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& BENDER LLC
ATTORNEYS

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December 11, 2013

Via Hand Delivery To:

Mr. Thomas R. Voss
President and CEO
Ameren Corporation
1901 Chouteau Avenue
St. Louis, MO 63103

Mr. Warner L. Baxter
President and CEO
Ameren Missouri
1901 Chouteau Avenue
St. Louis, MO 63103

Via Certified U.S. Mail To:

Mr. Mark Nealon
Registered Agent
Ameren Corporation
500 E. Independence Dr.
Union, MO 63084

Plant Manager
Labadie Energy Center
226 Labadie Power Plant Road
Labadie, MO 63055

Plant Manager
Meramec Energy Center
8200 Fine Road
St. Louis, MO 63129

Plant Manager
Rush Island Energy Center
100 Big Hollow Road
Festus, MO 63028

Re: Notice of Intent to Sue Ameren Corporation for Violations of the Clean Air Act at the Labadie, Meramec, and Rush Island Energy Centers

To Those Addressed Above:

On behalf of the Sierra Club and its members, we write to give you notice that Sierra Club intends to file a civil action against Ameren Corporation for violations of the federal Clean Air Act, 42 U.S.C. § 7401 *et seq.*, which have occurred and continue to occur at the Labadie, Meramec, and Rush Island Energy Centers (collectively, the "Facilities"). Each of the Facilities is a coal-fired electric generating station owned or operated by

Ameren Corporation, dba Ameren Missouri ("Ameren"). This notice is being provided pursuant to 42 U.S.C. § 7604(b) and 40 C.F.R. Part 54.

A. Factual Background

The Meramec Power Plant is located at 8200 Fine Road, St. Louis, St. Louis County, Missouri. The Meramec Plant has a rated capacity of 833 MW; it has four older vintage coal-fired boilers (manufactured between 1947-1958), each equipped with an ESP, low-NOx burners and overfire air. The Labadie Energy Center is located at 226 Labadie Power Plant Road, Labadie, Franklin County, Missouri. It has four tangentially fired coal boilers: Units 1 and 2, constructed in 1966, each have a rated capacity of 6183 mmBtu/hr; and Units 3 and 4, constructed in 1967, each with a rated capacity of 6107 mmBtu/hr. Each boiler emits pollution via a dedicated stack equipped with an ESP and has installed COMS. The Rush Island Energy Center is located at 100 Big Hollow Road, Festus, Jefferson County, Missouri. It has two tangentially fired coal boilers, both installed in 1971 and each with a rated capacity of 5922 mmBtu/hr. Each boiler emits pollution via a dedicated stack equipped with an ESP and a COMS.

Each of the coal-fired boilers identified above emits numerous air pollutants, including sulfur oxides (SOx), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), mercury, particulate matter, hydrogen chloride, and others. Individually and collectively these pollutants contribute to global warming, acid rain, regional haze, formation of ground level ozone or smog, fine particulates or soot, pollution of surface waters, and other effects harmful to human health and the environment. The violations described in this Notice Letter injure, and unless abated will continue to injure, the economic, aesthetic, health, and recreational interests of the Sierra Club and its members, several of whom live, travel, or recreate in the vicinity of, and downwind from, one or more of the Facilities.

B. Specific Clean Air Act Violations Alleged: Excess Opacity Emissions

Each of the three Facilities is subject to a limitation on the opacity of its emissions contained in the Missouri State Implementation Plan ("SIP") and the applicable operation permits issued to each of the Facilities pursuant to Title V of the Clean Air Act and 40

C.F.R. Part 70 ("Title V Permit"). The Missouri SIP contains a limit on opacity, which states in pertinent part as follows:

> (3)(A). Maximum Visible Emissions Limitations. Unless specified otherwise in this rule, no owner or other person shall cause or permit to be discharged into the atmosphere from any source, not exempted under this rule, any visible emissions greater than the limitations in the following table:

Area of State	Visible Emission Limitations	
	Existing Sources	New Sources
Kansas City Metropolitan Area	20%	20%
St. Louis Metropolitan Area	20%*	20%
Springfield-Greene County Area	40%	20%
Outstate Area	40%	20%

> ***
>
> (B) Visible Emissions Limitations, Exceptions Allowed In One (1) Six (6)-Minute Period. The visible emissions limitations in the following table shall be allowed for a period not aggregating more than one (1) six (6)-minute period in any sixty (60) minutes:

Area of State	Visible Emission Limitations	
	Existing Sources	New Sources
Kansas City Metropolitan Area	60%**	60%**
St. Louis Metropolitan Area	40%	40%
Springfield-Greene County Area	60%**	60%**
Outstate Area	60%	60%

Mo. Admin. Code § 10 CSR 10-6.220. This regulation is an EPA-approved component of the Missouri SIP, *see* 40 C.F.R. § 52.1320(c), 65 Fed. Reg. 64,145 (Oct. 26, 2000); it is therefore federally enforceable, including by citizens under the Clean Air Act's citizen suit provision.

The Meramec Plant is located in St. Louis County; Labadie is located in Franklin County; and Rush Island is located in Jefferson County, and therefore each plant is located within the "St. Louis Metropolitan Area" for purposes of the opacity limits in the Missouri SIP. Mo. Admin. Code § 10 CSR 10-6.020(2)(S)47. Thus, in simpler terms, the Missouri SIP imposes a 20% limit on opacity, except for one 6-minute period in any 60 minutes of not more than 40% opacity, on each of the Facilities' boilers.

The current Title V Permits for each of the three plants contain opacity limitations that are worded slightly differently, but result in the same 20% opacity limitation, with an exception for up to 6 minutes per any 60-minute period of not more than 40% opacity:

> 1. The permittee shall not discharge into the ambient air from any single source of emission whatsoever any air contaminant with opacity greater than 20 percent.
> 2. A source with a 20 percent limit may emit air contaminants with an opacity over 20 percent, but not greater than 40 percent for an aggregate length of time not to exceed six (6) minutes in any 60 minutes.

(Permit No. OP2009-017, Condition PW003, page 8 (Meramec); Permit No. OP2011+020A, Condition (B-1 through B-4)—002, p. 8 (Labadie); Permit No. OP2010-047, Condition (EU001 and EU002)—002, p. 8 (Rush Island)). Table 1, below, provides a summary of the applicable opacity limits for each facility.

Table 1: Summary of Applicable Opacity Limits

Station	Opacity Limit(s)	Regulatory Basis for Limit
Labadie Energy Center	20% opacity, except for "an opacity over 20 percent, but not greater than 40 percent for an aggregate length of time not to exceed six (6) minutes in any 60 minutes."	• Mo. Admin. Code § 10 CSR 10-6.220(3)(A)-(B) • Permit No. OP2011+020A, Condition (B-1 through B-4)—002, p. 8
Meramec Energy Center	20% opacity, except for "an opacity over 20 percent, but not greater than 40 percent for an aggregate length of time not to exceed six (6) minutes in any 60 minutes."	• Mo. Admin. Code § 10 CSR 10-6.220(3)(A)-(B); • Permit No. OP2009-017, Condition PW003, page 8
Rush Island Energy Center	20% opacity, except for "an opacity over 20 percent, but not greater than 40 percent for an aggregate length of time not to exceed six (6) minutes in any 60 minutes"	• Mo. Admin. Code § 10 CSR 10-6.220(3)(A)-(B); • Permit No. OP2010-047, Condition (EU001 and EU002)—002, p. 8

Each of the applicable opacity limitations, regardless of whether they appear in the SIP or in a Title V Permit, is separately and independently enforceable by Sierra Club under the Clean Air Act's citizen suit provision. The identification of specific Title V Permits by permit number in Table 1, above, is non-exclusive; Sierra Club believes that

each Facility has held one or more predecessor Title V permits with substantially the same opacity limit, and Sierra Club intends to enforce opacity violations that pre-date the issuance of each Facility's current Title V Permit.

Each of the Facilities included in this Notice Letter uses a continuous opacity monitoring system ("COMS") which measures and records the opacity at each emissions unit subject to an opacity limitation. The results of these measurements are reported on a quarterly basis by Ameren to the Missouri Department of Natural Resources ("MDNR") using Excess Visible Emissions Reports ("EERs") (typically comprised of a Continuous Emission Monitor Quarterly Report: Opacity, an Opacity Summary Report, an Opacity Excess Emissions Duration Report, and an Opacity Monitoring System Performance Report) that identify the date, time, duration, magnitude, and purported cause of each period of excess opacity emissions.

Enclosed with this Notice Letter are Ameren's quarterly opacity EERs for the period 2008 Q1 through 2013 Q1, and they are incorporated herein by reference. However, because Ameren maintains its COMS, maintains (and has sole access to) the data acquisition and handling system that is used to store the raw COMS data, and reviews the COMS data to prepare the content of its quarterly opacity EERs, Ameren is in the best position to determine precisely when the alleged opacity violations have occurred. The specific date, time, duration, and magnitude of each discrete 6-minute period of excess opacity emissions may therefore be identified by: (1) reviewing the enclosed opacity EERs (specifically, the report entitled "Opacity Excess Emissions Duration Report"), and (2) reviewing the raw COMS data maintained at each plant and searching for 6-minute increments during which the measured opacity exceeded the applicable opacity limit.

On its EERs, Ameren typically categorizes its excess opacity emissions by "reason code" or "causes of COMS excess emissions" (for example startup, shutdown, control equipment problems, process problems, soot-blowing, fuel problems, other known cause, unknown cause). Sierra Club disputes Ameren's attempt to classify its periods of excess opacity emissions as anything other than a violation of the applicable opacity limitations and the Clean Air Act, and intends to seek remedies for each period of excess opacity emissions regardless of Ameren's categorization of the purported cause of the excess emissions. This includes any period of excess opacity emissions for which Ameren may attempt to invoke an affirmative defense for periods of "malfunction, start-up, or

shutdown." Mo. Admin. Code § 10 CSR 10-6.050. Sierra Club contends that the requisite MDNR determination required by Mo. Admin. Code § 10 CSR 10-6.220(3)(C) has not been made for any reported period of excess opacity emissions. *See also id.* § 10 CSR 10-6.050(E) (noting that "[c]ompliance with this rule does not automatically absolve the owner or operator of such facility of liability for the excess emissions reported."). In any event, Ameren would bear the burden of proving that any such affirmative defense applies to each 6-minute opacity violation for which the defense is invoked.

Table 2, below, identifies the opacity violations that have occurred at each coal-fired unit at each of the Facilities during the period January 1, 2008 through March 31, 2013, as reported on Ameren's quarterly opacity EERs for quarters 2008 Q1 through 2013 Q1.

Table 2: Ameren Opacity Exceedences in Minutes Sorted by Station, and Unit (2008 Q1 - 2013 Q1)

Station / Unit	Total Minutes of Excess Opacity	Total Violations (6-Min Increments)
Labadie Unit #1	9222	1537
Labadie Unit #2	7788	1298
Labadie Unit #3	3666	611
Labadie Unit #4	4530	755
Meramec Unit #1	6570	1095
Meramec Unit #2	6936	1156
Meramec Unit #3	9042	1507
Meramec Unit #4	4434	739
Rush Island Unit #1	3744	624
Rush Island Unit #2	2262	377
Total	**58,194**	**9,699**

Each 6-minute period of excess opacity is a separate and distinct violation of the applicable opacity limitation contained in the Missouri SIP, the applicable Title V permit for the relevant facility, and the Clean Air Act. As identified above and in the attached unit-specific opacity EERs, Sierra Club alleges that Ameren committed at least 9,699 Clean Air Act violations during the period 2008 Q1 through 2013 Q1 at the Labadie, Meramec, and Rush Island Energy Centers by emitting air pollution with an opacity exceeding the applicable opacity limitation for those facilities.

Further, you are hereby put on notice that Sierra Club intends to enforce for any other opacity violation you may have committed but failed to report on your opacity EERs. For example, Ameren failed to submit opacity EERs for the Rush Island Station for the Fourth Quarter of 2010. Such failures to report are a separate and distinct violation of your permits and the Missouri SIP. *See, e.g.*, Permit No. OP2010-047, Condition (EU0001 and EU0002)-002, p. 9 (Rush Island reporting requiremens); Mich. Admin. Code § 10 CSR 10-6.220(4)(A) (containing the requirement to report excess emissions). Sierra Club also intends to sue for each such failure to report excess opacity emissions, including but not limited to 2010 Q4 at the Rush Island Station.

C. Party Giving Notice and Relief to be Sought

The party giving notice is the Sierra Club. Sierra Club has a national office located at 85 Second Street, 2nd Floor, San Francisco, CA 94105, and also has Missouri Chapter offices located at 7164 Manchester Ave., Maplewood, MO 63143. However, Sierra Club requests that all communications be addressed to its attorneys:

David C. Bender, Esq.
James N. Saul, Esq.
McGillivray Westerberg & Bender LLC
211 S. Paterson St., Suite 320
Madison, WI 53703
P: (608) 310-3560
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The citizen suit provision of the Clean Air Act allows Sierra Club to commence suit in a United States district court against you for violations of an emission standard or limitation. 42 U.S.C. § 7604(a). An emission standard or limitation is defined as any requirement under 42 U.S.C. § 7411 or § 7412, any condition or requirement applicable under a state implementation plan approved by the U.S. EPA, any Title V permit, or any requirement to obtain a permit as a condition of operations. 42 U.S.C. § 7604(f).

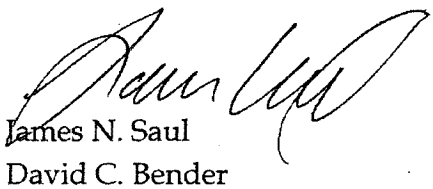
This letter serves as your notice that Sierra Club intends to file a suit to enforce the Clean Air Act for the violations described herein and any other violations for which this

letter provides sufficient notice. Sierra Club will ask the district court to impose appropriate injunctive relief, civil penalties, a beneficial environmental project in the areas impacted by air pollution emissions from Ameren's facilities, as authorized by 42 U.S.C. § 7604(g)(2), and Sierra Club's costs of litigation and attorneys' fees.

More recent compliance records, including Ameren's opacity EERs, have yet to be made publicly available, but Sierra Club believes it is likely to uncover additional violations at each facility during the 60-day notice period and during the course of litigation. Sierra Club also alleges that each of Ameren's Clean Air Act violations described herein are ongoing and likely to continue in the future until such time as a court grants Sierra Club its requested relief. As with your past violations identified herein, your future Clean Air Act violations will be measured and recorded by your COMS, and reported with specificity to MDNR and/or St. Louis County on your quarterly opacity EERs or PM monitoring reports, and thus will be readily apparent to you before they are reported to MDNR or available to Sierra Club. Therefore, Sierra Club intends to sue Ameren for any additional violations at the Facilities identified herein that have occurred or may occur after the date of this notice letter.

If you believe any of the facts described above are in error or have any information indicating that you have not violated the Clean Air Act we urge you to contact the undersigned counsel immediately. Sierra Club is interested in obtaining early and prompt resolution of these allegations, and is willing to discuss them during the 60-day notice period. However, if those discussions do not occur or if the matter is not resolved to Sierra Club's satisfaction before the end of the notice period, Sierra Club will file suit on or about the 60th day following the date of this letter.

McGillivray Westerberg & Bender LLC
Counsel for Sierra Club



James N. Saul
David C. Bender

Copies Sent Via Certified Mail To:

Ms. Gina McCarthy
Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dr. Karl Brooks
Regional Administrator
U.S. EPA, Region 7
Ralph Metcalfe Federal Building
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Chicago, IL 60604-3590

Hon. Eric H. Holder, Jr.
United States Attorney General
U.S. Department of Justice
950 Pennsylvania Avenue, NW
Washington, DC 20530-0001

Ms. Sara Parker Pauley
Director
Missouri Dept. of Natural Resources.
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McGILLIVRAY WESTERBERG & BENDER LLC
ATTORNEYS

211 S. Paterson St., Suite 320 • Madison, WI 53703

DEC 16 2013

Ms. Gina McCarthy, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

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Congress of the United States
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Washington, DC 20515–3605

REPUBLICAN POLICY COMMITTEE
CHAIRMAN

BUDGET COMMITTEE

OVERSIGHT AND GOVERNMENT REFORM COMMITTEE
SUBCOMMITTEE
CHAIRMAN
ENERGY POLICY, HEALTH CARE AND ENTITLEMENTS

December 13, 2013

The Honorable Regina McCarthy
Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

The Honorable Daniel Ashe
Director
US Fish and Wildlife Service
1849 C Street, NW
Washington, DC 20240

Mr. Samuel Rauch III
Acting Assistant Administrator for Fisheries
National Marine Fisheries Service
1315 East West Highway
Silver Spring, MD 20910

Mr. Gary Frazer
Assistant Director, Endangered Species
US Fish and Wildlife Service
1849 C Street, NW
Washington, DC 20240

Dear Administrator McCarthy, Director Ashe, Assistant Administrator Rauch, and Assistant Director Frazer,

I write to you today to respectfully request your attention to the proposed section 316(b) rule entitled "Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities" ("proposed rule"). I am concerned that consultations required under the Endangered Species Act ("ESA") in regards to this rule may have been applied in a way not intended by the law, and as a result could end in the imposition of new regulations beyond the scope of this rulemaking.

It is my understanding that the EPA determined that a formal ESA section 7 consultation with the Fish and Wildlife Service and the National Marine Fisheries Service (combined "the Services") is not needed for this proposed rule because it is unlikely to adversely affect listed species. However, it appears that the Services did not concur with this determination, as required under the rule, and the EPA is now in a formal section 7 consultation with these agencies.

Under a section 7 consultation, the ESA requires the EPA and the Services to specifically examine whether an agency action would adversely affect listed species compared to the conditions for the species absent the agency action. The stated purpose of this proposed rule is to provide additional protections for aquatic organisms by placing more stringent standards on

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cooling water intake structures at existing power plants than those already in place per existing state and federal laws. EPA is correct in stating that the proposed rule is unlikely to adversely affect species; in fact, the proposed rule adds additional protections that will likely improve conditions for species in the area of water intake structures.

I encourage the EPA and the Services to conclude the section 7 consultation expeditiously and allow the EPA to complete this rulemaking. The facts strongly support the Services resolving this matter by issuing concurrence with the original EPA finding of unlikely to adversely affect species. However, if the process has already been formally started the EPA and the Services should issue a "no jeopardy" biological opinion, reflecting that the proposed rule does not pose a danger to aquatic species.

Thank you for your careful consideration of this matter.

In God We Trust,

James Lankford
MEMBER OF CONGRESS

DAILY READING FILE

Gaines, Cynthia

From: Michael Bradley [mbradley@mjbradley.com]
Sent: Friday, January 24, 2014 2:55 PM
To: Mccarthy, Gina
Cc: Feldt, Lisa; Vaught, Laura; Carrie Jenks
Subject: 316(b) CEO Letter Regarding Nuclear Units
Attachments: 316(b) Letter to Gina McCarthy Jan 24 2014.pdf

Gina,

Please find attached a letter from the CEOs of Dominion, Exelon, NextEra, PG&E, and PSEG highlighting the potential implications of the Endangered Species Act provisions in the 316(b) rule, as we understand them, for the U.S. nuclear fleet. Please let me know if you have any questions.

Thank you and have a good weekend,

Michael

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January 24, 2014

The Honorable Regina A. McCarthy
Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Federal Building
1200 Pennsylvania Ave., NW
Washington, DC 20460-0001

Dear Administrator McCarthy:

As follow up to our last meeting with you on the Clean Water Act Section 316(b) rulemaking, this letter highlights the rule's potential implications for nuclear units. Since the rule was proposed in April 2011, three issues have arisen that could trigger the premature retirement of a significant portion of the nuclear fleet. The loss of these units would have significant economic, reliability, and climate change implications. These issues include:

1. Requirements for repowered, replaced, or rebuilt units that could require units to install cooling towers if they undertake nuclear uprates or routine maintenance, including the replacement of turbines and condensers;
2. Language that could be interpreted to require the use of willingness-to-pay surveys to monetize non-use benefits that could result in significantly overstated benefits that justify a decision to install towers; and
3. Overly broad Endangered Species Act (ESA) provisions that could require facilities to cease operation or install cooling towers if a threatened or endangered (T&E) species is located in a water body from which a facility draws water even without evidence of impact to that species.

Our letter to you dated December 20, 2013 outlines these concerns in detail. All three issues remain key areas of concern for the industry and must be resolved in order to preserve the U.S. nuclear fleet. However, the balance of this letter focuses on the potential implication of the ESA provisions, as we understand them, for nuclear units—the largest source of zero carbon electricity generation in the fleet today. We urge EPA to study the unintended impact of these provisions on the nuclear fleet and the clean energy benefits the fleet provides.

First, we believe the Services should conclude the rule is "not likely to adversely affect" T&E species. We agree with EPA's original finding that the rule does not authorize any actions that could potentially harm T&E species because the rule provides additional protections for species from impingement and entrainment at cooling water intake structures. Moreover, this rule applies to existing sources, and T&E issues have long been evaluated and addressed at each of our facilities as required by the ESA. Facilities that have already undertaken an ESA Section 7 consultation or obtained a Section 10 permit should not be required to revisit these authorizations, and the final rule should make that clear in the regulatory text.

Second, any ESA monitoring and study requirements must be focused on T&E species directly affected by the intake through entrainment or impingement. We understand that the proposed ESA provisions will require permittees to identify listed species that *may* be in the waterbodies from which a facility draws water and *might be* indirectly affected by intake structures, including by potential impacts to their prey. This overly broad approach could be interpreted to require facilities to prove that the facility is not adversely affecting any T&E species present or that may be present. Attempting to prove this negative would be extremely burdensome and potentially impossible. As a result, this approach could lead to the imposition of requirements not specifically included in the ESA, including potentially requiring a facility to cease operations immediately or install cooling towers. Moreover, the approach used to incorporate proposed ESA provisions into the state 316(b) permitting process represents a dramatic departure from the current NRC-initiated Section 7 consultations procedure used for nuclear facilities that involves multiple federal agencies. Having the ESA consultation take place prior to submittal of a state permit application would shift the decision-making to a single federal agency. Rather, any ESA study or consultation should occur as an integral part of the current permitting process and not separately. In summary, the rule, as we understand it, would impose new ESA requirements that are beyond the scope of this rulemaking and that set an untenable precedent for future EPA rulemakings. These new ESA provisions are much more expansive than the current applications of ESA in the existing NPDES permitting process and are not supported by court decisions interpreting the requirements of the ESA.

Ultimately, we are concerned that these new ESA provisions could require owners and operators of cooling water intakes to install cooling towers even if there is no evidence that the facility is causing an adverse impact. Cooling towers are particularly problematic for existing nuclear units because of high retrofit costs associated with safety issues at nuclear plants and space constraints. This is true for nuclear units in competitive and regulated markets. In recent years, the economic conditions in competitive markets have caused the profitability of nuclear units to deteriorate. For example, the precipitous and sustained decline in natural gas prices since 2008 has significantly undermined the economics of nuclear generation by lowering the market price for energy. In Eastern PJM, the profitability of nuclear units (after accounting for normal operating and maintenance costs) has fallen to levels comparable to those realized by natural gas fired combined cycle generators. These economics tend to favor construction of new natural gas facilities compared to making large capital investments in existing nuclear plants. In fact, the North American Electric Reliability Corporation (NERC) concluded in a 2011 report that most nuclear units facing an obligation to install cooling towers would retire, and that 25 to 39 GW of electric generating capacity could be economically vulnerable to retirement as a result of a 316(b) rule that imposes closed cycle cooling.[1]

Similarly, cooling tower retrofits pose a problem for nuclear units in regulated states where retrofits are limited to what the public utility commission will approve. There is no certainty that state regulators will determine that investing billions of dollars to retrofit an existing nuclear unit with a cooling tower is the "lowest reasonable cost option" to meet the requirements. Rather,

[1] North American Electric Reliability Corporation, *Potential Impacts of Future Environmental Regulations* (November 2011).

state regulators will likely elect to allow a nuclear unit to shutter and instead approve an investment in a new natural gas combined cycle unit, resulting in higher greenhouse gas emissions.

The retirement of even a small number of nuclear units would have significant reliability and climate change implications. For example, Exelon has decided upon early retirement of its Oyster Creek Generating Station in New Jersey rather than installing uneconomic cooling towers. Assuming that generation from Oyster Creek would be replaced by existing resources in New Jersey, Oyster Creek avoided nearly two million metric tons of CO_2 emissions in 2012 alone.

In Virginia, Dominion's preliminary estimate for retrofitting the Surry Nuclear Power Station with cooling towers is approximately $3 billion. As the NRC licenses for Surry's two nuclear units expire in 2032 and 2033, it is unlikely that such a significant investment in a facility with a limited remaining useful life will be viewed by Virginia's State Corporation Commission (SCC) as serving the best interests of Dominion's customers. With the long lead time necessary to plan and construct cooling towers coupled with the uncertainty of possible 316(b) ESA requirements and Dominion's obligation to reliably serve its customers' electric power needs, it is highly likely the SCC could reasonably find a new natural gas combined cycle facility to be a more viable option.

Similarly, in California, the Diablo Canyon Power Plant serves about 10 percent of the state's electricity needs with no greenhouse gas emissions. The state is currently implementing its once-through cooling regulations and estimates show that requiring closed-cycle cooling at Diablo Canyon would cost about $9 billion to $12 billion, providing a negligible environmental benefit.[2] State regulators and independent scientists have reviewed Diablo Canyon's impacts on numerous occasions, and all have reached the same conclusion: the facility's low impingement does not warrant any further assessment or action.[3]

Since October 2012, companies have announced the retirement of five reactors representing nearly 4,200 megawatts. Nuclear currently provides one fifth of the nation's electricity and 62 percent of U.S. clean generation.[4] Emissions would increase if generation from fossil fuel-fired power plants replaces a large share of the retiring nuclear units' generation. As shown in the attached graphic, if the current pace of nuclear retirements continues, 25 percent of the nuclear fleet would likely retire by 2020. This outcome would cause the U.S. to lose over half of the progress we have made to date toward meeting President Obama's 2020 emission reduction goal of 17 percent of 2005 emissions.

We appreciate the time you and your staff have taken to hear our concerns on this rule, and please do not hesitate to contact us if you have any questions regarding our ESA concerns as

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[2] Bechtel Power Corporation, *Final Technologies Assessment for Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for Diablo Canyon Power Plant (Final Draft)* (September 2013) (PG&E Comments submitted October 2013).

[3] See e.g., Tenera, *Diablo Canyon Power Plant 316(b) Demonstration Report* (March 2000), pp. 1-2; Central Coast Regional Water Quality Control Board, Staff Testimony (July 10, 2003), pp. 6-7.

[4] Energy Information Agency (EIA), Net Generation Data 2003 to June 2013 (Available at: http://www.eia.gov).

they relate to nuclear units. We look forward to continuing to work with you to finalize the rule in the coming weeks.

Sincerely,

Christopher M. Crane
President & CEO
Exelon Corp.

Anthony F. Earley, Jr.
Chairman, President & CEO
PG&E Corp.

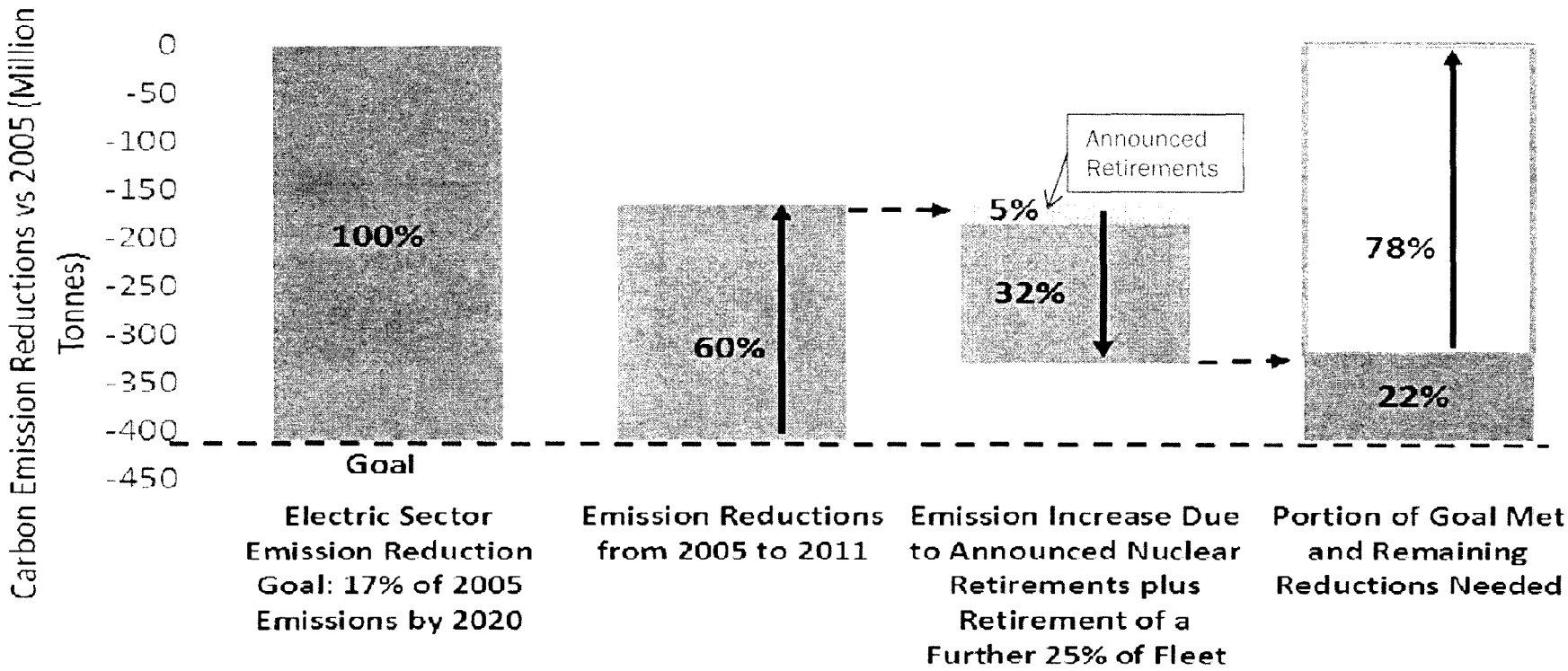
Thomas F. Farrell
Chairman, President & CEO
Dominion

Ralph Izzo
Chairman, President & CEO
Public Service Enterprise Group, Inc.

James L. Robo
Chairman, President & CEO
NextEra Energy, Inc.

Impact on carbon goals without nuclear

Retirement of 25% of nuclear fleet would give back over half the progress to date towards meeting 2020 emission reduction goal



Source: EIA; Exelon Estimates

Nuclear retirement increase assumes retirement of SONGS, Crystal River, Kewaunee, Vermont Yankee, and Oyster Creek plus 24.6 GW of additional "generic" capacity (29.4 GW total, including the announced retirements). Nuclear output is assumed to displace carbon at a rate of 0.67 tonnes per MWh of lost output.

"[T]he odds seem low that the world can avoid catastrophic warming without carbon-free nuclear power." – *Unavoidable Answer for the Problem of Climate Change*, New York Times (Nov. 2013)

Moritz, Brigette

From: glazec@pjm.com
Sent: Thursday, January 30, 2014 10:49 AM
To: Mccarthy, Gina
Cc: Feldt, Lisa; Vaught, Laura; boston@pjm.com
Subject: Section 316(b) Rulemaking: Letter from PJM Interconnection CEO to Administrator McCarthy re: Impacts of Rule on the Existing Nuclear Fleet
Attachments: EPA---Section 316(b)----Letter from PJM CEO to Administrator McCarthy--January 30, 2014.pdf

Administrator McCarthy:

On behalf of PJM President and CEO Terry Boston, I am transmitting to you the attached letter asking for your consideration of the economic viability of the existing nuclear fleet in your deliberations on the timing and scope of your final Section 316(b) rule. Please contact me or Terry Boston, PJM CEO if you wish to discuss further.

