (distribution system) system outages. As such, **APPA members are concerned that the new rules will preclude use of emergency RICE units for line maintenance.**

APPA members believe the rule limiting emergency RICE units to 50 hours of operation for non-emergency purposes that do not generate revenue is problematic. Public power systems served radially by a single transmission line or transformer can presumably use RICE units for backup power when weather-related and other types of damages occur to radial facilities that result in a total power outage. However, under the new rules, they might not be able to use emergency RICE units when radial lines and transformers periodically have to be taken out of service for routine maintenance. When such maintenance occurs, the local generation is the only means of providing power to customers. Otherwise, the local distribution system would go dark. Since a utility with a RICE unit can keep power flowing while electrically disconnected from the larger third party transmission system, it can also allow essential public services, like hospitals and schools to continue to serve the community during planned outages. Using RICE for planned maintenance is a key reason APPA supports an increase in the number of hours allowed for RICE engine non-emergency use.

EPA Should Not View Cost Recovery the Same as Profit

All power that is generated, even during an emergency, by agreement with the end user, necessarily generates revenue. Since all public power systems are not-for-profit, they are functioning as a part of their mission to maximize affordable power for the communities they serve over the long term – not profit economically. **It is one thing to preclude an activity such as peak shaving for economic purposes; it is another to preclude activities that are solely done for reliability purposes, such as distribution system voltage support due to transmission constraints, avoiding equipment thermal overload, and line maintenance.** Further, since APPA members are units of local government, they are not-for-profit and charge their customers cost-of-service based rates. **As such, they believe what they receive is better categorized as compensation, or cost recovery, than profit.** Power from a large generating station is invariably going to be more efficient to produce. Receiving some revenue from keeping the lights on during times of emergency is different from running RICE

Exhibit 2

SPIEGEL & MCDIARMID LLP

GEORGE SPIEGEL (1919-1997)
ROBERT C. McDIARMID
ROBERT A. JABLON
JAMES N. HORWOOD
THOMAS C. TRAUGER
CYNTHIA S. BOGORAD
SCOTT H. STRAUSS
LISA G. DOWDEN
PETER J. HOPKINS
DAVID E. POMPER
WILLIAM S. HUANG
PABLO O. NÜESCH
TILLMAN L. LAY
LARISSA A. SHAMRAJ
STEPHEN C. PEARSON

1333 NEW HAMPSHIRE AVENUE, NW
WASHINGTON, DC 20036

WWW.SPIEGELMCD.COM

Telephone 202.879.4000
Facsimile 202.393.2866
EMAIL INFO@SPIEGELMCD.COM

ASSOCIATES
REBECCA J. BALDWIN
KATHARINE M. MAPES
MELISSA E. BIRCHARD
ANJALI G. PATEL
DANIEL H. SILVERMAN*
KATHRYN BOUDOURIS**
LATIF M. NURANI*

OF COUNSEL
DANIEL I. DAVIDSON
FRANCES E. FRANCIS
MARGARET A. McGOLDRICK
JEFFREY A. SCHWARZ
BARRY M. SMOLER
LEE C. WHITE

Before the
Environmental Protection Agency
Washington, D.C. 20460

Comments of Kansas Power Pool

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

Docket ID No. EPA-HQ-OAR-2008-0708
77 Fed. Reg. 33,812 (June 7, 2012)

Lisa G. Dowden
Melissa E. Birchard
Spiegel & McDiarmid LLP
1333 New Hampshire Ave., NW
Washington, D.C. 20036
202-879-4000

Counsel for Kansas Power Pool

I. INTRODUCTION

Kansas Power Pool ("KPP") appreciates the opportunity to submit these comments regarding the U.S. Environmental Protection Agency's ("EPA") proposed national emission standards for hazardous air pollutants ("NESHAP") for reciprocating internal combustion engines ("RICE") rule in Docket No. EPA-HQ-OAR-2008-0708.

On March 3, 2010, EPA published a final NESHAP rule for existing compression ignition stationary RICE. 75 Fed. Reg. 9648 (Mar. 3, 2010). On December 7, 2010, EPA reopened the RICE NESHAP rule to request additional comments on questions related to the operation of stationary engines for up to fifteen hours per year as part of emergency demand response programs. 75 Fed. Reg. 75,937 (Dec. 7, 2010). On January 13, 2011, EPA held a public hearing to collect comments on these questions. On June 7, 2012, EPA released proposed amendments to the RICE NESHAP rule. 77 Fed. Reg. 33,812 (June 7, 2012). On July 10, 2012, EPA held a public hearing to collect comments on the proposed amendments. Kansas Power Pool, with and through its statewide trade association, Kansas Municipal Utilities ("KMU"), has participated throughout this rulemaking docket.

KPP thanks EPA for its efforts to arrive at a conclusion on the RICE NESHAP rule that will achieve environmental goals without compromising reliability bottom lines. KPP supports the amendments to the rule proposed on June 7, 2012, and believes these amendments constitute an important step toward ensuring that reliability needs are met for small, rural municipalities in areas of the country like Kansas where transmission limitations, small population bases, and economic constraints make large new power plants and transmission expansion infeasible.

II. BACKGROUND ABOUT KPP

KPP is a municipal energy agency, authorized by Kansas statutes and created by and for its members, all of which are municipal corporations located across the state of Kansas. KPP currently has 42 members and provides power services to 34 municipal utilities in Kansas with a total load of approximately 368 MW. KPP's members have a total of 113 stationary RICE units. KPP's members range in size from Winfield, serving 7,651 meters, to Arcadia, serving 191 meters. All of KPP's members qualify as small local governments under the federal Unfunded Mandates Reform Act ("UMRA") and as small businesses or small utilities under the federal Small Business Regulatory Enforcement Fairness Act ("SBREFA"). None of them are located in non-attainment areas for any air pollutant. In addition, none of the KPP RICE units are co-located with major sources of Hazardous Air Pollutants.

III. COMMENTS

EPA requests comments on the proposed amendments to its RICE NESHAP rule. KPP wishes to comment primarily on the allowance of 100 hours of operation for voltage events where voltage threatens to sag by 5% or greater. In addition, KPP expresses support for extending the compliance deadline for units affected by these amendments.

a. Voltage Deviations

KPP commends EPA on the proposed amendment to permit up to 100 hours of operation for voltage events where voltage threatens to deviate by 5% or greater from normal. As KPP has explained previously in this docket, Kansas consists primarily of rural areas and small towns. In electric power terms, the implications of this are that there are many small communities served by very long transmission lines. Whereas in some areas of the country there might be a payoff to incenting either the construction of new, cleaner power plants, or new transmission to reach existing power plants, it is economically infeasible to build larger lines or larger plants to serve numerous very small, scattered populations in remote locations across Kansas. Not only is it the case that small-scale population bases simply cannot support such large-scale costs; these large-scale projects would have their own out-sized environmental impacts.

In these areas, there is no redundancy – KPP members are not refusing to call on larger and more efficient power plants. KPP simply doesn't have them and cannot finance, much less maintain them. While this unfortunately means that KPP must sometimes operate uneconomic RICE units when, for example, severe weather causes a voltage event over a constrained transmission path, this is exactly what these RICE units are well-designed to do – backup generation that serves the community's needs on rare occasions when emergencies strike and the local power grid threatens to shut down.

As for the environmental impacts of running these RICE units, most KPP members run their RICE units on relatively clean natural gas. Dual-fuel RICE units require diesel for start-up, but otherwise burn roughly 90-95% natural gas. Accusations lodged by large natural gas power producers to the effect that the proposed amendments to the rule will result in greater use of dirty fuels are unfounded, at least in Kansas. In KPP's experience, operators of dual fuel units prefer to run them on natural gas because that is the most efficient and cost-effective way to do so.

Even with natural gas fuel, however, these units are highly uneconomic. In KPP's experience, operating these units costs on average two to three times (and as much as nine times) normal energy costs. The units themselves are not cost-effective to run and transportation costs for the intermittent use of natural gas in remote locations are very high. The notion that KPP members would deploy these units more frequently if given the flexibility provided in the proposed rules is simply untrue. These units are used only to keep the lights on when there is no other choice.

KPP particularly commends EPA on amending its rule to provide that a 5% voltage sag counts as a deviation event qualifying for the 100 hours of permitted operation, without requiring that the unit be called upon by a regional transmission organization ("RTO").[1] Southwest Power Pool ("SPP"), the RTO in Kansas, delegates to the individual Transmission Owners that own the transmission lines serving KPP, and sometimes to the cities themselves, the job of actually monitoring local system conditions to determine when the specified reliability criteria violations are likely to occur. KPP's members, therefore, are capable of monitoring and recording when there is a 5% voltage deviation on an incoming transmission line that triggers operation of a RICE unit for local voltage support.

KPP requests, however, that EPA clarify that a local system operator (or utility) does not need to wait until there is a full-blown outage before allowing the local utility to take action. Prudent utility practice dictates that utilities react when they see emergency conditions developing and not to wait for the harm to occur. The transition from developing conditions to actual emergency with outages can happen in seconds or fractions of a second. An actual 5% voltage drop on the local power system would constitute an emergency event triggering power outages and reliability violations. KPP asks EPA to clarify that rather than waiting for the 5% threshold and the potential outages that may arrive with it, a utility or relevant authority can identify the impending threat of such a reliability event by monitoring incoming lines for 5% voltage deviations. Operators can create reasonably contemporaneous records explaining the emergency that was pending.

KPP also asks EPA to maintain flexibility with respect to how a voltage deviation event is recorded. Different recording devices and logging mechanisms can be equally effective.

[1] In the Preamble to the Proposed Rule, at 33,817, EPA states that it "believes that the newly proposed language…will address all emergency events, including all those that would be recognized solely by the local system operators, such as local weather events."

KPP supports language such as that proposed by the Missouri Joint Municipal Electric Utility Commission in comments submitted in this docket:[2]

> In the event that the engine is operated for any reason, the owner or operator must keep reasonably contemporary records either electronically or in writing of the date and time of the commencement and ending of operation with reference to the non-resettable hour meter as well as the purpose of the engine operation. In the event that the engine was operated because of a deviation in voltage or frequency of 5% or greater, the record shall include amount of deviation and whether it was for voltage or frequency.

Finally, KPP encourages EPA to allow the use of RICE units for greater than 100 hours annually in instances of dangerous voltage deviation as well as in NERC Emergency Alert Level 2 events. KPP finds that many years its members do not need to run their RICE units at all, but that when they do, it is sometimes because there is an unpredictable emergency of large scale. In such events the units may need to be run for over one hundred hours, because RICE units serve as a lifeline for remotely located Kansas communities. One way to achieve this result would be for EPA to consider a rolling three-year average of 100 hours, rather than a strict limit of 100 hours per year. A rolling three-year average would better represent the sporadic and unpredictable nature of the need to use these units and would provide needed flexibility.

b. Compliance Extension

KPP urges EPA to extend the compliance deadline for units affected by the proposed amendments. May 3, 2013 is rapidly approaching and units affected by the proposed amendments are without certainty. KPP members who have not been certain whether they would be able to avail themselves of the opportunities provided by the proposed amendments

[2] Comment submitted by H. Floyd Gilzow, Director of Public Affairs, Missouri Joint Municipal Electric Utility Commission (Aug. 7, 2012), Docket ID EPA-HQ-OAR-2008-0708-0968.

until the proposals were published have been unable to move ahead with planning. If a unit clearly cannot fit under any amended provisions, then it is possible to move forward with planning and retrofitting now. Units that fit neatly under the emergency designation will not need to take further action. But for those engines that have been uncertain or that seek clarification of the proposed amendments, the future is unclear. As the deadline is fast approaching, there is little flexibility.

In order for KPP's members to be able to rationally and in an informed manner take the steps needed to modify, replace, or retain existing RICE units, EPA must issue a final rule. After the issuance of such a rule, there will be a significant lag time before appropriate equipment can be installed on units located remotely throughout Kansas. For this reason, KPP requests an 18-month extension of the compliance deadline.

IV. CONCLUSION

Thank you for providing KMU with an opportunity to comment on the proposed NESHAP rule for RICE. Please do not hesitate to contact us with any questions that you may have.

Submitted by:

/s/ Lisa G. Dowden

Lisa G. Dowden
Melissa E. Birchard
Spiegel & McDiarmid LLP
1333 New Hampshire Ave., NW
Washington, D.C. 20036
202-879-4000
Lisa.Dowden@spiegelmcd.com
Melissa.Birchard@spiegelmcd.com

Counsel for Kansas Power Pool

August 9, 2012

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.	)	

DECLARATION OF MELANIE KING

I, Melanie King, under penalty of perjury, affirm and declare that the following statements are true and correct to the best of my knowledge and belief, and are based on my own personal knowledge or on information contained in the records of the United States Environmental Protection Agency (EPA) or supplied to me by EPA employees.

1. I am an Environmental Engineer in the Sector Policies and Programs Division, Office of Air Quality Planning and Standards, Office of Air and Radiation (OAR) at EPA, a position I have held since May 2008. OAR is the EPA office that has the primary responsibility for developing regulations that implement sections 111 and 112 of the Clean Air Act (CAA) (42 U.S.C. sections 7411 and 7412).

2. Prior to becoming an Environmental Engineer at EPA, I worked at the North Carolina Department of Environment and Natural Resources, and as a contractor for the EPA. I have a bachelor's degree in Environmental Engineering.

3. In my current capacity as an Environmental Engineer, I am responsible for the promulgation of the NESHAP and NSPS regulations for stationary reciprocating internal combustion engines pursuant to the CAA. In this capacity, I am familiar with the processes required for compliance by owners and operators of stationary reciprocating internal combustion engines with EPA regulations under 40 C.F.R. part 60, subparts IIII and JJJJ, and 40 C.F.R. part 63, subpart ZZZZ.

4. This declaration is filed in support of EPA's motion to stay the issuance of the Court's mandate in this matter.

I. Background on Emergency Demand Response Provisions in NESHAP and NSPS Engine Rules

5. EPA promulgated revisions to NSPS and NESHAP regulations applicable to reciprocating internal combustion engines on January 30, 2013. 78 Fed. Reg. 6674 ("2013 Rule"). Relevant here, 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 under certain circumstances. Specifically, the revised regulations allowed engines to operate "for any combination" of the following three purposes, up to a cumulative total of 100 hours per year, and still be classified as emergency engines: (1) "maintenance checks and readiness testing"; (2) emergency demand response during periods when a reliability coordinator has declared an "Energy Emergency Alert Level 2" as defined by standards promulgated by the North American Electric Reliability Corporation; and (3) when there is a "deviation of voltage or frequency of 5 percent or greater below standard." *See, e.g.*, 40 C.F.R. § 63.6640(f)(2)(i)–(iii).

6. On May 1, 2015, the Court issued a decision in this case concluding that "the challenged rules that contain the 100-hour exemption for emergency engines" were arbitrary and capricious. *Delaware Dep't of Natural Resources & Envtl. Control*, 785 F.3d 1, 18 (D.C. Cir. 2015). The Court vacated certain regulations – 40 C.F.R. §§ 63.6640(f)(2), 60.4211(f)(2), & 60.4243(d)(2) – and remanded the matter to EPA for further action. *See id.* The Court left in place the remainder of the 2013 Rule, but indicated that if vacatur of the above-listed portions of the 2013 Rule would cause "administrative or other difficulties," EPA or other parties to this proceeding could "'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.* 18–19.

II. A Stay of the Mandate Until May 1, 2016, Would Provide a Reasonable Amount of Time for Engines to Install Controls

7. EPA has filed an unopposed petition for panel rehearing to seek clarification from the Court that the maintenance checks and readiness testing provisions are not vacated. With regard to the remaining provisions vacated by the Court, EPA's view is that on the date the Court's mandate is issued, engines that operate for purposes specified at 40 C.F.R. § 63.6640(f)(2)(ii)-(iii), 40 C.F.R. §§ 60.4211(f)(2)(ii)(iii), and 60.4243(d)(2)(ii)(iii) (referred to herein as emergency demand response (EDR) and voltage/frequency deviations) would not be considered "emergency engines" under the NSPS and NESHAP regulations.

8. Under the NSPS and NESHAP regulations, many types of emergency engines are subject to less stringent standards than non-emergency engines. For example, under the NESHAP regulations, emergency engines are generally required to meet work practice standards such as requirements to conduct periodic maintenance and inspection. In contrast, the NESHAP requirements applicable to many types of non-emergency engines establish numerical emission limits. *See, e.g.*, 40 C.F.R. part 63, Subpart ZZZZ, table 2c (imposing numerical emission limits on some types of non-emergency engines and work practice standards on emergency engines of the same type).

9. After the mandate issues, many emergency engine owners that choose to continue to operate for EDR or voltage/frequency deviations and retain their engines' "emergency engines" status will need to install emission control equipment to meet the NESHAP requirements applicable to non-emergency engines. Similarly, under the Spark Ignition Engine NSPS regulations, many emergency engine owners would be required to install controls to continue operating for EDR or voltage/frequency deviations.

10. In some cases, it will not be possible for engines currently classified as emergency engines to meet the non-emergency engine requirements. For example, the Compression Ignition Engine NSPS regulations contain different engine design requirements for some types of non-emergency engines and emergency engines. *See* 40 C.F.R. §§ 60.4201(a), (c), and (e); 60.4202(a)-(f); 60.4204(b); and 60.4205(b) (requiring certain non-emergency engines to meet "Tier IV" design requirements while emergency engines of the same type need only meet "Tier II" or "Tier III" design requirements). In addition, it is possible that some engines will choose not to operate for EDR or voltage/frequency deviations, and will thereby

avoid the need to install controls. EPA does not have information on the number of engines currently operating for EDR or voltage/frequency deviations that will need to install controls to continue to operate for such purposes, or on how many such engines will choose to cease operations for such purposes rather than install controls. Emergency engines used for EDR or voltage/frequency deviations are not required to report location or hours of operation for EDR or voltage/frequency deviations until March 31, 2016. *See* 40 C.F.R. §§ 60.4214(d), 60.4245(e), and 63.6650(h)). So, although EPA estimates that there are more than 1 million engines covered by the NSPS and NESHAP regulations (*see* Exhibit A, "Existing Population of Stationary RICE," Docket ID EPA-HQ-OAR-2008-0708-0014), EPA has very little information on the numbers and types of emergency engines operating for EDR or voltage/frequency deviations. However, set forth below is an estimate of the time required to install pollution control equipment that would be necessary to meet NSPS and NESHAP requirements for some types of non-emergency engines.