Once again, we appreciate the excellent working relationship we have had with EPA staff and appreciate your consideration of this request.

Thank you.

Craig Glazer
Vice President-Federal Government Policy
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January 30, 2014

The Honorable Regina McCarthy
Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Federal Building
1300 Pennsylvania Ave., NW
Washington, DC 20460-0001

Dear Administrator McCarthy:

PJM Interconnection, L.L.C. ("PJM") is the Regional Transmission Organization responsible for ensuring the reliability of the electric power grid in a 13-state region covering all or parts of New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, West Virginia, Ohio, Kentucky, Tennessee, Michigan, Indiana, Illinois and the District of Columbia. PJM manages the dispatch of over 180,000 MW of generating capacity in a region that includes 60 million people and accounts for over 20% of the U.S. economy. We are managing a significant shift in our region's generating mix that is occurring due to the increased availability of natural gas, state and federal regulations that have raised costs for coal-fired power generation, the aging of certain generating resources and other factors. More than 16,000 MW of coal-fired resources will retire by 2016 and new gas and renewable generating units are rapidly interconnecting to our system. We are working constructively through these changes and appreciate the ongoing working relationship we have had with your Staff. Nevertheless, the rapid shift in the profile of the generation fleet and our most recent winter experience underscores the importance of our maintaining fuel diversity in this region.

Effectively managing the timing of such a dramatic supply shift is an intricate process which triggers the need for significant investments in transmission and other infrastructure. This infrastructure does not spring up overnight---transmission facilities and new baseload generation can sometimes take years to move from initial concept to integration onto the grid. For this transition period and hopefully into the future, PJM is fortunate to be able to rely on more than 30 nuclear units providing over 30,000 MW of baseload capacity in this region. The region's nuclear resources allow us to maintain fuel diversity in our generation profile. These resources will, if anything, become even more important for reliability purposes as more intermittent resources are added to the mix.

We are concerned about the economic viability of the existing nuclear fleet in our region due to pricing pressure from all of these exogenous events. Analysis conducted by PJM's Independent Market Monitor demonstrates that the nuclear fleet in the PJM region has seen net revenues for 2012 and 2013 decline to the point of covering less than one-third of the fixed costs of a typical nuclear unit within the region. While it remains to be seen whether these economic pressures will continue and what impacts they may have on individual nuclear units, we urge caution in the imposition and timing of new regulatory costs on existing nuclear plants. Specifically, we respectfully ask that the present economic challenges facing the existing

fleet be considered as you develop Section 316(b) regulations, including the timing and scope of the Final Rule's implementation requirements on the existing nuclear fleet. From PJM's perspective as a transmission operator charged with ensuring reliability for the region, it is critical that the nuclear fleet in our region remains economically viable particularly as we head into this multi-year transition of the rest of our resource profile.

We appreciate your consideration of our perspective as you proceed with the Section 316(b) rulemaking. We thank you again for your consideration and reiterate our commitment to continue the excellent working relationship we have had with EPA Staff on these issues.

Sincerely,

Terry Boston

Thu Mar 13 14:52:58 EDT 2014
Yuhas.Darlene@epamail.epa.gov
FW: CWA 316(b) Rulemaking
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For CMS … thanks

From: Reed Super [mailto:reed@superlawgroup.com]
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Subject: CWA ? 316(b) Rulemaking

Hello,

Please see attached.

Best,
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Waterkeeper Alliance · Earthjustice · Environment America
Clean Air Task Force · Surfrider Foundation
Super Law Group · National Environmental Law Center

March 13, 2014

The Honorable Regina A. McCarthy, Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

The Honorable Sally Jewell, Secretary
U.S. Department of the Interior
1849 C Street, N.W.
Washington, D.C. 20240

The Honorable Penny Pritzker, Secretary
U.S. Department of Commerce
1401 Constitution Avenue, N.W.
Washington, D.C. 20230

Re: CWA § 316(b) – Cooling Water Intake Structure Rule

Dear Administrator McCarthy, Secretary Jewell and Secretary Pritzker:

As attorneys representing some of the largest national and regional environmental organizations in the United States, with millions of members keenly interested in protection of our nation's air, water and other natural resources, we write with respect to the Clean Water Act § 316(b) cooling water rule for existing facilities, which the Environmental Protection Agency (EPA) has committed to issue by April 17, 2014.

In particular, we wish to respond to certain requests, recommendations and legal assertions made in letters from the Edison Electric Institute and the heads of several utility and energy companies (collectively, "EEI") in September and December 2013, the Utility Water Act Group (UWAG) in October 2013, and Senator David Vitter and other Senators in July 2013 and February 2014.

As explained below, what EEI, UWAG and the Senators ask of EPA, the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) (collectively, the "Services") would plainly violate the Clean Water Act (CWA) and the Endangered Species Act (ESA).

I.

Endangered Species Act Consultation and
ESA-Related Requirements in 316(b) Rule

Cooling water intakes cause widespread and substantial harm to federally-listed threatened and endangered (T&E) species. In initiating formal consultation under the ESA, EPA acknowledged that "after promulgation and implementation of the 316(b) rule, the rule may allow as many as 215 T&E species and 30 habitats of T&E species to continue to be affected."[1] We wish to make six points in this regard:

- First, in light of the acknowledged effects on T&E species, if EPA were to issue the final rule in the absence of a final Biological Opinion from each Service, the agency would be in clear violation of ESA § 7(a)(2) and 50 C.F.R. § 402.14. Contrary to EEI and UWAG's assertions, the law is crystal clear that all future fish kills and thermal discharges at regulated facilities are legally attributable to EPA's upcoming rule. There is no such thing as "baseline impingement and entrainment" or "baseline thermal discharges"; to the contrary, the ***ESA baseline assumes that the plants and their intake structures have been built, but are not operating***.[2] Consequently, there is no legal or factual basis on which the Services could "vacate the consultation" as requested by Senator Vitter, *et al*., or conclude the consultation with a "not likely to adversely affect" concurrence, as requested by EEI and UWAG.

- Second, EPA should make clear in the 316(b) rule that nothing in the Section 7 consultation process can eliminate the duties of state agencies, federal agencies and plant operators to comply with the ESA Section 9 prohibition against taking listed species or modifying their critical habitat. EPA recognizes that "any take of listed species without an incidental take statement or ESA Section 10 take permit is in violation of ESA regulations."[3] As previously explained, the record provided by EPA to the Services precludes issuance of an Incidental Take Statement (ITS) that would insulate future take or habitat modification from ESA protections.[4]

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[1] Letter from Robert K. Wood, Director, Engineering and Analysis Division, EPA Office of Water, to Donna Wieting, Director, Officer of Protection Resources, NMFS, and Gary Frazer, Assistant Director, Endangered Species, USFWS, June 18, 2013, at 2.

[2] *See* Comments of Riverkeeper, *et al*. regarding ESA Biological Evaluation for CWA Section 316(b) Rulemaking, October 31, 2013, ("RK Comments") at 9-17 (citing *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 929 (9th Cir. 2008) and other authority).

[3] ESA Biological Evaluation for CWA Section 316(b) Rulemaking, June 18, 2013, ("BE") at 65.

[4] RK Comments at 44-45.

- Third, the record is also insufficient to support a "no jeopardy" finding, particularly in light of harm to a number of salmonid and sturgeon Distinct Population Segments and various species of freshwater mussel.[5] Closed-cycle cooling (CCC) technology must be the focus of any Reasonable and Prudent Alternative (RPA) analysis or Reasonable and Prudent Measures (RPM) analysis because it reduces fish kills and thermal discharges by approximately 98 percent and no other technology comes anywhere close.[6]

- Fourth, if the 316(b) rule directs permit writers to make any Best Technology Available (BTA) determinations on a case-by-case basis, the rule must require that EPA and the Services remain involved in permitting, in both delegated and non-delegated states, to identify the appropriate control requirements to be included in NPDES permits to protect listed species. Contrary to EEI's assertion, the ESA and CWA provide for those agencies' continuing involvement. For example, an ITS must establish clear triggers for subsequent consultation if there is a risk of jeopardizing the species.[7] Further, as the action agency, EPA must report on "the progress of the action and its impact on the species to the Service[s]."[8] Indeed, EPA and the Services agreed in their 2001 MOA to coordinate with State and Tribal permitting agencies to remove or reduce detrimental impacts of any NPDES permit on listed species, including, in appropriate cases, by EPA "objecting to and Federalizing the permit..."[9]

- Fifth, to implement that process, the 316(b) rule must require permittees to undertake robust monitoring, including the use of environmental metagenomic sampling to detect the presence of listed species near an intake. Because T&E species are, by definition, rare, they may not be collected or observed in limited, traditional sampling events despite being impinged and entrained.

- Sixth, the rule must require the submittal of comprehensive information on the potential for ***direct and indirect impacts*** to listed species, including impacts to listed species' prey. EEI's opposition to collecting information regarding the taking of prey or other indirect impacts to T&E species has no statutory basis. Avoiding "jeopardy" and avoiding "adverse modification of critical habitat" are separate and independent requirements.[10] Further, the taking of prey may

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[5] RK Comments at 44-45.

[6] RK Comments at 35-38, 39-42.

[7] *See Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1271-72 (11th Cir. 2009) (citing 50 C.F.R. § 402.14(i)(4)).

[8] 50 C.F.R. § 402.14(i)(3).

[9] Memorandum of Agreement Between the Environmental Protection Agency, Fish and Wildlife Service and National Marine Fisheries Service Regarding Enhanced Coordination Under the Clean Water Act and Endangered Species Act, January 2001, at 20.

[10] *Sierra Club v. U.S. Fish and Wildlife Service*, 245 F.3d 434, 441-43 (5th Cir. 2001).

constitute either a take of listed species or adverse modification of critical habitat,[11] and both must be avoided.

II.

Definition of New Units at Existing Facilities

In promulgating the Phase I Section 316(b) rule in 2001, EPA established Best Technology Available (BTA) standards for cooling water intake structures at new facilities based on closed-cycle cooling (CCC), a 0.5 foot-per-second maximum intake velocity, and a prohibition against withdrawals that are disproportionate to the size of the waterbody.[12] Throughout the administrative and judicial review processes, industry argued that CCC and the other standards should not be considered BTA or that BTA for new facilities should be determined case-by-case. Those arguments were fully considered and rejected, first by EPA and then by the court when it upheld the Phase I rule in 2004.[13]

In the context of the current existing facility rulemaking, a decade later, EPA is *not* reconsidering BTA for new facilities or comparing the merits of CCC with once-through cooling – an antiquated technology rarely installed in plants built since the 1980s. That debate was settled at the federal level long ago, in the first term of the Bush administration. The ***only remaining question concerns the retrofitting*** of CCC on existing facilities and whether those facilities can meet the velocity limits and proportional flow requirements.

The Phase I rule did not establish standards for new units built at existing facilities. Nor did EPA determine that such units were to be treated as existing facilities. Rather, EPA deferred regulation of those units until it had completed analysis of data on existing facilities.[14] Having completed that analysis, the draft proposed rule EPA sent to OMB shortly before proposal in 2011 required that "[n]ew units constructed at an existing facility … comply with provisions for impingement and entrainment mortality based on closed-cycle [cooling] that are similar to those required in the Phase I new facility rule."[15] That was appropriate because new units – including rebuilt, repowered and replaced units – are like new facilities; they do not encounter retrofitting issues.

Accordingly, the draft proposed rule defined new unit at an existing facility to

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[11] *See, e.g.,* 64 Fed. Reg. 60727, 60730 (Nov. 8, 1999) (NMFS adopting USFWS's definition of harm, and noting that "[r]emoving …fish … or other biota required by the listed species for feeding" can constitute a take).

[12] *See* 40 C.F.R. § 125.84; *see also generally* 66 Fed. Reg. 65256 - 65345 (Dec. 18, 2001).

[13] *Riverkeeper, Inc. v. EPA*, 358 F.3d 174, 197 (2d Cir. 2004) ("*Riverkeeper I*") ("The EPA considered all of the factors that UWAG now raises…").

[14] 66 Fed. Reg. at 65286.

[15] *See* EPA-HQ-OW-2008-0667-1295.2 (redline-strikeout version documenting changes made during Executive Order 12866 review) (hereinafter, "Redlined Version of Proposed Rule") at 2.

include "rebuilt, repowered, or replaced unit[s]."[16] EPA further defined "rebuilt" with reference to "major modifications affecting operation of the cooling water intake structure such as replacement of the turbine, boiler, or condensers" and defined "repowering" to mean rebuilding and replacing major components of a power plant instead of building a new one."[17] After many years of careful analysis by its engineers and economists, EPA explained why installing CCC at rebuilt, repowered and replaced units is unlike a retrofit:

> As [older] units are retired and replaced based on individual facility circumstances, facilities have the ideal opportunity to design and construct the new units without many of the additional expenses associated with retrofitting an existing unit to closed-cycle. … [D]owntime … may be avoided or minimized [,] … condensers can be configured for closed-cycle, reducing energy requirements, and high efficiency cooling towers can be designed as part of the unit replacement, allowing for installation of smaller cooling towers.[18]
>
> In summary, … repowering, replacement, and additional unit installation decisions can be accomplished feasibly and with lower costs than retrofitting an entire existing facility… New units are similar to new facilities, regardless of whether that unit is a green field construction, an additional unit, a replacement unit, or a repowered unit. … [N]ew units [also] would be similar to new facilities in terms of the useful expected plant life…[19]
>
> … EPA considered whether such requirements … would serve as a disincentive to replace older units and determined that this would not be the case given closed-cycle cooling's comparable cost relative to once through cooling and its small cost as a percentage of overall costs at the new unit. … Furthermore, the costs usually comprise less than 1 percent of the total costs of a new unit. Recent experience indicates that the Phase I requirements are not a disincentive for new facility construction...[20]

Shortly before proposal in the Federal Register, however, for reasons unknown and wholly unexplained, OMB changed the definition of new units at existing facilities to exclude rebuilt, repowered or replacement units.[21] That change should not have been made and, indeed, EPA has reconsidered it. According to EEI's recent letters, EPA's current approach more closely aligns with the February 2011 draft proposal in that the definition

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[16] *Id*. at 423 (proposed 40 C.F.R. § 125.92(r)).

[17] *Id*. at 423 (40 C.F.R. §§ 125.92(r) and 125.92(t)).

[18] *Id*. at 92-93.

[19] *Id*. at 147.

[20] *Id*. at 147-148.

[21] Proposed 40 C.F.R. § 125.92(r).

of new unit at existing facility includes repowered, replaced or rebuilt units, so long as the turbine and condenser are replaced (and the location of the cooling water intake structure or design intake flow is changed).[22]

There is no factual or legal basis for EEI's request that repowered, replaced or rebuilt units be excluded from the definition of new unit at an existing facility. As noted, EPA has considered and rejected EEI's argument that a CCC requirement would be a disincentive to upgrade or repower facilities. EEI also rehashes its argument that "EPA's authority under § 316(b) extends only to the *cooling water intake structure.*"[23] But for nearly four decades EPA has recognized that Section 316(b) authorizes it to regulate the volume and velocity of water withdrawn through a cooling water intake structure as a means of addressing capacity.[24] That authority is no different for new units than for new or existing facilities and does not depend on whether the intake structure or anything else has been modified. Moreover, given that existing facilities can be subjected to stricter requirements during permit renewal in the absence of any change to the facility,[25] there is obviously no legal impediment to regulating modified units in the absence of changes to the intake or design flow.

For those reasons, EPA should <u>not</u> define new unit based on whether the location of the intake structure or design intake flow will change. Using turbine and condenser replacement as the sole touchstone for rebuilt, repowered and replaced units is consistent with EPA's statutory authority, and properly recognizes that such units are, for all intents and purposes, new facilities.

If the electric power industry were given authority to repower the nation's existing fleet of antiquated, destructive once-through-cooled power plants by installing new boilers, new condensers and new turbines without also replacing their 1950s cooling systems, EPA would create an enormous loophole that would swallow not only the existing facility rule, but also the Phase I rule for new facilities as well.

Notably, the last time EPA (or OMB) attempted an Orwellian re-write of the definitions of "new" and "existing," that aspect of the Phase II rule was remanded by the Second Circuit, with the court noting that no deference is owed to an agency interpretation that is "plainly erroneous."[26]

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[22] EEI Dec. 20, 2013 letter at 3.

[23] EEI Sept. 17, 2013 letter at 3 (emphasis in original).

[24] *See* 66 Fed. Reg. at 65313 (citing *In re Brunswick Steam Electric Plant*, Decision of the General Counsel No. 41 (June 1, 1976)).

[25] Entergy's argument that Section 316(b) imposes only a *pre*-construction requirement and does not allow EPA to later revisit the design, location, capacity or construction of an existing plant's cooling water intake structure was rejected by the Second Circuit in *Riverkeeper II*. *See Riverkeeper, Inc. v. EPA*, 475 F.3d 83, 121-23 (2d Cir. 2007)

[26] *Riverkeeper II*, 475 F.3d at 117-20 (citing *Fowlkes v. Adamec,* 432 F.3d 90, 97 (2d Cir. 2005)).

III.

Permit Application Requirements & Deadlines

EEI has asked EPA to "[p]rovide a minimum of five years for all facilities to complete the permit application requirement."[27] Allowing five years to complete an application for a five-year permit would be patently excessive, particularly since it has long been clear to industry what information it will need to submit. As EPA noted in the proposal, many of the regulated facilities were previously subject to the withdrawn Phase II rule and should have already compiled much of the proposed application data, which can be used to meet many of the information submittal requirements.[28] For newly covered facilities, the 2011 proposal gave them advance notice as to what the agency's expectations are regarding application requirements.[29] Once the final 316(b) rule has been issued, plant operators can hit the ground running with their application materials and should be kept to a tight time frame. In light of this, the information submittal time periods are entirely too long; ***the schedule set forth in the proposal should be cut in half.***[30]

Apart from the length of the schedule, the proposed rule's phased approach for information submittal is a significant improvement over prior 316(b) rules because it requires facilities to submit application materials at intervals triggered by promulgation of the final rule.[31] This is critical because certain components of an application take less time to complete than others, regulators can evaluate only so much information at any one time and may not request information expeditiously, and certain items may need to be supplemented. Tying the schedule to the rule's promulgation date provides far greater efficiency, uniformity and transparency than if 50 permitting agencies were directed to set information submittal schedules for the 1,200 covered facilities.

Many facilities operate under long-expired, administratively-continued NPDES permits even though their renewal applications do not yet include the information needed by permit writers. As EPA is well aware, the CWA authorizes states to issue NPDES permits "for fixed terms, not exceeding five years."[32] The five-year, time-limited nature of the permit is central to Congress's plan to press new technologies – and incrementally stricter

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[27] EEI Dec. 20, 2013 letter at 4.

[28] *See* 76 Fed. Reg. at 22254.

[29] *See* 76 Fed. Reg. at 22248 (similar statement in context of compliance schedules).

[30] In addition, the Clean Water Act mandates compliance with the 316(b) rule no later than three years from promulgation. CWA Sections 301(b)(2)(C), (D), (E) & (F) and 301(b)(3)(A) & (B) require compliance "as expeditiously as practicable, but in no case later than three years after the date such limitations are promulgated…." As the courts have explained, "the time limits in sections 301 and 306 govern EPA's duty to take action under section 316(b). " *Cronin v. Browner*, 898 F. Supp. 1052, 1059 (S.D.N.Y. 1995). The same is true with respect to permittees' duty to comply.

[31] 76 Fed. Reg. at 22254.

[32] 33 U.S.C. § 1342(b)(1)(B).

effluent limits – onto dischargers at regular five-year intervals.[33] Once a five-year NPDES permit expires, the Administrative Procedure Act (APA) allows licensees who have made "timely and sufficient application for a renewal or new license *in accordance with agency rules*," to conduct "an activity of a continuing nature … until the application has been finally determined by the agency."[34]

As a result of the administrative continuance of their permits, some power plants are currently operating under permits that were issued in the late 1980s or early 1990s and expired approximately 20 years ago. These plants are typically inefficient and highly polluting facilities still using antiquated technologies from that era or earlier and badly in need of technology upgrades. The generational delay in repermitting them is unacceptable and plainly contrary to the intent of Congress. Consequences should be attached to the failure of a permit applicant to complete its renewal application on a timely basis. That failure can affect the administrative continuance of an expired permit or the opportunity to contend that the putative best technology for minimizing adverse environmental impact is not available at a particular plant. ***Such a "backstop" provision is necessary to prevent dilatory plant owners from continuing to operate under 1980s and 1990s permits in the 2020s and beyond.*** EPA must do its utmost to ensure that long overdue permits are reviewed, renewed and modified as needed. EPA's final rule should address this issue, in delegated and non-delegated states.

IV.

Cost-Benefit Analysis and EPA's Stated Preference Survey

EPA is most assuredly *not* required to base its Section 316(b) determinations on cost-benefit analysis or to direct permit writers to do so. In EPA's very first 316(b) rule, the agency stated: "No comparison of monetary costs with the social benefits of minimizing adverse environmental impacts, much less a formal, quantified 'cost/benefit' assessment is required by the terms of [§ 316] of the Act."[35] More recently, "[i]n *Entergy Corp. v. Riverkeeper*, the Supreme Court has now made pellucid that the EPA may but is not required to engage in cost-benefit analyses for CWIS rule making."[36]

Furthermore, as Justice Breyer noted in *Entergy*, Congress "intended the law's text to be read as *restricting … the use of cost-benefit comparisons.* … [because] the Act's sponsors … feared that such analyses would emphasize easily quantifiable factors over more qualitative factors (particularly environmental factors, for example, the value of preserving nonmarketable species of fish)."[37] Justice Breyer was particularly concerned

[33] *See NRDC v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987).

[34] 5 U.S.C. § 558(c) (emphasis added).

[35] 41 Fed. Reg. 17387, 17388 (Apr. 26, 1976).

[36] *ConocoPhillips Co. v. EPA*, 612 F.3d 822, 837 (5th Cir. 2010).

[37] *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 232 (2009) (Justice Breyer, concurring).

about "futile attempts at comprehensive monetization."[38] Justice Scalia's majority opinion similarly acknowledged that "arguments may be available to preclude such a rigorous form of cost-benefit analysis as that which was prescribed under the statute's former BPT standard, which required weighing 'the total cost of application of technology' against 'the … benefits to be achieved.'"[39]

Notably, EPA chose not to rely on cost-benefit considerations in developing its Phase III rule for new oil rigs, and neither that rule nor the Phase I rule include a cost-benefit variance. Both were upheld in court.[40] EPA's reason to eschew cost-benefit analysis in Phase III was plain: "it did not have enough information to perform a *meaningful* cost-benefit analysis."[41] The Fifth Circuit agreed, explaining that "[t]he agency's decision to regulate on the basis of economic achievability was borne out by the existence of cost information but not benefit information."[42]

EEI now asks EPA to *require* permit writers to rely on quantified, monetized cost-benefit analysis but to *prevent* them from using stated preference methods for valuing ecological benefits.[43] EPA must decline that request because doing so would guarantee the development of meaningless and futile analyses of the kind that Justice Breyer warned against in Phase II. The lack of meaningful benefits information is exactly the reason EPA did not employ cost-benefit analysis in Phase III, and it would also violate the Clean Water Act in ways that Justices Breyer and Scalia foreshadowed. States have informed EPA of the enormous difficulties in placing an accurate dollar value on aquatic resource impacts. And EPA itself recently noted that the "difficult, time-consuming and expensive" process of cost-benefit analysis "will rarely be sustainable for individual permits."[44] ***Accordingly, EPA should not mandate cost-benefit analysis as a part of the permit issuance process*** because it would result in 1,200 meaningless cost-benefit analyses.

Furthermore, to the extent that cost-benefit analysis is allowed as a *voluntary* component of permitting, the analysis must fully value all benefits by using the data from EPA's regional and national stated preference survey. EEI and the Senators' attempt to malign stated preference methods as "controversial" or "inappropriate" is belied by EPA and OMB's guidelines for regulatory analysis. Those guidelines have long recognized that such methods are not only appropriate and well-established economic tools, but also that they are *necessary* to a complete benefits analysis:

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[38] *Id.* at 235.

[39] *Entergy*, 556 U.S. at 223.

[40] *ConocoPhillips* at 833-42; *see also Riverkeeper I*, 358 F.3d 174.

[41] *ConocoPhillips*, 612 F.3d at 838 (emphasis added).

[42] *Id*. at 842.

[43] EEI Sept. 17, 2013 letter at 2-3; EEI Dec. 20, 2013 letter at 2-3.

[44] EPA - New England, Clean Water Act NPDES Permitting Determinations for the Thermal Discharge and Cooling Water Intake Structures at Merrimack Station in Bow, New Hampshire NPDES Permit No. NH 0001465 at 327.

> Stated Preference Methods (SPM) have been developed and used in the peer-reviewed literature to estimate both "use" and "non-use" values of goods and services. They have also been widely used in regulatory analyses by Federal agencies… A stated-preference study may be the *only* way to obtain quantitative information about non-use values…[45]

Because biological diversity and other non-use values are invariably significant in this context – typically they account for 98 percent of the total benefits[46] – conducting cost-benefit analyses without stated preference methods would result in virtually all of the benefits being zeroed out, thereby guaranteeing a completely useless analysis. The national and regional cost-benefit study EPA conducted in the context of the rulemaking represents the most comprehensive and rigorous effort yet to monetize all of the benefits of reducing impingement and entrainment. States have neither the time nor resources to conduct their own stated preference surveys. EPA's survey showed that the economic benefits of minimizing impingement and entrainment dramatically exceed the costs.[47] The use of those data in the plant-specific context would be manifestly more reliable than placing a zero value on benefits that are known to exist and that in the aggregate vastly outweigh the costs.

Accordingly, if permit writers are permitted to undertake cost-benefit on a voluntary basis, or to accept such analyses prepared by permit applicants, they should be prohibited from using any such analysis that does not take full account of all benefits, including ecological benefits, on equal footing with all other benefits and costs.

V.

Low Capacity Utilization Units ("Peakers")

EEI also asks EPA to "specify a capacity factor or flow rate below which the final rule's requirements will not apply," based on its unsupported assertion that low capacity utilization units (*i.e.*, "peakers") have "little risk" of adverse environmental impact.[48]

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[45] OMB Circular A-4 at § 4 (emphasis added); *see also* EPA, Guidelines for Preparing Economic Analyses.

[46] As EPA has explained, 98.2 percent of the aquatic organisms affected by intake structures are not harvested and thus do not go to market. 69 Fed. Reg. 41576, 41661 (July 9, 2004).

[47] *See* Comments on EPA's Section 316(b) Stated Preference Survey, Dr. Frank Ackerman, Stockholm Environment Institute-US Center, Tufts University, July 10, 2012. Notably, the Senators cite a NERA Consulting report prepared for UWAG and EEI for the proposition that the stated preference survey estimates benefits to be $2.275 billion annually for EPA's preferred option and five times the value of the costs. *See* July 22, 2013 letter from Senator Vitter, et al., to EPA at 2.

[48] EEI Sept 17, 2013 letter at 4-5; *see also* EEI Dec. 20, 2013 letter at 4.

In fact, as state regulators have found, there is "no predictable relationship" between capacity factor and cooling water use.[49] There are several reasons for this, including that cooling water systems at non-baseload facilities may be operated more than is necessary to condense steam.[50] Further, "non-targeted reductions" in cooling water use may have little effect on reducing adverse environmental impact because the "driving factors" influencing entrainment and impingement at a facility are the "seasonal dimension of both energy demand and fish reproductive and migratory life history."[51] In other words, peaking and load-following facilities can have a disproportionately large adverse environmental impact on aquatic resources if they operate when biological activity is high. In addition, many facilities that now operate as peakers or load-following units were originally designed as baseload units but are no longer efficient enough to be operated regularly. This means that they also have a disproportionately large adverse impact on air quality and climate relative to more efficient baseload facilities.

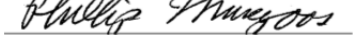
Moreover, a plant's past operational history does not guarantee that it will run infrequently in the future, due to changes in demand and fuel costs. Facilities should not be exempted from certain requirements based on prior capacity utilization and given free rein to ramp up operations in the future.

Consequently, if capacity factor or average flow rate is to be a component of BTA for certain facilities, the NPDES permit must contain mandatory limits on future capacity and flow. In addition, those limits must be expressed as targeted, seasonal reductions and/or be accompanied by additional requirements specifying the minimum reductions in impingement and entrainment to be achieved as a result of reduced operation, as has been done in some recent state-issued permits for peakers.

Thank you for considering these legal issues as the rulemaking is completed

Very Truly Yours,

Reed Super
Legal Director, Waterkeeper Alliance
Principal, Super Law Group



Phillip Musegaas
Hudson River Program Director
Riverkeeper, Inc.

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[49] *See generally* New York State Department of Environmental Conservation, The Relationship between Cooling Water Capacity Utilization, Electric Generating Capacity Utilization, and Impingement and Entrainment at New York State Steam Electric Generating Facilities, Technical Document, July 2010, at 2.

[50] *Id*. For example, plants may withdraw water when not generating electricity, or may withdraw a disproportionately high volume of water relative to kilowatt hours, in order to prevent condenser fouling; to dilute discharges; because they have single-speed intake pumps that do not allow withdrawals to be scaled down; or to cool the plant during the start-up and cool-down periods before and after operation.

[51] *Id*.

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Andrei Greenawalt, OIRA Associate Administrator
Nancy Sutley, Chair, Council on Environmental Quality
Dan Utech, Director for Energy and Climate Change, Domestic Policy Council
Robert Dreher, Acting Asst. Attorney General, Environment & Nat. Resources Div.

Thu May 15 12:28:39 EDT 2014
Yuhas.Darlene@epamail.epa.gov
FW: CEO calls
To: CMS.OEX@epamail.epa.gov; Gaines.Cynthia@epamail.epa.gov; Moritz.Brigette@epamail.epa.gov

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For cms. thanks

From: Michael Bradley [mailto:mbradley@mjbradley.com]
Sent: Thursday, May 15, 2014 10:14 AM
To: Mccarthy, Gina
Subject: CEO calls

Gina,

I understand that you will be calling a few CEOs to discuss the final 316(B) rule. If youre comfortable, it would be very helpful to mention to Tom Farrell and Tony Early that working closely with the Clean Energy Group was essential in developing an approach that both delivers substantial environmental improvements and is manageable for the electric industry. Tom and Tony have chosen to participate in our 316(B) work and are considering joining our effort on 111(d). Having you mention the value of CEG should push them to sign on. Both Tony and Tom saw the effectiveness of CEG during the MATS rule but were on the other side.

Michael

Wed Aug 06 09:14:18 EDT 2014
Leavy.Jacqueline@epamail.epa.gov
FW: UWAG Comments on EPA's Proposed Information Collection Request (ICR) for Clean Water Act § 316(b)
To: CMS.OEX@epamail.epa.gov

From: Moore, Susan [mailto:smoore@hunton.com]
Sent: Tuesday, August 05, 2014 3:55 PM
To: Southerland, Elizabeth
Cc: Mccarthy, Gina; Hewitt, Julie; jlaity@omb.eop.gov
Subject: UWAG Comments on EPA's Proposed Information Collection Request (ICR) for Clean Water Act § 316(b)

SENT ON BEHALF OF KRISTY A.N. BULLEIT:

Attached you will find a copy of the Utility Water Act Group's comments on EPA's proposed Information Collection Request ("ICR") relating to the section 316(b) final rule for existing facilities, which we filed on July 28 on regulations.gov. We appreciate the opportunity to comment, and we would be happy to discuss any of the issues raised with you and your staff.

Susan

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FILE NO: 29142.060024

August 5, 2014

BY EMAIL

Ms. Elizabeth Southerland
Director of the Office of Science and Technology
Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 4301T
Washington, DC 20460

Re: **UWAG Comments on EPA's Proposed Information Collection Request (ICR) for Clean Water Act § 316(b)**

Dear Ms. Southerland:

Attached you will find a copy of the Utility Water Act Group's comments on EPA's Proposed Information Collection Request ("ICR") relating to the section 316(b) final rule for existing facilities, which we filed on July 28 on regulations.gov. We appreciate the opportunity to comment, and we would be happy to discuss any of the issues raised with you and your staff.

Once you have had an opportunity to review our comments, please do not hesitate to contact me if have any questions or would like to have a follow up discussion.

Sincerely,

Kristy A. N. Bulleit

Attachment

cc: Administrator Gina McCarthy
Ms. Julie A. Hewitt
Mr. James A. Laity

COMMENTS OF
THE UTILITY WATER ACT GROUP (UWAG)
ON PROPOSED INFORMATION COLLECTION REQUEST (ICR)
RELATED TO COOLING WATER INTAKE STRUCTURES
AT "EXISTING" FACILITIES UNDER CLEAN WATER
ACT § 316(b) (FINAL RULE)
Docket ID No. EPA-HQ-OW-2008-0667
FRL-9911-52-OW
79 Fed. Reg. 30,605-07 (May 28, 2014)

July 28, 2014

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UWAG COMMENTS ON ICR FOR
§ 316(b) RULE FOR EXISTING FACILITIES

These are the comments of The Utility Water Act Group (UWAG)[1] on EPA's Proposed Information Collection Request (ICR) for Clean Water Act § 316(b), which regulates cooling water intake structures.

A prepublication version of the § 316(b) rule for cooling water intake structures at "existing" facilities (the "Existing Facility Rule" or "Rule") became available May 19, 2014. An Information Collection Request (ICR) for the rule was published in the Federal Register on May 28. See 79 Fed. Reg. 30,605 (May 28, 2014) (Doc. ID No. EPA-HQ-OW-2008-0667). The ICR has a 65-page Supporting & Related Material document, which summarizes the rule and calculates the estimated "burden" of complying with the rule. See http://www.regulations.gov/#!documentDetail;D=EPA-HQ-2008-0667-3157.

The *Federal Register* notice says that the ICR is a revision of the previous one three years ago, which was developed for EPA's "Phase II" rule for existing facilities. The Phase II rule was suspended on June 7, 2007, and will be withdrawn once the Existing Facility Rule becomes effective.

The issue for comment is whether the information collection requirements of the Existing Facility Rule comply with the Paperwork Reduction Act. EPA seeks comments on (1) whether the ICR is necessary for the proper performance of EPA's functions, including whether the

[1] UWAG is a voluntary, *ad hoc*, non-profit, unincorporated group of 191 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. The Edison Electric Institute is the association of U.S. shareholder-owned energy companies, international affiliates, and industry associates. The National Rural Electric Cooperative Association is the association of nonprofit energy cooperatives supplying central station service through generation, transmission, and distribution of electricity to rural areas of the United States. The American Public Power Association is the national trade association that represents publicly-owned (units of state and local government) energy utilities in 49 states representing 16 percent of the market. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the Clean Water Act and in litigation arising from those rulemakings.

information to be collected will have "practical utility"; (2) whether EPA's estimate of the burden is accurate; (3) how EPA could enhance the "quality, utility, and clarity" of the information to be collected; and (4) how EPA might minimize the burden on those who must respond (including using automated electronic, mechanical, or other technological collection techniques or other forms of information technology such as electronic submission of responses). 79 Fed. Reg. 30, 605-06 (May 28, 2014).

In light of these legal standards, UWAG asks EPA to consider the following comments and recommendations. Our comments address four categories of issues: (1) whether the information collection requirements are unnecessary, unduly burdensome, or lack practical utility as applied to certain facilities; (2) whether the information collection requirements are unnecessary or unduly burdensome by virtue of the deadlines imposed; (3) whether the information required is unnecessary, will be unduly burdensome to collect, or will lack practical utility in general; and (4) whether EPA's ICR burden estimates are clear, complete, sufficiently documented, and reasonably accurate.

In making these comments, UWAG wishes to emphasize that, in many respects, we believe EPA has done a commendable job of developing a reasonable and environmentally protective § 316(b) rule that is less costly than originally proposed. The Agency's job was made more difficult by the artificial court-ordered deadline under which it conducted the rulemaking. Such situations can introduce unintentional errors or ambiguities.[2] A number of our comments address what we believe are errors or ambiguities that would be simple and appropriate to correct or to make consistent with the Paperwork Reduction Act. In other cases, addressing our

[2] One such error (which has nothing to do with collecting information) appears in § 125.98(g), which provides that, for permit proceedings that began or begin before the effective date of the rule, permit requirements may be based on the factors for entrainment (§§ 125.98(f)(2) and (3)) and on the IM standards in "§ 125.95(c)." *See* the preamble to the Rule p. 558. This appears to be a typographical error that should read "§ 125.94(c)" – 94 not 95.

comments would require a more substantial modification to or clarification of a requirement to collect information. Making these changes is essential, we believe, to ensure that the information collection requirements of the Rule are clear to regulators and the regulated community alike, are not unnecessary or unduly burdensome, produce information that has practical utility, and ultimately are consistent with the Paperwork Reduction Act.

I. Some of the Information Collection Requirements Are Unnecessary or Unduly Burdensome or Lack Practical Utility as Applied to Certain Facilities or Units

A. The Director Should Have Authority to Waive Any or All of the Application Requirements for Facilities that Plan to Retire Within the Next Permit Cycle

The Rule authorizes the Director to waive entrainment-related requirements for existing facilities that plan to retire after the current permit expires but within one permit cycle (§ 122.21(r)(1)(ii)(G)), but it provides no similar authority to waive other application requirements, such as the application requirements for impingement mortality control and background information. Requiring a facility to collect and submit extensive, costly application information, when it will retire before that information can be processed and used to issue a new permit, is unnecessary and unduly burdensome and lacks practical utility. The Rule should authorize the Director to waive any and all of the otherwise applicable permit application requirements.

B. The Director Should Have Authority to Waive or Defer Application Requirements Where a Facility Is Planning to Retire Some Units at a Facility but not All

A facility may be planning to retire some units (but not all) before the permit expires or within the next permit cycle. The Rule appears to require the facility to collect and submit all the required permit application information for such a unit, even if the unit will retire before the current permit expires and even if it has an intake separate from other units at the same facility.

If the retiring unit or units are on a separate intake and will retire before the permit expires, the Rule should exempt them from permit application requirements, as it does for retiring facilities (§ 122.21(r)(1)(ii)(F)). Requiring such units to collect and submit extensive permit application information is unnecessary, unduly burdensome, and of no practical utility.

In addition, even if the retiring unit or units share a common intake with units that are *not* retiring, or if the planned retirement will not occur until the next permit cycle, the Rule should give the Director authority to waive or defer some or all of the permit application requirements. This is important, because unit retirements will decrease the flow through the intake structure and change the hydraulic zone of influence. If the studies are done *before* the units retire, the studies will not be representative of future operation. Thus the information will be misleading and lack practical utility.

C. New Units Should Not Have to Meet the Entrainment Application Requirements of § 122.21(r)(9)-(13)

The Rule says that if a new unit increases the actual intake flow of the facility to more than 125 MGD, the owner/operator of the facility must submit the information required by (r)(9) to (r)(13) *at the time of the permit application for the new unit*. *See* § 122.21(r)(1)(ii)(E). This means the entrainment characterization study, technical feasibility and cost evaluation study, benefits valuation study, non-water quality environmental impacts study, and peer review must be done by the time the application is submitted. Similarly, § 122.21(r)(14) requires, for new units choosing to comply using technologies that produce results comparable to closed-cycle cooling, that the applicant submit the Entrainment Characterization Study of § 122.21(r)(9) for the new unit.

But collecting entrainment characterization data requires the unit to operate, and a new unit cannot operate until the permit has been granted. And the other entrainment-related studies

all rely, in one way or another, on the information obtained from the Entrainment Characterization Study.

It is impractical (in fact impossible), as well as arbitrary and capricious, to require an applicant to submit studies that cannot be performed until the unit is operating. Also, by tying the permit application for the *new unit* to application requirements that will now apply to the *facility as a whole*, the Rule creates more burdens and delays in permitting new units, adding to the impracticability of the requirement.

The better way to deal with this would be to have the permittee submit the facilitywide application data during the new permit renewal. The Rule should be revised to specify that any required studies are to be submitted on a site-specific schedule established by the Director and commencing after the new unit has been permitted and is operating normally.

The Rule also requires a new unit that will increase the total capacity of an existing facility to more than 2 MGD DIF to satisfy the "applicable" provisions of § 122.21(r)(7). *See* § 122.21(r)(1)(ii)(E). Section 122.21(r)(7) calls for entrainment performance studies, namely "previously conducted studies" or studies from "other facilities."

Since the new unit will have to have closed-cycle cooling (or comparable impact), there is no reason to require entrainment studies from "other facilities." This requirement, like the others, is unduly burdensome and lacks practical utility, and it should be deleted. Instead, where adding a new unit causes the existing facility to exceed the 2 MGD threshold, any required information should be submitted by the existing facility during permit renewal.

D. Facilities with Closed-Cycle Cooling Should Not Have to Submit Entrainment Studies

Facilities that have closed-cycle cooling should not be required to complete the studies under § 122.21(r)(9)-(13), regardless of the AIF. It appears EPA has presumed that all facilities

with closed-cycle cooling have an AIF less than 125 MGD, but this is not always so. Some facilities may have two intakes, one with closed-cycle cooling and the other once-through, and the actual intake flow from both intakes taken together may exceed 125 MGD, thus triggering the study requirements even for the closed-cycle component of the plant. The Rule should not require entrainment studies for the closed-cycle part of the plant, and it should provide an exemption, not a mere waiver option. If EPA does require a request for waiver, then EPA needs to include the cost to submit information for at least some of these stations in the ICR, because there is no way to determine if any waiver will be granted.

Instead of asking for a waiver, the facility should be exempt from submitting the information in § 122.21(r)(9)-(13), and the Director should be allowed to request additional studies if warranted, which the Rule already allows. Such an approach would reduce costs and avoid unnecessary burdens on facilities and units that already have the technology that, in EPA's view, is the best-performing alternative.

E. The Rule Should Not Require Information from Existing Facilities that Obtain Cooling Water From Independent Suppliers

By the terms of § 125.91(b), a facility (such as a power plant) is subject to the § 316(b) rule and its application and other information collection requirements if it gets its cooling water by contract or arrangement with an independent supplier that is not itself subject to the Rule or to the "Phase I" rule for new facilities. Hence it is the independent supplier who controls access to the intake structure and nearby waters, but it is the power plant that is responsible for supplying information required about the structure. This requirement is unduly burdensome and should be deleted for the following reasons.

If the facility gets water from an independent supplier but has no legal right of access to the supplier's intake or nearby waters, the facility may not be able to comply with the application

requirements, let alone make physical changes to the supplier's intake structure. The rule makes the user responsible for supplying information that the supplier controls.

It is unfair and irrational for EPA to require one party to be make a different party comply with an EPA regulation. It also will do little to achieve § 316(b) goals, since, as EPA recognizes, such situations are rare. See preamble p. 33 (EPA expects independent supplier provision to have only limited applicability).

The core problem is that EPA's rule requires cooling water users to collect information under existing contracts that may not give them that right. Power plants that buy cooling water from others have little flexibility to modify longstanding agreements. For example, the contract between a power plant and a regional water supply agency that provides water to many sources is unlikely to grant the power plant any rights at all to access, control, or modify the agency's intake, nor could such a contract be easily modified to grant those rights. EPA's objective would be better served by requiring that, if an existing facility in the future transfers ownership or control of a cooling water intake structure (but not the entire generating facility itself) to an independent third party, the structure remains subject to the rule.

In short, EPA has not carefully considered the feasibility or, even if feasible the burden, of obtaining permission from independent suppliers before information can be collected for the § 316(b) rule. This burden has been disregarded or at best underestimated. To address these concerns, EPA should narrow the requirement to report information about third-party supplier intakes as discussed in the preceding paragraph and should fully account for the burden.

F. The Application Requirements Are Over-Inclusive and Should Be Clarified.

Section 122.21(r)(1)(ii)(A) says "[t]he owner or operator of an existing facility defined at 40 C.F.R. 125.92(k)" must submit specified information required by other parts of the rule, including source water physical data and cooling water intake structure data and "applicable"

provisions of (r)(4)-(8). The definition of "existing facility" in § 125.92(k) includes any facility that commenced construction on or before January 17, 2002. It does not exempt (though § 125.91 on "Applicability" does) facilities without cooling water intake structures, facilities with design intake flows less than 2 MGD, or other facilities excluded from coverage under Part 125 Subpart J.

We believe this is an unintentional error, reflecting a disconnect between § 122.21(r) on application requirements and § 125.91 on applicability. Section 125.91 controls and makes it unnecessary to submit studies for facilities not subject to the IM and entrainment standards. Still, it would be clearer and less confusing to include in § 122.21 an explicit exception for facilities not subject to the requirements of § 125.94 *et seq.*

II. Some of the Permit Application Requirements Are Unduly Burdensome by Virtue of the Deadlines Imposed

A. The Rule Should Not Require the Impingement Technology Performance Optimization Study Until the Entrainment Standard Has Been Set and Any Necessary Technology Has Been Installed

Sections 122.21(r)(6), (6)(i), and (6)(ii) say that, for two of the seven alternative IM technologies, the owner/operator must submit an impingement technology performance optimization study. The study must provide two years of biological data. The technologies that must have this optimization study are (1) modified traveling screens and (2) site-specific systems of technologies, management practices, and operational measures. *See* § 125.94(c)(5) and (6). For either of these technologies the Director must review the optimization study and then determine that either modified screens or site-specific systems are the "best technology available."

But an operator cannot "optimize" a technology or do an "optimization study" until the technology is installed. Hence the rule as written is circular: the operator must buy and install

the technology, then optimize its performance for two years, and then the Director must approve the technology. The "burden" of gathering information would be extraordinary if a facility chose one of the two technologies and installed it, collected optimization data for two years, and then discovered that the Director would not approve the technology. To avoid this unreasonable burden, the optimization study should be postponed until the Director has approved the complying IM technology (either modified traveling screens or a site-specific system of technologies).

In the preamble to the Rule, EPA acknowledges this issue and says it intends Directors to extend the deadline for submitting the optimization study for facilities that intend to use modified traveling screens but don't already have them in place. The preamble says that if the facility has not already installed modified traveling screens (option (c)(5)) and chooses that option, the Director may postpone the optimization study until the screens are installed. See preamble p. 90 and § VI.G.1.d; see also p. 197 (where the technology is not yet installed, the permit would include a schedule for both installing the technology and doing the optimization study). But there is nothing about such schedule adjustments in the Rule itself.

Also, the preamble acknowledges the need for relief only for modified traveling screens, not for site-specific systems. A provision in the rule for extending the deadline for optimization studies (as distinguished from overall compliance) should apply to both (c)(5) and (c)(6).

Even where the facility already has in place a modified screen or a combination of technologies that it believes complies with the IM standard and thus is in a position to perform an optimization study, there remains a risk that a later decision on *entrainment* technology would require the earlier IM technology to be modified or abandoned.

This is not EPA's intent. EPA agrees that permittees should not have to meet the compliance standard for IM until BTA for entrainment has been established, as shown by the "aligning deadlines" provision § 125.94(b)(1). But § 122.21(r)(6) requires the owner/operator to identify the compliance method for IM when it submits the application with the information the Director will use to decide on entrainment. And plants that choose (c)(5) modified traveling screens or (c)(6) systems of technology for IM, as noted above, must perform two-year optimization studies as well as entrainment studies. Thus, in effect, permittees are required to choose (and, for some options, demonstrate compliance by) IM control technologies before they know what entrainment technology will be required.

Thus, just as the optimization study should be postponed until the IM technology has been approved, so also the optimization study (for traveling screens or site-specific systems) should be postponed until the site's entrainment standard is determined. This clarification to the Rule would help avoid situations in which the burden of collecting information was unreasonable because the optimization study became irrelevant due to a later decision on entrainment.

In short, the Rule should provide that the optimization study may be postponed until the Director has made a final determination about the BTA entrainment standard and any required IM control technology has been installed. And this postponement should be available for both (c)(5) modified traveling screens and (c)(6) site-specific systems. These changes would lessen the burden and ensure that the information required has practical utility and that environmental protection is maximized.

B. The Rule Lacks Flexibility to Allow Additional Time for Permits that Expire More Than 45 Months After the Effective Date of the Rule

The Rule authorizes permit writers to set alternate schedules for facilities whose permits expire 45 months or less after the rule's effective date, but it provides no such flexibility for facilities whose permits expire *more than* 45 months after the rule's effective date. It should.

The Rule requires facilities to coordinate with the Director and obtain the Director's input or approval on many issues that must be determined before studies can begin (*e.g.*, point of measurement for AIF, point of compliance for entrainment, point of compliance for IM, and fragile species and nuisance species to be excluded from studies). That initial coordination is likely to take time and resources for which EPA has not accounted. Also, EPA assumes that facilities will be able to analyze and present all the Entrainment Characterization Data and design and perform in just nine months three major interconnected studies (on technology, benefits valuation, and non-water quality environmental and other impacts), which will be followed by a three-month peer review.

This schedule is unrealistic and leaves no room for unanticipated problems, which are not uncommon with biological monitoring. EPA should revise the rule to allow permit writers, for good cause shown, to extend the application deadlines for facilities with permits expiring later than 45 months after the effective date of the Rule. This change is important both to avoid unnecessary burdens and to provide enough time to collect information that has practical utility.

C. The Director Should Have Authority to Adjust Application Deadlines and Requirements for Facilities and Units on Long-Term Standby

For units that do not operate often, the Rule should allow the Director to adjust the application schedule and requirements for submitting information on both impingement and entrainment. The units may not run often enough to allow the required studies to be done in the time permitted by the terms of the Rule. Requiring a facility to operate a CWIS solely to satisfy

permit application requirements on a predetermined schedule would be counterproductive and unnecessarily burdensome. Also, requiring a CWIS to operate merely to allow optimization or entrainment data to be collected might conflict with other legal requirements, such as NPDES permit limits or state limits on how much water a facility is allowed to withdraw or when the unit may operate, state requirements for having a required amount of renewable energy, and dispatch requirements. EPA should at least allow the Director to recognize these limitations by adjusting the schedule.

D. To Avoid Undue Burdens, Additional Information Requests by the Director Should Not Affect the Completeness of the Permit Application

The Rule requires applicants to submit whatever additional information the Director may require – for threatened and endangered species or designated critical habitat, for IM, and for entrainment. *See* §§ 122.21(r)(1)(ii)(C), 125.98(i).

Because this requirement is part of the application requirements, the Rule on its face would appear to require the permittee to answer the Director's questions before the Director has had a chance to look at the application and raise questions in the first place, though EPA cannot have intended this. Also, it is not clear whether a facility can submit a "complete" and timely application without knowing in advance whether additional information will be required to answer the Director's question. Yet there is no deadline for the Director to advise the permittee of additional information requirements. And the Rule does not provide that supplementary information requests will not render an application "incomplete."

The Rule should state that additional information required by the Director, EPA, or the Services does not affect the completeness of the permit application for purposes of administrative continuance of expired permits.

E. To Avoid Undue Burdens, the Timing of Responses to Peer Review Questions Identified by the Director Should Be Clarified

External peer review is required, per § 122.21(r)(13), for (1) the comprehensive technical feasibility and cost evaluation study, (2) the benefits valuation study, and (3) the non-water quality environmental and other impacts study. The rule requires the permittee to respond to issues raised by peer reviewer questions or explain why not. It also requires the permittee to respond to significant peer reviewer issues identified by the Director or other entities the Director consults, such as ISOs.

This requirement is impractical if it is interpreted to require responses *before* the facility submits its permit application, and it puts a permittee in jeopardy of missing the application deadline through no fault of its own.

EPA may intend the rule to require the Director to identify significant issues requiring response *after* the application, including peer review, has been submitted. This would be a reasonable approach, but the Rule as written could be misinterpreted to require responses *before* submission. The Rule should be clarified to require responses to the Director's questions after submission, while stating that the application meanwhile will be viewed as timely filed.

III. Some of the Information Collection Requirements Are Unnecessary, Will Be Unduly Burdensome, or Will Lack Practical Utility

A. The Rule Should Clarify that New Impingement Technology Performance Optimization Studies Are Not Required Where Existing Studies Provide Adequate Information

For impingement compliance options in §§ 125.94(c)(5) (traveling screens) and (c)(6) (site-specific systems), the owner/operator must do an impingement technology performance optimization study. Section 125.98(e) says the Director may request further information as part of this study and may also consider previously collected biological data and performance

reviews. The Director may waive all or part of the optimization study, but only after the first permit cycle wherein the permittee is deemed in compliance.

These provisions could be read to require new IM studies, even if studies already done provide adequate information. Obviously a requirement to conduct new studies when existing studies are sufficient would be unnecessary, impose a needless burden, and lack practical utility.

The Rule should be clarified to say that an impingement optimization study does not need to have newly collected biological data unless existing data are inadequate or conditions have changed. Clearly this would reduce the burden of collecting information.

B. The Rules Should Not Require Facilities to Count Entrapment as Mortality

Section 122.21(r)(6)(i)(F) provides that if a facility "entraps" fish or shellfish, it must count the entrapment as mortality – that is, presume entrapped organisms are killed. Thus the Rule assumes that all entrapped organisms are killed. Originally EPA proposed that facilities install equipment to prevent entrapment, and that is what commenters addressed. See Comments of the Utility Water Act Group on the NODA Related to Impingement Mortality Control Requirements (July 11, 2012) at 44. In response, EPA has eliminated the no-entrapment requirement, but it has retained a requirement to treat entrapped organisms as destroyed.

But the Rule does not identify methods for counting entrapped organisms. And in fact, the process of collecting and counting organisms may well destroy them. Yet EPA has not accounted for or considered the costs or negative effects of counting entrapped organisms.

In short, the Rule does not address how "entrapped" organisms are to be counted, and EPA has not estimated the costs of such counting. Nor has EPA considered the burden or negative effects on fish and wildlife of a requirement that may cause the killing of organisms in the process of collecting and counting them, which hardly seems consistent with the purpose of the Rule. Hence EPA has not determined the burden of collecting this information. To avoid

these problems, EPA should delete the requirement to count and report entrapped organisms and should not count entrapment as mortality.

C. The Requirements for § 122.21(r)(7) Entrainment Performance Studies Should Be Clarified to Avoid Unnecessary Burdens

Section 122.21(r)(7) requires facilities to submit existing entrainment studies, and, for older studies or studies from other locations, to provide a detailed description of their relevance and interpretation. The Rule requires this information even if the operator does not believe the studies are relevant or representative and does not intend to rely on them.

It is unreasonable and unduly burdensome to require facilities to submit, explain, and interpret studies on which they do not intend to rely. The Rule should be clarified to say that entrainment studies need to have their relevance and interpretation described only if the permittee plans to rely on them.

D. The Rule Should Not Require Applicants to Identify or Evaluate Alternative Sources of Cooling Water or Modifications to Existing Facility Structures, the Availability of Adjacent Land, or Other Options That Do Not Involve Cooling Water Intake Structure Technologies

Information collection requirements that require facilities to develop information on alternatives that EPA lacks authority to require are, by definition, unnecessary, unduly burdensome, and without practical utility. For example, the Rule requires facilities with actual intake flows above 125 MGD to provide information on alternative water sources, modifications to facility infrastructure other than the cooling water intake structure, and the availability of adjacent land. *See* §122.21(10)(B)(C). If these provisions are meant to suggest EPA has authority to require a facility to use alternative water sources, rebuild parts of its facility other than the cooling water intake structure, or purchase property in order to implement §316(b), UWAG disagrees. The Rule should be modified to read that, at the applicant's discretion, such

information can be provided, if the applicant deems the information relevant to an alternative the applicant wishes to propose. The information should not otherwise be required.

Also, although EPA discussed alternative sources of water at 76 Fed. Reg. 22,199 (April 20, 2011) (preamble to proposed rule) and proposed to require applicants to describe process water reused and grey water actually used for cooling, 76 Fed. Reg. at 22,276 col. 3, there was no notice of or chance to comment on a requirement to change sources. At most, EPA should require an applicant to indicate whether it currently uses such water for cooling.

E. The Clean Water Act Does Not Authorize EPA to Require Information Aimed at Allowing EPA to Satisfy Consultation Requests Made by the Services

The Rule includes a number of new information collection requirements relating to listed threatened and endangered species and designated critical habitat, none of which was included in the proposal. Many of those requirements appear to have been inserted at the insistence of the U.S. Fish & Wildlife Service and the National Marine Fisheries Service to satisfy information requests EPA could not make during the consultation process.

The structure of the Rule suggests that studies of threatened or endangered species demanded by the Services would be separate from and in addition to the studies required by the Rule. UWAG questions EPA's authority to impose these additional requirements under the Clean Water Act and thus whether they are necessary to implement § 316(b). If the Endangered Species Act did require some action in individual cases, it would not be necessary to repeat the requirement in the § 316(b) rule.

In addition, it does not appear that EPA has provided an estimate of the extent of the information required, the parties who will be required to collect such information, and the cost of collecting it. Thus EPA's burden estimate does not account for the burden of collecting such

information. EPA should either delete the extra study requirements from the Rule or at least account for the costs and burdens of complying with them.

F. Information Collection Requirements Should Focus on What Is "Practicable," Not What Is "Possible"

In several places the Rule requires applicants to provide information or take actions reflecting the greatest level of effort "possible." *See, e.g.,* § 122.21(r)(6)(i)(C) (identification to lowest taxonomic level possible), and § 122.21(r)(v) (benefits to be quantified and monetized where possible). "Possible" can be read to mean whatever is theoretically possible, without regard to cost, time, or practicality.

We do not think this is what EPA intends. It is certainly not what EPA's burden estimates suggest the Agency intends. Thus we suggest that, to avoid placing unnecessary and unwarranted information collection (and other) burdens on existing facilities subject to the Rule, EPA change "possible" to "practicable."

G. The Rule Should Be Clarified to State that the Director Is Required to Confirm Only that Entrainment Technology Meets the BTA Standard After that Standard Has Been Set and the Technology Has Been Installed

According to § 125.98(f), for any permit reissued more than 45 months after the effective date of the Rule, the Director must "review the performance of the facility's installed entrainment technology to determine whether it continues to meet the requirements of § 125.94(d)" (*i.e.*, the site-specific entrainment standard). This provision assumes that an entrainment standard under § 125.94(d) necessarily will have been set and the technology installed for permits issued after the 45-month period. This may not always be so.

This requirement is inconsistent with the application and compliance provisions. At a minimum, EPA should not require review until the next permit cycle after new entrainment technology is installed and operating.

Also, requiring permit writers to revisit entrainment determinations every permit cycle is unduly burdensome and unnecessary for both the permit writer and the permittee. Giving the permit writer the option of reviewing entrainment decisions, rather than requiring it, would achieve the Act's goal without being unduly burdensome.

H. To Avoid Confusion and Creation of Unnecessary Burdens, EPA Should Delete the Preamble Reference to an Optimization Study Requirement for the Intake Velocity Compliance Option in § 125.94(c)(3)

The preamble to the Rule says that compliance option § 125.94(c)(3), as well as (5) and (6), requires a site-specific study to optimize the IM technology (preamble p. 258). Option (c)(3) is the 0.5 ft/sec actual intake velocity option. The Rule itself does not require an optimization study for this alternative, only that the owner/operator submit information demonstrating that the velocity does not exceed 0.5 ft/sec (§ 125.94(c)(3)).

The preamble is, then, technically inconsistent with the rule. And it would make no sense to "optimize" intake velocity when the requirement is simply to stay at or below 0.5 ft/sec. A statement by EPA that option (c)(3) (0.5 ft/sec actual intake velocity) does not require an optimization study, contrary to what the preamble says, would avoid misunderstandings.

I. To Avoid Confusion and Unnecessary Burdens, EPA Should Revise the ICR to Delete the Preamble Statement Indicating that Peer Review Is Required for the Entrainment Characterization Study

The ICR says that the Entrainment Characterization Study must have external peer review, whereas the Rule itself does not. *See* 79 Fed. Reg. 30,606 col. 3. Also, the supporting materials for the ICR (pp. 13, 15) correctly exclude the (r)(9) Entrainment Study from the studies that require peer review. EPA should clarify that the preamble statement is in error.

As we note below, however, EPA's estimate of the burden does not appear to account for the costs of conducting peer review even of the studies for which peer review *is* required. The burden estimate needs to reflect these costs.

Finally, UWAG reiterates its earlier recommendation[3] that the peer reviews in general should be conducted at the option of the Director. Allowing peer reviews to be used selectively as needed in the professional judgment of the Director would help to reduce the Rule's burden.

IV. EPA's Burden Estimates Are Not Clear, Complete, or Accurate

A. EPA's Burden Estimates Are Difficult to Follow and Appear to Contain Errors

EPA's calculations of "burden" are difficult to follow and appear to contain substantial errors. In particular, many of the Labor Costs, particularly in the tables in Exhibit A.1, do not seem to add up. Consider, for example, Exhibit A.1.c, which presents burden information on the entrainment studies to be performed by facilities with actual intake flows above 125 MGD:

Permit Application Activities for power plants with DIF 50≥ MGD w/ AIF >125 MGDStart-up Activities

Exhibit A.1c
Permit Application Activities for power plants with DIF≥50 MGD w/ AIF>125 MGD

	Facilities (Respondents)				Assumed Loaded Hourly Rate									Burden Per Facility	Labor Cost per Facility	Capital Cost per Facility	O&M Cost per Facility		Total Cost Per Facility	Total Burden (hrs.)	Total Initial Cost
					Facility Manager	Economist	Junior Technical	CAD Operator	Contracted Manager	Biologist	Statistician	Biological Technician	Clerical				Laboratory Analysis	ODCs*			
Activity	Year 1	Year 2	Year 3	Total	$96	$72	$40	$38	$68	$46	$59	$31	$24								
	A				Level of Effort (hrs)									B	C	D	E	F	C+D+E+F	A*B	A*(C+D)
Entrainment characterization study (r9)	0	71	142	**213**	200	0	340	40	182	1344	20	1568	36	3730	$164,632	$0	$0	$62,250		794,490	$35,066,616
Comprehensive technical feasibility and cost evaluation study (r10)	0	0	0	**0**	100	100	300	200	300	0	100	0	20	1120	$72,180	$0	$0	$500		-	$0
Benefits valuation study (r11)	0	0	0	**0**	100	200	200	0	300	150	150	0	20	1120	$77,630	$0	$0	$500		-	$0
Non-water quality environmental and other impacts study (r12)	0	0	0	**0**	100	0	250	100	300	250	200	0	20	1220	$76,580	$0	$0	$500		-	$0
Recordkeeping	354	354	354	**1062**	2	0	5	2	0	0	0	0	2	11	$516	$0	$0	$500		11,682	$547,992
Totals	**354**	**354**	**354**	**1062**										**759**	**$33,535**	**$0**	**$0**	**$12,985**	**$46,521**	**806,172**	**$49,404,773**

The "Labor Cost per Facility" column lists the costs of each study as $164,632 (entrainment characterization study), $72,180 (comprehensive technical feasibility and cost study), $ 77,630 (benefits valuation study), $76,580 (non-water quality environmental and other impacts study), and $ 516 (recordkeeping), a total of $ 391,538. But the total Labor Cost per Facility at the bottom of the column is only $ 33,539. And the column labeled "Total Initial Cost," which counts the costs across all covered facilities, uses "zero" as the cost of all but the Entrainment Characterization Study and recordkeeping.