11. As explained in more detail below, EPA received information recently from a vendor of pollution control equipment and from the American Public Power Association (APPA) regarding the time required to install controls. EPA also received information on the time required to install controls from engine owners in 2012 and 2013. The information EPA has received suggests that the time it could take to install controls that would be necessary to meet NSPS and NESHAP requirements for some types of non-emergency engines will vary widely depending on the particular circumstances, and could range from 4 weeks (for a simple installation) to 18 months (e.g., for a complex installation or for installation on a publicly owned engine where a budgeting and competitive bidding process may be required before installation can begin).

12. Miratech, a vendor of emission control equipment for stationary engines, provided to EPA its estimates of the time it would take to complete a project to install the type of catalyst that might be required to meet NSPS and NESHAP requirements for certain types of non-emergency engines. (Exhibit B). According to Miratech, delivery of the catalyst to the site typically takes between 2-4 weeks. Miratech further explained that the time required to install the controls can vary widely. Whereas a relatively straightforward installation (e.g., no building or space issues to contend with, everything is easily accessible) could take as few as 2 weeks, a more complicated installation could take 6 months of planning prior to installation if there are space, structural, or permitting issues that need to be

resolved before installation can occur. Miratech also explained that they book their installation company 3 months in advance. Based on this information, EPA believes that a complicated installation could take up to 10 months, even if some of the steps described by Miratech could occur simultaneously (e.g., ordering equipment, booking and planning installation including obtaining any necessary permits, and actual installation).

13. For a public entity such as a municipality or a public utility, the information EPA has received indicates that the budget approval and/or a competitive bidding process that occurs before controls can be ordered or installed can add several more months to an installation project.

14. APPA, a nonprofit trade organization whose members are units of state and local governments that own and operate electric generating, distribution and transmission assets, estimated that for some of its rural members, installation of controls could take 18 months (Exhibit C).

15. Under section 112(i)(3)(B) of the Clean Air Act and EPA's regulations at 40 C.F.R. § 63.6(i), sources can request -- and EPA or States can grant -- an extension allowing the source up to 1 additional year to comply with a section 112(d) NESHAP standard, if such additional period is necessary for the installation of controls. Compliance extension requests and other information received by EPA from sources concerning the 2013 compliance date for the 2010 NESHAP rule further informs EPA's estimate of the time needed to allow sources to comply with requirements applicable to non-emergency engines.

16. For example, the attached compliance extension request from the City of Stafford, Kansas describes steps taken or planned by the City before installation of controls, including steps to evaluate the costs and benefits of installing controls, to apply for a grant to help fund the installation, and to obtain contract bids. (Exhibit D). A November 1, 2013, compliance extension request from the Iowa Department of Health and Human Services explained that under Iowa law, a construction project to install controls requires a design/engineering set of bid documents to be produced for competitive bid. (Exhibit E).

17. In addition, a request for compliance extension received from NiSource on July 31, 2012 (Exhibit F), also suggests that installation of controls can take a year or more. The NiSource letter states, "we have found that catalyst installation projects are more complex than generally recognized and can require significant modifications to the engine control systems, infrastructure, exhaust piping, and

data acquisition systems. From the time of project kickoff, the total time required for project scoping, detailed engineering, procurement, installation, startup, and testing have typically been 9-15 months, and can exceed 18 months when issues arise outside of the original project scope."

18. EPA also received comments on the June 7, 2012 proposed rule amending NESHAP and NSPS engine regulations (77 Fed. Reg. 33,812) that discussed the time required to install controls in the context of requests for compliance extensions. Two municipal commenters (Missouri Joint Municipal Electric Utility Commission and Kansas Municipal Utilities) sought an extension of the compliance deadline based on "the complexity of the purchasing process at the municipal level," and cited various concerns including: regulatory issues that must be resolved with the state and coordinating with power suppliers or their joint action agency, design, testing, and implementation issues (including making physical modifications to the power plant building), and the need to educate city councils and decision makers about the need for costly equipment. Joint Appendix 2776 (EPA Response to Comments, excerpt attached hereto as Exhibit G).

19. Based on all the above information, EPA believes that a stay of the issuance of the mandate until May 1, 2016, would be appropriate to provide for a reasonable amount of time for engines previously qualifying as "emergency engines" to install the controls required of non-emergency engines.

III. A Stay of the Mandate is Appropriate in Light of Electric Grid Reliability Concerns

20. EPA believes that a stay of the mandate is also appropriate to support grid reliability. Issuance of the mandate before August 31, 2015, would mean that many engines that are committed to operate if called upon for EDR would not be available because they lack the emission controls required for non-emergency engines. A stay of the mandate through August 31, 2015 would allow an orderly transition for independent system operators ("ISOs") and regional transmission organizations ("RTOs") such as PJM Interconnection, LLC, that are relying on emergency engines to be available for the summer months.

21. EPA has conferred with PJM and with attorneys in the Office of the General Counsel for the Federal Energy Regulatory Commission ("FERC") concerning grid reliability concerns presented by the issuance of the mandate. PJM has informed EPA that vacatur of the allowance for emergency demand response in mid-summer "would cause [it] to lose these demand response resources with no realistic means

to replace that capacity in the midst of the summer months." (*See* Exhibit H at 2). PJM also stated that it prefers to avoid significant disruptions or new operating rules during the summer months because all resources are needed if there are multiple days of hot weather. *Id.* PJM stated that issuance of the mandate this summer would be "disruptive," *id.* at 3, and that issuance of the mandate after the summer season and before winter would allow for a more orderly transition, *id.* at 2.

22. EPA discussed with FERC the reliability issues raised by PJM. FERC's Office of the General Counsel has informed EPA that based on these issues, and in the interest of an orderly transition, FERC supports a stay of the mandate through August 31, 2015.

23. EPA has also received information from entities concerning the effects of vacatur of the allowances for emergency engines to operate up to 100 hours per year in situations where frequency or voltage deviates by 5 percent or more from standard. A June 19, 2015, memorandum from counsel for APPA (Exhibit I at 2) describes comments that APPA received from several of its members that vacatur of these allowances will impair their ability to respond to voltage drops caused by severe weather or other unexpected events. According to the information submitted to EPA, this is particularly true in rural areas or small municipalities, where there are few ties to the transmission grid and limited options (other than use of emergency engines) to address grid-threatening conditions. *See* Exhibit J (June 12, 2015, letter from counsel for Kansas Power Pool to EPA). EPA believes that these local grid reliability concerns warrant a stay of the mandate beyond the summer months, through May 1, 2016. A stay will maintain the status quo while EPA evaluates to need for a rulemaking to address these issues.

IV. A Stay of the Mandate Will Not Have Significant Adverse Impacts to the Environment or Public Health

24. EPA does not believe that a stay of the mandate until May 1, 2016, is likely to have significant adverse impacts to the environment or public health. A stay of issuance of the mandate does not necessarily mean that any emergency engines would actually operate for emergency demand response or voltage/frequency deviation purposes. While emergency engines could operate during the stay period if the criteria specified in EPA's regulations at 40 C.F.R. §§ 63.6640(f)(2)(ii)-(iii) are satisfied (e.g., 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"), EPA's understanding is that such operation would be limited to specific geographic areas and would be for short periods of time. *See* Joint Appendix 1547–48 (Feb. 14, 2011 letter from PJM, attached hereto as Exhibit K); Joint Appendix 1563–64 (Feb. 29, 2012 letter from EnerNOC, attached hereto as Exhibit L).

25. 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.

SO DECLARED:

Melanie King

Melanie King

Environmental Engineer

Office of Air Quality Planning and Standards

Office of Air and Radiation (OAR)

DATED: 7-15-15

Exhibit A

ALPHA-GAMMA TECHNOLOGIES, INC.

MEMORANDUM

DATE: June 26, 2008

SUBJECT: Existing Population of Stationary RICE

FROM: Tanya Parise, Alpha-Gamma Technologies, Inc.

TO: Jaime Pag n, EPA Energy Strategies Group

The purpose of this memorandum is to present the population of existing stationary reciprocating internal combustion engines (RICE) that will be used to estimate the national impacts of the national emission standards for hazardous air pollutants (NESHAP) for this source category. This memorandum addresses existing stationary RICE less than and equal to 500 horsepower (HP) located at major sources of HAP emissions and existing stationary RICE of all sizes located at area sources of HAP emissions.

The population of existing stationary RICE is based on information in the Power Systems Research's (PSR) North American Engine PartsLink Database provided by the U.S. EPA Office of Transportation and Air Quality. EPA has previously discussed the appropriateness for using estimates developed by PSR (see Attachment A to Document ID Number EPA-HQ-OAR-2005-0029-0007, available from http://www.regulations.gov.)

Population estimates have previously been developed for the new source performance standards (NSPS) for spark ignition (SI) and compression ignition (CI) stationary engines. These memoranda can be obtained from http://www.regulations.gov as Document ID Numbers EPA-HQ-OAR-2005-0030-0015, EPA-HQ-OAR-2005-0030-0063, and EPA-HQ-OAR-2005-0029-0007.

Existing Population of Engines

The existing population of engines in the U.S. was based on using the information from PSR's database as the baseline population. The baseline year for CI engines was 1998 and the baseline year for SI engines was 2002. The baseline population numbers are provided in Table 1. To estimate the existing population in 2008, engine sales information from PSR was used to project the number of new engines that would be sold in the years 1999 through 2007 for CI engines and 2003 through 2007 for SI engines. EPA applied the same method for determining the number of new stationary engines as was done under the CI and SI NSPS. The methodology applied to estimate the current population of engines was described in the memoranda referenced on page 1 of this memorandum.

Table 1. Baseline Population of CI and SI Stationary Engines (includes all engines at major and area sources)

HP Range	Population	
	SI (as of 2002)	CI (as of 1998)
25-50	109,075	0
50-100	21,815	124,064
100-175	44,262	197,076
175-300	9,755	130,744
300-600	9,554	140,058
600-750	1,116	24,359
750	10,369	47,478
Total	**205,946**	**663,780**

EPA applied the same assumptions that were used to develop the projected number of new engines under the CI and SI NSPS for consistency across rulemakings addressing similar or the same engines. The main assumptions used to develop the necessary population estimates for this rulemaking are as follows:

- No stationary CI engines below 50 HP.
- No stationary SI engines below 25 HP.
- Percent of stationary RICE located at major sources: 40
- Percent of stationary RICE located at area sources: 60
- CI engines breakdown:
    - o Percentage that are prime engines: 20
    - o Percentage that are emergency engines: 80
- New SI engines breakdown[1,2]:

    1,000 HP
    - o Percentage that are 4SLB: 53
    - o Percentage that are 4SRB: 47

    1,000-5,000 HP
    - o Percentage that are 4SLB: 75
    - o Percentage that are 4SRB: 25

    5,000 HP
    - o All 4SLB

[1]The breakdown for existing engines is 11 , 47 , and 42 for 2SLB, 4SLB, and 4SRB, respectively.
[2]2SLB engines represent less than 0.1 percent of new stationary SI engines.

The estimated total existing population of stationary engines and the population of these engines at major and area sources is presented in Tables 2, 3, and 4, respectively.

Table 2. Total 2008 Population of Stationary RICE

Size Range (HP)	Existing Population (2008)	
	SI Engines	CI Engines
25-50	142,667	0
50-100	41,569	262,505
100-175	76,262	328,759
175-300	22,576	254,778
300-600	18,134	191,239
600-750	1,909	31,807
750	21,530	79,976
Total	**324,646**	**1,149,064**

Table 3. 2008 Population of Stationary RICE at Major Sources

Size Range (HP)	Existing Population Major Sources (2008)	
	SI Engines	CI Engines
25-50	57,067	0
50-100	16,628	105,002
100-175	30,505	131,504
175-300	9,030	101,911
300-500	4,836	50,997
Total	**118,065**	**389,414**

Table 4. 2008 Population of Stationary RICE at Area Sources

Size Range (HP)	Existing Population Area Sources (2008)	
	SI Engines	CI Engines
25-50	85,600	0
50-100	24,941	157,503
100-175	45,757	197,255
175-300	13,545	152,867
300-600	10,881	114,744
600-750	1,145	19,084
750	12,918	47,986
Total	**194,788**	**689,438**

Information received from and developed in conjunction with the Engine Manufacturer's Association (EMA) in order to determine how the population of existing CI engines is distributed over various model years is presented in Table 5. A similar version of this information was presented in the Advanced Notice of Proposed Rulemaking (73 FR 4136). Note that this table is based on earlier population estimates and does not match the updated estimates presented in Tables 2 through 4 of this memorandum. Table 5 is intended to present an overview of how engines are distributed over different model years. The percentages of older engines to newer engines is what is relevant in the below table.

Table 5. Breakdown of Stationary CI RICE by Model Year

Size Range (HP)	<1980	1980-1994	1994-2001	2002-2005	Pre-1994	1994-2005	Totals
50-100	26,200	62,759	49,919	22,521	88,959	72,440	161,399
100-175	57,426	92,857	61,572	23,634	150,283	85,206	235,489
175-300	27,198	63,991	57,739	40,877	91,189	98,616	189,805
300-600	70,303	53,188	38,778	31,403	123,491	70,181	193,672
600-750	8,562	12,664	10,743	8,648	21,226	19,391	40,617
750	6,899	28,357	33,835	10,520	35,256	44,355	79,611
Total	**196,588**	**313,816**	**252,586**	**137,603**	**510,404**	**390,189**	**900,593**

References

1. Memorandum from Tanya Parise, Alpha-Gamma Technologies Inc. to Sims Roy, U.S. Environmental Protection Agency, OAQPS ESD Combustion Group. June 20, 2005. Population and Projection of Stationary Engines (EPA-HQ-OAR-2005-0029-0007).

2. Memorandum from Tanya Parise, Alpha-Gamma Technologies Inc. to Sims Roy, U.S. Environmental Protection Agency, OAQPS ESD Combustion Group. April 5, 2006. Population and Projection of Stationary Spark Ignition Engines (EPA-EPA-HQ-OAR-2005-0030-0063.)

3. Memorandum from Bradley Nelson, Alpha-Gamma Technologies Inc. to Jaime Pag n, U.S. Environmental Protection Agency, EPA Energy Strategies Group. April 5, 2006. Population and Projection for Stationary RICE at Major and Area Sources (EPA-HQ-OAR-2005-0030-0015).

4. Memorandum from Melanie Taylor and Chuck Zukor, Alpha-Gamma Technologies Inc. to Sims Roy and Jaime Pag n, EPA OAQPS ESD Combustion Group. June 22, 2004. Decision on Using Estimates from PSR or the RICE NESHAP Population Database for Engines above 500 Horsepower (EPA-HQ-OAR-2005-0029-0007).

Exhibit B

MIRATECH

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July 3, 2015

Ms. Melanie King
Energy Strategies Group
Sector Policies and Programs Division
Office of Air Quality Planning and Standards

U.S. Environmental Protection Agency
Mail Code D243-01
RTP, NC 27711
Phone: (919) 541-2469
Fax: (919) 541-5450
king.melanie@epa.gov

Dear Ms King,

In response to your inquiry about the length of time it would take to install catalysts for compliance with the Provisions of Rice NESHAP here are the current conditions with regards to production and installation.

Production of Equipment:

The supply of catalysts is pretty abundant, so you can typically get delivery of the catalyst within a month, and often within 2 weeks. That's pretty standard across the industry, not just for Miratech. Outside of custom formulations for Very Low exhaust temperature applications- the current availability of catalyst and housing materials is very high.

Installation: There is a much broader window with regards to the time to install the controls. If you have a fairly easy set-up (no building or space issues to contend with, everything is easily accessible), it takes about 2 weeks for installation. This would be the case if the engine is in its own stand-alone enclosure and at ground level. Most of the time if the installation is just the Oxidation catalyst the enclosures can bear the weight of the device with little additional support. Miratech works with several contractors across the country or directly with the engine dealer and as a general rule we book the installs about 3 months in advance.

If there are more challenges with the set-up, it can take longer. An example is buildings in New York City, engines are usually in the basement or on the roof, so you have space and/or structural issues to deal with, plus there is permitting involved. An installation in NYC typically takes 6 months of planning before the installation begins. So, there is a range of time that is needed, depending on facility

If you have any other questions or we can help in any way- please let us know

Regards,

Jim McDonald

Engineer

Miratech Corporation

Exhibit C

King, Melanie

From: Hofmann, Alex [mailto:ahofmann@publicpower.org]
Sent: Wednesday, July 08, 2015 5:00 PM
To: King, Melanie
Cc: Nipper, Joe; Patterson, Delia; Leslie Ritts; Elliott, Randolph; Hyland, Mike; Waterhouse, Desmarie
Subject: RE:

Hi Melanie,

We surveyed our members in response to your question regarding the amount of time it would take to comply with the RICE rule (if it was vacated and there were no hours to run). We found that a number of our members in rural areas would be looking at the following estimated time frame for the each element of the RICE retrofit process:

1) Selection of Engineer and completion of a Preliminary Opinion of Costs - 3 months
2) Issue Bonds for financing and perform unit backpressure testing - 5 months
3) preparation of specs and design Issue RFP - 3 months
4) Review and accept bids for site work and prepare equipment POs - 3 months
5) Build and Deliver Equipment (silencers and catalyst) - 3 months
6) Site installation and testing - 1 month

Total Time 18 months

So , in total this represents 18 months needed to comply and this was cited as a "doable, but aggressive timetable".

I should note that this information is an estimate and may change subject to certain situational factors. In addition, one thing that is important to highlight at this point in the regulatory process is that some RICE were designated emergency because there was/is no realistic application of control technology. Here is a quote from a member on this issue: "The issue we found was that most of the units that eventually took an emergency designation were the really old units that couldn't get hot enough to activate the catalyst – that is, they were never going to be brought into compliance." We think this is a significant situation that merits consideration in this process.

Again thank you and we are very appreciative of the opportunity to provide this information.