[3] Comments of the Utility Water Act Group on EPA's Proposed §316(b) Rule (August 18, 2011) at 40-41.

The same problem occurs in many other places, and the effect is always to understate costs and burdens. It may be that EPA has some reason for summing costs in this fashion, but if so the reason is not apparent from the supporting materials.

It may be that EPA is accounting for only some part of the costs that it believes facilities will incur over the three-year ICR approval period. If so, we have two concerns. First, we cannot tell how EPA decided which plants would have to do what. Second, unless EPA would be content to have facilities stop collecting information after the three-year period, accounting for costs in this narrow fashion ignores reality and thus severely biases and understates the true costs of the Rule to the regulated community, its customers, and the U.S. economy. This understatement does not serve the purpose of the Paperwork Reduction Act to "minimize the paperwork burden for individuals, small businesses, and others" (35 U.S.C. § 3501(1)).

We encourage EPA to review the Exhibits and account for the true costs of the information collection requirements.

B. EPA's Burden Estimates Do Not Account for Some Important Cost Factors or Are Otherwise Too Low

UWAG also is concerned that EPA may have omitted or understated the true costs of some information collection requirements. Below is a list of our questions and concerns.

1. The Amount of Time Allotted to Various Activities Is Unclear, so the Public Cannot Tell Whether EPA Has Properly Accounted for Some Activities

The exhibits in the ICR supporting materials identify the Rule's information collection requirements; identify the types of staff, by skill type, needed to comply with each requirement; identify the hourly rate for each worker by skill type; and estimate the total number of hours each worker would need for each requirement. The narrative accompanying the exhibits also

describes in general terms the types of tasks each worker might need to do for some requirements.

Except for Appendix C, which provides some detail about the impingement sampling estimates, nowhere does EPA state exactly how much time it has allotted for each worker and each task. Without this information, it is impossible to tell whether EPA has underestimated the time certain tasks will take.

For example, at p. 27 of the supporting statement EPA says it has included the costs of peer review in the costs of preparing each study for which peer review is required. Conducting a peer review will require recruiting, interviewing, and selecting peer reviewers for each study; coordinating with the Director to make sure he or she is satisfied with the applicant's choice and recruiting others if not; conducting the peer review (which the preamble says EPA expects to take around three months[4]); addressing comments made during the peer review process; compensating the peer reviewers,[5] at least for their expenses and perhaps for their time;[6] and addressing any further comments made by the Director.[7] We cannot tell how much of the overall estimate for each study is attributable to this process, what peer review tasks EPA included in the

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[4] It would be informative for EPA to document the time required, and the costs, of EPA's own peer reviews, such as reviews by Federal Advisory Committees and the Science Advisory Board.

[5] EPA may have assumed that peer reviewers will donate their time free of charge, in the interest of preserving their independence and advancing science. Given the amount of time and effort required to provide peer review on the many studies at issue here, we doubt they will work for free. Peer reviewers will most likely need to be paid, and it is unclear whether EPA's estimates account for this.

[6] In contrast, the cost of peer reviews conducted by the federal government are substantial. Consultants to Federal Advisory Committees are supposed to be paid up to $45.18 per hour or $361 per day, though they may serve without pay. See http://www.gsa.gov/portal/content/100786. For fiscal year 2008 GSA reported 917 advisory committees of almost 64,000 members, costing $344.3 million for the year. http://en.wikipedia.org/wiki/Federal_Advisory_Committee_Act. EPA's own website lists contracts for advisory services with total contract obligations of, for example, $8,686,365 (EPC09003), $129,963 (EPC12007), $179,796 (EPC12029), $149,870 (EPC12045), and $227,425 (EPC13010). See http://www.epa.gov/oam/ptod/ekrpt1.pdf.

[7] See section II above regarding the timing of Director input and applicant responses.

estimate, or how long EPA assumed each would take. EPA should document these assumptions and the basis for them.

This is just one example of many. Without access to more detailed information, we cannot evaluate the basis for EPA's estimates. The best we can say is that EPA's estimates seem far too low based on our experience. If EPA has a spreadsheet that provides further detail, it should provide it for review and comment.

Access to the revised Technical Development Document (TDD) and Economic and Benefits Analysis (EBA) would also be helpful. These documents have not been made available, yet they should provide critical detail for assessing assumptions, burden, and practicality. The TDD, for example, provides details on the number of facilities EPA identified as covered by the Rule and the compliance options it assigned to each. Because the information collection requirements for impingement control vary by compliance option, without the TDD there is no way to evaluate the underlying number of plants and compliance assignments. EPA should extend the comment period on the ICR until after the TDD becomes available.

2. The Basis for EPA's Estimates of Other Direct Costs Is Unclear

None of the information collection burden estimates includes capital costs, although EPA has estimated other direct costs (including materials, supplies, and services) as part of its operating and maintenance ("O&M") cost estimates.

In Exhibit A.2a, for example, EPA has estimated ODC for flow monitoring as $500 per facility. But even a single flow monitor costs more than $500, let alone several flow monitors plus installation and wiring. Instead of $500 per facility, $100,000 is probably more realistic. EPA should correct its estimate of burden by using accurate capital costs, including more realistic costs for monitors.

3. EPA Has Omitted or Underestimated Costs for Some Information Collection Requirements

UWAG understands that there is some unavoidable uncertainty in estimating the costs of complying with a new regulation. For example, EPA cannot fully predict what additional costs will be created by requirements State permit writers may impose. Even so, EPA's estimates appear far too low when compared to real-world experience. To that end UWAG asked its members to provide either actual monitoring costs from past sampling events or bids received from contractors for impingement and entrainment sampling. In response, UWAG members provided costs of performing biological studies of impingement and entrainment for permit applications and of compliance monitoring.

EPA estimates that the two-year Impingement Technology Performance Optimization Study will cost $122,632 in labor, plus $16,457 in other direct costs, for a total of $139,089. *See* Exhibit A.1.b, col. C and F (Totals). If we assume monthly sampling as the Rule, at a minimum, requires, EPA's average cost of a sampling event is $5,795.

By contrast, UWAG members reported costs by sampling event of $6,800 per sampling event (actual studies of impingement mortality in 2006), $10,000 - $15,000 (consultant estimate), $4,751.75 (consultant's estimate for impingement only, not mortality), $4,365 sampling plus $3,820 for mobilization (consultant's estimate for impingement, not mortality), and $10,198 (consultant's estimate for impingement, not mortality, not counting mobilization, materials, and other direct costs). These UWAG-collected numbers may not be precisely comparable to EPA's, but they are based on real-world experience. And they are all significantly higher than EPA's estimates.

Because EPA has changed its metric from impingement to impingement mortality, defined relative to a standardized mesh size, EPA's costs should be higher than the UWAG

member estimates for impingement studies because of the additional costs of using separate equipment to distinguish among collected fish of impingeable versus entrainable size and holding the collected fish for 18-96 hours as a check for latent mortality. Therefore, it appears EPA has significantly underestimated the costs of impingement mortality monitoring. The costs of entrainment characterization are also likely to be underestimated. EPA should revise its estimates of burden to use more realistic numbers.

Also, UWAG members have pointed out that actual costs of biological studies will be higher once the program is in full swing because of the limited supply of consultants. Monitoring for impingement and entrainment mortality is specialized work and has few providers nationally. One UWAG member believes its annual cost of $151,000 will roughly double to $300,000 a year due to the shortage of trained biologists that can do this sort of work.

In addition, EPA's estimates do not include cost estimates for some required activities, such as visual or remote inspections and entrainment monitoring requirements. *See* Exhibit A.2a. EPA should include these costs.

4. EPA's Description of the Source Water Baseline Biological Characterization Studies Erroneously Suggests that § 122.21(r)(4) Requires Applicants to Perform Additional Field Studies, Which It Does Not

The supporting materials for the ICR at p. 26 say that, for purposes of estimating the cost of the Source Water Baseline Biological Characterization Data (SWBBCD) requirements, EPA assumes that applicants who do not already have all the required information will collect two years of data. The accompanying exhibits list item for both the SWBBCD and "additional entrainment studies." *See* Exhibit A.1a, A.1d. Those references could be misread to suggest that EPA expects applicants to perform new field studies if they do not already have all the types of

information identified in § 122.21(r)(4). That would be incorrect and not required by the Rule itself.

Section 122.2(r)(4) was adopted as part of the Phase I rule for new facilities. By its terms, it does not require facilities to collect new information. Instead it requires a new facility to make a good-faith effort to obtain the information from existing sources, explain its efforts, and identify information that proves unavailable.[8] *See* 40 C.F.R. § 122.21(r)(4) (2013) ("This supporting information must include existing data (if they are available)"). The preamble to the Phase I rule confirms and reiterates that this is so. *See* 66 Fed. Reg. 65,306 col. 3, 65,315 col. 3, 65,316 col. 2 (Dec. 18, 2001).

Section 122.21(r)(4) has not changed in any way that would affect this question.[9] The same rule will now apply to new facilities and existing facilities alike, and in both cases the Rule makes collecting additional field information optional. As is the case for new facilities, existing facilities need only make a good-faith effort to find existing literature that answers the questions posed, provide that information, and explain their efforts. Nothing in § 122.21(r)(4) itself requires collecting new information.

If it did, EPA's cost estimates, just for this single requirement, would be grossly inadequate. (As indicated above, EPA's estimates for other application requirements are also too low.) As noted earlier, we cannot tell from the documents provided exactly what EPA included (or did not include) in the cost estimates for many activities. But we can say, based on

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[8] One might ask why EPA inserted this provision if field studies are purely optional with the applicant. The answer is that EPA also provided an alternative means of compliance that requires collecting certain baseline field information for purposes of showing that alternative controls will be comparable to those otherwise required. So some applicants would need that information to make the required showing

[9] EPA has added a few new requirements for existing facilities and new units at existing facilities, such as a requirement to identify protective measures, stabilization activities, fragile species, and information about "incidental take" exemptions. See 40 C.F.R. § 122.21(r)(4)(x)-(xii). But it has not changed most of the operative provisions, and none of its changes would require collecting new field data.

experience, that instream studies are complicated and extremely expensive. Even EPA agrees that field studies are expensive. See, for example, 66 Fed. Reg. 65,328, Ex. 5 (Dec. 18, 2001) (Phase I estimate of $274,845 for labor for source water baseline biological characterization study for Track II). The $ 3,500 - $17,000 range EPA estimates for the SWBBCD data (plus $2,502 for "additional entrainment studies") might well be accurate for efforts to identify and interpret existing information from various sources of literature, but it would not come close to the true cost of new field studies, which can cost hundreds of thousands or even millions of dollars to design, conduct, and report.

5. The ICR's Anticipated Schedule for Renewal Application Activities Does Not Appear to Match the Rule's, Illustrating Both a Problem with the ICR and a Problem with the Rule

The 20-year schedule EPA provides in the supporting documents shows a gap of five years between the first round of permit application activities under the Rule and the next round of permit renewals. But the Rule anticipates that permittees will submit all the required studies during each permit renewal, unless the Director specifically waives certain of those requirements. Some of the studies take two or more years to design, conduct, and report, and EPA acknowledges in the preamble[10] that facilities will need to begin those studies long before the normal application period (possibly even before they have installed the technology required by the initial permit).

This makes no sense. It is unnecessary and wasteful. But unless EPA is willing to reconsider the requirements to submit all studies for each permit renewal, it will need to account for the costs (including the costs to Directors of processing many waiver requests) during the appropriate time period in its 20-year forecast.

[10] *See* preamble p. 249 (EPA expects a minimum of 30 months will be necessary for § 122.21(r)(4) if the facility collects new data and as many as 39 months for all § 122.21(r) requirements).

CONCLUSION

Judging from the above problems with the Rule's information requirements and the ICR's supporting materials, EPA has not adequately analyzed the burden of collecting information nor shown, in several respects, why the information will have practical utility. UWAG recommends in particular that:

- The Director should have authority to waive any or all application requirements for facilities that plan to retire within the next permit cycle;
- The Director should have authority to waive or defer application requirements where a facility is planning to retire some, but not all, units at a facility;
- New units should not have to meet the entrainment application requirements of § 122.21(r)(9)-(13);
- Facilities with closed-cycle cooling should not have to submit entrainment studies;
- The Rule should not require information from existing facilities that obtain cooling water from independent suppliers;
- The application requirements are over-inclusive and should be reduced;
- The Rule should not require the Impingement Technology Performance Optimization Study until the entrainment standard has been set and any necessary technology has been installed;
- The Director ahould have authority to allow additional time for permits that expire more than 45 months after the effective date of the Rule;
- The Director should have authority to adjust application deadlines and requirements for facilities and units on long-term standby;
- To avoid undue burdens and delay, additional information requests by the Director should not affect the completeness of the permit application;
- To avoid undue burdens and delay, the timing of responses to peer review questions identified by the Director should be clarified and the peer review requirements narrowed;
- The Rule should clarify that new Impingement Technology Performance Optimization Studies are not required where existing studies provide adequate information;
- The Rule should not require facilities to count entrapment or treat it as mortality;

- The requirements for § 122.21(r)(7) Entrainment Performance Studies should be clarified to avoid unnecessary burdens;

- The Rule should not require applicants to identify or evaluate alternative sources of cooling water or modifications to existing facility structures, the availability of adjacent land, or other options that do not involve cooling water intake structure technologies;

- EPA should recognize that the Clean Water Act does not authorize EPA to impose information collection requirements aimed at allowing EPA to satisfy ESA consultation requests made by the Services;

- Information collection requirements must focus on what is "practicable," not what is "possible";

- The Rule must be clarified to state that the Director is required to confirm that entrainment technology meets the BTA standard only after that standard has been set and the technology has been installed;

- To avoid confusion and unnecessary burdens, EPA should delete the preamble reference to an Optimization Study Requirement for the intake velocity compliance option in § 125.94(c)(3);

- To avoid confusion and unnecessary burdens, EPA should revise the ICR to delete the preamble statement indicating that peer review is required for the Entrainment Characterization Study; and

- EPA should more fully and accurately account for all costs imposed by the Rule and should make that information available to the public, with an extension of the ICR comment deadline.

UWAG appreciates the opportunity to provide these comments and would be happy to discuss them further with EPA or OMB staff. If you have any questions, please contact Kristy A. N. Bulleit at 202-955-1547.

Riverkeeper, Inc. · Natural Resources Defense Council · Sierra Club
Waterkeeper Alliance · Earthjustice · Environment America
Clean Air Task Force · Surfrider Foundation
Super Law Group · National Environmental Law Center

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EXECUTIVE SECRETARIAT

March 13, 2014

The Honorable Regina A. McCarthy, Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

The Honorable Sally Jewell, Secretary
U.S. Department of the Interior
1849 C Street, N.W.
Washington, D.C. 20240

The Honorable Penny Pritzker, Secretary
U.S. Department of Commerce
1401 Constitution Avenue, N.W.
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Re: CWA § 316(b) – Cooling Water Intake Structure Rule

Dear Administrator McCarthy, Secretary Jewell and Secretary Pritzker:

As attorneys representing some of the largest national and regional environmental organizations in the United States, with millions of members keenly interested in protection of our nation's air, water and other natural resources, we write with respect to the Clean Water Act § 316(b) cooling water rule for existing facilities, which the Environmental Protection Agency (EPA) has committed to issue by April 17, 2014.

In particular, we wish to respond to certain requests, recommendations and legal assertions made in letters from the Edison Electric Institute and the heads of several utility and energy companies (collectively, "EEI") in September and December 2013, the Utility Water Act Group (UWAG) in October 2013, and Senator David Vitter and other Senators in July 2013 and February 2014.

As explained below, what EEI, UWAG and the Senators ask of EPA, the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS) (collectively, the "Services") would plainly violate the Clean Water Act (CWA) and the Endangered Species Act (ESA).

I.

Endangered Species Act Consultation and
ESA-Related Requirements in 316(b) Rule

Cooling water intakes cause widespread and substantial harm to federally-listed threatened and endangered (T&E) species. In initiating formal consultation under the ESA, EPA acknowledged that "after promulgation and implementation of the 316(b) rule, the rule may allow as many as 215 T&E species and 30 habitats of T&E species to continue to be affected."[1] We wish to make six points in this regard:

- First, in light of the acknowledged effects on T&E species, if EPA were to issue the final rule in the absence of a final Biological Opinion from each Service, the agency would be in clear violation of ESA § 7(a)(2) and 50 C.F.R. § 402.14. Contrary to EEI and UWAG's assertions, the law is crystal clear that all future fish kills and thermal discharges at regulated facilities are legally attributable to EPA's upcoming rule. There is no such thing as "baseline impingement and entrainment" or "baseline thermal discharges"; to the contrary, the ***ESA baseline assumes that the plants and their intake structures have been built, but are not operating.***[2] Consequently, there is no legal or factual basis on which the Services could "vacate the consultation" as requested by Senator Vitter, *et al.*, or conclude the consultation with a "not likely to adversely affect" concurrence, as requested by EEI and UWAG.

- Second, EPA should make clear in the 316(b) rule that nothing in the Section 7 consultation process can eliminate the duties of state agencies, federal agencies and plant operators to comply with the ESA Section 9 prohibition against taking listed species or modifying their critical habitat. EPA recognizes that "any take of listed species without an incidental take statement or ESA Section 10 take permit is in violation of ESA regulations."[3] As previously explained, the record provided by EPA to the Services precludes issuance of an Incidental Take Statement (ITS) that would insulate future take or habitat modification from ESA protections.[4]

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[1] Letter from Robert K. Wood, Director, Engineering and Analysis Division, EPA Office of Water, to Donna Wieting, Director, Officer of Protection Resources, NMFS, and Gary Frazer, Assistant Director, Endangered Species, USFWS, June 18, 2013, at 2.

[2] *See* Comments of Riverkeeper, *et al.* regarding ESA Biological Evaluation for CWA Section 316(b) Rulemaking, October 31, 2013, ("RK Comments") at 9-17 (citing *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 929 (9th Cir. 2008) and other authority).

[3] ESA Biological Evaluation for CWA Section 316(b) Rulemaking, June 18, 2013, ("BE") at 65.

[4] RK Comments at 44-45.

- Third, the record is also insufficient to support a "no jeopardy" finding, particularly in light of harm to a number of salmonid and sturgeon Distinct Population Segments and various species of freshwater mussel.[5] Closed-cycle cooling (CCC) technology must be the focus of any Reasonable and Prudent Alternative (RPA) analysis or Reasonable and Prudent Measures (RPM) analysis because it reduces fish kills and thermal discharges by approximately 98 percent and no other technology comes anywhere close.[6]

- Fourth, if the 316(b) rule directs permit writers to make any Best Technology Available (BTA) determinations on a case-by-case basis, the rule must require that EPA and the Services remain involved in permitting, in both delegated and non-delegated states, to identify the appropriate control requirements to be included in NPDES permits to protect listed species. Contrary to EEI's assertion, the ESA and CWA provide for those agencies' continuing involvement. For example, an ITS must establish clear triggers for subsequent consultation if there is a risk of jeopardizing the species.[7] Further, as the action agency, EPA must report on "the progress of the action and its impact on the species to the Service[s]."[8] Indeed, EPA and the Services agreed in their 2001 MOA to coordinate with State and Tribal permitting agencies to remove or reduce detrimental impacts of any NPDES permit on listed species, including, in appropriate cases, by EPA "objecting to and Federalizing the permit..."[9]

- Fifth, to implement that process, the 316(b) rule must require permittees to undertake robust monitoring, including the use of environmental metagenomic sampling to detect the presence of listed species near an intake. Because T&E species are, by definition, rare, they may not be collected or observed in limited, traditional sampling events despite being impinged and entrained.

- Sixth, the rule must require the submittal of comprehensive information on the potential for ***direct and indirect impacts*** to listed species, including impacts to listed species' prey. EEI's opposition to collecting information regarding the taking of prey or other indirect impacts to T&E species has no statutory basis. Avoiding "jeopardy" and avoiding "adverse modification of critical habitat" are separate and independent requirements.[10] Further, the taking of prey may

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[5] RK Comments at 44-45.

[6] RK Comments at 35-38, 39-42.

[7] *See Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1271-72 (11th Cir. 2009) (citing 50 C.F.R. § 402.14(i)(4)).

[8] 50 C.F.R. § 402.14(i)(3).

[9] Memorandum of Agreement Between the Environmental Protection Agency, Fish and Wildlife Service and National Marine Fisheries Service Regarding Enhanced Coordination Under the Clean Water Act and Endangered Species Act, January 2001, at 20.

[10] *Sierra Club v. U.S. Fish and Wildlife Service*, 245 F.3d 434, 441-43 (5th Cir. 2001).

constitute either a take of listed species or adverse modification of critical habitat,[11] and both must be avoided.

II.

Definition of New Units at Existing Facilities

In promulgating the Phase I Section 316(b) rule in 2001, EPA established Best Technology Available (BTA) standards for cooling water intake structures at new facilities based on closed-cycle cooling (CCC), a 0.5 foot-per-second maximum intake velocity, and a prohibition against withdrawals that are disproportionate to the size of the waterbody.[12] Throughout the administrative and judicial review processes, industry argued that CCC and the other standards should not be considered BTA or that BTA for new facilities should be determined case-by-case. Those arguments were fully considered and rejected, first by EPA and then by the court when it upheld the Phase I rule in 2004.[13]

In the context of the current existing facility rulemaking, a decade later, EPA is *not* reconsidering BTA for new facilities or comparing the merits of CCC with once-through cooling – an antiquated technology rarely installed in plants built since the 1980s. That debate was settled at the federal level long ago, in the first term of the Bush administration. The ***only remaining question concerns the retrofitting*** of CCC on existing facilities and whether those facilities can meet the velocity limits and proportional flow requirements.

The Phase I rule did not establish standards for new units built at existing facilities. Nor did EPA determine that such units were to be treated as existing facilities. Rather, EPA deferred regulation of those units until it had completed analysis of data on existing facilities.[14] Having completed that analysis, the draft proposed rule EPA sent to OMB shortly before proposal in 2011 required that "[n]ew units constructed at an existing facility ... comply with provisions for impingement and entrainment mortality based on closed-cycle [cooling] that are similar to those required in the Phase I new facility rule."[15] That was appropriate because new units – including rebuilt, repowered and replaced units – are like new facilities; they do not encounter retrofitting issues.

Accordingly, the draft proposed rule defined new unit at an existing facility to

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[11] *See, e.g.,* 64 Fed. Reg. 60727, 60730 (Nov. 8, 1999) (NMFS adopting USFWS's definition of harm, and noting that "[r]emoving ...fish ... or other biota required by the listed species for feeding" can constitute a take).

[12] *See* 40 C.F.R. § 125.84; *see also generally* 66 Fed. Reg. 65256 - 65345 (Dec. 18, 2001).

[13] *Riverkeeper, Inc. v. EPA*, 358 F.3d 174, 197 (2d Cir. 2004) ("*Riverkeeper I*") ("The EPA considered all of the factors that UWAG now raises...").

[14] 66 Fed. Reg. at 65286.

[15] *See* EPA-HQ-OW-2008-0667-1295.2 (redline-strikeout version documenting changes made during Executive Order 12866 review) (hereinafter, "Redlined Version of Proposed Rule") at 2.

include "rebuilt, repowered, or replaced unit[s]."[16] EPA further defined "rebuilt" with reference to "major modifications affecting operation of the cooling water intake structure such as replacement of the turbine, boiler, or condensers" and defined "repowering" to mean rebuilding and replacing major components of a power plant instead of building a new one."[17] After many years of careful analysis by its engineers and economists, EPA explained why installing CCC at rebuilt, repowered and replaced units is unlike a retrofit:

> As [older] units are retired and replaced based on individual facility circumstances, facilities have the ideal opportunity to design and construct the new units without many of the additional expenses associated with retrofitting an existing unit to closed-cycle. ... [D]owntime ... may be avoided or minimized [,] ... condensers can be configured for closed-cycle, reducing energy requirements, and high efficiency cooling towers can be designed as part of the unit replacement, allowing for installation of smaller cooling towers.[18]
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> In summary, ... repowering, replacement, and additional unit installation decisions can be accomplished feasibly and with lower costs than retrofitting an entire existing facility... New units are similar to new facilities, regardless of whether that unit is a green field construction, an additional unit, a replacement unit, or a repowered unit. ... [N]ew units [also] would be similar to new facilities in terms of the useful expected plant life...[19]
>
> ... EPA considered whether such requirements ... would serve as a disincentive to replace older units and determined that this would not be the case given closed-cycle cooling's comparable cost relative to once through cooling and its small cost as a percentage of overall costs at the new unit. ... Furthermore, the costs usually comprise less than 1 percent of the total costs of a new unit. Recent experience indicates that the Phase I requirements are not a disincentive for new facility construction...[20]

Shortly before proposal in the Federal Register, however, for reasons unknown and wholly unexplained, OMB changed the definition of new units at existing facilities to exclude rebuilt, repowered or replacement units.[21] That change should not have been made and, indeed, EPA has reconsidered it. According to EEI's recent letters, EPA's current approach more closely aligns with the February 2011 draft proposal in that the definition

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[16] *Id.* at 423 (proposed 40 C.F.R. § 125.92(r)).

[17] *Id.* at 423 (40 C.F.R. §§ 125.92(r) and 125.92(t)).

[18] *Id.* at 92-93.

[19] *Id.* at 147.

[20] *Id.* at 147-148.

[21] Proposed 40 C.F.R. § 125.92(r).

of new unit at existing facility includes repowered, replaced or rebuilt units, so long as the turbine and condenser are replaced (and the location of the cooling water intake structure or design intake flow is changed).[22]

There is no factual or legal basis for EEI's request that repowered, replaced or rebuilt units be excluded from the definition of new unit at an existing facility. As noted, EPA has considered and rejected EEI's argument that a CCC requirement would be a disincentive to upgrade or repower facilities. EEI also rehashes its argument that "EPA's authority under § 316(b) extends only to the *cooling water intake structure.*"[23] But for nearly four decades EPA has recognized that Section 316(b) authorizes it to regulate the volume and velocity of water withdrawn through a cooling water intake structure as a means of addressing capacity.[24] That authority is no different for new units than for new or existing facilities and does not depend on whether the intake structure or anything else has been modified. Moreover, given that existing facilities can be subjected to stricter requirements during permit renewal in the absence of any change to the facility,[25] there is obviously no legal impediment to regulating modified units in the absence of changes to the intake or design flow.

For those reasons, EPA should <u>not</u> define new unit based on whether the location of the intake structure or design intake flow will change. Using turbine and condenser replacement as the sole touchstone for rebuilt, repowered and replaced units is consistent with EPA's statutory authority, and properly recognizes that such units are, for all intents and purposes, new facilities.

If the electric power industry were given authority to repower the nation's existing fleet of antiquated, destructive once-through-cooled power plants by installing new boilers, new condensers and new turbines without also replacing their 1950s cooling systems, EPA would create an enormous loophole that would swallow not only the existing facility rule, but also the Phase I rule for new facilities as well.

Notably, the last time EPA (or OMB) attempted an Orwellian re-write of the definitions of "new" and "existing," that aspect of the Phase II rule was remanded by the Second Circuit, with the court noting that no deference is owed to an agency interpretation that is "plainly erroneous."[26]

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[22] EEI Dec. 20, 2013 letter at 3.

[23] EEI Sept. 17, 2013 letter at 3 (emphasis in original).

[24] *See* 66 Fed. Reg. at 65313 (citing *In re Brunswick Steam Electric Plant*, Decision of the General Counsel No. 41 (June 1, 1976)).

[25] Entergy's argument that Section 316(b) imposes only a *pre*-construction requirement and does not allow EPA to later revisit the design, location, capacity or construction of an existing plant's cooling water intake structure was rejected by the Second Circuit in *Riverkeeper II*. *See Riverkeeper, Inc. v. EPA*, 475 F.3d 83, 121-23 (2d Cir. 2007)

[26] *Riverkeeper II*, 475 F.3d at 117-20 (citing *Fowlkes v. Adamec*, 432 F.3d 90, 97 (2d Cir. 2005)).

III.

Permit Application Requirements & Deadlines

EEI has asked EPA to "[p]rovide a minimum of five years for all facilities to complete the permit application requirement."[27] Allowing five years to complete an application for a five-year permit would be patently excessive, particularly since it has long been clear to industry what information it will need to submit. As EPA noted in the proposal, many of the regulated facilities were previously subject to the withdrawn Phase II rule and should have already compiled much of the proposed application data, which can be used to meet many of the information submittal requirements.[28] For newly covered facilities, the 2011 proposal gave them advance notice as to what the agency's expectations are regarding application requirements.[29] Once the final 316(b) rule has been issued, plant operators can hit the ground running with their application materials and should be kept to a tight time frame. In light of this, the information submittal time periods are entirely too long; ***the schedule set forth in the proposal should be cut in half.***[30]

Apart from the length of the schedule, the proposed rule's phased approach for information submittal is a significant improvement over prior 316(b) rules because it requires facilities to submit application materials at intervals triggered by promulgation of the final rule.[31] This is critical because certain components of an application take less time to complete than others, regulators can evaluate only so much information at any one time and may not request information expeditiously, and certain items may need to be supplemented. Tying the schedule to the rule's promulgation date provides far greater efficiency, uniformity and transparency than if 50 permitting agencies were directed to set information submittal schedules for the 1,200 covered facilities.

Many facilities operate under long-expired, administratively-continued NPDES permits even though their renewal applications do not yet include the information needed by permit writers. As EPA is well aware, the CWA authorizes states to issue NPDES permits "for fixed terms, not exceeding five years."[32] The five-year, time-limited nature of the permit is central to Congress's plan to press new technologies – and incrementally stricter

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[27] EEI Dec. 20, 2013 letter at 4.

[28] *See* 76 Fed. Reg. at 22254.

[29] *See* 76 Fed. Reg. at 22248 (similar statement in context of compliance schedules).

[30] In addition, the Clean Water Act mandates compliance with the 316(b) rule no later than three years from promulgation. CWA Sections 301(b)(2)(C), (D), (E) & (F) and 301(b)(3)(A) & (B) require compliance "as expeditiously as practicable, but in no case later than three years after the date such limitations are promulgated...." As the courts have explained, "the time limits in sections 301 and 306 govern EPA's duty to take action under section 316(b). " *Cronin v. Browner*, 898 F. Supp. 1052, 1059 (S.D.N.Y. 1995). The same is true with respect to permittees' duty to comply.

[31] 76 Fed. Reg. at 22254.