Alex

Exhibit D

City of
Stafford
112 W. Broadway Stafford, KS 67578
Municipally Owned Water and Light cityofstafford@sbcglobal.net

December 28, 2012

REC'D
JAN 03 2013
APCO

To: David Peter
Environmental Engineer
U.S. Environmental Protection Agency, Region 7
901 North 5th Street
Kansas City, KS 66101
Peter.David@epamail.epa.gov

From: City of Stafford, Kansas
112 W. Broadway
Stafford, Kansas 67578
Facility Number 1792401

Re: **Request for Grant of Extension for Installation of Compliance Controls**
National Emission Standards for Hazardous Air Pollutants;
Stationary Reciprocating Internal Combustion Engines
40 CFR part 63, subpart ZZZZ

The City of Stafford, Kansas hereby requests a one-year extension to comply with the NESHAP CI-RICE rule, pursuant to 40CFR 63.6(i)(4)(i)(A) and §63.6(i)(6) for the following effected units:

EU #1 Fairbanks-Morse Unit #1	Destroyed by Fire	
EU #2 Fairbanks-Morse Unit #2	900 kW	Diesel/Natural Gas Dual Fuel
EU#3 General Electric Unit #3	700 kW	Diesel/Natural Gas Dual Fuel
EU #4 Fairbanks-Morse Unit #4	1365 kW	Diesel/Natural Gas Dual Fuel
EU #5 Fairbanks-Morse Unit #5	1136 kW	Diesel/Natural Gas Dual Fuel

City Office
(620) 234-5011

City Police
(620) 234-5161

Power Plant
(620) 234-5561

All City Offices FAX (620) 234-6033

Reason for Request:

The units listed above are not able to meet emission standards for CI-RICE that become effective on May 3, 2013. The City has evaluated each of its RICE units and concluded that the units listed above are capable of meeting the new standards through the installation of control equipment. The financing for the installation of the necessary equipment will be partially covered by utility revenue and partially from funds obtained through a grant the city is in the process of competing to receive. Stafford has completed the system study that will allow them to apply for a CDBG grant to cover the cost of the system update and/or upgrade of their electrical system, including the retrofitting of the RICE units. A copy of the report is attached. In addition, our council has approved us to gather bids to retrofit our units. We hope to be approved for funding and in the meantime, we are securing the vendor cost to complete the retrofit.

Other steps that have been taken include evaluating costs and benefits of installing the control equipment under the rule, with and without EPA's proposed amendments and under changing market conditions, including purchase of available capacity. Currently, Stafford is not part of any supply pool so obtaining minimal capacity via a purchase agreement from other utilities is fairly complex but we do have experience in buying capacity from other cities as recent as this past summer. However, we plan to retrofit our units and be able to carry our own load.

On May 22, 2012, the EPA proposed amendments to the final rule in National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Docket No. EPA-HQ-OAR-2008-0708. The city of Stafford supported the proposed amendments through comments made on its behalf by Kansas Municipal Utilities, the American Public Power Association, and others. However, the order adopting amendments was not issued until December 14, and now has been delayed to January 14th, 2013. Because of the uncertainty regarding the need to retrofit the engine, we could not proceed with installation of control equipment, which would have placed a significant and potentially unnecessary cost burden on the community and its customers.

Only now, with the final rules becoming available is the Utility able to complete its evaluation of the costs and benefits of retrofitting the units to which this request applies. A one year extension will allow time to obtain contract bids and secure the grant funding to install the control technology. We will be able to complete the installation well within the one year extension. Should the date by which final compliance is achieved be after the end date of the extension, Stafford will operate the unit in accordance with the provisions of the rule as of that date, until compliance is achieved.

The controls to be installed for each engine, if the evaluation of the final rule and relevant costs and benefit warrant, include a catalytic converter sized to achieve compliance, associated modification of the exhaust stack, monitoring equipment, and possible crankcase ventilating systems.

The following is the compliance schedule for this request:

Date	Action
February 15, 2013	Complete cost benefit analysis for installation of control technology, based on operating parameters permitted under the final rule, as it may be amended in Docket No. EPA-HQ-OAR-2008-0708 and issue and RFP to install equipment
March 15, 2013	Select vendor to retrofit units
May 23, 2013	Effective date of final rule and first day of requested one-year extension
July 21, 2013	Complete installation of unit conversions
September 1, 2013	Perform and complete all EPA testing and validation
May 24, 2014	Final compliance achieved and end-date for requested one-year extension

Certification:

I certify that the information contained in this request is accurate and true to the best of my knowledge.

By: Shawn J Burgey

Shawn Burgey
City Utility Superintendent
620-234-5561
Cityofstafford@sbcglobal.net

Shawn,

Thank you for your interest in our products and services. FMI proposes to supply and install catalyst/silencer units, instrumentation and training as previously described to bring the following units into compliance with current NESHAP regulation for RICE.

Option 1 - RICE NESHAP

Engine #4	Fairbanks Morse	720 RPM	1365 kW
Engine #5	Fairbanks Morse	720 RPM	1136 kW
	Total Cost Project:	$183,768.00 *(excludes sales tax)*	

Option 2 - RICE NESHAP

Engine #2	Fairbanks Morse	720 RPM	900 kW
Engine #4	Fairbanks Morse	720 RPM	1365 kW
Engine #5	Fairbanks Morse	720 RPM	1136 kW
	Total Cost Project:	$266,652.00 *(excludes sales tax)*	

As another option, financing is available through Farabee Mechanical Inc. If interested contact Donna Oehm Client Service Manager (402) 405-7288.

The Operating Support you need...
When you need it.

August 24, 2012

Shawn Burgey
City of Stafford
112 W. Broadway
Stafford, KS 67578

Dear Mr. Burgey,

Thank you for this opportunity for ***Utility HelpNet, Inc.*** to provide engineering services for your community.

Based on our on-site visits, and conversations with management and field personnel, we have prepared the enclosed preliminary report regarding the review of the City's electrical distribution system.

Please feel free to call me at **(316) 946-1144** if you have questions or if you would like additional information.

We appreciate the opportunity to work with you and with the City Council regarding this report.

Sincerely,

Cris Naegele

Cris Naegele, Chief Operations Officer

Electrical System Assessment

General Observations

The City does not have any formally adopted line construction standards. The City should adopt the current versions of the National Electric Code (NEC) and the National Electric Safety Code (NESC) as standards that must be followed within the City limits. The City does not have any current maps which are suitable for an assessment of the existing system condition. Current maps have become a requirement for federal FEMA assistance as a result of the December, 2007 Ice storm.

Joint Pole Use agreements should be reviewed to clearly specify the City policy that current standards shall be followed when adding any attachments to a pole. Joint Pole Use agreements should also clearly define who is responsible for any costs to evaluate code compliance and any costs for upgrades or replacements which may be needed to meet or exceed code.

A formal operational procedure and service policy should be in place for customer-owned generation, including any net metering agreements. Procedures and policies could apply to solar, wind, fuel cells, or generators.

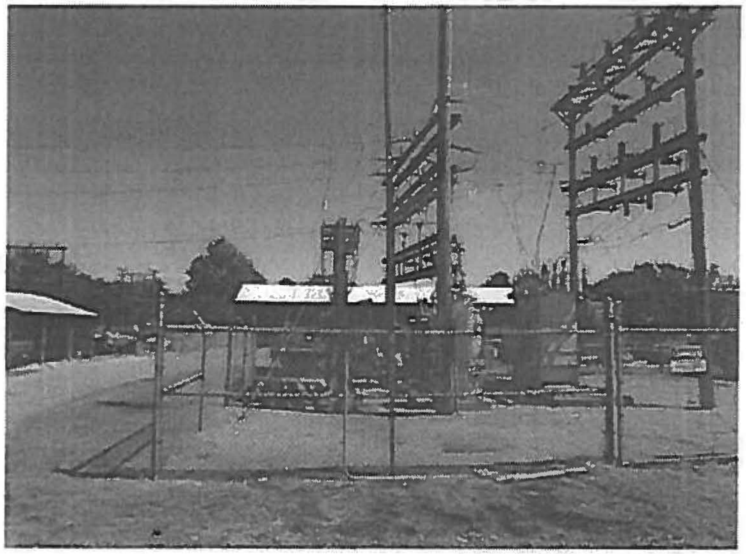
There is no engineering data available for conducting an arc hazard analysis for work conducted around energized equipment. Arc hazard analysis is required by the NESC and Code of Federal Register 29CFR1910.269. Arc hazard labels must be applied to any electrical switchgear and panels. Workers must be properly trained and have the proper personal protective equipment (PPE) for the tasks performed around energized equipment.

Grid Interconnect

The City receives its power from Midwest Energy from a substation located just north of the power plant. The transformer is a 2010 model and is rated at 2500/3500kW.

The normal rated output from the MWE substation is 2500kW. The emergency rating allows the load to be increased up to 3500kW under certain conditions. The City's summer peak for 2011 was 3400kW; therefore, this substation tie point should be considered overloaded at peak times. Further, the wooden structures are nearing the end of their useful life. An upgrade to the interconnect substation should be discussed with Midwest Energy.

Continuing to operate the existing substation transformer under overloaded conditions will result in a decrease in its expected life span and reliability.



Generation

The City currently has 4 generators. The nameplate capacity of all current generation is 4,101kW.

Generator 1: Destroyed by fire 2011

Generator 2: 1952 – Fairbanks Morse 900kW, last major engine work performed in 1991.

Generator 3: 1957 – General Electric 700kW, last major engine work performed in 1981

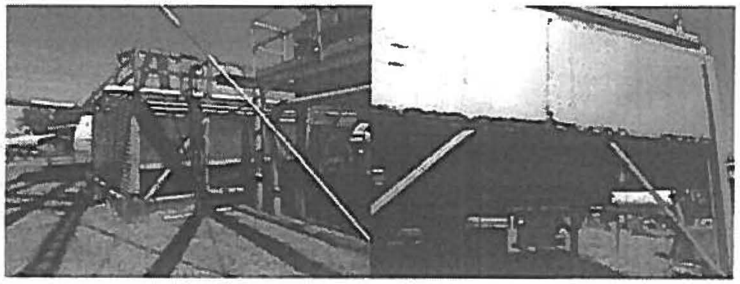
Generator 4: 1973 – Fairbanks Morse 1365kW, last major engine work performed in 1992

Generator 5: 1961 – Fairbanks Morse 1136kW, last major engine work performed in 1989

None of the existing engines will meet the National Emission Standards for Hazardous Air Pollutants that will go into effect May, 2013. Without upgrades to the exhaust system, the existing engines can only be operated as emergency units after this date. There is a proposal to allow a limited amount of generation up to 100 hours a year per engine until 2017, but the final rule has not yet been issued and will not go into effect until March of 2013.

The City is securing a short term power contract to import 1 MW of firm power. This will require the City to generate to meet its own load down to this 1MW level during the summer of 2012 when called on by Midwest Energy to do so. Currently the City does not have manual control of the voltage regulators in the MWE substation. This manual control is required to properly regulate the City's voltage when running parallel to the grid.

There are 2 cooling towers at the plant. Both are usable but require ongoing repairs and are prone to leaks. Significant repairs or replacement could be expected in the next 5-10 years.



All 4 of the existing generators use the original generator control system. This is an electro-mechanical system that has not changed in basic design since the 1950s. This type of system is above average in reliability, but below average in usability on today's modern grid. When operated isochronously, or off the grid, both the frequency and voltage generated by this type of system would be expected to vary by a noticeable amount. This can be an issue with the sensitive electronics in use today. The generator oil circuit breakers in this switchgear should be considered near the end of their useful life.

The City has plans to replace the destroyed Generator 1 with a modern 2000kW generator from Caterpillar. These plans provide the City with the opportunity to install one engine with a modern control system and a compliant air quality exhaust.

This single new engine will carry the entire town load part of the year and may also be used for peaking purposes. However, while off the grid, the City may experience operational issues when attempting to operate the old and new generators together, without first installing control upgrades to one or more of the older units.

Distribution

The electric distribution system is a 4160 volt wye system.

There are five distribution circuits which are all fed from switchgear located in the power plant. The circuits are protected by standard overcurrent relays and oil circuit breakers. The switchgear and components appear to have been tested and maintained on a regular basis. However, they are over 40 years old and should be considered at the end of their useful life

There are approximately 1200 poles in the distribution system. The preliminary assessment indicates 20-40% of these support structures should be considered at the end of their useful life of 40 years. Another 20-40% could be considered near or at the end of their useful life with in the next 5-10 years.

A significant weather event (not necessarily a tornado) would be expected to cause major damage to the distribution system and may cause extended power outages for several days.

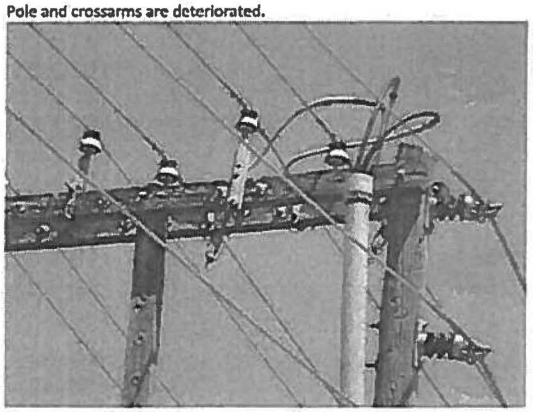
The 2-pole structures in the downtown alley areas have numerous NESC code violations and are in poor to bad condition.

Many of the poles located on circuits which feed critical loads are in poor to bad condition.

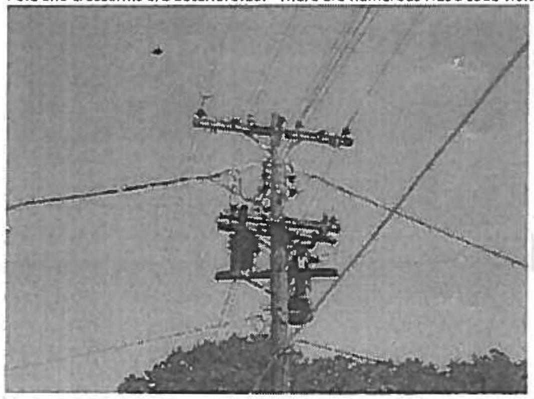
There are several areas of town with old copper conductor that is in poor to bad condition. This wire has become brittle over the years and may break under wind and icing conditions. These broken wires will cause outages and may endanger workers and the general public.

There are several areas in town where the system neutral conductor is not properly bonded to ground. This can cause problems with voltage imbalance and in extreme cases cause damage to equipment or become unsafe to work around.

Pole and crossarms are deteriorated.



Pole and crossarms are deteriorated. There are numerous NESC code violations.



System Losses and Energy Efficiency

Based on preliminary calculated data, the system energy line losses are between $15,000 and $30,000 annually. This is based on a 4160V system, a peak load of 3400kW, and an off-peak load of 1600kW.

A conversion to 12.47kV and replacing the smaller conductor on the system may reduce these line losses by up to 80%.

Replacing existing equipment with higher efficiency transformers and street lighting would further reduce these losses.

Recommendations

The following are project recommendations and an Opinion of Probable Cost for each project. The costs should be considered a Class 5 estimate and only represent an order of magnitude of possible costs. The actual cost may vary 50% or more from these estimated values.

These recommendations are divided into project phases. Phase 1 projects are those that should be completed in the next 12 months. Phase 2 projects should be completed within the next 24 months. Phase 3 projects should be completed within the next 36 months.

Phase 1 — **$810,000**

Prepare Maps of Distribution System — **$10,000**

This project would provide maps of the City's electrical distribution system. This would include a base map of the streets and roads, pole locations, transformer location and size, and conductor size and type. This project would contain sufficient information for a subsequent arc hazard study. This project would also include a system condition assessment to meet FEMA pre-existing condition documentation requirements.

Replace Generator 1 — **$800,000**

This project would replace generator number 1 destroyed in the 2011 fire. A new or lightly used 2000kW generator would be installed with the proper emissions control to meet EPA air quality standards. Modern generator controls and protection equipment would allow this unit to be used for peaking, voltage control, and emergency use. This single unit would carry the entire City load for much of the year. This project scope includes all engineering, materials, permits, and related electrical infrastructure to connect to the existing system.

Phase 2	$806,500

Arc Hazard Study $6,500

This project would provide the necessary information for conducting an arc hazard analysis as specified by the NESC. Prior to beginning this project, accurate distribution system maps would be required or data provided that includes conductor size and length. This project would create a computer model of the City's electrical system to calculate available short circuit and arcing current. This information would enable workers to determine the proper level of PPE required to be worn while performing tasks around energized equipment. This project would also provide the installation of equipment labels on necessary electrical panels at the power plant.

Replace Distribution Feeder Switchgear $300,000

This project would replace the existing switchgear currently located in the power plant to a location outside the plant. This may include a new building or substation yard installation.

Rebuild Distribution Feeder Circuits part 1 $250,000

Replace poles and conductor at various locations to provide a more reliable and efficient distribution system. Priority should be given to improving line which is serving critical loads, such as hospital, schools, grocery stores, gas stations, emergency services.

Upgrade Generator 4 $250,000

This project would replace the existing generator control and protection systems and upgrade the exhaust system to meet NESHAP regulations. This would include replacing the engine governor, adding an electronic speed control, replacing the voltage regulator, adding a generator control system, replacing the generator breakers, adding the grid synchronizing controls, appropriate monitoring and catalyst system to meet the National Emission Standards

Phase 3	$800,000

Replace Cooling Towers $200,000

This project would replace the 2 existing cooling towers with new ones.

Upgrade Generators 5 and 2 $375,000

This project would replace the existing generator control and protection systems and upgrade the exhaust system to meet NESHAP regulations. This would include replacing the engine governor, adding an electronic speed control, replacing the voltage regulator, adding a generator control system, replacing the generator breakers, adding the grid synchronizing controls, appropriate monitoring and catalyst system to meet the National Emission Standards

Rebuild Distribution Feeder Circuits part 2 $225,000

Replace poles and conductor at various locations to provide a more reliable and efficient distribution system. Priority should be given to improving line which is serving critical loads, such as hospital, schools, grocery stores, gas stations, emergency services.

Exhibit E

Location:	Powerhouse (711 S. Vine; Glenwood, IA)	See attached campus map
Unit Number:	EU-5 (diesel generator no. 1)	EU-6 (diesel generator no. 2)
Engine Make:	Cummins	Cummins
Engine Model:	1500DFLE-4083	1500DFLE-4083
Engine Serial Number:	L030578793	L030578794
Site Rated Horsepower:	2,220 BHP	2,220 BHP
Date of Construction:	2003	2003

Please provide notice of receipt of this letter. If you have any questions, please contact me at 712.525.1444.

Sincerely,

Kelly Brodie

Kelly Brodie
Glenwood Resource Center
711 South Vine Street
Glenwood, IA 51534

Cc: NESHAP Coordinator, Iowa Department of Natural Resources, Air Quality Bureau (1)
State of Iowa, Department of Administrative Services (1)
File (1)

Iowa Department of Human Services

Terry E. Branstad
Governor

Kim Reynolds
Lt. Governor

Charles M. Palmer
Director

November 1, 2013

Elizabeth Kramer
Air Compliance and Enforcement Section
US EPA Region 7
11201 Renner Blvd
Lenexa, KS 66219

RE: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines 40 CFR Part 63, Subpart ZZZZ Request for Compliance Extension at Glenwood Resource Center

Glenwood Resource Center submits the following information in request of a second extension to comply with the NESHAP/RICE requirements for emissions standards.

In April, GRC was granted an initial extension to update / upgrade the two (2) existing generators on-site to meet the NESHAP/RICE requirements related to emissions. At that time the granted compliance date by the EPA was extended to November 15, 2013.

In accordance with Iowa code, these types of construction projects require a design / engineering set of bid documents to be produced and issued for competitive bid. In the interest of economy, the two (2) generators at Glenwood were included with a multiple facility project handled by the State of Iowa's Department of Administrative Services (DAS) where multiple generators across the state requiring the emissions upgrade were included for design and subsequently competitive bid.

The other facilities, as part of the process, submitted and received compliance extensions of May 3, 2014.

As of today, the contract for these upgrades has been awarded and submittal review / equipment fabrication is currently in progress. The current construction schedule places this work to be completed at the Glenwood Resource Center during the week of January 6th. In similar fashion to the other state facilities, we would like to request the compliance extension to be extended to May 3, 2014.

The extension request would cover existing units information are as follows:

Exhibit F

NiSource
1700 MacCorkle Avenue S.E.
Charleston, WV 25314

July 31, 2012

John Dupree
Office of Enforcement and Compliance Assurance
USEPA Headquarters
Ariel Rios Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 2227A
Washington, DC 20460

Subject: 40 CFR 63 Subpart ZZZZ Request for Compliance Extension under §63.6(i)

Dear Mr. Dupree:

NiSource, Inc. (NiSource) operates electric generating units and natural gas compressor stations in 10 states and five EPA Regions (2, 3, 4, 5 and 6). Most of our stations have one or more engines that are subject to the RICE MACT (Subpart ZZZZ of 40 CFR 63). In total, NiSource owns and operates 51 engines that may be required to install emissions controls according to the March 3, 2010 revisions to Subpart ZZZZ that establish a compliance deadline of May 2, 2013 for Compression Ignition engines and the August 20, 2010 revisions that establish an October 19, 2013 deadline for Spark Ignition engines. Attachment A lists the station names and locations of these engines. On June 7, 2012, EPA proposed revisions to the compliance requirements for engines located at Area Sources that are in "remote" areas, which may remove the requirement for emissions reductions.

Delegation of Authority for enforcement of Subpart ZZZZ has been accepted by some of the states where the NiSource affected engines are located. However, Ohio, Pennsylvania, and Virginia have not accepted delegation of authority. For the reasons discussed below, and as allowed in 40 CFR 63.6(i), NiSource submitted requests for extensions to EPA Regions 3 and 5 and to individual states for several of the affected engines. However, we were recently advised by Ray Chalmers of Region 3 and Erik Hardin in EPA Region 5 to submit all extension requests for engines at affected facilities not delegated to states, to EPA Headquarters and that you are the point of contact for such requests. The basis for the request for an extension is summarized below.

NiSource began work on the design, installation, startup, and performance testing of catalysts soon after the 2010 revisions to Subpart ZZZZ was promulgated. As of the end of 2011, NiSource has completed catalyst installations on 11 engines, an additional 15 engines were scheduled for 2012, and NiSource was beginning work on the Scopes of Work for the remaining engines when the recent rule changes were proposed.

Based on our experience since 2010, we have found that catalyst installation projects are far more complex than generally recognized and can require significant modifications to the engine control systems, infrastructure, exhaust piping, and data acquisition systems. From the time of project kickoff, the total time required for project scoping, detailed engineering, procurement, installation, startup, and testing have typically been 9-15 months, and can exceed 18 months when issues arise outside of the original project scope . During development of project schedules for the remaining engines, we have identified several concerns that may impact compliance with the deadlines for Subpart ZZZZ. These concerns include:

- A limited supply of equipment suppliers and qualified contractors to perform the work, as many are already busy with projects in Marcellus and Utica shale fields development;
- The amount of time required to ensure that the controls and monitoring systems are properly functioning after installation;
- Limited availability of qualified emissions testers available to handle the load of initial performance tests and ongoing periodic tests already required by permits and rules; and
- Our recent catalyst installation history that encountered unforeseen technical issues requiring significant additional analysis and engineering.

NiSource is also requesting extensions, perhaps most importantly, due to the recent proposed changes to the rule. The day the proposed changes were proposed NiSource was forced to stop installation of a catalyst that was underway and suspend plans for several others due to begin with days. NiSource believes it is irrational to define and implement compliance plans until the EPA has promulgated final rules, and for the reasons discussed above.

NiSource is requesting a one-year extension in the compliance deadline for all engines that have not yet installed catalysts and for five (5) engines that already have. (As discussed above, several engines are experiencing ongoing issues regarding engine operation since catalyst installation). The Attachment shows the location, type, and disposition of each engine affected by proposed emissions reductions in the 2010 version of the rule. This submittal is requesting extensions for those engines for which delegation of authority has not been accepted by the states. We will also be requesting extensions from the delegated state authorities for the remaining engines.

Each of the request forms provides, as best as can be supplied at this time, the information identified in 40 CFR 63.6(i) and 63.9(c). Some information, such as dates control devices will be contracted, dates installation of controls will begin, and dates onsite construction is to be completed cannot be determined at this time as the final scope of these projects is still being developed or their status is in question since the rule is in flux.

To assist NiSource's compliance with the RICE MACT by the compliance due dates, we are requesting U.S. EPA's response within 30 days after submittal as provided in 40 CFR 63.6(i)(12)(i). If you have any questions or require additional information, please contact Joe Morgan at (304) 357-2196 or jmorgan@nisource.com.

Sincerely,

William T. Kilpatrick

William T. Kilpatrick
Vice President of Natural Gas Transmission & Storage

Cc. Ohio EPA – Division of Air Pollution Control
Pennsylvania DEP – Bureau of Air Quality
Virginia DEQ – Air Quality Division

NiSource

1700 MacCorkle Avenue S.E.
Charleston, WV 25314

ATTACHMENT A – ENGINE LIST

Station Name	State	Major/Area MACT Status	Engine Type	Region	Major Source Delegation	Area Source Delegation	Target Year of Installation	Catalyst Type	Notes
Brinker	OH	Area	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Brinker	OH	Area	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Brinker	OH	Area	4L	5	Yes	No	2012	OC	Requesting Extension/EPA
Crawford	OH	Major	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Crawford	OH	Major	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Crawford	OH	Major	4R	5	Yes	No	2012	NSCR	Requesting Extension/EPA
Miley	OH	Area	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Miley	OH	Area	4R	5	Yes	No	2010	NSCR	Catalyst Installed
Miley	OH	Area	4L	5	Yes	No	2012	OC	Requesting Extension/EPA
Buff Lick	WV	Area	4R	3	Yes	No	2010	NSCR	Catalyst Installed/Requesting Extension/EPA
Kenova	WV	Area	4R	3	Yes	No	2010	NSCR	Catalyst Installed/Requesting Extension/EPA
Kenova	WV	Area	4R	3	Yes	No	2010	NSCR	Catalyst Installed/Requesting Extension/EPA
Kenova	WV	Area	4R	3	Yes	No	2010	NSCR	Catalyst Installed/Requesting Extension/EPA
Kenova	WV	Area	4R	3	Yes	No	2010	NSCR	Catalyst Installed/Requesting Extension/EPA
Corning	NY	Area	4L	2	Yes	No	2012	OC	Requesting Extension/EPA
North Greenwood	NY	Area	4L	2	Yes	No	2012	OC	Requesting Extension/EPA
Artemas	PA	Major	4R	3	Yes	No	2012	NSCR	Requesting Extension/PADEP
Blackhawk	PA	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Delmont	PA	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Delmont	PA	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Donegal	PA	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Donegal	PA	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Easton	PA	Area	4R	3	Yes	No	2013	NSCR	Requesting Extension/EPA
Glady	WV	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA

Glady	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Glady	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Hubball	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Hubball	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Smithfield	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Smithfield	**WV**	Area	4L	3	Yes	No	2012	OC	Requesting Extension/EPA
Walbridge	**KY**	Area	4L	4	Yes	Yes	2013	OC	Requesting Extension/KY
Hellertown	**PA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Hellertown	**PA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Boswell Tavern	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Boswell Tavern	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Emporia	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Emporia	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Gala	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Gala	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Gala	**VA**	Area	4L	3	Yes	No	2013	OC	Requesting Extension/EPA
Petersburg	**VA**	Area	4R	3	Yes	No	2013	NSCR	Requesting Extension/EPA
Majorsville	**WV**	Major	4R	3	Yes	No	2013	NSCR	Requesting Extension/WV DAQ
Majorsville	**WV**	Major	4R	3	Yes	No	2013	NSCR	Requesting Extension/WV DAQ
Majorsville	**WV**	Major	4R	3	Yes	No	2013	NSCR	Requesting Extension/WV DAQ
Majorsville	**WV**	Major	4R	3	Yes	No	2013	NSCR	Requesting Extension/WV DAQ
Majorsville	**WV**	Major	2L	3	Yes	No	2013	OC	Requesting Extension/WV DAQ
Rockport	**WV**	Area	4R	3	Yes	No	2013	NSCR	Requesting Extension/EPA
Rockport	**WV**	Area	4R	3	Yes	No	2013	NSCR	Requesting Extension/EPA
Rockport	**WV**	Area	4R	3	Yes	No	2013	NSCR	Requesting Extension/EPA
Terra Alta	**WV**	Major	4R	3	Yes	No	2013	NSCR	Requesting Extension/WV DAQ
Grass Creek	**IN**	Area	4L	5				OC	Not Operating

Exhibit G

8.0 Compliance Date

8.1 Comment: A number of commenters (875, 877, 916, 939, 941, 942, 943, 945, 948, 951, 952, 967, 968, 970, 974, 975, 976, 977, 978, 979, 984, 985, 986, 996, 997, 999, 1002, 1003, 1007, 1015, 1017, 1018, 1019, 1022, 1024, 1027, 1029, 1031, 1034, 1035, 1036, 1038, 1039, 1040, 1041, 1043, 1045, 1049, 1051, 1055, 1056, 1060, 1061, 1073, 1074, 1075, 1079, 1082, 1083, 1095, 1097, 1105, 1111, 1113, 1119, 1127, 1128, 1130, 1136, 1138, 1146, 1148, 1149, 1150, 1151, 1169, 1315, 1317, 1318, 1319, 1326, and 1445) are concerned with the compliance dates in the rule, especially if the proposed revisions are not finalized.

Several commenters asked that the EPA extend the compliance dates in the rule because the current timing of the rule does not allow enough time to comply with the rule. Some commenters (1060, 1073, 1083 and 1097) requested a 1-year extension from the current May 3, 2013 deadline. Several commenters (877, 974, 1031 and 1130) said that the compliance date should be extended to May 3, 2014 to give sources in Alaska time to design, fund, order and install controls, monitoring systems and other equipment and to avoid winter construction. Alternatively, if the rule does not retain the remote definition or makes significant revisions, extend the compliance date by 22 months after signature, Alaska commenters said. If the final rule significantly changes the provisions that were proposed, two commenters (1105 and 1136) urged the EPA to extend the initial compliance date to October 2014 or by 22 months after the final rule is signed. One commenter (877) stated that the EPA's final definition of "remote areas of Alaska" will determine whether or not their facilities are required to retrofit their engines with expensive customized equipment. The commenter (877) is concerned about not having sufficient time to design, fund, order, and install this new equipment by the May 3, 2013 compliance deadline if the final definition for "remote area of Alaska" excludes any of their RICE units. The commenter (877) stated that if the EPA issues the final rule as late as December 14, 2012, they would be forced to conduct construction activities during Kodiak's extreme winter season, which typically runs through May. The commenter (877) recommended that to avoid an unreasonable and unsafe situation in Kodiak and other remote Alaskan communities, the EPA should offer special consideration to all of the Alaskan area sources not connected to the Alaska Railbelt Grid by extending the compliance deadline to May 3, 2014.

Similarly, commenter 1089 also urged the EPA to finalize the changes as proposed otherwise significant issues with the rule will remain. If for some reason the rule is not finalized in a substantially similar way as proposed, commenter 1089 noted that it would want to discuss with the EPA an extension to the current compliance dates in the rule to at least late 2014 or 2015. Commenter 916 said that without extending the compliance date the EPA is treating a subset of engines unfairly. Owners of engines subject to the rule have several decisions to make in order to comply with the rule and with the final rule pending it creates uncertainty amongst affected stakeholders, the commenter (916) said. Not much time is provided from when the final rule comes out and owners knowing what they will have to comply with until they have to comply with the rule, commenter 916 added. There is a provision allowing for extension requests, but it is time consuming and involved and does not solve the problem, the commenter (916) said who therefore requested the compliance date be extended until November 3, 2014. Commenter 1075 said that the EPA should give special consideration to owners/operators of affected engines and suggested that a temporary amnesty period from enforcement action could be provided from the time the final rule is published to a year after. Commenter 1075 recommended that affected sources be free from enforcement action if a deviation occurs during this amnesty period as long as the source comes into compliance by the end of the amnesty period. Commenters 975, 977, 979, 996, 997, 1003, 1019, 1034, 1035, 1061, 1111, 1138, 1150, 1169, 1315, 1317, 1318, 1319, and 1326 requested a 6-month extension after the final rule is published in order for sources to comply. Commenters 976, 985, 986, 999, 1018, and 1029 recommended that the CI and SI compliance dates be aligned and set at the SI compliance date of October 19, 2013 for all engines to provide enough time to reach compliance and would have the added benefit of lessening confusion by making the compliance deadlines consistent.

Some commenters (978, 981, 984, 1027 and 1055) said that it is more reasonable to require compliance by the fall of 2014. In the event the proposed requirements are not finalized in terms of the relief provided to existing non-emergency 4-stroke SI engines above 500 HP in remote areas, commenter 1095 requested that the EPA provide a full 3 years from the date the rule is final in order to reach compliance.

The commenter (1082) suggested that the EPA should provide a 17-month extension to the RICE rule compliance deadline to help bypass the winter and summer peak times, give small utilities adequate time to comply with the new requirements, and give utilities adequate time to follow their city budgeting process. One commenter (1104) concurred that the compliance dates be extended past the normal fall outage period in 2014 – for a period of approximately 17 months total – in light of these concerns. In addition, the commenter (1104) proposed that both the CI and SI compliance dates be aligned so that the date for SI compliance would be the same for CI compliance (October 19, 2014). Commenter (1104) further proposed that the EPA retain the additional one-year for compliance, which could be requested by units on a case-by-case basis, and believes that this 17-month extension should reduce the need for the EPA to evaluate case-by-case extension requests.

One commenter (1148) stated that the compliance date needs to be adjusted since the final rule is not expected until the end of December 2012. The commenter (1148) asserted that it is unrealistic to expect that vendors could travel to the many hundreds of locations across the United States in the winter of 2013 in order to have the equipment calibrated and running by May 2013. Commenter (1148) stated vendors and the small utilities should have until the fall of 2014 to fully retrofit their RICE units since those same RICE units might be needed during the time when the region that they operate in is impacted by compliance with EPA's EGU mercury MACT or MATS regulations.

One commenter (1067) said that the Agency should allow a transition period under May 31, 2016, in order to give owners/operators and demand resource aggregators sufficient time to install emissions controls on their engines if they wish to participate in power markets. This provision would indicate the expectations of owners/operators who wish to bid their units into capacity markets who rely on an exemption in the RICE NESHAP, the commenter (1067) said. Also, the availability of these units would assist RTO, ISO and other balancing authorities during this temporary transition period.

Some commenters (939, 943, 967, 968, 1002,1036, 1038, 1074, 1113 and 1445) said that it is essential that the EPA consider extending the compliance deadline for this rule as a result of the inordinate delay in finalizing important and crucial details during the reconsideration process. Two commenters (968 and 1002) are concerned that municipalities and agricultural irrigation operations will not have enough time to adjust for major changes in the draft reconsideration such as allowing the use of CI-RICE for peak shaving. Commenter 968 said that municipalities will not know the final details of the regulatory matrix until the end of the year with only 4 ½ months before they have to be in compliance by May 3, 2012. Two commenters (968 and 1017) described the complexity of purchasing process at the municipal level. These two commenters (968 and 1017) cited various concerns including:

- Regulatory issues that must be resolved with the state and coordinating with power suppliers or their joint action agency
- Design, testing and implementation (including making physical modifications to the power plant building) issues that preclude meeting such a short time line
- The need to educate city councils and decision makers about the need for costly equipment
- Evaluating whether limited funds might be better used in investing in a new and presumably more efficient generating unit.

Other commenters (1017 and 1051) voiced similar concerns about the nearness of the May 2013 deadline and the impact on smaller plants and small communities in particular. According to one commenter (1017), while larger plants are moving forward with the installation of catalysts, smaller plants will need additional time to determine whether to seek emergency designation and gain compliance. The commenter (1017) added that municipal utilities that opt to designate their RICE units as "emergency" should be able to comply with a May 2013 deadline, as the installation of oxidation catalysts would not be required. However, the commenter (1017) said that members that decide they cannot operate under emergency designation will need more time. The commenter (1017) recommended an 18-month delay in the compliance deadline.