[32] 33 U.S.C. § 1342(b)(1)(B).

effluent limits – onto dischargers at regular five-year intervals.[33] Once a five-year NPDES permit expires, the Administrative Procedure Act (APA) allows licensees who have made "timely and sufficient application for a renewal or new license *in accordance with agency rules*," to conduct "an activity of a continuing nature ... until the application has been finally determined by the agency."[34]

As a result of the administrative continuance of their permits, some power plants are currently operating under permits that were issued in the late 1980s or early 1990s and expired approximately 20 years ago. These plants are typically inefficient and highly polluting facilities still using antiquated technologies from that era or earlier and badly in need of technology upgrades. The generational delay in repermitting them is unacceptable and plainly contrary to the intent of Congress. Consequences should be attached to the failure of a permit applicant to complete its renewal application on a timely basis. That failure can affect the administrative continuance of an expired permit or the opportunity to contend that the putative best technology for minimizing adverse environmental impact is not available at a particular plant. ***Such a "backstop" provision is necessary to prevent dilatory plant owners from continuing to operate under 1980s and 1990s permits in the 2020s and beyond.*** EPA must do its utmost to ensure that long overdue permits are reviewed, renewed and modified as needed. EPA's final rule should address this issue, in delegated and non-delegated states.

IV.

Cost-Benefit Analysis and EPA's Stated Preference Survey

EPA is most assuredly *not* required to base its Section 316(b) determinations on cost-benefit analysis or to direct permit writers to do so. In EPA's very first 316(b) rule, the agency stated: "No comparison of monetary costs with the social benefits of minimizing adverse environmental impacts, much less a formal, quantified 'cost/benefit' assessment is required by the terms of [§ 316] of the Act."[35] More recently, "[i]n *Entergy Corp. v. Riverkeeper*, the Supreme Court has now made pellucid that the EPA may but is not required to engage in cost-benefit analyses for CWIS rule making."[36]

Furthermore, as Justice Breyer noted in *Entergy*, Congress "intended the law's text to be read as *restricting ... the use of cost-benefit comparisons.* ... [because] the Act's sponsors ... feared that such analyses would emphasize easily quantifiable factors over more qualitative factors (particularly environmental factors, for example, the value of preserving nonmarketable species of fish)."[37] Justice Breyer was particularly concerned

[33] *See NRDC v. EPA*, 822 F.2d 104, 123 (D.C. Cir. 1987).

[34] 5 U.S.C. § 558(c) (emphasis added).

[35] 41 Fed. Reg. 17387, 17388 (Apr. 26, 1976).

[36] *ConocoPhillips Co. v. EPA*, 612 F.3d 822, 837 (5th Cir. 2010).

[37] *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 232 (2009) (Justice Breyer, concurring).

about "futile attempts at comprehensive monetization."[38] Justice Scalia's majority opinion similarly acknowledged that "arguments may be available to preclude such a rigorous form of cost-benefit analysis as that which was prescribed under the statute's former BPT standard, which required weighing 'the total cost of application of technology' against 'the ... benefits to be achieved.'"[39]

Notably, EPA chose not to rely on cost-benefit considerations in developing its Phase III rule for new oil rigs, and neither that rule nor the Phase I rule include a cost-benefit variance. Both were upheld in court.[40] EPA's reason to eschew cost-benefit analysis in Phase III was plain: "it did not have enough information to perform a *meaningful* cost-benefit analysis."[41] The Fifth Circuit agreed, explaining that "[t]he agency's decision to regulate on the basis of economic achievability was borne out by the existence of cost information but not benefit information."[42]

EEI now asks EPA to *require* permit writers to rely on quantified, monetized cost-benefit analysis but to *prevent* them from using stated preference methods for valuing ecological benefits.[43] EPA must decline that request because doing so would guarantee the development of meaningless and futile analyses of the kind that Justice Breyer warned against in Phase II. The lack of meaningful benefits information is exactly the reason EPA did not employ cost-benefit analysis in Phase III, and it would also violate the Clean Water Act in ways that Justices Breyer and Scalia foreshadowed. States have informed EPA of the enormous difficulties in placing an accurate dollar value on aquatic resource impacts. And EPA itself recently noted that the "difficult, time-consuming and expensive" process of cost-benefit analysis "will rarely be sustainable for individual permits."[44] ***Accordingly, EPA should not mandate cost-benefit analysis as a part of the permit issuance process*** because it would result in 1,200 meaningless cost-benefit analyses.

Furthermore, to the extent that cost-benefit analysis is allowed as a *voluntary* component of permitting, the analysis must fully value all benefits by using the data from EPA's regional and national stated preference survey. EEI and the Senators' attempt to malign stated preference methods as "controversial" or "inappropriate" is belied by EPA and OMB's guidelines for regulatory analysis. Those guidelines have long recognized that such methods are not only appropriate and well-established economic tools, but also that they are *necessary* to a complete benefits analysis:

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[38] *Id.* at 235.

[39] *Entergy*, 556 U.S. at 223.

[40] *ConocoPhillips* at 833-42; *see also Riverkeeper I*, 358 F.3d 174.

[41] *ConocoPhillips*, 612 F.3d at 838 (emphasis added).

[42] *Id.* at 842.

[43] EEI Sept. 17, 2013 letter at 2-3; EEI Dec. 20, 2013 letter at 2-3.

[44] EPA - New England, Clean Water Act NPDES Permitting Determinations for the Thermal Discharge and Cooling Water Intake Structures at Merrimack Station in Bow, New Hampshire NPDES Permit No. NH 0001465 at 327.

> Stated Preference Methods (SPM) have been developed and used in the peer-reviewed literature to estimate both "use" and "non-use" values of goods and services. They have also been widely used in regulatory analyses by Federal agencies... A stated-preference study may be the *only* way to obtain quantitative information about non-use values...[45]

Because biological diversity and other non-use values are invariably significant in this context – typically they account for 98 percent of the total benefits[46] – conducting cost-benefit analyses without stated preference methods would result in virtually all of the benefits being zeroed out, thereby guaranteeing a completely useless analysis. The national and regional cost-benefit study EPA conducted in the context of the rulemaking represents the most comprehensive and rigorous effort yet to monetize all of the benefits of reducing impingement and entrainment. States have neither the time nor resources to conduct their own stated preference surveys. EPA's survey showed that the economic benefits of minimizing impingement and entrainment dramatically exceed the costs.[47] The use of those data in the plant-specific context would be manifestly more reliable than placing a zero value on benefits that are known to exist and that in the aggregate vastly outweigh the costs.

Accordingly, if permit writers are permitted to undertake cost-benefit on a voluntary basis, or to accept such analyses prepared by permit applicants, they should be prohibited from using any such analysis that does not take full account of all benefits, including ecological benefits, on equal footing with all other benefits and costs.

V.

Low Capacity Utilization Units ("Peakers")

EEI also asks EPA to "specify a capacity factor or flow rate below which the final rule's requirements will not apply," based on its unsupported assertion that low capacity utilization units (*i.e.*, "peakers") have "little risk" of adverse environmental impact.[48]

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[45] OMB Circular A-4 at § 4 (emphasis added); *see also* EPA, Guidelines for Preparing Economic Analyses.

[46] As EPA has explained, 98.2 percent of the aquatic organisms affected by intake structures are not harvested and thus do not go to market. 69 Fed. Reg. 41576, 41661 (July 9, 2004).

[47] *See* Comments on EPA's Section 316(b) Stated Preference Survey, Dr. Frank Ackerman, Stockholm Environment Institute-US Center, Tufts University, July 10, 2012. Notably, the Senators cite a NERA Consulting report prepared for UWAG and EEI for the proposition that the stated preference survey estimates benefits to be $2.275 billion annually for EPA's preferred option and five times the value of the costs. *See* July 22, 2013 letter from Senator Vitter, et al., to EPA at 2.

[48] EEI Sept 17, 2013 letter at 4-5; *see also* EEI Dec. 20, 2013 letter at 4.

In fact, as state regulators have found, there is "no predictable relationship" between capacity factor and cooling water use.[49] There are several reasons for this, including that cooling water systems at non-baseload facilities may be operated more than is necessary to condense steam.[50] Further, "non-targeted reductions" in cooling water use may have little effect on reducing adverse environmental impact because the "driving factors" influencing entrainment and impingement at a facility are the "seasonal dimension of both energy demand and fish reproductive and migratory life history."[51] In other words, peaking and load-following facilities can have a disproportionately large adverse environmental impact on aquatic resources if they operate when biological activity is high. In addition, many facilities that now operate as peakers or load-following units were originally designed as baseload units but are no longer efficient enough to be operated regularly. This means that they also have a disproportionately large adverse impact on air quality and climate relative to more efficient baseload facilities.

Moreover, a plant's past operational history does not guarantee that it will run infrequently in the future, due to changes in demand and fuel costs. Facilities should not be exempted from certain requirements based on prior capacity utilization and given free rein to ramp up operations in the future.

Consequently, if capacity factor or average flow rate is to be a component of BTA for certain facilities, the NPDES permit must contain mandatory limits on future capacity and flow. In addition, those limits must be expressed as targeted, seasonal reductions and/or be accompanied by additional requirements specifying the minimum reductions in impingement and entrainment to be achieved as a result of reduced operation, as has been done in some recent state-issued permits for peakers.

Thank you for considering these legal issues as the rulemaking is completed

Very Truly Yours,

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Hudson River Program Director
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[49] *See generally* New York State Department of Environmental Conservation, The Relationship between Cooling Water Capacity Utilization, Electric Generating Capacity Utilization, and Impingement and Entrainment at New York State Steam Electric Generating Facilities, Technical Document, July 2010, at 2.

[50] *Id.* For example, plants may withdraw water when not generating electricity, or may withdraw a disproportionately high volume of water relative to kilowatt hours, in order to prevent condenser fouling; to dilute discharges; because they have single-speed intake pumps that do not allow withdrawals to be scaled down; or to cool the plant during the start-up and cool-down periods before and after operation.

[51] *Id.*

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October 17, 2014

RE: 60-day notice of intent to sue under the Endangered Species Act for the Environmental Protection Agency's failure to comply with the Act regarding the Final Rule for National Pollutant Discharge Elimination System – Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities

Dear Administrator McCarthy:

In accordance with the 60-day notice requirement of Section 11(g) of the Endangered Species Act ("the Act" or "ESA"), 16 U.S.C. § 1540(g), you are hereby notified that Sierra Club, Waterkeeper Alliance and Center for Biological Diversity, contact information for which are provided below, intend to bring a civil action in federal court challenging your failure to comply fully with the ESA regarding the Final Rule for National Pollutant Discharge Elimination System – Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities ("Final Rule"). 79 Fed. Reg. 48,300; *see also* Agency Docket ID No. EPA–HQ–OW–2008–0667, FRL–9817–3. EPA's Final Rule authorizes power plants to continue operating cooling water intakes that kill millions of

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threatened and endangered fish and other animals and also have adverse effects on the habitats of hundreds of threatened and endangered species. The threatened and endangered species and habitats at issue include the more than 200 identified in the EPA Biological Evaluation on the 316(b) Rule, *e.g.* Southern Resident Killer Whale, Cook Inlet beluga whale, Hawaiian Monk Seals, Leatherback Sea Turtle, Loggerhead Sea Turtle, Green Sea Turtle, Hawksbill Sea Turtle, Kemp's Ridley Sea Turtle, Salmonids, including Chinook, Shortnose sturgeon, Atlantic sturgeon, Gulf sturgeon, Pallid sturgeon, Abalone, and staghorn and elkhorn corals.

Under the ESA, every federal agency must "utilize their authorities in furtherance of the purposes of this chapter by carrying out programs for the conservation of endangered species and threatened species"; and "insure" that their actions are "not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat" deemed critical to such species. 16 U.S.C. § 1536(a)(1) and (2). However, the Final Rule does not satisfy these requirements. It provides for situations where certain species can and will be jeopardized and/or their critical habitat adversely modified. The EPA's reliance on the Services' findings of no jeopardy and no adverse modification of critical habitat is arbitrary and capricious since, among other things, the Services' findings were not based on the best available science, were improperly limited in scope, were contrary to the evidence before the agency, did not meet the requirements for an incremental or programmatic consultation, and otherwise do not meet the requirements of the ESA and applicable regulations.

Moreover, the EPA did not comply fully with the ESA's consultation requirements. Under ESA section 7, if an agency's proposed action is likely to affect an endangered species, the agency must consult with the Secretary of the Interior, through the U.S. Fish & Wildlife Service and the National Marine Fisheries Service ("the Services"), to obtain an opinion evaluating the agency's action under the Act. *Id.* § 1536; 50 C.F.R. §§ 402.01, 402.14. As part of the consulting process, the acting agency submits a Biological Evaluation to assist the Services in evaluating whether the agency's proposed action "is likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat." 50 C.F.R. § 402.14(g)(4), (h).

On June 18, 2013, EPA did submit a Biological Evaluation, supporting materials, and a request for formal consultation regarding the Final Rule, pursuant to Section 7(a)(2) of the ESA, to the Services. However, the Biological Evaluation was written at a level of generality that did not allow for any meaningful analysis. And EPA provided virtually no data to the Services about the status of the various populations of threatened and endangered species that would be harmed by federally-regulated cooling water systems. On October 31, 2013, Sierra Club and multiple allied environmental groups submitted timely comments to EPA and the Services detailing those and multiple other flaws in the consultation process that were violations of the law. Those comments are attached hereto and incorporated by reference into this letter. Nevertheless, those violations were not remedied and form part of the basis for this proposed citizen suit.

At the outset, EPA's characterization of the consultation was fundamentally at odds with the ESA. EPA indicated that the Services' Biological Opinion would not need to include a thorough analysis of the impacts on listed species or critical habitat because a full ESA analysis can be deferred to a later date. This proposition is unlawful and unrealistic. First, for most

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existing intakes, no federal agency will be involved in the reissuance of their NPDES permit because these permits are issued by state agencies in states where EPA has delegated permitting authority to the states. The consultation on the Final Rule is thus the only opportunity for the Services to complete a comprehensive biological opinion on the EPA's action. Second, many of the states that administer the NPDES program have not examined the effects of existing cooling water intake structures in decades and have ignored existing federal law that requires such review in every NPDES cycle. EPA has rarely, if ever, challenged these practices. Third, the NPDES permit backlog for large power plants that are the main users of cooling water is so great that the five-year cycle often takes ten years or more to complete. At coal fired power plants alone, more than 87 million MWh of generation operates without an up-to-date permit as of 2011, and nationwide, 255 existing plants were operation on expired permits. EPA's rule will only worsen this problem by creating further extended timelines before "best technology available" decisions are made. Thus, EPA's approach is not reasonably certain to avoid harm, jeopardy or adverse modification of critical habitat, and is no substitute for complying with the agency's consultation duties under ESA section 7.

EPA also did not comply with its duty to provide the Services with "the best scientific and commercial data available or which can be obtained during the consultation for an adequate review of the effects that an action may have upon listed species or critical habitat." 50 C.F.R. § 402.14(d); and see the Act at §1536(a)(2)("each agency shall use the best scientific and commercial data available."). Instead, EPA provided limited information in the categories typical for such a document. EPA did not even collect and evaluate all Incidental Take Statements, Incidental Take Permits, and state, federal and/or permittee monitoring reports or studies on endangered and threatened species and their habitat related to currently permitted facilities.

The Services repeatedly noted the lack of data provided by EPA in their final Biological Opinion. *See* Endangered Species Act Section 7 Consultation Programmatic Biological Opinion on the U.S. Environmental Protection Agency's Issuance and Implementation of the Final Regulations Section 316(b) of the Clean Water Act, May 19, 2014 ("Biological Opinion"), at 47 ("The biological evaluation provided limited data regarding the effect of impingement and entrainment on ESA-listed species."), and generally 41-49. This failure violates the ESA and is arbitrary and capricious. Without assessing the best available data, the Services could not reach a thorough, comprehensive, and reasoned opinion as to whether EPA's rule "is likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat," as required under the ESA. 50 C.F.R. § 402.14(g)(4).

Further, EPA's Biological Evaluation failed to take into account and be coordinated with the States' Clean Water Act § 303(d) lists to determine whether the waters impacted by cooling water intake and subsequent discharge are listed due to habitat degradation, temperature, dissolved oxygen levels, or other factors related to once-through cooling water intakes. EPA also neglected to consider the Final Rule's effect on total maximum daily loads (TMDLs) for temperature in impaired waters, or the absence of such TMDLs. Both Section 303(d) lists and TMDLs are subject to EPA approval, and thus in EPA's possession, and should have been considered "available" data.

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Federal courts have demanded complete, thorough consultations that meet of all of the ESA's standards in similarly complex situations in the past. *See Dow AgroSciences LLC v. Nat'l Marine Fisheries Serv.*, 707 F.3d 462, 466 (4th Cir. 2013)(vacating and remanding a pesticide reregistration Biological Opinion for failure to explain modeling and overlooking recent data); *Forest Serv. Emples. For Envt'l Ethics v. Wunited States Forest Serv.*, 726 F. Supp. 2d 1195, 1202 (D. Mont. 2010)(rejecting claims that a proper consultation involving 387 species and an action area of more than 192 million acres would be too hard, and noting that "Defendants cannot excuse the failure to comply with the law Congress passed by arguing that compliance would be too hard"); *NRDC v. Evans*, 364 F. Supp. 2d 1083 (N.D. Cal. 2003). In sum, EPA's failure to adequately consult, and then the agency's resulting unreasonable reliance on the legally flawed Biological Opinion in promulgating the Final Rule is a violation of the ESA.

This letter serves to put EPA on notice of its liability for violating the ESA and informs EPA of the intent of Sierra Club, Waterkeeper Alliance and Center for Biological Diversity that should EPA's violations of the ESA remain uncorrected, the parties to this notice intend to file suit following the expiration of the statutory 60-day notice period, seeking injunctive relief to compel compliance with the ESA, as set forth above, as well as other appropriate relief including but not limited to costs and attorneys' fees. This notice is provided pursuant to, and in accordance with, ESA § 11(g)(2), 16 U.S.C. § 1540(g)(2).

Sincerely,

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SUPER LAW GROUP, LLC

October 31, 2013

Via Electronic Mail and U.S. Mail

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Re: Comments of Riverkeeper, Sierra Club, Natural Resources Defense Council, Center for Biological Diversity, American Littoral Society, Southern Alliance for Clean Energy, Environment America, Earthjustice, Delaware Riverkeeper Network, New York/New Jersey Baykeeper, Casco Baykeeper, Los Angeles Waterkeeper, and the Waterkeeper Alliance Regarding ESA Biological Evaluation for CWA Section 316(b) Rulemaking and Initiation of Formal Consultation on EPA's Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities.

Dear Ms. Wieting and Mr. Frazer,

We write on behalf of Riverkeeper, Sierra Club, Natural Resources Defense Council, Center for Biological Diversity, American Littoral Society, Southern Alliance for Clean Energy, Environment America, Earthjustice, Delaware Riverkeeper Network, New York/New Jersey Baykeeper, Casco Baykeeper, Los Angeles Waterkeeper, and the Waterkeeper Alliance ("Commenters"). On June 18, 2013, the U.S. Environmental Protection Agency submitted to you a Biological Evaluation, supporting materials, and a request for formal consultation, pursuant to Section 7(a)(2) of the Endangered Species Act, with the National Marine Fisheries Service and the U.S. Fish & Wildlife Service (individually "NMFS" and "FWS", and together "the Services"). The subject of this consultation is EPA's pending release of final regulations to

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implement Section 316(b) of the Clean Water Act at existing industrial facilities. Section 316(b) requires EPA to establish regulations that minimize the adverse environmental impact of cooling water intake structures at industrial facilities that are subject to the National Pollutant Discharge Elimination System ("NPDES").

We have reviewed the Biological Evaluation and supporting materials prepared by EPA, and we are deeply concerned. EPA has not complied with its duty to assist the Services in issuing a Biological Opinion ("BiOp") by providing "the best scientific and commercial data available or which can be obtained during the consultation for an adequate review of the effects that an action may have upon listed species or critical habitat." 50 C.F.R. § 402.14(c). We have prepared this letter and supporting materials[1] to assist the Services in obtaining the best available data in order to reach a thorough, comprehensive, and reasoned opinion as to whether EPA's rule "is likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat." 50 C.F.R. § 402.14(g)(4).[2]

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[1] The supporting materials referred to below are voluminous, totalling over 90 MB. Thus in addition to sending this letter via electronic mail, we will also send you a hard copy of this letter along with a compact disc of the supporting materials.

[2] "Jeopardy," with its focus on the survival and recovery of the species, and "the adverse modification of critical habitat" that is prohibited under the ESA, 16 U.S.C. §1536(c)(2), are *not* equivalent or interchangeable terms. *Sierra Club v. U.S. Fish and Wildlife Service*, 245 F.3d 434, 441-43 (5th Cir. 2001). Therefore, EPA and the Services must analyze each of these elements and not "jeopardy" alone.

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1. Summary

EPA's Biological Evaluation for its proposed cooling water system regulations falls far short of the requirements of the Endangered Species Act. The agency is about to finalize a rule that authorizes power plants to continue operating once-through cooling water intakes that kill many hundreds of billions of organisms annually, including millions of threatened and endangered fish and other animals. The rule also has adverse effects on the habitats of hundreds of endangered species in an action area that includes nearly every major waterbody in the United States. EPA has approached the Services very late in the rulemaking process, within months of a court-ordered deadline to promulgate a final rule, and stated that, even after years of research and policy formulation, it has collected almost none of the information the Services need to determine whether continued operation of these cooling water intakes will avoid jeopardizing the survival or the recovery of listed species or adversely modify their critical habitat.

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EPA did conclude that cooling water intakes harm endangered species both directly and indirectly, that cooling water intakes overlap with habitat used by 215 listed aquatic species,[3] that there are 21,039 potential interactions between a particular intake and a particular species (meaning that, on average, each species is affected by nearly 100 intakes),[4] that 94% of all intakes overlap with at least one listed species,[5] and that 153 facilities kill fish and release waste heat in more than 290 designated critical habitats.[6] Clearly, the risks of harm to endangered species are both widespread and substantial.

But, with only a handful of exceptions, EPA claims to be unable to quantify or even qualitatively describe the extent of these harms with respect to particular endangered species in particular waterbodies. EPA knows that a great deal of harm is occurring generally, but claims to be unaware of how any particular endangered or threatened populations are holding up under the continued onslaught of habitat modification, impingement, and entrainment caused by cooling water systems regulated under its new rule.

Not having done its homework, EPA now seeks a blank check from the Services to allow power plants to kill endangered species on the flawed basis that its rule may marginally reduce the number of endangered animals that EPA authorizes power plants to kill every year. Of course, any reduction in the killing of endangered species is welcome. But where EPA's regulations allow power plants to kill millions of endangered animals every year, the question is not whether a change that may prevent the deaths of a few animals is good, but whether an EPA action that authorizes the continued killing of millions more jeopardizes the survival or recovery of these species or results in the destruction or adverse modification of critical habitat.

The limited and inadequate record that EPA has presented to the Services cannot support a no jeopardy finding. In fact, the evidence that EPA has provided is so deficient that it likely cannot support any serious analysis by the Services. As Commenters note below, EPA has ignored a wealth of readily available information about the impacts of cooling water intakes on listed species that is available in the academic literature, in government reports authored by other agencies, and even in EPA's own records.

The Services should demand that EPA actually provide them with the best available scientific and commercial data to support a biological analysis. Failing that, the Services must gather and analyze for themselves the readily available information that EPA has ignored, some of which Commenters have attached to this letter.

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[3] *See* Biological Evaluation ("BE") at 60.

[4] *See id.* at 60.

[5] *See id.* at 61.

[6] *See id.* at 60 and Table 7-1, 83-88.

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Finally, if the Services decide not to seek better information at this time and instead choose to issue Biological Opinions (BiOps) with such a poor base of information and so much residual uncertainty about the harms done by EPA's rule to various listed species, the only possible conclusion is that EPA's proposal to continue the operation of hundreds of existing cooling water systems jeopardizes the continued existence of numerous endangered species, including a number of salmonid and sturgeon Distinct Population Segments, and various species of freshwater mussel. And the only reasonable and prudent alternative to EPA's rule that can avoid jeopardy is a requirement to use closed-cycle cooling at most or all large cooling water intakes, and a requirement for cooling water intake operators to adopt significantly better monitoring practices to measure and avoid impacts on endangered species.

2. Background: significance of the Biological Evaluation

EPA acknowledges in the Biological Evaluation that the status quo it has tolerated for decades, largely unrestricted killing of listed species by cooling water intakes, is illegal:

> EPA acknowledges that T&E species have been impacted by CWIS (as documented in Section 3.0) and recognizes that any take of listed species without an incidental take statement or ESA Section 10 take permit is in violation of ESA regulations. . . . [EPA] does not suggest that the status quo, which includes the take of T&E species, is acceptable.[7]

EPA also admits that it is starting from an incredibly poor understanding of the context: there are enormous gaps in EPA's understanding of how many endangered animals are killed by cooling water intakes. EPA's best quantitative estimate looks at just 20 out of the 215 listed species that EPA believes are affected by this rule. Based on documented kills, most of which are not extrapolated out to population-wide values, EPA nonetheless reckons that the annual take of endangered species easily runs to more than 10 endangered sea turtles, 600 Chinook salmon, 60,000 smelt, and 790,000 sturgeon, along with unknown millions of other threatened and endangered organisms from dozens (and possibly hundreds) of different listed species. Sadly, EPA provides the Services with absolutely no information on population viability, distribution, or trends – even for those twenty species – to help put these very limited figures in context.

On this flimsy basis, EPA is asking the Services to opine that a rule that perpetuates this status quo of blind and unmitigated killing, a rule that allows continued operation of once-through cooling systems with only the slightest of reductions in harm, will not jeopardize the continued existence of listed species. But at best, EPA's proposed rule,[8] which was based on a numeric impingement standard and a case-by-case, open-ended decision making process for

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[7] *Id.* at 65.

[8] *See* EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed. Reg. 22,174 (April 20, 2011) (the "Proposed Rule").

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entrainment, will have little effects on the number of fish killed. In fact, as explained more fully below, EPA's proposed rule could actually increase the number of fish killed by cooling water intakes. And since the rule likely will not reduce the capacity or flow of cooling water systems (and may even increase them), by extension, the rule also will not reduce the discharge of thermal and chemical pollution from EPA-regulated facilities. Based on the proposal, it appears that EPA may have decided to carry out the mandate of Section 316(b) of the Clean Water Act by creating a rule that allows cooling water systems throughout the United States to kill hundreds of billions of organisms, and discharge thousands of Petajoules of waste heat, fundamentally altering thousands of miles of riverine and estuarine habitat.[9]

The importance of this consultation may be unprecedented for two other reasons. First, almost none of this harm to endangered species has ever been evaluated under the ESA before. Astoundingly, although the ESA has been law for 40 years, EPA has never asked systematically whether these staggering fish kills and ecosystem modifications jeopardize either the survival or recovery prospects of listed species or destroy or adversely modify critical habitat.

Second, because the Clean Water Act is largely administered by the States, there are no other opportunities to evaluate the systemic impact of cooling water intakes on the recovery and survival of endangered populations. With the exception of a handful of facilities owned or controlled by federal agencies, or whose NPDES permits are issued directly by the federal government, this rulemaking is the single federal action that authorizes continuing operation of thousands of cooling water intakes and thermal discharges throughout the United States.

Therefore, this is the only opportunity to conduct an ESA analysis and issue an incidental take statement from a comprehensive perspective that looks at the full range of impacts on the entire U.S. population of most of these endangered and threatened species. This makes EPA's failure to provide the best available commercial and scientific data on the effects of its action and the status of affected species all the more problematic. Any subsequent BiOp and Incidental Take Statement ("ITS") by the Services based on this inadequate compilation or evaluation of data would similarly be inadequate.

3. Complexity and completeness

Unquestionably, this consultation will lead to one (or two) of the most complex and ecologically significant BiOps that the Services have ever been asked to render. Yet the task is

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[9] EPA's BE and its proposed rule should take into account and be coordinated with the States' CWA §303(d) lists, to determine whether the waters impacted by cooling water intake and subsequent discharge are listed due to habitat degradation, temperature, dissolved oxygen levels, or other factors related to once-through cooling water intakes. And EPA should consider the effect of its proposed rule on total maximum daily loads (TMDLs) for temperature in impaired waters, or the absence of such TMDLs. As the lists and TMDLs are subject to EPA approval, they are in EPA's possession and should be considered "available" data.

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far from insurmountable. And the federal courts have demanded complete, thorough BiOps that meet all of the ESA's standards in similar or even more complex situations in the past.

For example, because of the national reach and complex effects of pesticides, the Section 7 consultation handbook describes pesticide registration BiOps as among the most complex ever undertaken. Yet NMFS has developed BiOps to support multiple pesticide registrations, one of the notable was EPA's re-registration of six widely used pesticides, including chlorpyrifos, diazinon, and malathion. The 482 page final BiOp concluded that re-registration of those three pesticides jeopardized 28 endangered salmonids and 26 critical habitats. *See Dow AgroSciences LLC v. Nat'l Marine Fisheries Serv.*, 707 F.3d 462, 466 (4th Cir. 2013).

A few years after drafting the consultation handbook, NMFS issued a global BiOp covering the U.S. military's use of Low Frequency Active Sonar from hundreds of ships, located across millions of square kilometers of ocean, in nearly every waterbody on the planet. In that case, NMFS was asked to evaluate the impact of sonar use upon uncounted millions of marine mammals and other animals including endangered species of whales, dolphins, seals, sea turtles and salmon. *See NRDC v. Evans*, 364 F. Supp. 2d 1083 (N.D. Cal. 2003).

The Services also developed a BiOp for the Forest Service on its ongoing use (which began in 1955) of chemical fire retardants throughout all National Forest System Lands. *Forest Serv. Emples. for Envt'l Ethics v. United States Forest Serv.*, 726 F. Supp. 2d 1195, 1202 (D. Mont. 2010). In that case, the Fish and Wildlife Service defined the action area as "all National Forest System lands (totaling 192 million acres) together with a buffer area surrounding those lands" while NOAA Fisheries defined the action area "broadly to encompass lands and waters of the United States with particular emphasis on [Forest Service] lands and adjacent properties." *Id.* Together, the Services considered effects upon 414 listed species. *See id.*

Notably, although the Services completed dauntingly complex BiOps in these cases and others, the courts rejected aspects of these final BiOps because either the action agency or the consulting agency attempted to cut corners. The *Dow AgroSciences* court vacated and remanded the pesticide BiOp primarily because NMFS failed to explain its modelling and chose to rely on water quality data that it acknowledged was outdated and inaccurate, while overlooking more recent data. *See Dow AgroSciences LLC.*, 707 F.3d at 475. Similarly, the *NRDC v. Evans* court rejected the LFA sonar BiOP's conclusions because NMFS authorized adverse modification of critical habitat that was necessary to the recovery of various species and the military deliberately withheld some of the best available scientific information from NMFS, leading NMFS to ultimately issued a no jeopardy opinion that did not include the required incidental take statement. *See NRDC*, 364 F. Supp. 2d at 1127-1139. Finally, the *Forest Service Employees for Environmental Ethics* court rejected the Forest Service's and Fish and Wildlife Service's claims that it was just too hard to do a proper BiOp for "a consultation that involved 387 species and an action area of more than 192 million acres." Cite. The court explained that "Defendants cannot excuse the failure to comply with the law Congress passed by arguing that compliance would be too hard." *Forest Serv. Empls. for Envt'l* Ethics, 726 F. Supp. 2d at 1224. Even when the Services are faced with a complex analytical task in a nationwide or global BiOp, the federal

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courts demand and expect that final BiOps will meet the ESA's standards for comprehensive, detailed analysis. The courts will not tolerate illegal shortcuts, failure to consider habitat necessary for species recovery, action agencies that withhold the best available data, or Service BiOps that ignore that data.[10]

4. Despite EPA's failures, the Services must gather and use the Best Available Data.

The ESA requires the Services to base their BiOps on the best available commercial and scientific data regarding the effects of a proposed federal action and the status of the affected species. *See, e.g.*, *Conner v. Burford*, 848 F.2d 1441, 1454 (9th Cir. 1988) ("In light of the ESA requirement that the agencies use the best scientific and commercial data available to insure that protected species are not jeopardized, 16 U.S.C. § 1536(a)(2), the FWS cannot ignore available biological information"); *Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1265 (11th Cir. 2009) ("In deciding what is 'best available' the Service is required to seek out and consider all existing scientific data.") (quoting *Heartwood, Inc. v. U.S. Forest Serv.*, 380 F.3d 428, 436 (8th Cir. 2004)).