One commenter (968) said that the EPA should extend the deadline by the 16 months that communities have been in limbo about the regulatory details of this rule, to this point, or that the extension should cover the entire period from December of 2010 when reconsideration was announced until December of 2012 when the final rule is published. The commenter (968) added that, while the existing rule gives individual states with delegated authority the opportunity to grant extensions, this option is not as forcefully presented as the recent MATS rule that was very forceful in its encouragement to the states to issue extensions to municipal utilities that were struggling to meet the relatively short time-frames in the rule because of legally imposed requirements. Two commenters (948 and 968) requested that the Agency use forceful language similar to that used and promulgated in the MATS rule to make it clear to state regulators that extensions are appropriate and expected by the Agency.

Some commenters (1036, 1045, 1074, 1151 and 1445) said that it is more reasonable to give vendors and the small utilities until the fall of 2014 to fully retrofit their RICE units since those same RICE units might be needed during the time when the region that they operate in is impacted by compliance with the EPA's EGU mercury MACT or MATS regulations. The commenters (1045, 1074, 1151. 1445) said that some larger utilities with coal plants might be making significant changes and have many baseload coal units offline or converting to gas, which could lead to more RICE units being called upon during the transition time of 2015-2017. Commenter 1036 added that such an extension would bypass the first summer and winter peak demand periods. One commenter (967) requested that the EPA extend the RICE NESHAP compliance date to be at least 6 months after the date the EPA's final action is published in the *Federal Register* to provide affected facilities with adequate time for review and compliance.

Two commenters (939 and 943) requested that the compliance date for RICE be extended by one full calendar year to allow unit owners sufficient time to make retrofits. The commenter asserted that requiring each facility to individually petition for additional time is cumbersome, inefficient and unnecessary.

One commenter (1038) said that the regulated community should be provided an additional 3 years to come into compliance.

Another commenter (1002) described two issues with relying on the 1-year compliance extension provisions. First, the commenter (1002) said that compliance extension requests must be submitted no less than 120 days before the compliance date, January 2013. The commenter (1002) said if the rule is finalized in December 2012, sources have less than 1 month to determine and develop plans for compliance. Second, the commenter (1002) said, the EPA and state resources are not sufficiently prepared for the number of case-by-case extension requests that will be submitted by sources affected by this rulemaking. The commenter (1002) believes that a compliance extension of 1 year in the final rule would be more effective and reasonably attainable for affected sources. The commenter (1002) added that if the compliance date cannot be changed for all sources, at a minimum the EPA should extend the compliance date for area sources. Commenter 1036 said that at a minimum, state administrative agencies charged with enforcement should be given discretion to grant expedited approval of individual and group requests for 1-year extensions.

Response: Section 112(i)(3) of the CAA requires that compliance for existing engines be "as expeditious as practicable, but in no event later than three years after the effective date of such standard…" The compliance date for existing stationary engines is already set at 3 years following the effective date of the standards. As the EPA did not propose any requirements that are more stringent than those finalized in 2010, regulated parties that would be regulated under either the final rules promulgated in 2010 or the proposed revisions have had sufficient time to prepare for compliance. Regarding provisions that were subject to change as a result of the proposal, for the most part, the EPA is finalizing provisions as proposed and therefore in those cases the existing compliance dates will remain. The EPA believes the existing compliance dates are appropriate and justified in those scenarios where there is no difference between the proposed and final rule, because the new requirements are as or less stringent than the prior requirements and reduce the compliance burden for many sources. Regulated parties have had sufficient time to prepare to meet such requirements.

For instance, the EPA is finalizing the proposal to allow THC to be used as an alternative to demonstrating compliance with the formaldehyde percent reduction requirement for existing and new 4SRB engines above 500 HP at major sources. Further, the EPA is finalizing amendments to the requirements that apply to existing stationary non-emergency 4-stroke SI RICE greater than 500 HP located at area sources of HAP emissions, which had been subject to a numerical emission standard and regular monitoring and testing requirements under the final rule published in 2010, and which under the final rule are subject to either management practices, for engines in remote areas, or to an equipment standard and less burdensome monitoring requirements and less onerous and more flexible testing requirements, for engines not located in remote areas. The EPA is also promulgating regulatory relief for certain existing CI engines that are already certified to CAA standards and management practices instead of emission standards for CI engines above 300 HP on OCS vessels. In all these cases, the final rule establishes regulatory relief and will lessen the compliance burden and a compliance extension is not necessary.

In those situations where the EPA is not finalizing revisions as proposed, the EPA is providing additional time to demonstrate compliance. The EPA is finalizing the allowance for stationary engines operating as part of emergency DR allowing a total of 100 hrs/yr, including hours spent for maintenance and testing, as proposed. However, the final rule includes a requirement that stationary emergency CI RICE above 100 HP and a displacement of less than 30 l/cyl that operate or are contractually obligated to be available for more than 15 hrs/yr use ULSD fuel. Since this requirement is a new requirement that was not contemplated at proposal, owners and operators have until January 1, 2015, to start using ULSD. In addition to the ULSD fuel requirement, owners and operators of these engines must report the dates and times the engines operated for emergency DR annually to the EPA, beginning with operation during the 2015 calendar year. Again, since the reporting requirement was not in the proposed rule, the EPA is delaying the start of this requirement. The EPA is adding these requirements beginning in January, 2015, rather than upon initial implementation of the NESHAP for existing engines in May or October of 2013, to provide sources with appropriate lead time to institute these new requirements and make any physical adjustments to engines and other facilities like tanks or other containment structures, as well as any needed adjustments to contracts and other business activities, that may be necessitated by these new requirements. The EPA believes that giving until January 2015 will give sources sufficient time to comply with the rule, and will also allow the EPA necessary time to implement the new reporting requirement.

The EPA is not finalizing the proposed temporary 50-hour allowance for existing stationary emergency engines located at area sources engaged in peak shaving and other non-emergency use as part of a financial arrangement with another entity. Therefore, acknowledging the short time between this final rule and the existing compliance dates (May 3, 2013 for CI and October 19, 2013 for SI), the EPA is allowing existing stationary emergency engines located at area sources to operate for this purpose until May 3, 2014. The EPA believes that it is appropriate to provide a compliance extension in this case to provide more time for sources that wish to engage in peak shaving until they can come into compliance with the applicable requirements for non-emergency engines. Owners and operators that wish to ask for more time to comply with standards based on the particular circumstances of their sources may still do so under the compliance extension provisions. While such provisions may be time consuming, it is appropriate that sources with particular issues be required to specify those conditions and request an extension, rather than EPA granting a blanket exemption not contemplated by the CAA.

8.2 Comment: One commenter (1134) does not believe that the EPA should extend the compliance deadlines in the rule. It is the commenter's (1134) opinion that owners of engines and DR aggregators have had plenty of time to develop compliance strategies for the 2010 rule. The commenter (1134) also reiterated that there is no reliability-related justification for extending the compliance deadline.

Response: As discussed in RTC 8.1, the EPA does not believe it is necessary to provide an extension across the board, but only in cases where the rule is not finalized as proposed. The EPA does believe it is appropriate and justified to provide sources additional time to comply with new requirements not contemplated at proposal, that is, the requirement to use ULSD fuel for emergency engines that operate or that have contractual obligations to operate for more than 15 hrs/yr and report their operation to the EPA.

8.3 Comment: One commenter (1145) noted that the EPA solicited comment on "whether special consideration should be given to engines whose requirements would be reduced by this proposal if, in the final rule, the EPA does not finalize the proposed reduced requirements." The commenter (1145) supports retaining the proposed requirements and added that significant compliance issues will need to be addressed if this is not the case.

Response: The EPA acknowledges the commenter's input. By and large, the EPA is finalizing the requirements as proposed. The EPA does not anticipate any significant compliance issues with such provisions.

Exhibit H

Craig Glazer
Vice President, Federal Government Policy
1200 G Street, N.W., Suite 600
Washington, DC 20005
Office: 202-393-7756
Mobile: 202-423-4743

June 2, 2015

Austin D. Saylor
U.S. Department of Justice
Environment & Natural Resources Division
Environmental Defense Section
P.O. Box 7611
Washington, D.C. 20044

Re: Delaware Dept. of Natural Resources et. al v. EPA
US Court of Appeals D.C. Circuit
Docket No. 13-1093

Dear Mr. Saylor:

I am writing to provide you with certain key facts associated with the impact of the Court of Appeal's ruling in the above-captioned case on reliability of the bulk power electric grid in the 13-state region served by PJM Interconnection, L.L.C. PJM is the FERC-regulated Regional Transmission Organization ("RTO") serving all or portions of the states of New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, West Virginia, Kentucky, Tennessee, Ohio, Michigan, Indiana, Illinois and the District of Columbia. Among other tasks, PJM is responsible for ensuring the reliability of the bulk power electric grid in this region and ensuring adequate resources to cover customer demand for electricity in our 13-state region.

PJM administers a market for "capacity resources". Through that market, PJM commits, on a three year forward basis, sufficient resources in order to ensure adequate generation and demand response resources are available to cover customer demand along with an adequate reserve margin. A capacity resource in PJM is obligated to provide energy or reduce its consumption when called upon by PJM in response to PJM-declared emergency conditions.

Pursuant to its FERC-approved tariff, "demand response resources" (in addition to generation resources) compete in PJM's market to serve as capacity resources. Demand response resources commit to curtail their consumption when called upon by PJM in response to declared emergency conditions. In this way, demand response resources serve as the mirror image to generation resources---demand response resources reduce their consumption from the grid while generation resources generate more electricity to respond to the PJM-identified need. As detailed below, a number of locations such as commercial and industrial establishments agree to serve as demand response resources in PJM's market since they maintain power to their site through the use of on-site back-up generation including resources which fall under the RICE rule.

As of today, PJM has 10,600 MW of demand response resources committed to meet the period which begins today, June 1, and runs through May 31, 2016 ("2015/16 Planning Year"). This represents approximately 6% of our total resources for the 2015/16 Planning Year. The Curtailment Service Providers who register as demand response resources are required to inform us of the status of their environmental permits. It appears from our review of the submitted data, that approximately 14% of the total demand response resources or 1,500 MW out of 10,600 MW are restricted to running for 100 hours and appear to be RICE units and thus affected by the Court's decision in the above case.

Because the US Supreme Court has granted certiorari of the Court of Appeal's decision in *EPSA vs. FERC*, we are no longer facing the potential loss of all demand response resources during the 2015/16 Planning Year. The Court of Appeals in the *EPSA* case held that FERC had no jurisdiction over demand response which, absent the stay issued by the US Supreme Court, would have put a cloud over all of PJM's demand response procurement for the 2015/16 Planning Year. As a result of the US Supreme Court's grant of certiorari, the impact of the Court's decision in *Delaware* for 2015 is lessened but still impactful to the upcoming summer cooling and winter heating seasons. Specifically, issuance of a mandate in June by the Court of Appeals in the Delaware case, would have the following implications for PJM:

- Although the majority of demand response resources are not obligated to perform under our present market rules during the winter period, demand response resources were helpful to PJM in maintaining reliability during extreme winter events such as the Polar Vortex conditions experienced in the winter of 2014. Given the obvious lack of summer air conditioning programs as a resource to call upon, the voluntary participation of demand response resources (supported by RICE units) contributed to the total demand response resources that respond to winter emergencies and were helpful to PJM for reliability purposes during the 2014 Polar Vortex;

- The remand being issued in the third week of June would cause us to lose these demand response resources with no realistic means to replace that capacity in the midst of the summer months. As a system operator, we have a long-standing practice of attempting 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. As a result, issuance of the mandate in June, with virtually no prospect for replacing the 1,500 MW and potential litigation as to whether such units can even legally run when called upon, creates particular operational challenges for PJM and demand response resource providers given its timing. Issuance of the mandate after the summer season and before the winter (i.e. September 1- November 30) would allow for a more orderly transition as well as potential adoption by EPA of interim rules governing the operation of these units so as to provide greater clarity as we enter into the winter portion of the 2015/16 planning year.

As it explained in the proceedings before the agency, PJM reiterates that although RICE units make up part of a portfolio of resources that curtailment service providers use to develop their demand response bids, PJM does not have direct visibility or control over these units. Moreover, for purposes of meeting PJM's demand response requirements, the performance of individual units can be aggregated so long as the aggregated total meets the locational requirements associated with demand response resources' capacity obligation. As a result, there may remain some latitude for operation of these units even if the per unit 100 hour restriction is eliminated as a result of the Court's ruling. However, the ability of these units to run at all upon issuance of the mandate, and the rules governing how long they can run if called upon in a PJM-declared emergency, would need to be sorted out---a task which could prove particularly difficult in the middle of the summer season when PJM is most likely to need these units to perform in order that the demand response commitment for the 2015/16 planning year is met.

PJM expresses no opinion as to the feasibility or time associated with retrofitting these units to install the applicable pollution controls. Rather, per your request, PJM is setting forth the above facts and the challenges associated with a disruptive transition in the middle of the summer months should the Court's remand order not be stayed.

Please contact me with any questions or if you need any further information.

Very truly yours,

Craig Glazer
Vice-President-Federal Government Policy
PJM Interconnection, L.L.C.

Cc: Michael Bardee, FERC
Ted Franks, FERC
Julie Simon, FERC
Jamie Simler, FERC
David Morenoff, FERC
Peter Langbein, PJM
Jacqulynne Hugee, PJM
Jennifer Tribulski, PJM
Michael Bryson, PJM

Exhibit I

RITTS LAW GROUP, PLLC
MEMORANDUM

To: Austin Saylor, Esq., U.S. DOJ Environment & Natural Resources Division
Environmental Defense Section
Sheila Igoe, Esq., U.S. EPA Office of General Counsel

From: Leslie Ritts, on behalf of the American Public Power Association (APPA)

Re: 40 C.F.R. § 63.6640(f)(2)(ii) & (iii): Need for 100-hour Level 2 Emergency Demand Response Provisions and Transmission Voltage Support

APPA surveyed its members over the past two weeks to assess the consequences of vacatur by the D.C. Circuit of the 40 C.F.R. § 63.6640(f)(2)(ii) and (iii) provisions allowing uncontrolled emergency stationary RICE to operate for up to 100 hours per year as part of an emergency Demand Response (DR) program, relating to both subpart (ii) bulk-power, grid-level DR programs (as administered by an RTO, for example) and subpart (iii) local distribution reliability use. These responses underscore the importance of the existing emergency DR provisions, particularly in the Midwest and Northern Plains for grid reliability and in other areas with limited transmission and to distribution systems to support local power.

The Upper Midwest Municipal Energy Group (UMMEG) is a Wisconsin joint action agency with 16 small public power members (each serving between 2,000-to-12,000 people) in Wisconsin, Iowa and Minnesota. UMMEG members own a total of approximately 60 diesel RICE, with an aggregate nameplate capacity of about 140 MW that are operated primarily for local reliability and emergency back-up purposes and as emergency demand response units to meet their planning reserve margin requirements under the MISO tariff. As emergency demand response units, they are required to be available for dispatch by the local balancing authority (Dairyland Power Cooperative) as a last resort to prevent firm load shedding at the transmission level, and by the municipal utilities themselves to keep the lights on during an emergency. MISO will call on the LBA to reduce load using these units registered as Load Modifying Resources in the MISO module E construct during EEA Level 2 Emergency events.

The UMMEG units cleared MISO's capacity auction and are required to be available for the upcoming MISO plan year beginning in June, 2015. In addition, UMMEG members have executed long term requirements contracts with Dairyland Power Cooperative, which factor in the availability of the units to meet member capacity requirements. A subset of or all the units may be called upon during a MISO event. APPA understands from UMMEG that MISO has calculated a 74% chance of EEA level 2 dispatch this summer, so it will look to run one *or all* of the UMMEG units, which are registered for 5 events each lasting a minimum of 4 hours. Non-performance could carry some very significant penalties, plus the potential loss of the capacity accreditation. (An UMMEG official also stated that "**Imposition of a 15-hour limit under the prior RICE rule would mean that the units will not be eligible for MISO registration and therefore will not be usable to meet reserve margin requirements."**

ElectriCities of NC (ECNC) is a Joint Action Coalition that operate 34 RICE serving public power communities in North Carolina, South Carolina and Virginia, including the North Carolina Municipal Power Agency Number 1 and North Carolina Eastern Municipal Power

Agency. The RICE are used for peak shaving units and for emergency operation and for NERC Alert 2 reliability situations such as transformer overloading, utility outages. Twelve units have been retrofitted with DOC equipment and four have been retrofitted with SCR equipment. All are included in ECNC's reserve capacity. (ECNC also has agreements in place with cities (Cornelius and Morganton) to operate these emergency units during times of excessive loading on substation transformers. According to the Joint Action Coalition, loss of the 100 hour exemption could limit the time it operates the generators and it would lose some reserve capacity.

Missouri Joint Municipal Electric Utility Commission ("MJMEUC") is the joint action agency for 86 Missouri communities with an average population of 5,800 customers and 3 large cities (Springfield (MO) City Utilities with over 110,000 meters, the City of Independence with 56,000 meters, and the City of Columbia with almost 45,000 meters.) According to its Director, **§ 63.6640(f)(2)(iii) is vacated,** a number of communities will be in a position where they will watch voltages drop in the summer until the distribution system collapses (resulting in an emergency situation under 40 C.F.R. § 63.6640(f)(1)), whereupon they will utilize their CI RICE units without limit until their supplier can get the system stabilized. In the meantime sensitive electronic computers and other control equipment may be damaged. He also worries that impacted businesses may decide to take their operations to other areas all of Nguyen [Missouri] and other small towns with the jobs that go with them.

American Municipal Power (AMP) is a nonprofit multistate public power entity that currently has 132 member political subdivisions that own and/or operate municipal electric utility systems in Ohio, Pennsylvania, Michigan, Virginia, Kentucky, West Virginia, Indiana, Maryland. AMP also includes the Delaware Municipal Electric Corporation ("DEMEC"), a joint action agency that itself has nine municipal members. In addition to meeting their electric and energy needs in a reliable and economic fashion through the ownership of electric generating facilities, scheduling and dispatch of Member-owned generation, AMP makes power supply and transmission arrangements with third-parties at the request of and on behalf of its Members in both PJM Interconnect, LLC ("PJM") and MidContinent ISO ("MISO"). (In part to facilitate these arrangements, AMP Members have formed 5 Joint ventures known as the Ohio Municipal Electric Generation Agency ("OMEGA") Joint Ventures ("JVs") that are owned by 51 individual municipalities serving over 200,000 meters.)

RICE owned by AMP members including gas and diesel units were converted to emergency generators in 2013 which now operate under Ohio's Permit-by-Rule ("PBR") provisions. Since their conversion to PBR status, RICE have been used for emergency demand response, requiring the units be committed as capacity resources in the PJM forward capacity construct through which PJM secures, through forward auctions, the rights to offered resources to meet the region's capacity needs three years in the future. (In other words, to use a resource as demand response in the summer of 2015, it would have to have been committed in an auction conducted in May 2012.) AMP, on behalf of its Members and the JVs, has committed the JV1, JV2, JV5 and Member-owned RICE units as emergency demand response units through the PJM 2015-2018 Delivery Years. .

PJM's Limited demand response product requires that the resource be available to generate for up to 10 events, each 6 hours long, between June 1 and September 30 of each delivery year. The maximum number of hours a unit could be called to run is 60. A generator with 100 hours of run time can fully participate as a Limited demand response product. If the hours per year limit on RICE units being used for emergency demand response were to be reduced to 15 hours, it will effectively eliminate the opportunity for these units to operate at all, as the hour limit includes all emergency and non-emergency operation, which includes all hours operated for maintenance and testing. Entry of the mandate in *Delaware v. EPA c*ould negatively impact AMP's and its Member's resources in that have already cleared in PJM's capacity market and AMP does not have any ability to mitigate the risk for the 2015-2016 Delivery Year because all of the capacity auctions have already been conducted. Further, while AMP could buy additional capacity in subsequent auctions for the 2016-2017 and 2017-2018 Delivery Years to replace the lost backup generation units, this purchase may be at a loss as shown in the chart below of resources already committed as capacity resources by PJM Delivery Year. Revenue derived from its commitment that would either be lost or reduced if AMP and its Members are required to replace those commitments:

	2015-2016		2016-2017		2017-2018	
Project	**Revenue, Committed kWs**	**Potential Revenue, Uncommitted kWs**	**Revenue, Committed kWs**	**Potential Revenue, Uncommitted kWs**	**Revenue, Committed kWs**	**Potential Revenue, Uncommitted kWs**
JV1	$360,824	$ -	$282,408	$27,552	$232,186	$116,093
JV5	$1,047,180	$ -	$804,304	$62,681	$671,403	$345,956
JV2 Unit 1	$68,156	$ -	$55,104	$ -	$40,632	$21,284
AMP owned total	$1,476,160	$ -	$1,141,816	$90,233	$944,221	$483,333

Member units						
Bedford WWTP	$11,505	$ -	$7,020	$ -	$ -	$12,558
Bryan #5 Nordberg	$41,400	$ -	$32,400	$ -	$58,046	$ -
Dover Diesel #5	$106,204	$ -	$ -	$65,160	$77,280	$38,640
Lodi	$71,363	$ -	$61,992	$ -	$69,656	$ -
New Knoxville Diesel	$31,860	$ -	$ -	$19,680	$38,698	$3,870
Prospect #1	$133,488	$22,248	$41,328	$6,888	$54,096	$ -
Shelby Plant Diesel	$106,200	$ -	$59,053	$ -	$116,093	$ -
Shelby Waste Water	$63,720	$ -	$35,432	$ -	$69,656	$ -

In addition, APPA also confirmed and updated information from the following public power utilities that was in the docket:

Central Minnesota Municipal Power Agency (CMMPA) is a joint action agency which has 12 rural members such as Delano and Blue Earth MN Light & Water, 11 of whom own and operate RICE to meet their obligation to own or buy reserve capacity from the Midwest Independent Transmission Service Operator MISO, under its "Open Access Transmission and Energy and Operating Reserves Market Tariff. The municipal utility typically receives a "credit" from their power suppliers for reserve capacity enabling the community to afford the engines use during emergencies and maintenance events to sustain the cities when transmission lines are out of service. Effectively these MISO payments enable these rural communities to maintain and utilize the affected RICE during emergencies. For example, Springfield MN (pop 2,100 residents) owns 5 Caterpillar diesel RICE with approximately 9.1 MW of installed capacity that are accredited by MISO as must run units during an Emergency Operating Procedure (NERC EOP-002_ event).

CMMPA also explained that members do not receive any financial compensation or energy payment because when they operate their emergency engines the owner generation serves the local municipal customers and the output of the generation appears to MISO as net load (the net of the actual gross load delivered from the transmission grid less the local generation). So the public utility bears the cost of the fuel because it is consumed to serve local load and that is an avoided cost to the City and a capacity/reliability resource to MISO available to them to dispatch for EOP-002 NERC events to avoid a potential blackout condition.

Nebraska City Public Utility – Nebraska City uses its RICE units for voltage support and loss of transmission at its interconnect. The NCPU local distribution system is interconnected to the surrounding transmission grid at two points. The stronger of Nebraska City's two feeds is from the south and is dependent upon properly operating equipment at a substation on a 161KV to 69KV system approximately 20 miles south of the community. During times of maintenance or outages at this substation, voltage may drop depending on electric loads below an acceptable level where upon the local transmission provider calls upon Nebraska City to support the voltage on this 69KV line. This is done not only for the Nebraska City system but also the Omaha Public Power District's system connected to the 69KV line, which serves a significant rural area.

Manitowoc Public Utilities (MPU) is a Wisconsin public power utility that was established in 1899 to provide power to a grist mill and electricity for lighting between dusk and 9 pm to the city's residents. It has one 5 MW dual fuel emergency demand response (EDR) diesel unit. The unit is a 1985 model and was reclassified as an EDR and no longer an economic unit and is a BTMG (Behind the meter generation) resource. The requirement when registering the unit as an LMR/EDR (load-modifying resource/emergency demand response) is that MPU must "certify" that the unit is available for the first five events of the summer season for which it is called, at a minimum run-time of 4 hours each (thus a 5x4=20 hour availability). Comments from MISO re any restrictions on BTMG (such as environmental restrictions on RICE units) have been that "those risks are the Market Participant's to manage." Therefore for MPU in the MISO region it would be very helpful to have at least 20 hours for EDR.

Exhibit J

SPIEGEL & MCDIARMID LLP

GEORGE SPIEGEL (1919-1997)
JAMES N. HORWOOD
THOMAS C. TRAUGER
CYNTHIA S. BOGORAD
SCOTT H. STRAUSS
LISA G. DOWDEN
PETER J. HOPKINS
DAVID E. POMPER
WILLIAM S. HUANG
PABLO O. NÜESCH
TILLMAN L. LAY
STEPHEN C. PEARSON

SENIOR COUNSEL
ROBERT C. McDIARMID
ROBERT A. JABLON

1875 EYE STREET, NW
SUITE 700
WASHINGTON, DC 20006

WWW.SPIEGELMCD.COM

Telephone 202.879.4000
Facsimile 202.393.2866
EMAIL INFO@SPIEGELMCD.COM

Direct Dial 202.879.2046
EMAIL LISA.DOWDEN@SPIEGELMCD.COM

ASSOCIATES
REBECCA J. BALDWIN
KATHARINE M. MAPES
MELISSA E. BIRCHARD
ANJALI G. PATEL
JESSICA R. BELL
LATIF M. NURANI
FRANCES J. WADE*
*MASSACHUSETTS BAR ONLY

OF COUNSEL
DANIEL I. DAVIDSON
FRANCES E. FRANCIS
MARGARET A. McGOLDRICK
JEFFREY A. SCHWARZ

June 12, 2015

<u>Via Email</u>

Melanie King
Energy Strategies Group
Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Mail Code D243-01
RTP, NC 27711

Re: <u>D.C. Circuit Case No. 13-1093</u>

Dear Ms. King:

At the suggestion of Austin Saylor, this letter provides information from Kansas Power Pool (KPP), a respondent-intervenor in Case No. 13-1093 before the Court of Appeals for the D.C. Circuit, in support of KPP's request that EPA seek a stay of the Court's mandate in order to revise the RICE rule to address the concerns associated with 40 CFR § 63.6640(f)(iii). KPP notes that no intervenor opposed the concept of specific provisions addressing the difficulties the RICE rule poses for small towns and rural areas, except for the asserted failure to consider alternatives more narrowly tailored to rural areas or areas outside of organized, central capacity markets. The court also did not take issue with the concept (and even noted that there was evidence in the record as to the need for such provisions for "small, rural municipalities"), beyond the asserted failure to consider more narrowly tailored alternatives. KPP notes that all of its members are located in the Southwest Power Pool (SPP), a Regional Transmission Organization that does not have a central, organized capacity market.

Assuming for the purposes of this letter that the result of the immediate vacatur of the rule would be that operators of emergency RICE engines would be limited to a total of 15 hours of annual operation, certain rural municipal members of KPP would be harmed by such a result. KPP notes that a 15 hour annual limit is just sufficient to operate the unit in testing mode to assure that it will start in the event of an actual emergency and that operators refresh their training to assure that they can operate the system when it is necessary to call upon the units. It does not allow for other uses that might be necessary to address reliability concerns.

The city of Wellington, Kansas is one such member of KPP that would be harmed. Wellington, Kansas is a small town with a peak load of approximately 30 MW in 2014. The town is served by a single tie to the transmission grid. However, when a specific line is lost under high load conditions there is a 17 MW import limit into Wellington due to certain grid limitations on the 69kV line serving the Wellington tie. In reliability terms, the loss of the line creates a situation where there is no slack in the system to absorb a second contingency if one were to occur. Reliability criteria require that transmission systems be operated such that they could sustain a second contingency in such an "n-1" situation. As a result of the potential for violation of reliability criteria, SPP requires Wellington to operate internal generation to cover the remainder of its load when conditions so require. The local reliability coordinator (Westar) decides whether dispatching the Wellington generation is the most feasible solution if the conditions of concern arise.

Wellington primarily relies on its gas turbine and steam turbine (non-RICE units) to provide power in these conditions. However, the steam turbine requires 24 hours in which to ramp up to its full capacity, and the emergency conditions requiring its dispatch sometimes arise more quickly. In those instances, Wellington relies on its RICE units for black start (the ability to provide power during blackout conditions to other generators that may require power to start up) and to support the grid in Wellington. If Wellington were not able to rely on those generators while its steam unit is ramping up, it would have to drop customers from electric service. Blackouts would become more frequent.

Under its contract with KPP, Wellington receives some compensation from KPP whenever it operates its RICE units in this situation. Wellington does not make money from this arrangement. These units are expensive to operate and the KPP payments only cover Wellington's fuel costs. It is this compensation arrangement that makes 40 CFR § 63.6640(f)(iii) necessary to Wellington. Because Wellington has a "financial arrangement" with KPP for dispatch of the engines, and the engines supply power to the local Wellington system, it is ambiguous whether Wellington's RICE engines dispatched in situations of this type qualify as "emergency engines" under 40 CFR § 63.6675. Rather than amending the definition of emergency engine to unambiguously accommodate the uses and types of compensation arrangements commonly in place for these engines (as KPP originally suggested), EPA instead modified the definition of "emergency demand response" to accommodate these types of uses, even if partly or fully compensated.

If the rule is vacated without addressing these situations, the electric customers in Wellington and other similarly situated rural towns will suffer more electric outages than they would otherwise.

Respectfully submitted,

Lisa G. Dowden

Lisa G. Dowden
Melissa E. Birchard

Attorneys for the Kansas Power Pool

LGD
cc: Sheila Igoe
Austin Saylor

Exhibit K

February 14, 2011

Ms. Melanie King
Energy Strategies Group
Sector Policies and Programs Division
USEPA (D243-01)
RTP, NC 27711

Re: Docket ID No. EPA-HQ-OAR-2008-0708

Dear Ms. King,

PJM Interconnection, L.L.C. (PJM) provides these written comments as a supplement to the testimony it provided at the EPA's public hearing held in Raleigh, North Carolina on January 13, 2011. PJM is the Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Operator (RTO) that administers the electricity grid in the Mid-Atlantic region. PJM is an independent entity with no economic or other ties to any market participants, including owners of generation, in the PJM region. The PJM region includes all or part of 13 states plus the District of Columbia. PJM's members meet the electricity needs of the 51 million people who live and work in the PJM region. PJM's obligation as an RTO includes coordination of the region's 90,520 kilometers of transmission lines, 164,905 MW of generating capacity and 9,052 MW of committed load reduction capability ("Load Management").

PJM's role includes: reliable operation of the region's bulk power system, transparent administration of the competitive markets that comprise wholesale electricity service, and transmission planning. PJM's markets are designed to recognize the important role that Demand Response resources can provide both as a capacity resource and as a means to reduce energy demand in response to peak conditions or prices.

PJM appreciates the opportunity to comment and wishes to serve as an information resource to the EPA. Moreover, PJM appreciates the EPA's recognition that some type of emergency operations exemption to the compliance rules for stationary reciprocating internal combustion engines ("RICE units") is appropriate to recognize the role that these units play in responding to system emergencies. The purpose of these comments is provide information about PJM's emergency procedures as they apply to Load Management resources and to address the impact of 40 CFR Part 63.6640(f)(4). This provision of the EPA's regulations limits to 15 hours per year the operation of RICE units for emergency purposes. In short, to the extent that the 15 hour limitation was intended to recognize that an exception should be available for these units to run in emergency conditions, the limitation is too narrow to enable effective use of these units in times of emergency at the bulk power level. PJM's position is explained below.[1]

At the outset PJM wishes to emphasize that its role is limited to administering the bulk power system (generally 138KV and above) and in dispatching generation directly tied to that system. By contrast, many of the "RICE" units are tied to the grid at a lower voltage level and therefore considered "behind the meter" generation not directly available as resources dispatchable by PJM. Nevertheless, these units do play a role in a portfolio of resources aggregated by a Curtailment Service Provider ("CSP") to provide emergency demand response to PJM. A load serving entity such as a municipal utility can serve as a CSP and provide emergency demand response services in PJM. Moreover, load serving entities have specific obligations to curtail load in the event of emergencies as detailed below.

PJM emergency procedures are documented in PJM Manual 13, "Emergency Operations." Manual 13 specifies the phases of an emergency (Alert, Warning and Action) and the obligations of each market participant including PJM during each phase of an Emergency event.[2] Triggers for these obligations are linked to Energy Emergency Alert Levels established by the North American Electric Reliability Council (NERC). This means, for example, that PJM Operations issues a NERC Energy Emergency Alert Level 2 (EEA2) when any of the following has been implemented: "[P]ublic appeals to reduce demand, voltage reduction, interruption of non-firm load in accordance with applicable contracts, demand side management/active load management (Load Management), or utility load conservation measures" [3]

PJM's FERC approved Tariff imposes a mandatory obligation on Load Management resources to be able and willing to reduce load for at least 60 hours per summer period (10 calls X 6 hours per call).[4] CSPs can meet their Load Management obligations through **either** operation of on-site generators such as RICE units, or reductions in load by industrial and commercial customers or a combination of both. PJM planners model contingency conditions when developing the mandatory Load Management requirements in order to ensure compliance with the loss of load probability planning standard of 1 day in 10 years. As a result, the number of such emergency calls has been limited. Load Management resources (formerly known as Active Load Management or ALM) have only been called by PJM 35 times since the

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[1] PJM is not responsible for ensuring reliability of the distribution system. RICE units can provide a role in addressing distribution system emergencies, however that use of these units is beyond the scope of these comments.

[2] PJM Manual 13, "Emergency Operations," Revision 41, effective 10/01/10.

[3] *Id.* at P 20.

[4] *Id.*

inception of ALM in 1991.[5] It is important to note that many of these Load Management calls involved only a part of the PJM region and/or lasted for fewer than 6 hours.[6] As a result, should the EPA tie the definition of emergency to the system operator protocols, based on a large number of years of historical data it should not be concerned that the occurrences will be frequent or long-lasting.

The proposed EPA 15-hour limit on RICE units runs contrary to the minimum PJM requirement that demand response resources must be available to reduce load a minimum of 60 hours per year. The 60 hour minimum, which is incorporated into the PJM tariff, recognizes that for a resource to be useful to PJM in emergency conditions over a year, a minimum of 60 hours of availability is essential. This does not mean that a CSP could not put together a combination of RICE units to meet the 60 hour requirement. That alternative, however, creates management and administrative challenges for the CSP and complicates compliance for the CSP and measurement and verification for both PJM and the EPA. This outcome in turn frustrates the intent of the EPA's regulation, which is to recognize that running such units in emergencies is justified as an exception to the emissions control requirements otherwise directed by the RICE rules.

PJM understands the need for a clearly written rule and compliance parameters that can be readily verified by the EPA. Although different RTOs and system operators may have different thresholds than PJM's 60 hour minimum requirement, PJM would suggest that a rule which defines emergencies as "bulk power system operator declared emergencies in accordance with NERC emergency requirements" would appropriately bound the declaration of an emergency and allow for easy verification as such emergencies are posted on the websites of system operators. Moreover, the appropriateness of a system operator's actions in declaring an emergency is already subject to regulatory review by NERC and the FERC. Although this suggested language would not address the definition of emergencies at the distribution level, PJM believes that a reference to "bulk power system operator declared emergencies in accordance with NERC emergency requirements " would, at least at the bulk power level, be far preferable to the EPA attempting to define "emergency" in this rule. As PJM testified, there are many different operating conditions that give rise to an emergency. Therefore, incorporating the industry-established and FERC-regulated *processes for declaring and responding to emergencies* is preferable to attempting to list each and every condition that may give rise to a distribution or bulk power grid emergency.

Through these comments, PJM takes no position on the appropriate level of environmental controls imposed on RICE units, the costs of retrofits or other technical and environmental unit-specific emergencies. Rather, PJM provides these comments

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[5] http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/rew-adeq/load-forecast/alm-history.ashx

[6] *Id.*

and offers to serve as a resource to the EPA as it seeks to craft an emergency operation exception for RICE units that is workable, verifiable, and recognizes the value that such units could provide as part of the CSP"s Load Management portfolio.