EPA's inadequate BE has left the Services ill-equipped to perform their duty. Under the ESA, EPA must support the Services in rendering their opinions by providing them "with the best scientific and commercial data available or which can be obtained during the consultation for an adequate review of the effects that an action may have upon listed species or critical habitat." 50 C.F.R. § 402.14(d). Instead, EPA has provided exactly the kind of input data to the Services, "limited in scope, heavy on general background information, and deficient in focused and meaningful discussion and analysis of how these large [fish takes], and complex management measures which regulate them, affect endangered [species]" that the courts have rejected when found in a final BiOp. *Greenpeace v. Nat'l Marine Fisheries Serv.*, 80 F. Supp. 2d 1137, 1148 (W.D. Wash. 2000). Those parts of EPA's Biological Evaluation describing the affected species and their habitats are written at a level of generality that prevents the Services from performing any meaningful analysis. And EPA has provided virtually no information to

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[10] Although the courts hold the Services to the ESA's demanding standards, once those standards are met the courts will defend the Services' reasoning against all comers. This is illustrated nicely in *Greenpeace v. Nat'l Marine Fisheries Serv.*, where the district court rejected a vague, rushed, and inadequately researched NMFS BiOp for an Alaskan fishery that affected endangered Steller sea lions, condemning the BiOp and the quality of the data underlying that BiOp in harsh terms. *See* 80 F. Supp. 2d 1137 (W.D. Wash. 2000). Thirteen years later, in *State of Alaska v. Lubchenco*, the Ninth Circuit revisited a new BiOp governing the same fishery, and this time it upheld NMFS' BiOp against industry challenges. *State of Alaska v. Lubchenco*, 723 F.3d 1043 (9th Cir. 2013). The difference was that the subsequent BiOp, which concluded "that continuing to authorize fisheries at the levels previously authorized in the fishery management plans would both jeopardize the continued existence of the wDPS [of Steller sea lions] and adversely modify its critical habitat," did not repeat the earlier BiOp's mistakes of "focusing solely on a vast scale" and providing only vague information with little analysis. *Id.* at 1050, 1052. The second time around, NMFS more carefully "consider[ed] the impact of sub-populational decline on a species as a whole." *Id.* at 1052.

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the Services about the status of the various populations of threatened and endangered species that are harmed by federally-regulated cooling water systems.

EPA claims that the kind of data that the Services need to their job properly simply do not exist, but this is plainly false. Through this submission, Commenters will do what they can to assist the Services in filling the large gap that EPA has left. It remains incumbent on both EPA and the Services, however, to comply with their respective statutory obligations to ensure that the final BiOp is based on the best available scientific data. It would be arbitrary, capricious, and in contravention of the ESA and APA, for either EPA or the Services to take final agency action in the absence of a first-rate effort on the part of all three agencies to obtain and analyze such data. The ESA does not allow the Services to issue a BiOp based on limited and incomplete analysis if some of the information needed is available but simply could not be analyzed in the time allowed. *Greenpeace*, 80 F. Supp. 2d at 1148. The Services have authority to request that EPA furnish the data necessary to ensure an informed analysis. *See* 50 C.F.R. § 402.14(f).

5. The Biological Evaluation is premised on an unlawful interpretation of the ESA.

At the outset, Commenters note that EPA is attempting to compensate for the deficiencies in its data provision by trying to move the ESA's goalposts. In the Biological Evaluation, EPA is clearly attempting to encourage the Services to accept two unlawful propositions as the basis for the BiOp:

- *EPA suggests that the BiOp should examine only how the rule will change the number of fish killed in comparison to current levels of impingement and entrainment.* For example, EPA's discussion of the "effects of the proposed action" begins with the statement: "This section evaluates the potential effect of the proposed action on ESA-listed species and designated critical habitats. This evaluation is based on comparison of the *baseline I&E* with that estimated under the final rule." BE at 73 (emphasis added). EPA then argues that its action is benevolent because "[t]he proposed action does not authorize any new activities or increased discharge of pollutants," BE at 81. And EPA concludes with the assertion that "[u]nder the final rule, regulated improvements in CWIS characteristics and operations will have the designed effect of reducing I&E mortality, which in turn is expected to have beneficial effects for some T&E species." BE at 90.

- *EPA also implies that the Services' BiOp need not include a thorough analysis of impacts on listed species or critical habitat because a full ESA analysis can be deferred to a later date.* For example, EPA states that "[u]nder the final rule, all regulated facilities are required to submit baseline source water biological characterization data. Among other data, these studies will identify T&E species present . . . [In addition the rule requires] entrainment studies [that] may identify IM&E of T&E species, information that will be considered by EPA in its determination of BTA for EM on a facility-specific basis, both at the facility

conducting the IM&E study, as well as at nearby facilities." BE at p. 55. EPA repeats elsewhere in the BE that the five-year NPDES permit cycle provides "an opportunity to regularly review ESA issues and adjust discharge permit conditions or monitoring requirements as needed." BE at 4.

Both propositions are counterfactual and unlawful, as explained more fully below.

a. There is no such thing as "baseline I&E" or "baseline thermal discharge"

EPA's first tactic is a transparent effort to game the baseline for the forthcoming BiOp(s). Contrary to EPA's assertion, there is no such thing as "baseline I&E" (or "baseline thermal discharge"). EPA has regulatory options for implementing the mandate of Section 316(b), that is, how to minimize the adverse environmental impact of cooling water systems. Because EPA is authorizing continued operation of hundreds of existing cooling water intakes, the BiOp must look at the full impact of continuing to operate these intakes, including *all* continuing impingement and entrainment and discharges of thermal pollution, as well as all other impacts, in determining whether EPA's rulemaking jeopardizes the continued existence of any species or adversely modifies any designated critical habitat.

The ESA demands that federal agencies "afford first priority to the declared national policy of saving endangered species" in light of the "conscious decision by Congress to give endangered species priority over the 'primary missions' of federal agencies." *Tennessee Valley Auth. v. Hill*, 437 U.S. 153, 185 (1978). This means that "[w]hen an agency, acting in furtherance of a broad Congressional mandate, chooses a course of action which is not specifically mandated by Congress and which is not specifically necessitated by the broad mandate, that action is, by definition, discretionary and is thus subject to Section 7 consultation." *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 929 (9th Cir. 2008). In this case, EPA's discretion in carrying out its duty under Section 316(b) of the Clean Water Act must be exercised in a manner that neither jeopardizes the recovery or survival of listed species nor adversely modifies critical habitat. *See, e.g.*, *Am. Rivers, Inc. v. U.S. Army Corps of Eng'rs.*, 421 F.3d 618, 631 (8th Cir. 2005) ("[T]he FCA does not mandate a particular level of river flow or length of navigation season, but rather allows the Corps to decide how best to support the primary interest of navigation in balance with other interests. . . . Because the Corps is able to exercise its discretion in determining how best to fulfill the purposes of the reservoir system's enabling statute, the operation of the reservoir system is subject to the requirements of the ESA.").

In determining whether EPA's rule jeopardizes listed species or adversely modifies critical habitat, the Services must "evaluate the current status of the listed species" and "[e]valuate the effects of the action and cumulative effects on the listed species or critical habitat." 50 C.F.R. §§ 402.14(g)(2)-(3). This requires the Services to distinguish between the pre-action condition of all affected species and critical habitat and the direct, indirect, and cumulative effects of EPA's action:

> "'Effects of the action' include both direct and indirect effects of an action that will be added to the 'environmental baseline.' The environmental baseline includes 'the past and present impacts of all Federal, State or private actions and other human activities in the action area' and 'the anticipated impacts of all proposed Federal projects in the action area that have already undergone formal or early section 7 consultation.'"

Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv., 422 F.3d 782, 790 (9th Cir. 2005) (citing regulatory definitions found at 50 C.F.R. § 402.02).

The baseline does not include future fish kills or habitat impacts. The courts have held numerous times that where, as here, a federal agency exerts control over ongoing activities, practices or operations that affect listed species, the "effects of the action" include the full future consequences of continuing those activities, practices, or operations.

The prohibition against gaming the baseline is stated clearly and recently in *National Wildlife Federation v. National Marine Fisheries Service*, a case related to continued operation of the Federal Columbia River Power System (FCRPS), an immense series of dams and reservoirs on the Columbia River, most of which were built more than 50 years ago. *See* 524 F.3d 917 (9th Cir. 2008). Dams affect endangered aquatic species in many of the same ways that cooling water intakes do: they modify water temperature, block fish passage, and in the case of hydroelectric dams, can impinge and entrain fish in their intakes. With respect to the FCRPS, the Ninth Circuit affirmed the trial court's rejection of a BiOp because the BiOp's jeopardy evaluation compared the effects of the planned operations of the FCRPS to a hypothetical state of operations that "degraded" the baseline by folding in part of the power system's ongoing impact. *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 929 (9th Cir. 2008). The court held that it was illegal for federal agencies to attempt to disregard certain ongoing impacts of FCRPS operations, rather than focusing "on whether the action effects, when added to the underlying baseline conditions, would tip the species into jeopardy." *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 524 F.3d 917, 929 (9th Cir. 2008). The court explained that there was a critical difference between the basic existence of the dams and the discretionary federal decision about how to continue operating them:

> "The current existence of the FCRPS dams constitutes an 'existing human activity' which is already endangering the fishes' survival and recovery. See ALCOA, 175 F.3d at 1162 n.6 (citing 50 C.F.R. § 402.02). Although we acknowledge that the existence of the dams must be included in the environmental baseline, *the operation of the dams is within the federal agencies' discretion* under both the ESA and the Northwest Power Act, 16 U.S.C. § 839."

Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv., 524 F.3d 917, 930-931 (9th Cir. 2008) (emphasis added).

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Similarly, in reviewing continued operation of the federal Klamath Irrigation Project, which had operated for more than ninety years "following essentially the same procedures for storing and releasing water," the Supreme Court stated that the proper focus of a Section 7 consultation was on whether "long-term operation of the Klamath Project was likely to jeopardize the continued existence of the Lost River and shortnose suckers." *Bennett v. Spear*, 520 U.S. 154, 159 (1997). The year after *Bennett v. Spear* was decided, the Services published a Section 7 consultation handbook that made clear that, with respect to all federal water projects, the effects of construction and past operation of locks, dams, reservoirs, water diversions, and similar modifications form part of the environmental baseline, but BiOps must distinguish between this baseline and the future direct and indirect impacts of continued operation of these water projects. *See* Consultation Handbook p.4-30. The same is true for water projects that are not built by the federal government. For example, where private dams are licensed by the Federal Energy Regulatory Commission and have existed for many years, continued operation of the dams by a municipality is still subject to ESA consultation and to protective measures designed to achieve a 75%-95% fish passage survival rate for endangered species that encounter the dam. *See Cowlitz Indian Tribe v. FERC*, 186 Fed. Appx. 806, 809 (9th Cir. 2006).

The Services have established court-approved techniques to distinguish the existential impact of physical assets like dams and power plants (the baseline impact) from the effects of their continued operation (the action). For example, in order to distinguish between the harms caused by the existence of dams and reservoirs built decades ago on the upper Missouri River, and the harms caused by their continued operation now, "[t]he FWS [Fish and Wildlife Service] used a 'run-of-the-river' baseline in which the dams and physical channel modifications are assumed to be in place, but all floodgates are assumed to be wide open, with no flow control." *Am. Rivers, Inc. v. United States Army Corps of Eng'rs.*, 421 F.3d 618, 632-633 (8th Cir. 2005). The Eighth Circuit upheld this approach as the correct way to distinguish between the past creation of such physical assets and their future operation. *See Am. Rivers, Inc. v. United States Army Corps of Eng'rs.*, 421 F.3d 618, 632-633 (8th Cir. 2005).[11] "

In *American Rivers*, the Eight Circuit explained that the Army Corps attempts to add "hypothetical continued operation" of dams to the baseline "is essentially a different twist on the argument that the Corps has no discretion in operating the reservoir system. . . . However . . . the FCA 'clearly gives a good deal of discretion to the Corps in the management of the River. . . .'" *Id.* By analogy with *American Rivers*, EPA's suggestion that the current level of impingement, entrainment, and thermal discharge should be considered as the "environmental baseline," and that the jeopardy analysis of its new regulations should ask only whether the new rules decrease or increase these effects, is tantamount to arguing that EPA has no ability to affect the existing level of cooling water intake operations through its choices in this rulemaking. That is plainly untrue. In enacting regulations to implement the broad mandate of Section 316(b) of the Clean

[11] For EPA's rule, the equivalent would be a baseline in which cooling water intakes and their associated diversion canals, walls, and other infrastructure exist in rivers and continue to adversely modify habitat (for example through shoreline hardening), but are not operated.

Water Act, EPA has options for "minimizing adverse environmental impact" through controls on the "location, design, construction, and capacity" of existing cooling water systems. 33 U.S.C. § 1326(b).

For example, in its 2011 proposed rule, EPA's preferred option would allow existing intakes to continue operating with only slight reductions in current levels of take and no effect whatsoever on thermal discharges. At the other extreme, EPA could determine that to minimize adverse environmental impact it is necessary to end all withdrawals of cooling water in the United States, reducing take to zero. In between these extremes lie options such as Options 2 and 3 in EPA's proposed rule, which would require all or most of the largest existing facilities to gradually retrofit to closed-cycle cooling systems, in the process reducing direct take from impingement and entrainment by more than 97% and effectively ending the discharge of thermal pollution and its impact on habitat. While some incidental take will continue to occur under these middle-of-the-road options, the take of listed species take likely would drop in parallel with overall mortality, i.e. a decrease of 97% or more from current conditions, and adverse habitat impacts would decline dramatically as well.

The BiOP in *American Rivers* also is another good example of the Services' ability to comply with their duties under Section 7 of the ESA even when facing a complex challenge involving the impacts of multiple structures spread across hundreds of river miles and multiple endangered species. Although the first BiOp was remanded by a district court for failure to consider all of the future effects of the system's operation, once the FWS completed a BiOp with the correct scope, the court upheld it against a variety of challenges. *See Am. Rivers, Inc. v. U.S. Army Corps of Eng'rs.*, 421 F.3d 618, 626-627 (8th Cir. 2005).

The principle that the "federal action" under review in a Section 7 consultation includes all future effects of a federal regulation that authorizes continuation of an activity or operation applies in all regulatory settings, not just when dealing with water infrastructure. See, e.g., *Dow AgroSciences LLC v. Nat'l Marine Fisheries Serv.*, 707 F.3d 462 (4th Cir. 2013) (BiOp covering EPA's re-registration of decades old, commonly used pesticides under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) must evaluate all continuing uses of those pesticides); *Ctr. for Marine Conservation v. Brown*, 917 F. Supp. 1128, 1137 (S.D. Tex. 1996) (BiOp regarding Gulf Coast shrimp fisheries asks whether "the continued long-term operation of the shrimp fishery in the southeastern United States [is] likely to jeopardize the continued existence of the Kemp's ridley sea turtle. . . ."); *Greenpeace v. Nat'l Marine Fisheries Serv.*, 80 F. Supp. 2d 1137, 1143-1144 (W.D. Wash. 2000) (quoting *Conner v. Burford*, 848 F.2d 1441, 1458 (9th Cir. 1988)) (BiOp reviewing the fishery management plans (FMPs) that govern the annual groundfish catches in Alaskan waters must "be equal in scope to the FMPs" because "biological opinions under the ESA must be 'coextensive' with the agency action.").

When the government regulates private activities on federal lands through plans or policies, the federal action reviewed in a Biological Opinion includes all subsequent regulated activities, and not just any incremental changes from the last plan or policy. The elements of a plan that protect listed species, such as road closures or other use restrictions, are balanced

against aspects of the plan that might injure species, such as continued (or expanded) road use, logging, or off-road recreational use authorizations. All are considered "relevant factors" in reaching a final determination as to whether continued use of the federal lands under the plan jeopardizes the continued existence of species in the plan area. *See, e.g., Ctr. for Biological Diversity v. Bur. of Land Mgmt.*, 422 F. Supp. 2d 1115, 1138, 2006 U.S. Dist. LEXIS 14675 (N.D. Cal. 2006) (rejecting as arbitrary and capricious a biological opinion that involved both recreational use of critical habitat as well as offsetting protection measures); *cf. Ctr. for Biological Diversity v. Bur. of Land Mgmt.*, 2011 U.S. Dist. LEXIS 114039 (D. Az., Sept. 30, 2011) (upholding a BiOp that reviewed BLM land use regulations for Arizona that included both activities likely to cause take of endangered tortoises and also offsetting conservation measures, stating that, "despite impacts [on endangered tortoises] from OHV use and grazing . . . FWS adequately assessed the current status of the desert tortoise population and its critical habitat, analyzed the possible future effects resulting from the RMPs, considered all relevant factors and the best available scientific data, and provided a reasoned and rational explanation supporting its 'no jeopardy'" and 'no adverse modification' determinations."); *See also Forest Serv. Empls. For Envt'l Ethics v. U.S. Forest Serv.*, 726 F. Supp. 2d 1195, 1200 (D. Mont. 2010)(Forest Service's ongoing practice of annually "dumping millions of gallons of chemical fire retardant on national forests" required consultation with Services that considered the full ongoing impacts of all fire retardant use).

Many agencies facing a Section 7 consultation on rules or plans that govern ongoing operations or activities have tried to game the baseline in a similar way and failed. There is no such thing as "baseline I&E" or "baseline thermal discharge." The Services must include all the relevant factors in a jeopardy and adverse modification determination – above all, the adverse consequences of allowing hundreds of cooling water intakes to continue killing millions of listed organisms. The Services must determine whether, taken as a whole, and in light of baseline and cumulative effects, EPA's regulation will avoid jeopardizing the continued existence of all of the 215 affected species and will protect their habitat, whether designated as critical or not.[12]

Finally, even if EPA's approach of evaluating only the increase or decrease in "baseline I&E" were legal, the fact is that EPA's proposed rule is actually likely to increase harm to endangered species. As compared to the current trends, which began a decade ago, in which a rising number of plants are retrofitting to closed-cycle systems, EPA's proposal is likely to both

[12] All impacts to habitat must be considered as part of the jeopardy analysis, because habitat impacts in turn affect species and thus may contribute to jeopardy. *See Miccosukee Tribe of Indians of Florida v. FWS*, 566 F.3d 1257, 1262-63 (11th Cir. 2009) (describing biological opinion which found that continued flooding of non-designated Cape Sable seaside sparrow habitat would lead to species extinction); 50 C.F.R. § 222.102 ("Harm in the definition of 'take' in the Act means an act which actually kills or injures fish or wildlife. Such an act may include significant habitat modification or degradation which actually kills or injures fish or wildlife by significantly impairing essential behavioral patterns, including, breeding, spawning, rearing, migrating, feeding or sheltering."); *cf.* 16 U.S.C. § 1533(a)(1)(A) (listing "destruction, modification, or curtailment of [] habitat" as one rationale for listing species as endangered or threatened).

reduce the number of existing intakes that are ultimately retrofitted to closed-cycle cooling systems and to increase the total flow of cooling water through those existing intakes. Thus, EPA's proposal likely will *increase* the number of listed organisms killed directly in cooling water intakes and also increase the volume of thermal discharge pollution released that adversely modifies the habitat of listed species.

To understand why EPA's proposed rule likely will have such effects, it is necessary to first understand the regulatory status quo. In the absence of a federal rule, a few states have adopted policies phasing out all use of once-through cooling, but most states make case-by-case decisions to regulate cooling water intakes pursuant to the "best professional judgment" provisions of EPA's NPDES regulations. *See* 40 C.F.R. § 125.3. "Best professional judgment" determinations under the Clean Water Act consider a limited number of factors. In practice, "EPA's record shows numerous instances of existing facility retrofits to closed-cycle"[13] under this long-standing approach.

But in the proposed rule, EPA's preferred option abandons the limited factors of the best professional judgment standard in favor of an open-ended set of factors that the state's permitting director deems to be "relevant." 76 Fed. Reg. 22,174, 22,204 (col. 2). Permitting agencies are then simply told to choose the technology the agency deems "warranted." 76 Fed. Reg. at 22,283 (col. 2). And EPA now explicitly invites permitting directors to determine that "no additional control requirements are necessary beyond what a facility is already doing." 76 Fed. Reg. 22,262 (col. 2). To the extent that EPA's proposed rule encourages States to consider a broader range of factors than they currently use in settings standards for cooling water intakes, and encourages permittees to provide more complex justifications for lax regulatory standards, EPA's rule is likely to slow an already glacial regulatory process even further and to lead some plants that may have been forced to retrofit under the old process to avoid retrofits.

EPA also plans to worsen the status quo by unlawfully extending the schedule for making BTA determinations. Although the Clean Water Act clearly requires that BTA determinations be made and revisited every five years, Under EPA's proposed rule permitting directors will be given up to eight years from the effective date of the new rule to make BTA decisions with respect to impingement, and an indefinite schedule for controlling entrainment.[14]

EPA's new rule also replaces a commonly used and fairly stringent regulatory standard for comparing different cooling system options, called the "wholly disproportionate" standard, with an open-ended formula. Since the 1970's, EPA and many state permitting authorities have used the "wholly disproportionate" test to interpret Section 316(b) (EPA writes permits directly

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[13] 76 Fed. Reg. at 22,204 (col. 1).

[14] *See* 76 Fed. Reg. 22,248 (col. 1) ("As proposed, facilities would have to comply with the impingement mortality requirements as soon as possible . . . (not to exceed eight years as described below) . . . With respect to entrainment requirements, under the proposal, existing facilities must comply as soon as possible . . . .").

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for facilities in a few states). Under the "wholly disproportionate" test, a BTA analysis begins with consideration of the best performing and available technology to reduce entrainment or impingement – which is almost always cooling towers. Only if the Director rejects the best performing technology because its costs were "wholly disproportionate" to the benefits it provided could the Director consider the next most effective technology. In the absence of a final 316(b) Phase II rule governing existing facilities, many states and EPA Regional Offices have used some variation of this approach. This approach has contributed to the above-noted retrofits of many cooling water intakes in recent years. But EPA now plans to do away with the "wholly disproportionate" standard and substitute instead a far weaker cost benefit analysis, under which a Director may reject any technology if the costs "are not justified" by the benefits.[15]

Further, EPA's rule worsens the status quo by introducing a new provision that grandfathers the use of existing once-through cooling systems at many new generating units built at existing power plants, including repowered[16] or replaced generating units at these facilities. Such repowerings and replacements of existing power plants are occurring frequently in the current economic circumstances because many older plants have reached the end of their useful life at a point where fuel switching from coal to natural gas makes compelling economic sense. As just one example, the 50 year old B.L. England power plant near Cape May, New Jersey is scheduled to repower over the next five years. It will close down two generating units cooled by an antiquated once-through cooling system. These fifty year old turbines have run as peaking units only for the past ten years. These units will be replaced with a single combined-cycle turbine that is more powerful than either of the two old units, and will run at a much higher capacity factor. But the New Jersey Department of Environmental Protection has already decided that this powerful new turbine can use the 50 year old once-through cooling system rather than a closed-cycle cooling system, despite the fact that there is already a functional closed-cycle cooling system on site that supports a third turbine. The New Jersey Department of Environmental Protection referenced the pending federal rule in concluding that the new turbine, which will kill at least a billion organisms a year by using the existing closed-cycle cooling system, should be exempted from federal regulations for new units that otherwise would have required the use of a cooling tower.[17]

Thus, there are two primary effects of EPA's departure from the "best professional judgment" decision making process, abandonment of the "wholly disproportionate standard," and grandfathering of repowered or replaced facilities. First, many existing intakes that would otherwise have been retrofitted to closed cycle cooling in the coming years now will not be.

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[15] Proposed 40 C.F.R. § 125.98(e), 76 Fed. Reg. at 22,288 (col. 1).

[16] Repowering is the practice of rebuilding and replacing the major components of an existing power plant.

[17] New Jersey Department of Environmental Protection, Division of Water Quality, Bureau of Surface Water Permitting, BL England Generating Station, NJPDES Permit Number: NJ0005444, Response to Comments, at 16 of 40.

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Second, many of the high capacity factor new generating units that are being built to replace low capacity factor older units will be grandfathered under EPA's new rule, greatly increasing the "actual intake flow" of existing cooling water intakes. As such, the net effect of EPA's new rule over the coming years is likely to be an increase in the number of listed animals killed by cooling water intakes, and an increase in the area of habitat that is adversely modified by thermal discharge, when compared to the situation that would exist if current trends were extended into the future.

The proposed rule is likely to increase harm in other ways as well, for example, by weakening the definition of "species of concern" under the Clean Water Act in a way that would actually exclude many rare, endemic or uniquely valuable species from future environmental analyses. For a more detailed critique of the ways in which EPA's proposal actually worsens the status quo, see the attached comments on EPA's 2011 proposal.[18]

b. Now is the only opportunity to prepare a comprehensive and meaningful Biological Opinion.

EPA's other tactic is to imply that the Services should issue superficial BiOps that will somehow be supplemented later. This is illegal and unrealistic. As discussed above, EPA is promulgating an enormously important regulation that will affect hundreds of listed species and their habitats. For most existing intakes, no federal agency will be involved in the reissuance of their NPDES permit because these permits are issued by state agencies. The EPA rule is the only federal action affecting these intakes. Now is the only opportunity for the Services to complete a comprehensive biological opinion.[19]

EPA's statements about how future studies of impingement and entrainment will factor into future NPDES permit reviews are confusing, if not outright misleading. Most NPDES permits are issued by States, not EPA. The requirements to perform future studies under EPA's proposed rule will be enforced by States, not EPA. And the studies themselves are to be performed and supervised not directly by (under-resourced) state agencies, but rather by the permittees, with "peer review" by experts that are paid by and report to permittees.[20] Thus, it is

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[18] Comment Letter from Riverkeeper, Inc., Natural Resources Defense Council, Sierra Club, Waterkeeper Alliance, Earthjustice, Environmental Law And Policy Center, Clean Air Task Force, Network For New Energy Choices, California Coastkeeper Alliance, Soundkeeper, Inc., Delaware Riverkeeper Network, Save The Bay – Rhode Island, Friends Of Casco Bay, NY/NJ Baykeeper, Hackensack Riverkeeper, Santa Monica Baykeeper, San Diego Baykeeper, Scenic Hudson, American Littoral Society, And Conservation Law Foundation, re National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 Fed. Reg. 22,174 (April 20, 2011), Docket ID No. EPA-HQ-OW-2008-0667, dated August 18, 2011 (hereinafter "August 2011 Comment Letter").

[19] In addition, a properly done BiOp or ITS under ESA section 7 should be incorporated into the 316(b) rule itself as the federal action permitting state regulators to issue permits for cooling water intake systems in their NPDES permits.

[20] *See* August 2011 Comment Letter, at 42-44, 71-72, 82, 160.

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unclear under what legal authority EPA believes it can ensure that these studies are conducted at all, much less in an adequate manner, or how EPA will have a meaningful opportunity to make use of the study results.

Nor is it obvious how EPA intends to use the "five-year cycle" for issuing NPDES permits to periodically review ESA compliance at cooling water systems. *See* BE at 4. First, most periodic NPDES reviews and permit reissuances are conducted by the States, not EPA, pursuant to agreements that delegate administration of the NPDES program to state authorities. Generally speaking, EPA is not directly involved in writing or periodically reviewing NPDES permits for cooling water intakes.

Second, many of the states that administer the NPDES program have not examined the effects of existing cooling water intakes in decades and have ignored existing federal law that requires them to review the impacts of cooling water intakes in every NPDES permit cycle.[21] These states either do not review the effects of a cooling water intake at all, or they conduct a perfunctory review summarized as "no significant change" in a single sentence placed in a draft NPDES permit fact sheet.[22] EPA has rarely, if ever, challenged these practices.

Third, the NPDES permit backlog for the large power plants that are the main users of cooling water is so great that the five-year permit cycle often takes ten years or more to complete. At coal fired power plants alone, more than 87 million MWh of generation operates without an up-to-date permit as of 2011, and nationwide, 255 existing power plants were operating on expired permits. Many of these permits (at least 65) were expired for more than an entire five-year permit cycle,[23] with a number operating on permits that expired in 1995 or earlier. As noted above, EPA's proposed rule would only worsen this problem by creating an extended timeline of up to eight years from the effective date of the new rule before BTA

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[21] For example, Section 402(a)(1)(A) of the Clean Water Act authorizes issuance of NPDES permits for point source discharges "on condition that such discharge will meet … all applicable requirements under sections [301 and 306]," one of which is section 316(b)'s requirement that cooling water intake structures reflect BTA. Thus, every time a permit writer issues or re-issues a NPDES permit, he or she must ensure that the facility still complies with Section 316(b). Both EPA's suspended Phase II regulations, and EPA's proposed rule, also require explicitly that BTA determinations be revisited with each five year permit cycle. This requirement is found at 40 C.F.R. § 125.98 in both the suspended and proposed versions of the rules.

[22] *See* GRACE Communications Foundation, Sierra Club, Riverkeeper, Waterkeeper Alliance, River Network, "Treading Water; How States Can Minimize the Impact of Power Plants on Aquatic Life," *Available at* http://www.gracelinks.org/3124/power-plants-kill-fish-treading-water-report.

[23] Commenters have attached a list, compiled in 2011, of coal plants with cooling water intakes operating on expired permits; 18 of these were more than 10 years overdue.

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decisions are made for impingement, and EPA is setting an indefinite deadline for BTA decisions regarding entrainment.[24]

Once EPA promulgates the Phase II 316(b) regulations, it will in all likelihood wash its hands of the vast majority of all future impacts to listed species and their habitats, except in the very few instances where it retains NPDES permitting authority for regulated facilities.[25] Such an approach to ESA compliance is not reasonably certain to avoid harm and therefore is not lawful. The Services must complete a full BiOp now, while it is still possible for EPA to issue a final rule that meets its ESA obligations to avoid jeopardy to listed species, avoids adverse modification of critical habitat, and implements all reasonable and prudent alternatives to jeopardy and/or reasonable and prudent measures to minimize incidental take.

6. EPA has not presented the Best Available Data to the Services.

EPA has clearly failed in its obligation to provide the Services with the best available commercial and scientific data on the effects of its proposed rule and the status of the listed species affected by it. To properly support a formal consultation, EPA should have ensured that its Biological Evaluation contained "the best scientific and commercial data available or which can be obtained during the consultation for an adequate review of the effects that an action may have upon listed species or critical habitat." 50 C.F.R. § 402.14(d). Instead, EPA's submission is an exercise in box-checking: it provides limited information in the categories typical for such a document (*see* 50 C.F.R. § 402.12) and falls far short of providing the best available data for the Services' consideration, despite having access to this best available commercial and scientific data.[26]

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[24] *See* 76 Fed. Reg. 22248 ("As proposed, facilities would have to comply with the impingement mortality requirements as soon as possible . . . (not to exceed eight years as described below) . . . With respect to entrainment requirements, under the proposal, existing facilities must comply as soon as possible . . . .").