For further information or if you have questions, please contact Craig Glazer of PJM at 202-423-4743 or by e-mail at GLAZEC@PJM.COM or Susan Covino at 610-666-8829 or by e-mail at COVINS@PJM.COM.

Respectfully submitted,

Craig Glazer
Vice President-Federal Government Policy
PJM Interconnection, L.L.C.

Suite 600
1200 G Street, N.W.
Washington, D.C. 20005

Exhibit L

February 29, 2012

Michael Horowitz
Office of the General Counsel
Air and Radiation Law Office
U.S Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W. – Mail Code 2344A
Washington, D.C. 20460

RE: EnerNOC et al Review of Comments Filed on Proposed Settlement Agreement

Dear Mr. Horowitz:

EnergyConnect, Inc., EnerNOC, Inc., and Innoventive Power, LLC (collectively the "Companies") signed a Settlement Agreement with the U.S. Environmental Protection Agency ("EPA" or the "Agency"), resolving the Companies' lawsuit against the Agency challenging the National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (the "RICE NESHAP") in the United States Court of Appeals for the District of Columbia Circuit: *EnerNOC, et al v. EPA*, No. 10-1090 (DC Cir.) and *EnerNOC, et al v. EPA*, No. 10-1336 (DC Cir.). As required by Section 113(g) of the Clean Air Act, EPA solicited public comment on the Settlement Agreement by notice in the Federal Register on January 4, 2012. Under the terms of the proposed Settlement Agreement, by April 20, 2012 EPA will sign a notice of proposed rulemaking that includes a proposal to revise the RICE NESHAP and the stationary internal combustion engine new source performance standards ("ICE NSPS") to allow owners and operators of emergency stationary internal combustion engines ("ICE" or "Engines") to operate emergency stationary ICE in emergency conditions, as defined in those regulations, as part of an emergency demand response ("DR") program for 60 hours per year or the minimum hours required by Independent System Operator tariff, whichever is less. The notice of proposed rulemaking may also allow for more hours of operation.

The Companies appreciate the time EPA has taken to understand the importance of emergency DR to the integrity of the electric grid in the United States. The Companies fully support the entire proposed Settlement Agreement and urge EPA to finalize it. The Companies further look forward to the proposed rulemaking by EPA in April, 2012. The Companies have also reviewed all of the comments submitted in favor and against the proposed Settlement Agreement, and offer this analysis of those comments.

Commenters Supporting the Settlement Agreement

Forty-two entities submitted comments on the Settlement Agreement. Thirty-one of these support the Settlement Agreement, with many commenters asking for more flexibility than what is in the Agreement.

- Twenty three Electric Cooperatives support the Settlement Agreement with many asking for 100 hours per year for emergency DR, testing/maintenance, and also they would like to expand the settlement beyond emergency DR to include peak shaving;
- Progress Energy and Florida Power and Light ("FPL") support the Settlement Agreement, but request that emergency DR operation be considered emergency operation with no annual hour limits;
- The Midwest Independent System Operator ("MISO") confirms that the current 15 hour per year limit is not sufficient and supports the proposed Settlement Agreement terms;
- The State of Maryland Department of the Environment ("MDE") notes that emergency DR programs protect public health and safety and supports the Settlement Agreement;
- Four trade Associations, the Edison Electric Institute ("EEI"), American Public Power Association ("APPA"), the National Rural Electric Cooperative Association ("NRECA"), and the American Coatings Association ("ACA") support the Settlement Agreement and in some cases request even more flexibility. For example, NRECA requests up to 100 hours per year and requests that peak shaving be allowed within that 100 hours and EEI believes the minimum should be 100 or even 120 hours per year.

Commenters Opposing the Settlement Agreement

Eleven entities did not support the Settlement Agreement. Of these eleven, five are from generators (PSEG, Calpine, GenON Energy) and their trade associations (EPSA, and PJM Power Providers) ("the generators and their trade associations"). The other six are from two states (Delaware and New Jersey), the American Lung Association (both the National Headquarters and the Mid Atlantic Office), the Clean Air Council, and the Independent Market Monitor ("IMM") for PJM (collectively, the "Adverse Commenters").

The generators and their trade associations, along with IMM, claim that the settlement agreement does nothing to promote the reliability of the electric grid; will distort competition in the nation's energy markets; will result in adverse environmental impacts; and will stifle the development of cleaner generation sources. Delaware and its supporters claim the settlement agreement will result in adverse environmental impacts. As discussed below, none of these arguments has any merit. Accordingly, EPA should reject these comments and finalize the settlement agreement.

Summary of Responses to Arguments Made by Adverse Commenters

As set forth below, the Parties offer the following responses to the arguments made by the Adverse Commenters:

The Proposed Settlement Promotes Reliability

- *ISOs and Utilities Responsible for Grid Reliability Support the Settlement and Demonstrate that the Existing 15 Hour Emergency DR Limit is not Sufficient*
- *Emergency Generators Can ONLY be Dispatched by the Grid Operator, and Strict Sequencing of Dispatch Rules Must be Followed*

Emergency DR Programs Benefit the Environment

- *Emergency DR is Rarely Used and That is Likely to be the Case in the Future as Well*
- *There is No Correlation Between High Ozone Days and Emergency DR*
- *States Support the Use of Engines for Emergency DR Primarily Because Occasional Use of Emergency DR is Superior to Having All Emergency Generators Run in the Event of a Blackout*
- *Emergency Engines Have Environmental Benefits Compared to Central Station Generation*
- *The Proposed Settlement is Not a Departure from EPA Policy*

The Proposed Settlement Does Not Stifle the Development of Cleaner Generation Sources

- *Most of the Generator Complaints are About Market Structure Issues in PJM, and are thus in the Jurisdiction of PJM and FERC – EPA Should Disregard Them*
- *This Settlement Cannot Affect Wholesale Energy Markets*
- *Emergency DR Has Contributed to Lower Prices in Capacity Markets But that is a Good Thing and Should Not Prevent EPA from Going Forward with the Settlement*
- *Emergency DR Has Not Prevented the Growth of Renewable Energy*

Discussion

The Proposed Settlement Promotes Reliability

ISOs and Utilities Responsible for Grid Reliability Support the Settlement and Demonstrate that the Existing 15 Hour Emergency DR Limit is not Sufficient

The generators and their trade associations claim that the current 15 hour limit for emergency DR in the NESHAP is sufficient and that there is no justification for the increase proposed in the Settlement Agreement[1]. This claim has no foundation. As noted by PJM Interconnection, L.L.C. ("PJM") in their February, 2011 letter to the NESHAP docket (see Attachment 1 for EPA-HQ-OAR-2008-0708-813.1):

> The proposed EPA 15-hour limit on RICE units runs contrary to the minimum PJM requirement that demand response resources must be available to reduce load a minimum of 60 hours per year. The 60 hour minimum, which is incorporated into the PJM tariff, recognizes that for a resource to be useful to PJM in emergency conditions over a year, a minimum of 60 hours of availability is essential. This does not mean that a CSP could not put together a combination of RICE units to meet the 60 hour requirement. That alternative, however, creates management and administrative challenges for the CSP and complicates compliance for the CSP and measurement and verifications for both PJM and the EPA. This outcome in turn frustrates the intent of the EPA's regulation, which is to recognize that running such units in emergencies is justified as an exception to the emissions control requirements otherwise directed by the RICE rules.

In addition, Craig Glazer, Vice President – Federal Government Policy for PJM -- testified at the EPA Public Meeting on the RICE NESHAP reconsideration (see Attachment 2 for EPA-HQ-OAR-2008-0708-0699). EPA summarized his comments as follows:

> The 15-hour limit is insufficient and precludes engines from being considered emergency generators under PJM, which requires a unit to be available to operate for at least 60 hours; and regarding what role these RICE units play in emergency demand response from PJM's perspective, Mr. Glazer explained that these units are "behind the meter" and that the RTO simply expects that the system can deliver a certain voltage. As such, the RICE units should remain in the system's demand response portfolio.
>
> According to Mr. Glazer, the 15 hours limit in the rule knocks out engines to be able to be used because 60 hours per year is the minimum number of hours required to be considered an emergency resource for purposes of PJM. According to Mr. Glazier, if any engine is restricted to operate for a maximum

[1] PSEG Comments, p. 4

> of 15 hours, PJM would not even recognize the engines as having any value, because planning and dispatch is complicated and time-consuming, and it is not worth counting an engine as an emergency resource unless that engine can operate for a certain number of hours. The engine could not be utilized and furthermore the 15 hours does not match with the Independent System Operator-New England (ISO-NE) requirements or PJM requirements. Thus the engine could not qualify for an emergency and Mr. Glazer underscored that the allowed number of hours is too short. Mr. Glazer pointed out, however, that the number of times emergencies are declared is very few.

In addition, the Midwest Independent Transmission System Operator, Inc. ("MISO") also agreed that 15 hours is insufficient to maintain reliability, and MISO therefore supports the Settlement Agreement. (see Attachment 3 for EPA-HQ-OGC-2011-1030-012) MISO stated:

> [I]nternal combustion engines that seek to be qualified as Demand Resources within the Midwest ISO Region must be capable of being operated for a total of at least 20 hours per Planning Year. Other RTO/ISOs have similar operational requirements for emergency capacity resources…. MISO respectfully requests that EPA also recognize the importance of balancing environmental concerns with the need to maintain electric grid system reliability during emergency conditions by using appropriate and consistent reliability standards for emergency stationary internal combustion engines.

Outside of the parts of the country that are covered by organized wholesale markets such as PJM and MISO, vertically integrated utilities have the responsibility for maintaining voltage, frequency and preventing outages. Two such utilities, Progress Energy and FPL both support this Settlement, and both request even more hours beyond the 60 hours contemplated in the Settlement.

FPL states:

> It is critical that utilities be permitted to use emergency DR resources to maintain grid reliability under any conditions.[2]

Progress Energy states:

> The Standby Generator Program (SBG) is activated to reduce the load on the bulk electric system to a level that can be safely maintained until either system load diminishes or additional resources can be made available. The program supports

[2] FPL comments, p. 1.

our compliance with the North American Reliability Corporation's (NERC) Emergency Operations Planning standards (EOP) (NERC Standard EOP-002)[3].

What is telling about the support of companies like FPL and Progress Energy is that like the generators who oppose the settlement, they too own and operate fleets of large, central station power plants. However, unlike the generators who oppose the settlement these utilities also have responsibility for maintaining system reliability and they recognize that emergency generators used in an emergency DR program are an important tool to maintaining reliability. For all of these reasons, EPA should reject the claims made by the generators and their trade associations regarding the alleged sufficiency of 15 hours of emergency DR.

Emergency Generators Can ONLY be Dispatched by the Grid Operator, and Strict Sequencing of Dispatch Rules Must be Followed

A critical flaw in the arguments raised by the Adverse Commenters is that they fail to understand or admit that the EPA Settlement Agreement *applies only to engines operating in emergency DR programs*. Many of the concerns they raise or allegations they make conflate *emergency* DR with other forms of DR based on the price of energy. The RICE NESHAP defines emergency DR as when "the regional transmission organization or equivalent balancing authority and transmission operator has 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." 40 C.F.R. §63.6640(f)(4); 75 Fed. Reg. at 9677. The Adverse Commenters label this generator use as behind the meter ("BTM") and then make unfounded comments that the use of emergency DR does not provide any reliability benefits to the grid. The comments of utilities and system operators, above, clearly refute this notion.

The Adverse Commenters refuse to acknowledge that only ISOs, or utilities with responsibility for maintaining the grid (also known as "Balancing Authorities"), may activate emergency DR, typically using North American Electric Reliability Council ("NERC") procedures under Energy Emergency Alert Level 2 (EEA Alert 2) procedures. EEA Alert 2 includes demand-side management along with public appeals to reduce demand, voltage reductions, interruption of non-firm end-use loads in accordance with applicable contracts, and utility load conservation measures. Emergency DR is only called when a Balancing Authority determines that projected energy from generation is, or is expected to be, insufficient to meet demand plus prudent operating reserves; the next step is brownouts and blackouts (in fact, ISO New England dispatches emergency DR using emergency generators concurrently with the start of voltage reductions). The key feature here is that neither the emergency generator owner, nor

[3] Progress Energy comments, p. 1.

its agents, can decide when to operate emergency DR. Only the entity responsible for maintaining system reliability and integrity can make the decision. For example, Attachment 4 from the PJM Manual 13 Emergency Operations; shows graphically the emergency operations sequence.

One of the generators erroneously claims that a “Maximum Generation” emergency event was never called in PJM on July 22, 2011; implying that emergency DR is preventing generators from operating[4]. This is incorrect. As shown in Attachment 5 which is from the PJM’s Emergency Message records, a Maximum Generation Action was called for PJM’s Mid-Atlantic Region, Duquesne and BGE on July 22, 2011 at 1151, 1153 and 1147 respectively. This preceded the requested Emergency DR loading time of 1200 (Emergency DR is known in PJM as Emergency Load Management Program or ELRP). We also note that a NERC Emergency Action Level 2 (EEA 2) was called at 1007.

Emergency DR Programs Benefit the Environment

Emergency DR is Rarely Used and That is Likely to be the Case in the Future as Well

For the reasons stated in the section above, emergency DR is rarely dispatched. Some of the generators claim that emergency DR dispatches will become more common in the future. This claim is entirely speculative and is refuted by the record. In fact, as noted by PJM’s February, 2011 comment letter to EPA (see Attachment 1):

> PJM planners model contingency conditions when developing the mandatory Load Management requirements in order to ensure compliance with the loss of load probability planning standard of 1 day in 10 years. As a result, the number of such emergency calls has been limited. Load Management resources (formerly known as Active Load Management or ALM) have only been called by PJM 35 times since the inception of ALM in 1991. It is important to note that many of these Load Management calls involved only a part of the PJM region and/or lasted for fewer than 6 hours. As a result, should EPA tie the definition of emergency to the system operator protocols, based on a large number of historical data it should not be concerned that the occurrences will be frequent or long-lasting.

In Texas, there have only been two emergency DR events under the Emergency Interruptible Load Service (“EILS”) Program since program inception in 2008. In New England, since the emergency DR Program has been implemented, the use of emergency engines in emergency DR has only been called three times in all of New England. The only system wide call was on August 2, 2006 for a total of 3.75 hours[5].

[4] PSEG Comments, p. 7 PSEG apparently failed to properly filter the Message Types for their screen shot and omitted the “Max Emerg Gen Action Trans” message
[5] http://www.iso-ne.com/sys_ops/op4_action_archiv/2006/index.html

The first and most important responsibility of a Balancing Authority, to which all other considerations must defer, is the continuing reliability of the electric system. NERC emergencies are to be avoided at all costs. The notion that PJM, or any other Balancing Authority is going to allow emergencies to become more frequent, in effect, abdicating its responsibility to maintain reliability, is highly speculative and does such entities a disservice. EPA should not base its policy decisions on the assumptions that Balancing Authorities will be derelict in the fulfillment of their duties.

Even though these resources have historically been rarely called, and even though the grid operators are the only ones who can dispatch them and they are constrained by reliability rules, the generators continue to claim that the settlement agreement will increase the incidence of these emergency DR dispatches. As mentioned above, it is unlikely that such dispatches will increase in the future, but this proposed settlement, which *reduces* the number of hours emergency generators can operate from the current unlimited level to a *maximum* of 60 hours cannot possibly be the cause of such an increase. Emergency events may increase due to factors outside the control of Balancing Authorities, such as excessive, unplanned generator outages and failures like those that imperiled the Texas grid last year, but far from worsening the situation, the settlement agreement will assure that system operators will have more resources to help correct the system than would otherwise be the case.

One factor that contributes to the fallacious logic of the generators is that they believe that the Settlement Agreement is a 300 percent increase in operating hours from the existing regulation's 15 hours.[6] This is wrong on two counts. First, the Settlement Agreement judiciously allows for *the lesser of* 60 hours or the minimum number of hours required by the Independent System Operator tariff. MISO indicates in its comments that it requires a minimum of 20 hours for reliability purposes.[7] ERCOT, the ISO for Texas, requires an emergency DR resource to be available for 8 hours in a 4 month period or a total of 24 hours per year. The generators conveniently ignore this part of the settlement and their rhetoric only references the 60 hour maximum.

Second, the current status quo is no nationwide restriction on hours of operation for emergency DR purposes. The new hour restrictions, whether 15 or up to 60 hours, would not go into effect until mid-2013. Therefore, the allegations of *increased* use of emergency DR due to *increased* hours contained in the settlement agreement are logically false. In actuality, if the settlement agreement is approved, it would still represent a *reduction* in permissible hours compared to the *status quo ante*. As the companies have repeatedly demonstrated, the use of emergency DR has been exceedingly rare in the past with no restrictions on hourly usage. There

[6] PSEG Comments, p. 9
[7] MISO Comments, p. 2

is no reason to assume that *adding* restrictions on annual operations will lead to *increased* dispatch of emergency DR by system operators.

There is No Correlation Between High Ozone Days and Emergency DR

In their comments on the settlement numerous Adverse Commenters allege that emergency DR is dispatched by the ISOs on days of high ozone, thereby implying that the use of emergency generators will increase the number of ozone exceedance days[8]. However, in its comments submitted to EPA in February, 2011, the Companies submitted a detailed analysis entitled "Analysis of Emergency DR and Ozone Concentrations," in which we demonstrated that there is no correlation between emergency DR and ozone exceedance days. Although some emergency DR events are called during high ozone days, many DR events occur on non-ozone exceedance days and many more days have ozone alerts but no DR events. The data does not show that the use of emergency engines during the DR events causes high ozone, particularly since in many instances the ozone concentrations are as high or higher on the days preceding an event. For the 2010 PJM ozone analysis, preliminary ozone data were used for monitoring stations in Maryland. That data base has now been finalized so an addendum to the original analysis is attached (see Attachment 6). In addition, corrections to some of the 2010 PJM emergency DR dates have been made. The results have not changed from the original analysis. No data has been introduced into the record that refutes this analysis.

Finally, Delaware in its comments references a technical paper entitled "Using Backup Generators for meeting Peak Electricity Demand: A Sensitivity Analysis for Emission Controls, Location and Health Endpoints" (Gilmore, Adams & Lave, 2010)[9]. Unfortunately, Delaware once again does not differentiate between *emergency* and *non-emergency* DR. The referenced paper analyzes the use of generators for *non-emergency* DR e.g., economic peak shaving. Such operation would not be permitted under the settlement agreement.

States Support the Use of Engines for Emergency DR Primarily Because Occasional Use of Emergency DR is Superior to Having All Emergency Generators Run in the Event of a Blackout

Delaware and its supporters claim that emergency DR is bad for the environment. Numerous states disagree with this assertion. The following states either amended their existing regulations (denoted by an *) to allow emergency engines to participate in emergency DR programs or allow its use under existing air regulations: Maryland*, Virginia*, Pennsylvania, Ohio*, West Virginia, Indiana, Illinois, New York, Texas, Florida, Connecticut*, Massachusetts*, New Hampshire*, Vermont*, and Maine. None of these states would have gone through the extensive effort required to amend their regulations or allowed use under existing

[8] American Lung Association, p. 4; American Lung Association Mid Atlantic, p. 1
[9] Delaware Comments, p. 8-9

regulations if the use of engines in emergency DR was found harmful to the environment. These states, unlike Delaware, understand the importance of having a subset of generators available for a short time to avoid losing the electric grid rather than waiting for the electric grid to be lost, thereby causing enormous environmental and health and safety damage, to say nothing of the operation of <u>every</u> emergency engine in the affected region. There are other states that endorse the use of emergency engines for emergency DR, but the Parties do not operate emergency engines in emergency DR programs in those other states.

The Maryland Department of the Environment ("MDE") summarized the position of the majority of states in its comment letter to the settlement docket (see Attachment 7 EPA-HQ-OGC-2011-1030-0020):

> The Department supports the emergency demand response restriction increase to 60 hours per year contained in the Proposed Settlement Agreement. This is a welcome change to the 15 hour restriction in the current Final Rule, which may prevent emergency engines from participating in emergency demand response (DR) programs. …. Specifically, the Department believes that emergency DR programs protect public health and safety by calling into action emergency generators to help meet energy demands when the main electrical grid is disrupted or when brown outs are imminent. The Final Rule, as codified in 40 CFR Part 63, §§63.6580 to 63.6675, appropriately explains emergency DR as necessary when "the regional transmission organization or equivalent balancing authority and transmission operator has 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." The current 15 hours per year maximum on emergency DR use in the Final Rule, however, may prevent emergency engines from participating in emergency DR programs since the engines may not be able to meet RTO tariff requirements that specify minimum hours of availability to participate.

The Florida Department of Environmental Protection ("FDEP") in its comments to EPA filed in the NESHAP docket dated February 9, 2011 (see Attachment 8 EPA-HQ-OAR-2008-0708.0719.1) fully supports the increase of hours for emergency DR:

> [t]he FDEP feels that the use of emergency RICE under the oversight of a demand response program is a beneficial use that should be allowed without additional constraints.
>
> Under the demand response program, these emergency RICE are only allowed to be called upon when the regional transmission organization or equivalent

> balancing authority and transmission operator 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. If the grid fails, every emergency generator in the area will likely operate for many hours or days until the electric grid is restored, while those without an emergency generator are left completely without power. Allowing some of these emergency RICE to be called upon in order to stabilize the grid and prevent a massive outage would result in much less environmental impact than if all emergency engines were operated in response to the loss of the grid.

The Texas Commission on Environmental Quality ("TCEQ") proposed unlimited hours for emergency DR in its comments to EPA filed in the NESHAP docket (see Attachment 9 EPA-HQ-OAR-2008-0708.0764.2):

> The TCEQ also agrees with the petitioners' assertion that emergency demand response programs provide an environmental benefit. Selected and limited operation of emergency generators to avert a blackout is preferable to the possible operation of thousands of generators if a blackout occurs. The 15 hours allowed by the final rule may not provide adequate flexibility for emergency demand response programs.
>
> The TCEQ considers the operation of engines in response to an officially declared emergency by the regional transmission authority to be emergency operation. …. While the 60 hours proposed by the petitioners may appear reasonable based on historical operation, future demand operation for emergency purposes may not be reliably predicted. Therefore, TCEQ suggests that the EPA revise the rule to specify that operation of an engine under an emergency demand response program is considered emergency operation and not subject to hourly limitations as provided by 40 CFR §63.6640(f)(1)(i) provided that the operation is in direct response to an official energy emergency declared by the regional transmission or balancing authority.

Emergency Engines Have Environmental Benefits Compared to Central Station Generation

In an EPA sponsored study entitled "Modeling Demand Response and Air Emissions in New England" prepared by Synapse Energy Economics, Inc. (the "EPA DR Study"), the authors found that by having available quick-start capacity to handle emergency conditions on the electric grid, there would be less reliance on old, dirty power plants that have to run at 50% load or higher all the time so that they can be available when needed (e.g., these are called spinning reserves in New England). The EPA DR Study found that even if one assumes that all DR is from diesel-fired generators, there is a net benefit in air quality because having quick start resources available, such as emergency DR, whether or not those resources are ever called, causes less reliance on spinning reserves. This is a huge benefit to air quality. The best analogy we can think of is this – relying solely on spinning reserves is like having a taxi running outside your house 24/7 for the one or two times a week you need it.

PSEG in its comments criticizes this report for several spurious reasons.[10] First, PSEG criticizes the report for only modeling the use of emergency generators for limited hours (90 hours per year) despite the fact that this regulation will limit such generators to 60 hours or less. The criticism then alleges that the study does not take into account an increase in allowable hours by "a multiple of four". In fact, as described above, this settlement, if approved, would actually *reduce* the number of hours that are allowable compared to when the study was done because previously there were no national level limit on hours of operation. The study is not perfect, but it is the best one available and it correctly modeled a limited number of hours that is similar to what is proposed in this settlement.

Emergency generators have other environmental and economic benefits that are not available to central station power plants. They already exist. Virtually all generators that participate in emergency DR previously existed because their owners needed a way to ensure electric supply in the event of a grid emergency. In the experience of the Companies, commercial and industrial customers do not go out and install generators so they can participate in emergency DR. They participate in emergency DR if they already have an emergency generator. The alternative of building new central station power plants raises siting problems, habitat disruption and environmental impacts from major construction.

The Proposed Settlement is Not a Departure from EPA Policy

The proposed settlement agreement is not a departure from EPA policy. Indeed, in the existing rule, EPA crafted the following flexibility for emergency generators – there is no time limit on the use of emergency generators in emergency situations; emergency generators may be used for up to 100 hours for maintenance checks and readiness testing, provided the tests are recommended by the government or the manufacturer or insurer; and emergency generators may be used for up to 50 hours in non-emergency situations. 40 CFR 63.6640(f). In addition, the Settlement Agreement will bring the RICE NESHAP and ICE NSPS in line with another final EPA regulation that allows for the use of emergency engines in emergency DR programs. In EPA's Mandatory Reporting of Greenhouse Gases; Final Rule (40 CFR Part 86 et seq.), emergency generator is defined as "[a]n emergency generator operates only during emergency

[10] PSEG Comments, pp.8-9.

situations, for training of personnel under simulated emergency conditions, *as part of emergency DR procedures,* or for standard performance testing procedures as required by law or by the generator manufacturer." 40 CFR § 98.6, published in the Federal Register at 74 Fed. Reg. 56,387 (October 30, 2009) (emphasis added). In fact, this final regulation does not even restrict the number of hours that generators can participate in emergency DR programs as the Settlement Agreement does.

<u>The Proposed Settlement Does Not Stifle the Development of Cleaner Generation Resources</u>

Most of the Generator Complaints are About Market Structure Issues in PJM, and are thus in the Jurisdiction of PJM and FERC – EPA Should Disregard Them

The generators, their trade associations and the IMM make various claims that by implementing this settlement EPA will distort both *energy* and *capacity* markets and thereby stifle the construction of new, cleaner generation. However, upon closer examination, most of these claims stem from policy disagreements with the *structure* of these markets, policy determinations that are within the purview of the organized wholesale markets (i.e. the ISO/RTOs that cover a portion of the country) and the Federal Energy Regulatory Commission ("FERC") which regulates the ISO/RTOs. These disagreements range from how DR resources should be compensated for providing *energy* (the subject of FERC Order 745 which has been upheld by FERC multiple times), the types of *capacity* products that one can bid on in PJM (the subject of PJM tariffs approved by FERC[11]) and what terms and requirements demand side resources generally must be able to meet in order to participate in organized markets.

A clear example of this attempt to re-litigate settled issues is contained in the comments of the PJM IMM. They state,

> The result of the increased role played by *limited DR product* is to suppress the price in the PJM capacity markets below the competitive level, which, among other things, reduces the ability of other generating units to pay for environmental upgrades based on EPA requirements. The limited DR product would also displace generating units that are required to be available every day of the year. The Market Monitor has recommended that the *limited DR product* be eliminated from the capacity market.[12] (italics added)

The "limited DR product" referenced by the IMM is a new innovation that PJM created and FERC approved. Instead of having only one capacity product in their market they have created three. The limited DR product is much like the traditional DR product in the past which requires a resource to be available up to 60 hours during the summer months. However, in order to create a higher value product that represents the unique value that generators can provide year round,

[11] ER11-2288, 134 FERC ¶ 61,066
[12] PJM IMM Comments, p. 3.

PJM also created an unlimited product that presumably will be priced higher because of its wider availability. This new product structure is supposed to provide higher pricing signals to incentivize generators to enter the market. Despite this shift in PJM toward differential incentives for generators, the IMM had recommended that the limited DR product be eliminated altogether, as stated in their comments above. PJM and FERC did not agree with the IMM and instead kept the limited DR product, presumably because they felt it had value in reliability and/or market structure. The point is not to debate the wisdom of these outcomes but rather to point out that the IMM lost in its attempt to get PJM and FERC to accept its view. Now the IMM is trying to get EPA to overturn those other agencies in a matter that is rightly within the purview of those agencies.

EPA should let the ISO/RTOs and FERC make the determinations as to what is needed both for reliability and for economic efficiency in their markets and not let the generators re-litigate those issues here. In addition, the proposed Settlement would affect generators throughout the country, not just in the organized wholesale markets, so EPA should consider the bigger picture, not just the views of disgruntled market participants in the organized markets.

Conceivably, EPA might wish to enmesh itself in the intricacies of wholesale market design if PJM's and FERC's actions were imperiling the environment, but fortunately they are not. While it is true that the emissions from emergency generators are typically higher than those of the new and existing facilities operated by the generators, it is also true that emergency generators providing *capacity* as emergency DR resources can be expected to operate for far less than 60 hours per year while the generators are likely to run for thousands of hours per year.

This Settlement Cannot Affect Wholesale Energy Markets

The generators claim that approving this Settlement will do harm to both the energy and capacity markets by reducing prices, thereby reducing their profits and incentive to build new generation. However, this Settlement cannot affect prices in energy markets.

Economic DR is a miniscule portion of the energy marketplace. In PJM, widely considered the ISO with the most robust DR activity, economic DR delivered just 17,388 MWh of response in all of 2011.[13] This represents just 2.2 one thousandths of a percent (0.0022%) of the 794,000,000 MWh of energy demand in PJM last year[14]. It is almost laughable that this amount of DR, or 10 times this amount of DR, could distort energy prices.

[13] http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/2011-dsr-activity-report-updated-20120209.ashx

[14] PJM fact sheet. http://www.pjm.com/documents/~/media/about-pjm/newsroom/fact-sheets/pjm-statistics.ashx

Even in limited hours where, due to high demand and scarce resources, small amounts of supply or curtailment can have significant impact on energy prices, the FERC in Order 719, has directed organized markets to implement "scarcity pricing" rules to minimize price distortions. These rules are intended to insure that energy prices remain high in the face of increasing demand – even demand met by voluntary (or mandatory) load curtailments.

Finally, this settlement only applies to emergency generators participating in emergency DR capacity programs or markets. By participating in an *energy* market, the DR participant would be participating in an economic DR activity and, as such, would be subject to installing the non-emergency controls required by the NESHAP, and not subject to the limited exemption contemplated by this settlement.

Emergency DR Has Contributed to Lower Prices in Capacity Markets But that is a Good Thing and Should Not Prevent EPA from Going Forward with the Settlement

EPSA claims that the settlement will distort the "Nation's Energy Markets" but cites only PJM's capacity market. EPSA expresses concern that the settlement would "allow BTM (behind the meter) generators to squeeze traditional generators out of the market, and could also result in suppressed prices." This statement shows clearly that the generators and their trade associations are primarily interested in higher capacity prices at the expense of consumers. Whether lower capacity prices resulting from emergency generators participating in PJM capacity auctions are "suppressed" or simply "reasonable" is, of course, a matter of perspective. The PJM Capacity Market model, and similar mechanisms elsewhere, were designed to encourage reliability from a number of sources, including emergency DR. It cannot be concluded that DR participation, even through use of emergency generators, somehow "distorts the market" merely by participating. Capacity prices are unquestionably lower than would have been the case without such participation, but it is unclear why anyone would term this a "distortion."

The final arbiter on that question is the FERC, and they have repeatedly supported greater participation of DR in capacity markets in different proceedings precisely because of this benefit to consumers. And, if the balance swings too far in one direction or the other, FERC also has the authority to redress that imbalance.

Going forward in PJM, emergency DR will no longer compete with generation in capacity markets because, as noted above, PJM has created three capacity products. Emergency DR will only be able to bid into the Limited Capacity product while generation can bid into the Unlimited Capacity product. So, going forward emergency DR will not compete against generation in the PJM capacity markets and therefore will not be reducing the price for generation capacity.

Also, it is important to remember that the proposed Settlement represents a *reduction* in allowed hours of operation in emergency operation from the *status quo ante* of unlimited hours to 60 hours per year or far less in most circumstances. Therefore, this settlement by itself will not lead to an increase of DR in capacity markets and therefore will not further reduce capacity prices.

Emergency DR Has Not Prevented the Growth of Renewable Energy

Many factors have the potential to drive or inhibit the growth of renewable energy, including' but not limited to state renewable portfolio standards, investment and production tax credits, and natural gas prices that reduce the costs of competing energy. The claim that emergency DR engines will somehow stunt the growth of renewable resources is unfounded.

For example, in PJM, where DR has grown faster than anywhere else, renewable energy resources are growing at an equally furious pace. Figure 1 below illustrates the amount of MW of demand response and renewable capacity that has cleared in the last three Base Residual Auctions for the PJM Capacity Market. While we are not arguing causation between the two, judging by this graph and these numbers, it is difficult to conclude that renewable energy growth in PJM has been slowed by demand response.

Over the last two auctions in PJM, 1341 MW of renewable resources were offered into the auction, and all 1341 MW cleared the auction. It is not our intent to scrutinize the specifics of PJM auction rules or results, but clearly neither demand response nor any other resource for that matter have prevented renewable energy from securing a commitment in the PJM Capacity Market. If states or utilities wished to build renewable energy as part of their Renewable Portfolio Standard ("RPS") goals, as several states have, it would clear the auction regardless of demand response participation. Also, as long as it is available, renewable energy will always be dispatched by system operators before emergency DR engines.[15]

Nationally, the trend is the same. According to the EIA, renewable energy production soared from 5 Billion BTUs in 2001 to 8 billion BTUs in 2010, a 56% increase over the same time period in which demand response participation has also dramatically increased.[16] Again, no causation can be argued, but there is certainly no evidence of DR suppressing the growth of renewable generation outside of PJM either.

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[15] PJM Base Residual Auction Results: 2012-2015

[16] http://www.eia.gov/energy_in_brief/renewable_energy.cfm

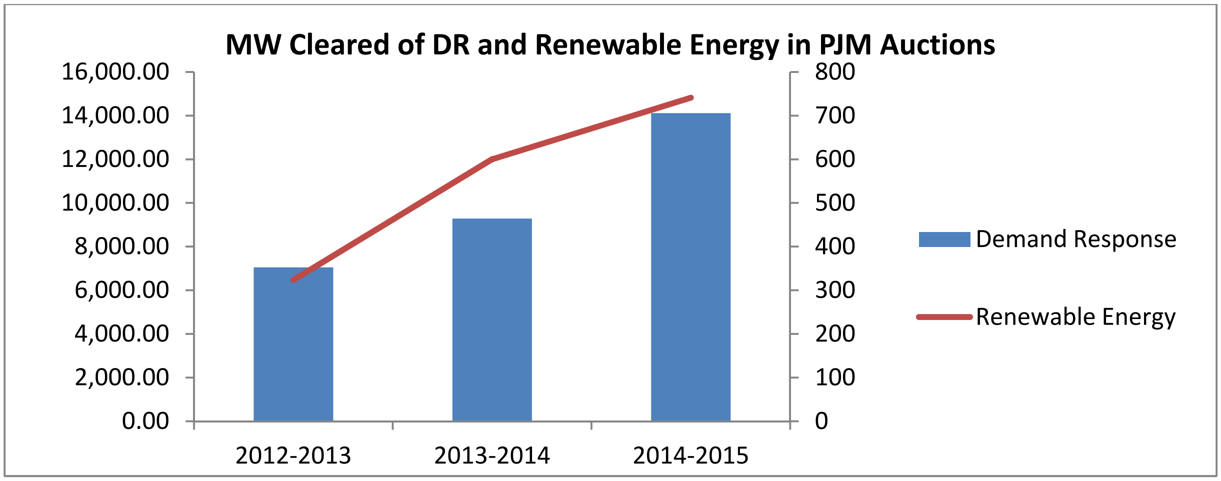

Figure 1.

Additional detailed backup for the Companies' position may be found in the original Petition for Reconsideration submitted to EPA on May 10, 2010. The petition and all attachments are found in this docket under EPA-HQ-OGC-2011-003 through 005

Thank you for allowing us to provide comments. The Companies urge EPA to reject the comments of the Adverse Commenters and promulgate the proposed changes to the NESHAP in the Federal Register as provided for in the settlement agreement.

Respectfully submitted,

Richard H. Counihan,
V.P. Government Affairs
EnerNOC Inc., on behalf of

EnergyConnect, Inc.
EnerNOC, Inc.
Innoventive Power, LLC

cc Peter Tsirigotis
Melanie King