[25] For most NPDES permits, the only other conceivable nexus for federal action is EPA's ability, under Section 402(d) of the Clean Water Act, to object to state-issued NPDES permits. But surely EPA does not seriously propose to seek 1200+ individual consultations with the Services. And even if EPA planned to combine the pending BiOps with thousands of future, site-specific BiOps, this would not avoid the need for the Services to reach a conclusion about jeopardy now and issue an incidental take statement. *See Forest Serv. Emples. for Envtl. Ethics v. U.S. Forest Serv.*, 726 F. Supp. 2d 1195, 1229 (D. Mont. 2010) ("programmatic" biological opinions are not excused from the incidental take requirement). If this site-specific BiOp approach is indeed the direction that EPA is suggesting to the Services, it is illegal because it is not reasonably certain to avoid jeopardy to listed species and adverse modification of critical habitat. The Services and EPA "may not rely on plans for future actions to reduce threats and protect a species." *Or. Natural Resources Council v. Daley*, 6 F. Supp. 2d 1139, 1154 (D. Or. 1998).

[26] EPA did not even collect and evaluate all Incidental Take Statements, Incidental Take Permits, and state, federal and/or permittee monitoring reports or studies on endangered and threatened species and their habitat (whether designated "critical" or not) related to currently permitted facilities. With these comments we are providing additional data and information to be considered by the agencies, which also indicate the incompleteness of EPA's data gathering.

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For the most part, the Biological Evaluation is written at a level of generality consistent with high school textbooks. EPA spends five pages defining, in single paragraphs, ecosystems such as the "intertidal zone," the "pelagic zone," and "rivers and streams." See BE at 15-19. But EPA never identifies the actual rivers, intertidal zones, and other ecosystems affected by cooling water intakes and discharges, or quantifies the extent of those impacts. EPA simply contends that it is impossible to do so. But as explained below, it is quite possible to identify the reaches affected by once-through cooling water systems and use available models to quantify the impacts that cooling systems have upon them, such as the temperature increase caused by thermal discharges.

EPA then spends another 35 pages listing the 215 endangered species that it believes are affected by the continued operation of existing cooling water systems and describes most of the genera (not species) affected by the rule in broad terms, with a sentence or two on their life history. *See* BE at 19-54. EPA never once discusses the status of any of these listed species: population trends, number of breeding individuals, distribution, etc.

Further, EPA never presents the kind of information necessary to determine whether the survival or recovery of even a single listed species is jeopardized by the continuing operation of once-through cooling water systems. The BE provides no information on the existence of important sub-populations of listed species, except for those officially listed as Distinct Population Segments, and no information on the impacts that the rule might have on such important sub-populations. It contains no meaningful data on habitat modification generally, nor on designated critical habitats in particular.

The BE also fails to include well-documented and easily accessible information about other ongoing projects that affect listed species, such as dredging operations in the Delaware River, the operation of the Klamath and Columbia River power systems, or the impacts that Gulf, Pacific, and Atlantic coast fisheries have on sea turtles, sturgeons, and numerous other listed species caught as bycatch. Thus, in addition to not providing sufficient data about the status of the species affected or the effects of impingement, entrainment, and thermal discharges on those species, EPA has also provided woefully insufficient information on the environmental baseline or relevant cumulative effects. Overall, the data provided by EPA to the Services is insufficient to specify levels of incidental take that might occur for any of the species affected by this rule, even in broad or order of magnitude terms.

Instead, EPA repeatedly claims that it lacks adequate information about the affected species. As these comments show with respect to just a few species and locations, EPA clearly made little or no effort to find that information, despite the fact that these models and data are readily available. The agency has no excuse as to why it overlooked and failed to provide the Services with this information.

For example, EPA states that, after searching through impingement and entrainment studies from 98 facilities, the agency could not find any examples in the last 20 years of

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impingement and entrainment of listed species; the examples they did find were limited to eight species. *See* BE at 62-67. But the 98 facilities EPA looked at make up less than 10% of the universe of existing facilities regulated under Section 316(b). With only a small fraction of EPA's resources and innate knowledge of the subject, Commenters were able to quickly identify several recent examples of cooling water systems harming endangered species, including impacts on species not discussed by EPA. These are discussed below:[27]

a. Columbia Generating Station – Intakes and Thermal Discharge Harm Salmonids[28]

On May 7, 2012, NOAA wrote to EPA, requesting consultation on EPA's possible approval of a state-issued NPDES permit for the Columbia Generating Station in Washington. Two ESA-listed species of steelhead and salmon live in the Hanford Reach of the Columbia River near the plant, and the area is designated critical habitat for the species. NOAA explained that adult Upper Columbia River steelhead are known to spawn near the intake and discharge structures and juveniles inhabit this area. Although the Columbia Generating Station uses a closed-cycle cooling system that withdraws 98% less water than comparable once-through systems, NOAA concluded that even this limited intake was likely to adversely affect listed

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[27] In addition to the resources discussed below, Commenters provide two more general exhibits. The first is a Sierra Club report entitled *Giant Fish Blenders: How Power Plants Kill Fish & Damage Our Waterways*, which includes citations to data and studies on impacts to threatened and endangered species. This includes evidence of direct harm to listed species including: Gulf sturgeon; Alabama shad; saltmarch topminnow; mangrove rivulus; green, Kemp's Ridley, loggerhead and leatherback sea turtles in the Gulf of Mexico; shortnose sturgeon in the Hudson River; three species of endangered turtles in New York harbor; and a number of listed species in California coastal waters, for example the impingement and entrainment at the Pittsburg and Contra Costa plants in the San Francisco Bay Delta of more than 300,000 listed fish per year, including Sacremento splittail, chinook salmon, steelhead trout, Delta smelt and Longfin smelt. The study also notes the indirect harms to species that are dependent on healthy populations of fish that are subject to impingement and entrainment. The report describes how power plant intake structures harm these species and also names 17 power plants with one-through cooling systems. Second, Commenters provide a table of representative *Coal-Fired Power Plants using Once-Through Cooling with Endangered Species Impacts*, with plant name, state, water body, daily intake capacity, and the identities of listed species living in the water body that are likely threatened with impingement or entrainment, and in a few cases, records of harm to listed species from these power plants.

[28] Attached to this comment letter are the following three documents: (1) Letter from the United States Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, to U.S. Environmental Protection Agency, Region 10, re: Columbia Generating Station – NPDES permit renewal by State of Washington, dated May 7, 2012; (2) Letter from the United States Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service, to U.S. Nuclear Regulatory Commission, re: Columbia Generating Station, Consultation No. I/NWR/2011/05286, dated June 11, 2012; and (3) Memorandum from Briana Balsam, Biologist, Office of Nuclear Reactor Regulation to Jeremy J. Susco, Acting Chief , Office of Nuclear Reactor Regulation, re: Conclusion of Informal Section 7 Consultation with U.S. Fish and Wildlife Service of Columbia Generating Station and Section 7 Consultation Report, dated June 13, 2012.

species by killing fry; therefore, it requested formal consultation. Since once-through cooling systems kill approximately 50 times as many fish, it follows that NOAA's concerns would be fifty times more significant at a comparable plant with a once-through cooling system. Although EPA's consultants reviewed the Columbia Generating Station's NPDES permit in preparing the BE, they did not look beyond it to any other cooling water intakes on the Columbia River.

b. Impingement and Entrainment of Atlantic Sturgeon in the Delaware River

On the East Coast, power plants have documented the repeated killing of both shortnose and Atlantic sturgeon in the last ten years. The continued existence of the recently-listed Atlantic sturgeon, in particular the Delaware River Atlantic sturgeon, a genetically unique component of the New York Bight Distinct Population Segment (DPS), is potentially jeopardized by continuing operation of once-through cooling systems on the Delaware.

With respect to Atlantic sturgeon, we respectfully direct the Services' attention to the comment letters sent to NOAA Fisheries by the Delaware Riverkeeper Network, dated April 6, 2012[29] and June 12, 2012[30], highlighting the need for immediate designation of critical habitat in the Delaware River and commenting on the Section 7 consultation on the U.S. Army Corps of Engineers' planned dredging of the Delaware River main channel (the "Deepening Project"). We also respectfully direct the Services' attention to the July 19, 2013 comments of the Natural Resources Defense Council regarding NMFS' recent draft "batched" BiOp for a number of Atlantic fisheries.[31] NRDC's comments, and the attached expert reports, identified significant concerns about the validity of NMFS' most recent estimates of Atlantic sturgeon abundance throughout their range. Because the studies cited in and attached to NRDC's and the Delaware Riverkeeper Network's comments are already in NOAA's possession, we do not append them now. The Services' obligation to use the best available commercial and scientific data necessarily includes studies and comments submitted to the Services during previous consultations.

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[29] *See* attached letter from DRN to NOAA re Endangered Species Act Section 7 Consultation Biological Opinion -- re Critical Habitat Designation, ESA Section 7 Consultation on the Deepening Project, and Monitoring on the Atlantic Sturgeon in the Delaware River, dated April 6, 2012, at 1-2 (hereinafter "DRN April 2012 Letter").

[30] *See* attached Letter from DRN to NOAA re ESA Section 7 Consultation on the Deepening Project's Effects on Atlantic Sturgeon and Shortnose Sturgeon in the Delaware River, dated June 12, 2012.

[31] *See* Comment Letter from NRDC to NOAA re Endangered Species Act Section 7 Consultation Biological Opinion -- Endangered Species Act Section 7 Consultation on the Continued Implementation of Management Measures for the Northeast Multispecies, Monkfish, Spiny Dogfish, Atlantic Bluefish, Northeast Skate Complex, Mackerel/Squid/Butterfish, and Summer Flounder/Scup/Black Sea Bass Fisheries [Consultation No. F/NER/2012/01956], dated July 19, 2013.

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We also direct the Services to the recent NMFS BiOp for the killing of shortnose and Atlantic sturgeon at the Indian Point nuclear generating station on the Hudson River.[32] In that opinion, NMFS found that even with protective measures and improved monitoring efforts, the Indian Point station on the Hudson is expected and permitted to take 564 shortnose sturgeon and 416 Atlantic sturgeon over the next twenty years. The opinion also is notable for purposes of this consultation because it demonstrates consideration of both climate change and thermal discharge impacts at a level that EPA could have performed, even if only on a case study basis, but did not perform.

As Delaware Riverkeeper Network noted in its 2012 letters, the status of the Delaware River Atlantic sturgeon is "extremely precarious" for a number of reasons, beginning with the fact that while "there were once 180,000 spawning female Atlantic sturgeon in the Delaware River[,] NMFS' latest population estimate based on fisheries bycatch data is that there is a mean of 87 spawning adult Atlantic sturgeon annually in the Delaware River." DRN April 2012 Letter at 1-2. Of these few remaining adults:

> [T]he best available scientific and commercial data recently released by NMFS demonstrat[e] a 38% intercept rate for Atlantic sturgeon in Northeast fisheries with an average mortality rate of 20% in sink gillnets (27% in monkfish fisheries) and 5% in otter trawls.

DRN April 2012 Letter at 5.

This dire context makes it all the more significant that "the open water intake cooling systems at Hope Creek Generating Station and the Salem Nuclear Generating Stations on the Delaware River . . . are likely to result in the impingement and entrainment of various life stages of Atlantic sturgeon. PSEG Nuclear, LLC found a dead Atlantic sturgeon on the Salem facility's intake structure trash bars on March 18, 2011." DRN April 2012 Letter at 6. Again in March and July of 2013, PSEG filed reports with the Nuclear Regulatory Commission indicating that the Salem power plant impinged at least one juvenile shortnose sturgeon and one juvenile Atlantic sturgeon.[33] Sturgeon may also be impinged and entrained at the Delaware City Refinery's cooling water intake, on the Delaware side of the estuary.

The Mercer power plant has also killed both species of sturgeon through impingement and entrainment. According to the Delaware River Basin Priority Conservation Areas and

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[32] *See* NMFS, NOAA, *Dept. of Commerce, Biological Opinion for Continued Operations of Indian Point Nuclear Generating Unit Nos. 2 and 3* (Jan. 30, 2013).

[33] *See* attached Letter from PSEG Nuclear LLC to U.S. Nuclear Regulatory Commission, re: Report of Impingement of Atlantic Sturgeon; Salem Generating Station Unit No. 1; Docket No. 50-272, dated March 29, 2013 and Letter from PSEG Nuclear LLC to U.S. Nuclear Regulatory Commission, re: Report of Impingement of Shortnose Sturgeon; Salem Generating Station Unit No. 1; Docket No. 50-272, dated August 1, 2013.

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Recommended Conservation Strategies Final Report, prepared by The Nature Conservancy, the Partnership for the Delaware Estuary and the Natural Lands Trust, the area of the Delaware River in which Mercer's intakes are located is likely spawning habitat for Atlantic sturgeon and juvenile overwintering habitat for shortnose sturgeon.[34] In fact, according to a report submitted by PSEG (owner of the Mercer plant) to the New Jersey Department of Environmental Protection, the intake system at Mercer has killed shortnose sturgeon in the past (without an incidental take permit) and is estimated to kill eight juvenile Atlantic sturgeon annually (also unpermitted take). By comparison, in its July 2012 final BiOp for the Army Corps' Deepening Project, NMFS authorized the incidental take of only 9 Atlantic sturgeon over the 15 year period of dredging and annual maintenance.[35] Mercer impinges nearly this many Atlantic sturgeon in a year.

Notably, not one of the published peer-reviewed studies provided to NOAA and listed in the DRN April 2012 Letter bibliography provided by Delaware Riverkeeper Network was cited by EPA in its Biological Evaluation. The peer-reviewed literature is, obviously, available data.

Nor did EPA provide any of the reports referenced in the attached letters from Delaware Riverkeeper Network that were developed by the New Jersey Department of Environmental Protection or the Delaware Department of Natural Resources and Environmental Conservation. In fact, from the face of the Biological Evaluation, it appears that EPA did not make any kind of systematic effort to reach out to colleagues in state government about the impacts of cooling water intakes on threatened and endangered species and their habitats. Yet state agencies directly regulate the overwhelming majority of the cooling water intakes affected by EPA's pending rule and protect habitat in the vicinity of the intakes, and thus are more likely than EPA to possess information about harm to listed species. Thus, it appears that EPA is not taking seriously its duty to provide the Services with the best available data. The commenters urge the Services to contact state environmental and wildlife protection agencies directly.[36]

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[34] *See* The Nature Conservancy, the Partnership for the Delaware Estuary and the Natural Lands Trust, "Delaware River Basin Priority Conservation Areas and Recommended Conservation Strategies Final Report," Appendix II: Diadromous Fish Habitat Maps, November 2011.

[35] *See* attached National Marine Fisheries Service Endangered Species Act Biological Opinion, by Army Corpos of Engineers (ACOE), Philadelphia District, dated July 11, 2012, Considering Deepening of the Delaware River Federal Navigation Channel (Reinitiation).

[36] A few examples of records of power plant take that are available to EPA (and the Services) and that EPA (or if it fails to do so, the Services) must gather and consider before a BiOp can issue are: 1) records accumulated pursuant to incidental take permits issued by NOAA to seven California power plants in 2008 (*see* NOAA, "Taking and Importing of Endangered Species; Taking of Sea Turtles Incidental to Power Plant Operations," 73 Fed. Reg. 19826 (April 11, 2008); 2) records from the Crystal River Energy Complex, a plant for which NMFS consulted in 1999 and issued a BiOp and instructions on record keeping to monitor take of sea turtles; and 3) records from at least the following NPDES permits for coal fired power plants with once-through cooling systems that include impingement and entrainment monitoring requirements for listed species to be performed by the permittee and/or states: Morgantown GenOn in Maryland; Big Cajun II in Louisiana (pallid sturgeon); Nine Mile Entergy plant in Louisiana

At the current level of fishery bycatch, vessel strikes, and continued operation of cooling water intakes, the loss of the genetically unique Delaware River component of the New York Bight DPS of Atlantic sturgeon is very possible. And this is before the cumulative impacts of climate change and new dredging in the Delaware are taken into account. With fewer than 100 breeding adults in the river every year, every single fish counts. The loss of the Delaware River population would jeopardize the entire DPS.[37] The best available data show that the loss of juvenile sturgeon at cooling water intakes in the Delaware River, notably the intakes of the Mercer and Salem generating stations, is a serious blow to an irreplaceable population of endangered Atlantic sturgeon.

c. Taking of Endangered Sea Turtles in Florida: the St. Lucie Nuclear Plant Case Study

As a power plant that kills five separate species of endangered sea turtles, the St. Lucie nuclear plant provides a powerful example of the harm that cooling water intakes cause to listed species. But it is also an object lesson in the failures of case-by-case regulatory efforts to protect listed species, whether under Section 316(b) of the Clean Water Act or Section 10 of the Endangered Species Act.[38]

Florida Power and Light's (FPL) St. Lucie nuclear power plant began operation of Unit 1 in 1976 and Unit 2 in 1983. The plant is on Hutchinson Island, about eight miles southeast of Ft. Pierce, Florida. For twenty years, no biological opinion governed the operation of this cooling system and its effects on sea turtles.[39] It appears that the Nuclear Regulatory Commission ("NRC") only initiated formal consultation after it determined that an increasing number of sea turtles were being captured and killed at the St. Lucie plant and there was no allowance for such take.[40]

(pallid sturgeon); New Madrid, Missouri; Bridgeport Energy Facility, Connecticut (sturgeon), and the Monroe plant in Michigan.

[37] *See* NOAA, *Endangered and Threatened Wildlife and Plants; Threatened and Endangered Status for Distinct Population Segments of Atlantic Sturgeon in the Northeast Region*, Final Rule, 77 Fed. Reg. 5880, 5883 (Feb. 6, 2012).

[38] The documents referred to in this discussion of the St. Lucie plant are attached to this comment letter.

[39] Cover letter from United States Nuclear Regulatory Commission to Florida Power and Light Company, re: Biological Opinion, St. Lucie Plant, Units 1 and 2 (TAC NOS. MA6374 and MA6375), dated May 18, 2001, attaching National Marine Fisheries Service, National Oceanic and Atmospheric Administration, United States Department of Commerce, "Biological Opinion" re: the St. Lucie Nuclear Power Plant, at 1-2 ("NMFS Biological Opinion on St. Lucie Plant").

[40] *Id.* at 2.

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NMFS issued a BiOp in 1997, but NRC and NMFS reinitiated formal consultation shortly thereafter, in 1999,[41] and again in 2006,[42] in both cases because incidental take limits were exceeded, and in 2005 when an endangered small-tooth sawfish was found in the intake canal.[43] In fact, consultation has been ongoing between NMFS and the NRC since 2007 and a new BiOp is expected soon.[44]

For all this consultation, NMFS' involvement has not effectively reduced the risks to endangered sea turtles from the St. Lucie cooling water intakes. A total of 6,576 turtles of all five listed species were removed from the St. Lucie intake canal during the 23-year period from 1976-1999.[45] Yet in the subsequent 12 years, from 2001-2013, a total of 8,198 turtles were captured, including 67 injuries/mortalities.[46] After the deaths of hundreds of sea turtles at the FPL plant, including fifteen years of take since NMFS first got involved, FPL now purports to be "developing a plan to install turtle excluder grating at the offshore intake structures."[47]

There are also serious questions about the adequacy of monitoring and reporting of take at St. Lucie and at other power plants. The ESA requires that incidental take statements establish clear triggers for subsequent consultation if there is a risk of jeopardizing the species. *See Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1271-72 (11th Cir. 2009) (citing 50 C.F.R. § 402.14(i)(4)). Further, action agencies must report on "the progress of the action and its impact on the species to the Service."[48] But at St. Lucie, while it appears that mortality reports are sent to the NRC (and presumably are forwarded to NMFS), it is unclear whether reports on the monthly non-lethal entrainment and impingement of sea turtles are also forwarded to the NRC and NMFS. And a 2009 Government Accountability Office report concluded that the extent to which the Services require ongoing monitoring in BiOps varies from action to action, that the consistency with which the Services track monitoring reports varies from field office to field office, and that the Services lack complete monitoring information for many of their formal consultations.[49] Clearly, this system exhibits potential for communication breakdown between the applicant, the State, any federal action agency, and the Services.

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[41] *Id.* at 2-3.

[42] NRC, "Biological Assessment, St. Lucie Nuclear Power Plant Units 1 and 2, Reinitiation of Section 7 Consultation to Include Sea Turtles" (August 2007).

[43] *See* Letter from Frank Gillespie, NRC, to David Bernhart, NOAA, (Feb. 24, 2006).

[44] FPL St. Lucie Plant Annual Environmental Operating Report, at 18 (2012).

[45] NMFS Biological Opinion on St. Lucie Plant, Units 1 and 2, at 6.

[46] FPL Marine Turtle Removal Monthly Summary (August 2013)

[47] FPL St. Lucie Plant Annual Environmental Operating Report, at 18 (2012).

[48] 50 C.F.R. § 402.14(i)(3).

[49] U.S. Gov't Accountability Office, *Endangered Species Act: The U.S. Fish & Wildlife Service Has Incomplete Information About Effects on Listed Species From Section 7 Consultations,* GAO-09-550 (2009).

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The poor implementation, inadequate monitoring, lengthy delays, and above all, the decades long failure to actually reduce harm to turtles at the St. Lucie plant, all indicate that the Services cannot be reasonably certain that the listed species protection efforts at this one plant are effective. And St. Lucie is in that minority of plants that are directly regulated by a federal agency and submit monitoring reports that are available to NMFS. Under EPA's proposed rule, the situation at state-regulated facilities will be worse, and harder to monitor.

The Services and EPA "may not rely on plans for future actions to reduce threats and protect a species." *Or. Natural Resources Council v. Daley*, 6 F. Supp. 2d 1139, 1154 (D. Or. 1998). The agencies should be "reasonably certain" that promised future actions will occur before concluding that a threatened species is not jeopardized. *Northwest Envtl. Advocates v. EPA*, 268 F. Supp. 2d 1255, 1273 (D. Or. 2003). Neither the Services nor EPA can be reasonably certain that a roll out of endangered species protections one cooling water intake at a time under EPA's proposed rule, at facilities regulated by states, will actually occur. And even if listed species protections are put in place through case-by-case decisions, as EPA envisions, this scheme is not reasonably certain to control the killing of listed species or avoid damaging their habitat. The example of the St. Lucie plant strongly suggests that the Services cannot have reasonable confidence that EPA's proposed rule will achieve even the small reductions in take of listed species that EPA projects.

d. Thermal Discharge Causing Widespread Adverse Habitat Modification

EPA also failed to present the Services with readily available data about the extent to which existing cooling water intakes discharge thermal loads that adversely modify the habitats of hundreds of listed species.[50] In the Biological Evaluation, EPA catalogued all of the reasons that temperature is considered a "master environmental variable for aquatic ecosystems" and the many ways in which it may adversely affect endangered species and their habitats (BE p.70-71), but never attempted to quantify the impacts of thermal discharge on habitats and never considered or attempted to evaluate the impact of thermal discharges on specific habitats or species. Even a cursory review shows that EPA has ignored readily available information about the specific harms to listed species and their habitats caused by thermal discharges.

For example, Madden *et al.* (2013) reviewed "federal datasets documenting water temperature at intakes and discharges from power plants during the summer in the United States between 1996 and 2005."[51] They point out that, since 1974, the Energy Information

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[50] "Significant habitat modification or degradation which actually kills or injures fish or wildlife by significantly impairing essential behavioral patterns, including, breeding, spawning, rearing, migrating, feeding or sheltering" constitutes the taking of endangered species. 50 C.F.R. § 222.102.

[51] N. Madden, A. Lewis and M. Davis, "Thermal effluent from the power sector: an analysis of once-through cooling system impacts on surface water temperature," 8 Environ. Res. Lett., Article ID 035006, at 2 (2013).

Administration has compiled systematic records of water withdrawals, discharges, and temperatures from power plants using once-through cooling systems, which make up the bulk of the regulated universe by volume under Section 316(b). They also identify other sources of information on once-through cooling system thermal discharges to make up for deficiencies in the EIA database. Using an approach similar to the one that EPA used to identify overlaps between endangered species and cooling systems generally, Madden *et al.* used the presence of high numbers of endangered species as a proxy for biodiversity to focus their analysis on 33 watersheds where very high aquatic biodiversity (more than 10 imperiled species) overlap with high thermal discharges. *See* Madden *et al.* at 3 and Figure 2, at 5. The authors then examined the Upper Catawba watershed in North and South Carolina as an example of one such watershed. The found that all five power plants in the Upper Catawba "reported discharging water that exceeded state limits on ΔT and maximum discharge temperatures during the summer (figure 3). However, their NPDES permits revealed that all five power plants had been granted thermal variances that allowed them to exceed state water quality limits[.]" Madden *et al.* at 5. EPA is currently reviewing two of these permits directly, but the wider point is clear: EPA's rule will continue the operation of cooling water intakes that are poorly regulated at the state level and are located in watersheds where they are likely to impinge, entrain, and adversely modify the habitat of listed species. EPA could use a technique like this to focus on high priority watersheds.

Note that EPA provided no information to the Services about the Catawba watershed. But EPA's direct review of permits in the watershed, coupled with the fact that thermal discharges into the Catawba were linked to mass die-offs of striped bass in 2004, 2005, and 2010,[52] strongly suggest the potential for direct or indirect effects on listed species living in various reaches of the Catawba, including different sturgeon and freshwater mussel species.

The Union of Concerned Scientists and independent scientists from a number of governmental and academic laboratories have formed a collaboration called "Energy and Water in a Warming World" (EW3), which has also closely examined existing water withdrawal and thermal discharge data. At the outset, it is worth noting that EW3 identified major inaccuracies in the Energy Information Administration data on water withdrawals that EPA has based part of its own regulatory analyses upon. The problems vary from the unfortunate, such as power plants reporting estimated rather than measured values, to the egregious: "201 freshwater-cooled coal and natural gas plants nominally reported water use to the EIA but claimed to withdraw and consume no water at all (Figure 8). Such reporting is obviously in error: these plants could not run without water." EW3 at 21. Based on their size and operations, EW3 estimates that this "mistake" leads to unreported withdrawals of 1.1 trillion to 2.6 trillion gallons. *See* EW3 at 22.

EW3 also identified 350 power plants that discharge wastewater at peak summer temperatures exceeding 90 degrees Fahrenheit, and singled out power plants in the upper Dan

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[52] *See* A Report of the Energy and Water in a Warming World Initiative "Freshwater Use by U.S. Power Plants; Electricity's Thirst for a Precious Resource" November 2011, at 29, *available at* www.ucsusa.org/publications (hereinafter "EW3").

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River of North Carolina and Virginia for peak summertime discharges exceeding 110 degrees Fahrenheit, a temperature that is generally lethal to wildlife and far in excess of most state standards. *See* EW3 at 27-29. The Dan River is home to rare and endangered freshwater fish and mussels, including the James spinymussel.

In its 2011 publication, "Freshwater Use by U.S. Power Plants; Electricity's Thirst for a Precious Resource," EW3 compiled a record of thermal discharges from power plants that have caused and have potential to cause significant harm to aquatic organisms:

- In the summer of 2010, Tennessee River water temperatures rose above 90°F, forcing the Browns Ferry nuclear plant in Athens, AL, to drastically cut its output for nearly five consecutive weeks in order to meet water quality standards. A similar event occurred in August of 2007 and 2011.

- Until Georgia Power retrofitted the Plant Harllee Branch coal-fired power plant on the Lake Sinclair reservoir on Georgia's Oconee River with a cooling tower in 2002, extensive fish die-offs had been common.

- In August 2007, the Riverbend and G.G. Allen coal plants discharged cooling water in excess of water quality based effluent limits designed to protect fish in North Carolina's Catawba River. The plants were forced to cut back power generation in an effort to comply with these limits.

- In 2006, Quad Cities Reactors near Cordova, Illinois reduced power output because thermal discharges exceeded water quality based effluent limits. In 2012, the plant's owners sought a 316(a) variance to increase the temperature of their discharge.

- In summer 2012, the Braidwood Nuclear Plant, in Illinois, raised the temperature of its receiving water body to 102°F.

- Throughout 2012, the E.D. Edwards plant, also in Illinois, required a special variance to continue operating because it could not comply with extant thermal limits designed to protect aquatic organisms.

- The Joliet, Will County, and LaSalle power plants, also in Illinois, needed similar thermal variance throughout the summer of 2012 (in the case of LaSalle, the variance was required from March).

- In the summer of 2012, the Cumberland and Gallatin coal plants in Tennessee both had to curtail operations in order to meet thermal discharge limits set to protect the Cumberland River.

- The Dresden nuclear plant in Illinois exceeded thermal limits set to protect the DesPlaines and Kankakee Rivers in 2012 (and later received a provisional variance to these limits).

- To avoid violating thermal limits, the Monticello nuclear plant in Minnesota reduced power output throughout August 2006 and August 2010.

To overcome the gaps in current temperature data sets, scientists have also developed thermal exchange models for evaluating the interactions between power plant discharges and the environment that allow for a more systematic assessment of the effects of EPA's decision to allow continued operations of once-through cooling systems. Miara *et al.* (2013) describe "a simulation model of power plant operations, the Thermoelectric Power and Thermal Pollution Model (TP2M)" that "simulates the operations of contemporary and emerging power plants according to climate and hydrology conditions, engineering requirements, electricity demand and environmental regulation," and is "coupled to a regional biogeophysical model, the Framework for Aquatic Modeling in the Earth System (FrAMES) . . . a spatially distributed hydrology model with gridded river networks (3 min) that simulate transport, mixing and re-equilibration of water temperatures along river reaches at a daily time step" in order to "quantify, in high-resolution, regional patterns of thermal pollution, electricity generation on a single power plant and regional scale, river temperatures and power plant efficiency losses associated with changes in available cooling water that incorporates climate, hydrology, river network dynamics and multi-plant impacts."[53]

This kind of modeling analysis could assist the Services in trying to quantify and estimate the effects on various aquatic habitats of the thermal discharges from hundreds of once-through cooling systems that will continue to operate under EPA's rule. EPA should have run such models for itself, or sought the assistance of these or similar modelers. Notably, after running different configurations of the model, one of Miara *et al.*'s findings is that "by significantly reducing the amount of heat input to the river system, conversion to [cooling towers] result in the greatest improvements for aquatic ecosystem indicators." Miara *et al.* at 7 (Col. 2).

The Miara *et al.* study also examines the cumulative effects of a scenario in which the current cooling configuration in the Northeast remains in place and thermal pollution load remains similar to current conditions, combined with the anticipated climate change in the Northeast. The anticipated impacts of climate change over the coming decades include "increases in ambient temperatures and precipitation" and "higher seasonal fluctuation of stream flow" leading to "reduced river discharge in mid-northern latitudes (i.e. Northeastern US) despite an increase in precipitation. Combined low flow and rising temperatures will result in a warming of rivers." *Id.*at 8. The model indicates a greater than 100% increase "in unsuitable habitat for

[53] Ariel Miara, Charles J. Vorosmarty, Robert J. Stewart, Wilfred M. Wollheim and Bernice Rosenzweig, "Riverine ecosystem services and the thermoelectric sector: strategic issues facing the Northeastern United States," 8 Environ. Res. Lett., Article ID 025017, at 2 (2013).

fishes with maximum average weekly temperature thresholds of 24 C (cold) and 29 C (cool) [in the Northeast]." *Id.* The study also indicates a similar increase in unsuitable habitat "for fishes with 34 C (warm) thresholds," but this could be mitigated by heightened efficiency and enforcing otherwise applicable water quality standards on thermal discharges (i.e. ending the use of CWA Section 316(a) variances). *Id.*

Applying the same models, Stewart *et al.* (2013) found first that 28.4% of all the heat generated at inland Northeastern thermoelectric plants was transferred directly to rivers via once-through cooling systems (by comparison, the amount of heat converted to electricity was only marginally greater at 34.3%).[54] The following table is adapted from Stewart *et al.* (*See id.* at 4). It quantifies the impact of once-through cooling ("OTC") waste heat on major river basins in the Northeast.

Basin	Electricity produced with OTC (TWh/yr)	OTC Heat Input to River (PJ/yr)	Temp. Increase at River Mouth (deg C) (all generation)			Heat attenuated by riverine ecosystem (%) (all generation)		
			Summer	Winter	Annual	Summer	Winter	Annual
Atlantic (all rivers)	250.4	1055	1.9	0.9	0.9	11.9	12.9	11.3
Penobscot	1.7	7.6	0.2	0.1	0.1	7.6	22.3	10.5
Merrimack	13.3	25.5	1.0	0.6	0.6	19.1	33.6	22.2
Connecticut	23.4	50.3	0.8	0.4	0.5	20.3	39.6	23.8
Hudson	36.1	252.3	5.0	2.4	2.5	6.4	7.5	6.2
Delaware	12.2	86.7	2.7	0.9	1.1	12.9	11.9	12.5
Susquehanna	33.8	239.7	2.9	1.3	1.5	11.1	11.6	9.7
James	24.5	177.6	8.2	3.1	3.9	21.5	13.9	18.1

These figures clearly show the significant impacts of all this waste heat. For example, the Connecticut and Merrimack Rivers absorb and dissipate almost 25% of the heat generated at thermoelectric plants along their banks, meaning that they continually experience significant warming for much of their length. And the effect upon the estuaries at the mouths of all these rivers is substantial. In summer time, when many threatened and endangered species approach their thermal tolerance limits and dissolved oxygen impairments in coastal aquatic habitats are at their worst, the Hudson, Delaware, Susquehanna and James rivers are all several degrees warmer

[54] *See* Robert J. Stewart, Wilfred M. Wollheim, Ariel Miara, Charles J. Vorosmarty, Balazs Fekete, Richard B. Lammers and Bernice Rosenzweig, "Horizontal cooling towers: riverine ecosystem services and the fate of thermoelectric heat in the contemporary Northeast US," 8 *Environ. Res. Lett.*, Article ID 025010 at 3 (2013).

at the mouth than they would otherwise be.[55] The thermal discharges from once-through cooling systems that will continue to operate under EPA's rule contribute to dissolved oxygen impairments that affect dozens (if not hundreds) of listed species and their habitats.

The impact of thermal discharges into these rivers is equivalent in scale to many decades (or in the case of the Hudson and the James Rivers, more than a century) of anticipated climate change. Put differently, ending this adverse impact on the habitat of hundreds of listed species would help to buy humanity and these species another 100 years to recover and adapt to the coming changes in our climate.

Stewart *et al.* conclude that "[i]n aggregate, OTC plants produce all of the total net annual heat loads to rivers." Stewart *et al.* at 6. The researchers then mapped the dissipation of those heat loads, finding that hundreds of river miles in most of the listed river systems are between 1 and 5 degrees warmer in summer due to these discharges. *See* Stewart *et al.* at 6. Effectively, the "thermal plumes" in major Northeastern rivers take over the whole river for hundreds of miles.

Stewart *et al.* also provide EPA with a way to quantify and locate adverse habitat modifications, instead of just giving up. Their paper lists 12 common aquatic species and their average weekly temperature tolerance and uses the model results to quantify the number of river kilometers that are rendered unsuitable by discharges from once-through cooling systems regulated by EPA's rule. Since the model described in these papers is a gridded network, temperature values are determined for each point in the grid, thus the model provides the exact locations of the affected reaches in the Northeast. All of the supporting data and figures for these studies are available to the Services electronically. Even if EPA fails to act on this information, using these modelling techniques and results, and taking the species discussed in Stewart *et al.* as proxies for endangered species with similar thermal tolerances, the Services could quantify and precisely locate the habitats adversely affected by EPA's decision to authorize continued operation of once-through cooling systems.

Again, EPA provided none of this readily available information in its consultation package; it simply threw up its hands and claimed that it was "not possible" to evaluate the impacts of individual facilities whose continued operation will be authorized by this rule. BE at 37. For most of the species discussed in the BE, EPA simply asserts that "EPA does not have sufficient data to evaluate to what extent these species have also been affected by environmental alterations or indirect effects of existing CWIS and associated discharges." *See* BE at 41-53. EPA repeated this claim with respect to all listed cranes and storks, marine birds, shorebirds, waterfowl, Everglade Snail Kite, all of the eighty three listed species of clams, as well as corals,

[55] Note, however, that the model does not account for tidal dilution, which is an important variable in the Hudson, Delaware, and James rivers.

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Atlantic salmon, logperch, multiple minnow species, Pacific eulachon, Smalltooth sawfish,[56] Tidewater goby, Unarmored threespine stickleback, Pacific salmonids, rockfish species, seven sturgeon species, three sucker species, six Western trout species, whales, pinnipeds, manatees, sea otters, endangered species of sea turtles, and fifteen species of freshwater snails. Despite EPA's obvious lack of diligence in seeking out the best available information about these species, the fact is that the Services can obtain a great deal of information about these species with only a modicum of effort. It falls to the Services to obtain these data and analyze them on its own, or to extend the consultation period and refuse to issue a BiOp until EPA fulfills its statutory duty to provide the best available information for the Services' review.

e. Invasive Species in Thermal Plumes

Another area in which EPA failed to provide the best available data to the Services is with respect to the role of these thermal plumes in sheltering and promoting the growth of invasive species that harm threatened and endangered native species. EPA notes correctly that invasive species are a stressor affecting listed species and that "[t]hermal discharges from 316(b) facilities may extend the seasonal duration of non-resident organisms, allowing transient summer species to become permanently established in geographic areas beyond their historical range." But EPA provides only the example of increased abundance and overwintering of "the predacious ctenophore *Mneimiopsis leidyi*" in Mount Hope Bay, Massachusetts. This comb jelly is a seasonal resident native to the Atlantic coast. EPA's observation downplays the seriousness of this problem.

EPA failed to inform the Services of a far more worrying development: in recent years, scientists have documented the role of thermal plumes as protective niches for Asian clams (*Corbicula fluminea*) and quagga mussels (*Dreissena bugensis*), two highly invasive species that threaten dozens of listed freshwater bivalves in waterbodies already affected by large, regulated cooling water intakes (including waterbodies designated as critical habitat for bivalves). More than a decade ago, Mitchell *et al.* (1996) found that quagga mussels are present in abnormally high concentrations in areas affected by the thermal discharge plume of a power station and posited that, by decreasing the severity of wintertime low temperatures, thermal plumes create an opening for these invasives to establish and spread.[57] Thermal plumes were also the launching point for an Asian clam invasion of the Connecticut River.[58]

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[56] Charlotte Harbor, Florida is in the National Estuary Program and is designated critical habitat for the smalltooth sawfish.

[57] Jeremy S. Mitchell, Robert C. Bailey, and Richard W. Knapton, "Abundance of Dreissena polymorpha and Dreissena bugensis in a warmwater plume: effects of depth and temperature," 53 *Can. J. Fish. Aquat. Sci.* 1705, 1710 (1996).

[58] *See* D.E. Morgan, M. Keser, and J.T. Swenarton, "Population dynamics of the Asiatic clam, *Corbicula fluminea* (Muller) in the Lower Connecticut River: Establishing a foothold in New England," 22 *J. of Shellfish Research* 193-203 (2003).

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Last year, Simard *et al.* (2012) found that the thermal plume of the Gentilly-2 nuclear power plant in Quebec, on the north short of the St. Lawrence River, now provides a stable winter home for a population of invasive Asian clams.[59] With this discovery, the Asian clam has extended its northern boundary to include the entire United States.

These scientific studies, and others like them,[60] are readily available to the Services. Their findings should be reviewed and considered by EPA and the Services as they evaluate whether continued operation of existing once-through cooling systems jeopardizes the continued existence of numerous species of freshwater bivalves and/or adversely modifies their critical habitats. EPA did not include these or similar studies in its bibliography for the BE.

f. Connecticut River – Mount Tom Generating Station Biological Assessment

The most egregious example of EPA's failure to provide the best available data is EPA's failure to discuss information that is obviously in its possession, such as EPA Region 1's 2012 Biological Assessment for reissuance of a NPDES permit to the Mount Tom Generating Station, located on the Connecticut River.[61] Because it is in the non-delegated state of Massachusetts, Mount Tom is one of the few NPDES permitted facilities that EPA actually regulates directly. In preparing a Biological Assessment, although Region 1 focused on the portion of the Connecticut River near Holyoke, Massachusetts, the agency compiled a great deal of information that would be beneficial to the Services in determining the effects of EPA's rule throughout the length of the river.

The Biological Assessment for Mount Tom contains relevant information about conditions in the Connecticut River, including average seasonal flows and temperatures, habitat quality, and a host of water quality indicators, as well as information about the species found in the area. Among other highly relevant facts, the Biological Assessment states that the population of shortnose sturgeon in the Connecticut River appears to be stable at around 1000 fish (orders of magnitude below historic levels), and is divided into two breeding populations above and below the Holyoke Dam. The Assessment also provides important information about the breeding success of these fish, for example, the presence of high numbers of reproductive organ tumors that may have a negative effect on fecundity and are believed to be associated with PAH contamination in the Connecticut River. Finally, the Assessment reviews multiple stressors on sturgeon throughout the Connecticut River and concludes that continued operation of the cooling

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[59] *See* M. Anouk Simard, Annie Paquet, Charles Jutras, Yves Robitaille, Pierre U. Blier, Réhaume Courtois and André L. Martel, "North American range extension of the invasive Asian clam in a St. Lawrence River power station thermal plume," 7 *Aquatic Invasions* 81–89 (2012).

[60] *E.g.,* I.C. Rosa, J.L. Pereira, R. Costa, F. Goncalves and R. Prezant, "Effects of upper-limit water temperatures on the dispersal of the Asian clam corbicula fluminea," *PLoS One* 7 e46635 (2012).

[61] *See* EPA Region 1, Water Permits Branch, Office of Ecosystem Protection, "Biological Assessment Mount Tom Generating Station National Pollution Discharge Elimination System Permit Reissuance (Permit No. MA0005339)," dated May 25, 2012.

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water intake at Mount Tom likely will impinge and entrain specific numbers of adult, juvenile, and larval shortnose sturgeons at the Mount Tom plant, and therefore will adversely affect listed organisms, requiring formal consultation with the Services that the Commenters believe is presently ongoing.

EPA could have included information from this and other water-body specific research, such as EPA's investigations in the Catawba and Dan River watersheds, noted above. Clearly, this information would aid the Services in evaluating the effect of authorizing continued operation of multiple cooling water intakes on the Connecticut, Catawba, and Dan Rivers. Yet EPA chose to simply state that there was no available information about the effects of intakes on particular waterbodies or species affected by this rule.

7. The Services cannot reach a no jeopardy finding on the basis supplied by EPA.

Although it is short on specifics, EPA's Biological Evaluation provides a great deal of alarming information on the broad trends, risks to listed species and critical habitat, and pervasive environmental damage caused by cooling water intakes. As noted above, cooling water intakes regulated under this rule affect 215 listed aquatic species and discharge waste heat into 290 designated critical habitats.[62] In addition, EPA points out that:

- "Overall, aquatic species are disproportionately imperiled relative to terrestrial species. For example, 39 percent of freshwater and diadromous fish species . . . , 67 percent of freshwater mussels . . . and 48 percent of crayfish . . . are classified as T&E." BE at 3.

- "Proximity to T&E species and/or designated critical habitat (in addition to consideration of Essential Fish Habitats) is a documented concern at many power plant facilities." BE at 3. There is an extremely high degree of overlap between listed species' habitat and cooling water intakes. *See* BE at 55-62.

- "For T&E species, I&E from CWISs may represent a substantial portion of annual reproduction. Consequently, I&E may either lengthen species recovery time, or hasten the demise of these species much more so than for species that are abundant. For this reason, the population-level and social values of T&E losses are likely to be disproportionately higher than the absolute number of losses that occur." BE at 3.

- The available data likely understates threats to listed species because regulators do not routinely revisit concerns surrounding threatened and endangered species during relicensing or permitting proceedings. *See* BE at 4.

[62] *See* BE at 60 and Table 7-1, 83-88. The 290 designated critical habitats overlap each other (i.e. the same habitat is used by multiple species).

- Endangered species are rarely found in impingement and entrainment samples because sample sizes are small and by definition listed species are rare. "T&E species are found at low population densities, and the volume of water sampled by facility-level impingement and entrainment studies is low. Thus, it is likely that many T&E species suffered IM&E outside of sampling periods and are never recorded." BE at 63-64. Therefore, the absence of listed species in sampling data does not mean they aren't being killed. If listed species are present in the vicinity of cooling water intakes, they can be killed periodically even if individuals are not found during rare sampling episodes.

- EPA's investigation of NPDES permits for facilities known to overlap with the ranges of multiple endangered species found that none of the permits contained conditions aimed specifically at protection of listed species and there was little or no analysis related to listed species at these facilities. *See* BE at 4.

- "The operation of CWISs and discharge returns significantly alter patterns of flow within receiving waters, both in the immediate area of the CWIS intake and discharge pipe, and in mainstream waterbodies. Flow alteration may be particularly disruptive in inland riverine settings. Flow alterations can create changes in the overall aquatic habitat and thus affect T&E species in a number of ways." BE at 68.

- "Many T&E species are particularly vulnerable to degraded water quality" (BE at 69) and "many aquatic organisms subject to the effects of cooling water withdrawals reside in impaired (i.e., CWA 303(d) listed) waterbodies. Accordingly, they are potentially more vulnerable to cumulative impacts from other anthropogenic stressors." BE at 65.

Thus EPA's Biological Evaluation, while vague, provides a great deal of negative information demonstrating that cooling water intakes may jeopardize the survival and recovery of listed species, or may adversely modify designated critical habitat. And EPA has failed to provide the kind of site-specific, quantitative data that would be needed to demonstrate that it will comply with its statutory obligation to avoid jeopardy and adverse modification.

Despite EPA's failure to provide the best available data, it is ultimately the obligation of the Services to issue comprehensive BiOps that reach a well-reasoned final opinion about whether EPA's action will jeopardize the continued existence of any species or adversely modify habitat. Under guidance issued by the Services, when faced with pervasive uncertainty and an obligation to complete a BiOp promptly, the Services must "develop the biological opinion with the available information[,] giving the benefit of the doubt to the species." Handbook at 1-7; *see also Natural Res. Defense Council v. Kempthorne*, 506 F. Supp. 2d 322, 360 (E.D. Cal. 2007) (agency cannot abdicate responsibilities by characterizing available information as uncertain, in the face of uncertain information Congress intended to give benefit of the doubt to the endangered species); *Rock Creek Alliance v. U.S. Fish & Wildlife Serv.*, 390 F. Supp. 2d 993, 1008, (D. Mont. 2005) ("[A] tie in the evidence should go to the species, especially because of female mortality. FWS must demonstrate a rational explanation for its conclusions, and given the

clear possibility that bears are at least not increasing, contemplating the loss of additional bears related to the mine is not rational."), *accord Conner v. Burford*, 848 F.2d 1441, 1454 (9th Cir. 1988) (requirement to use the best available information must always be met because "to hold otherwise would eviscerate Congress' intent to give the benefit of the doubt to the species.").

In the face of so much information about the potential of cooling water intakes to cause harm, so little information to suggest that endangered species can continue to withstand this harm, and so little effort by EPA to provide the best available data or establish a regulation that positions the agency to closely monitor and control harm to endangered species in the future, the prudent way to give the benefit of the doubt to listed species is to conclude that EPA's rule will jeopardize their continued existence.

NMFS' 2012 Biological Opinion on the U.S. Army Corps of Engineers' nationwide permit program provides a recent example of this kind of jeopardy finding in the face of poor information.[63] The Biological Opinion addressed the Army Corps' decision to renew more than 40 nationwide general permits that collectively authorized, *every year*, tens of thousands of actions that involve dredging, filling, and modification of tens of thousands of acres of aquatic and wetland habitats throughout 45 of the 50 states.

NMFS concluded that the Army Corps' nationwide permits – which set up a system of one-time authorizations with little follow up, notification of permitted activities, and monitoring by the Army Corps – authorized the kinds of activities known to cause substantial harm to listed species and left the Corps blind to the impacts its permitting might have and unable to respond to emergent problems:

> [T]he U. S. Army Corps of Engineers has failed to insure that the Nationwide Permits it proposes to use to authorize activities in navigable and other waters of the United States are not likely to jeopardize the continued existence of endangered and threatened species under the jurisdiction of the National Marine Fisheries Service and are not likely to result in the destruction or adverse modification of critical habitat that has been designated for these species. . . .
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> [T]he evidence available suggests that the USACE has not structured its proposed Nationwide Permit Program so that the USACE is positioned to know or reliably estimate the general and particular effects of the activities that would be authorized . . . and, by extension, be positioned to know or reliably estimate the general and particular effects of those discharges on endangered and threatened species. The USACE also has not structured its proposed Nationwide Permit Program so that it is positioned to take actions that are necessary or sufficient to prevent the activities that

[63] NMFS, NOAA, U.S. Dept. of Commerce, *National Marine Fisheries Service Endangered Species Consultation Biological Opinion on U.S. Army Corps of Engineers' Nationwide Permit Program* (Feb. 2012).

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> would be authorized by the proposed Nationwide Permits from individually or cumulatively degrading the quality of the waters of the United States that would receive those discharges. It has not structured its proposed Nationwide Permit Program so that the USACE is positioned to *insure* that endangered or threatened species and designated critical habitat are not likely to be exposed to [harm] . . . [a]nd it has not structured its proposed Nationwide Permit Program so that the USACE is positioned to *insure* that endangered or threatened species and designated critical habitat do not suffer adverse consequences if they are exposed to [harm].
>
> To satisfy its obligation pursuant to section 7(a)(2) of the Endangered Species Act of 1973, as amended, the USACE must place itself in a position to (a) monitor the direct, indirect, and cumulative impacts of the activities the proposed Nationwide or General permits would authorize, (b) monitor the condition of those effects on the subwatersheds or watersheds in which those activities occur, (c) monitor the consequences of those effects for listed resources under NMFS' jurisdiction, and (d) take timely and effective corrective actions when the consequences of those actions exceed measurable standards and criteria.[64]

In this rule, EPA is setting itself up in much the same situation: EPA is prepared to authorize the operation of cooling water intakes despite the fact that they cause harms that the agency has not yet managed to assess, and has no future plans to assess. The information provided by EPA is so clearly inadequate that the Services cannot reasonably conclude that EPA's regulation will avoid jeopardizing the continued existence of endangered or threatened species and will avoid destroying or adversely modifying designated critical habitat. The only appropriate conclusion for a BiOp based on EPA's limited data provision is a jeopardy finding like that reached in the Army Corps BiOp.

8. The deadline for EPA to issue a final rule is likely to be extended; the Services should take this opportunity to demand that EPA provide the Best Available Data.

The Services cannot reasonably conclude that EPA's 316(b) regulations will avoid jeopardy based only on the limited information provided by EPA about the harms to listed species from continued operation of existing cooling water intakes. Nor, on this basis, can the Services issue quantified incidental take statements with clear triggers for subsequent action. In these circumstances, one option open to the Services is to reach a jeopardy conclusion and set forth a reasonable and prudent alternative to EPA's rule.

But "[w]here significant data gaps exist," the Services' handbook lays out another alternative as well: "if the action agency concurs, extend the due date of the biological opinion until sufficient information is developed for a more complete analysis." Handbook at 1-7. At this stage, gathering and analyzing new information is the only defensible alternative to issuing a

[64] *Id.* at 223-224.

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jeopardy opinion. EPA has not provided the best available data, and the Services cannot issue opinions that are not based on the best available data.

Commenters have demonstrated that EPA has ignored readily available information sources ranging from government reports to thermal modeling analyses. The Services' Handbook explains what is to be done in such cases:

> If relevant data are known to be available to the agency or will be available as the result of ongoing or imminent studies, the Services should request those data and any other analyses required by the regulations at 50 CFR §402.14(c), or suggest that consultation be postponed until those data or analyses are available . . . .

Handbook at 1-6.

9. Closed-Cycle Cooling Technology should be the focus of any Reasonable and Prudent Alternative (RPA) analysis or Reasonable and Prudent Measures (RPM) analysis.

Unfortunately, EPA's Biological Evaluation did not provide the Services with information on closed-cycle cooling technology. More information about closed-cycle cooling would assist the Services to select Reasonable and Prudent Alternatives in case of a jeopardy finding, and to develop Reasonable and Prudent Measures for inclusion in an incidental take statement. Again, Commenters seek to assist the Services in filling this gap.

Closed-cycle cooling technology provides the only reasonable and prudent alternative means for EPA to minimize the adverse environmental impacts of cooling water intakes under Section 316(b) of the Clean Water Act.

To that end, we attach to this letter our comments to EPA on its proposed rule as published in 2011.[65] Those comments discussed the use of closed-cycle cooling in detail, including the technical and economic feasibility of a national rule that would require widespread use of cooling towers. Of course, Commenters cannot bridge the data gap left by EPA alone, and encourage the Services to seek additional information.

Widespread adoption of closed-cycle cooling in place of once-through cooling intakes is a valid Reasonable and Prudent Alternative:

1. closed-cycle cooling is almost certain to avoid jeopardizing endangered species by reducing impingement and entrainment by 98% and eliminating thermal discharges;

2. closed-cycle cooling is consistent with the purposes of EPA's rule – minimizing the adverse environmental impact of cooling water intakes;

[65] August 2011 Comment Letter.

3. closed-cycle cooling is consistent with EPA's authority – EPA considered such options in developing this rule; and

4. closed-cycle cooling is economically and technologically feasible.

See 50 C.F.R. §402.02 (defining the elements of a Reasonable and Prudent Alternative).

In developing its cooling water intake rule, EPA had before it regulatory options – national categorical standards based on the performance of closed-cycle cooling systems (Options 2 and 3 from the proposed rule) – that would protect the environment at a reasonable cost to industry, create jobs, and cause no significant adverse effects on the environment, electric reliability, or consumer prices. EPA unlawfully rejected these options in favor of preserving the status quo. Closed-cycle cooling is a feasible and readily affordable technology. A national, categorical entrainment standard based on that technology could include a narrow safety-valve variance to properly take account of site-specific factors for those plants fundamentally different than the majority.

EPA can and should establish a uniform national standard based on the use of closed-cycle cooling technology: EPA determined that closed-cycle cooling is a best performing technology[66] and that numerous existing facilities had retrofitted to closed-cycle.[67] During the rulemaking process, EPA expressed concern that "closed-cycle cooling is not practically feasible in a number of circumstances" that "are not isolated or insignificant."[68] But Congress gave EPA the ability to subcategorize regulated industries and to offer variances precisely to address such concerns. *See* 33 U.S.C. § 1311(n) (fundamentally different factors variance). And properly crafted variance provisions have been upheld under Section 316(b) before. *See Riverkeeper, Inc. v. U.S. EPA,* 358 F.3d 174, 193-94 (2d Cir. 2004).

As the attached comments explain more fully, Options 2 and 3 from EPA's proposed rule, both of which involve conversion of many existing intakes to closed-cycle systems, are technically and economically feasible. It is technically feasible to set uniform national standards because closed-cycle cooling and other technologies are available to the industry as a whole and EPA has the ability to issue variances in the rare case where it is technically infeasible. As the comments show in detail, the technical issues that EPA raised in the preamble to the proposed rule are not serious obstacles to widespread adoption of closed-cycle cooling.

The attached analysis also shows that closed-cycle cooling retrofits are economically feasible – they are well within the economic reach of virtually all regulated entities. The economic feasibility test under the Endangered Species Act is a test of affordability, not a cost-

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[66] *See* 76 Fed. Reg. at 22,203 (col. 3).

[67] *See* 76 Fed. Reg. at 22,204 (col. 1).

[68] 76 Fed. Reg. at 22,207 (col. 1).

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benefit analysis. The "economically and technologically feasible" language in the Act does not require an agency to "balance the benefit to the species against the economic and technical burden on the industry before approving an RPA" because this would be inconsistent with the purposes of the ESA. *Delta Smelt Consol. Cases v. Salazar*, 760 F. Supp. 2d 855, 955 (E.D. Cal. 2010). As the Supreme Court has explained, Congress determined that the protection of endangered species is, literally, priceless. *See TVA v. Hill*, 437 U.S. 153, 184 (1978) ("The plain intent of Congress in enacting this statute was to halt and reverse the trend toward species extinction, whatever the cost. This is reflected not only in the stated policies of the Act, but in literally every section of the statute.").

For these reasons, as explained more fully in the attached comments to EPA, a rule that requires widespread adoption of closed-cycle cooling is a reasonable and prudent alternative to EPA's preferred option, which jeopardizes the continued existence of many species. In fact, it is the only reasonable and prudent alternative.

10. A closed-cycle cooling rule is the only option that allows the services to develop a defensible incidental take statement.

Better information about closed-cycle cooling is also necessary because, without it, the Services cannot develop valid incidental take statements. By reducing the take of endangered species and the instances of adverse habitat modification by more than 98%, the use of closed-cycle cooling will bring incidental take of listed species down to a level that is actually manageable and quantifiable for the Services.

A BiOp that concludes that a federal action does not violate Section 7(a)(2) of the ESA must include an incidental take statement that "specifies the impact, i.e., the amount or extent, of such incidental taking on the species." 50 C.F.R. 402.14(i); *see also* 16 U.S.C. § 1536(b)(4). An incidental take statement must set "a 'trigger' for further consultation at the point where the allowed incidental take is exceeded, a point at which there is a risk of jeopardizing the species." *Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1271-72 (11th Cir. 2009) (citing 50 C.F.R. § 402.14(i)(4)).

In their handbook on ESA consultations, the Services determined that to set the trigger, incidental take may be quantified through the number of individuals killed or the extent of habitat disturbed. In either case, however, "a specific number . . . or level of disturbance to habitat must be described." Handbook p. 4-50. Subsequent to issuance of the Services' handbook, the federal courts have repeatedly held that Congress clearly expressed a preference for numerical population counts in incidental take statements and therefore the number of individual animals of a species that may be taken incidentally through a federal action must be specified unless the Services and EPA can establish that no numerical value could be practically obtained. *See Oregon Natural Res. Council v. Allen*, 476 F.3d 1031, 1037 (9th Cir. 2007) (invalidating incidental take statement that used habitat markers in place of a number of animals without explaining why determining a number of animals was impracticable); *Arizona Cattle Growers' Ass'n v. United States Fish and Wildlife Service,* 273 F.3d 1229, 1250 (9th Cir. 2001)

(same); *Miccosukee Tribe of Indians v. United States*, 566 F.3d 1257, 1274 (11th Cir. 2009) (invalidating take statement and discussing cases in which Services managed to express take in numerical form even for "elusive" species including snakes and sea turtles). Even if a BiOp logically concludes that a federal action poses no jeopardy to the continued existence of endangered species, an agency that does not provide the Services with enough data to set numeric limits in the incidental take statement risks seeing the BiOp vacated. *Id.*

If EPA hopes that the Services will reach a no jeopardy and no adverse modification conclusion, and hopes to obtain an incidental take statement, then it should have provided the Services far better information. EPA's shoddy work creates a heavy burden for the Services. Blanket statements that there are no better data on the impacts of cooling water intakes or the current status of hundreds of endangered species do not build a convincing case that it is impractical to specify the amount of incidental take, particularly where Commenters can readily identify better data for particular species. "Moreover, even where numerical values are improper, an ITS still must contain some surrogate for defining the amount or extent of incidental take." *NRDC v. Evans*, 364 F. Supp. 2d 1083, 1136 (N.D. Cal. 2003) (citing *Arizona Cattle Growers' Ass'n v. United States Fish and Wildlife Service,* 273 F.3d 1229, 1239 (9th Cir. 2001). EPA's failure to provide information about the extent of habitat needed to preserve endangered species would make even this fallback option a difficult one for the Services.

Although Commenters hope to aid the Services in filling the information gap left by EPA, the fact is that EPA's rule affects hundreds of endangered species in thousands of ecosystems across the United States. The only realistic way to issue a legally adequate incidental take statement is to first reduce the severity of the rule's impacts such that the overwhelming majority of facilities no longer pose a serious threat to endangered species. Closed-cycle cooling is likely to reduce the impingement and entrainment of many endangered species at individual facilities down to single digits or tens, instead of hundreds or even thousands. And by eliminating the thermal discharge problem, closed-cycle cooling essentially ends the widespread adverse modification of aquatic habitats. The residual incidental take will occur at a small enough number of facilities, and will affect a lesser number of species, such that the problem of quantifying take can be solved.

11. The BiOp(s) must significantly improve monitoring and reporting of impacts on listed species.

As EPA acknowledges in the Biological Evaluation, the status quo is abysmal in terms of monitoring and reporting on impacts to endangered species. *See* BE at 4-5. Cooling water intakes cause considerable and illegal harm to endangered species. This harm is rarely reported and is not subject to any kind of systematic review – not at the watershed, regional, or national level, nor even at a single site over time. EPA's review of NPDES permits found little or no consideration of endangered species, and EPA acknowledges that, even under the best of circumstances, endangered species have low population densities and are rarely found in periodic impingement and entrainment sampling.

Currently even when listed species or species of concern are greatly affected by a cooling water intake, reports may not reach state or federal regulators in a timely manner, or at all. For example, on January 14, 2012, the Palm Beach Post reported that the cooling water intake at the St. Lucie power plant in Florida had killed between 50 and 75 Goliath grouper – a long-lived top predator – on a single day in August 2011. The Goliath grouper was for many years a federally listed threatened species, although thanks to a fishing moratorium the Florida population is believed to be recovering and the species was delisted several years ago. The Goliath grouper is still a protected fish in Florida waters. "Although the fish kill occurred in late August, the Florida Fish and Wildlife Conservation Commission, Florida Department of Environmental Protection and U.S. Nuclear Regulatory Commission did not learn of the magnitude of the loss until December, sparking concern by officials and outrage by researchers."[69] From the reporting, it appears that neither the EPA nor the Services were directly informed of this fish kill even six months later, although Commenters hope very much that the Services were later informed of this fish kill by their colleagues in Florida.

This kind of lax reporting environment is unacceptable. It is no surprise that EPA has a hard time locating data on fish kills at cooling water intakes. As a condition of any BiOp(s), the Services should require EPA to dramatically improve its ability to monitor and report on the status of endangered species. Among many other measures, this should include:

- Develop *mandatory* standard NPDES permit requirements, procedures, and reporting methods for anticipating, evaluating, and reporting take of endangered species;

- Develop monitoring requirements that include surveying fish to find parasitic life stages of endangered bivalves that are attached to the gills or other parts of fish killed by intakes;

- Require the use of hydrophones and other acoustic monitoring equipment near intakes in all rivers in which tagged endangered species are known to be present, in order to better understand the abundance and behaviors of listed individuals in the area near an intake;

- Create a response capacity at EPA that can rapidly address reported take of listed species and any situations in which a cooling water intake causes sufficient harm to trigger review under the terms of an incidental take statement.

With respect to monitoring, however, by far the most significant change that NMFS can require is to demand that permittees regulated under EPA's rule undertake environmental metagenomic sampling to detect the presence of endangered species in or near an intake, rather than relying on impingement and entrainment assessments conducted once a decade or less.

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[69] Christine Stapleton, "Nuke Plant Fish Kill Leads to Improved Reporting Procedures," *Palm Beach Post* (Jan. 14, 2012), http://www.palmbeachpost.com/news/news/state-regional/nuke-plant-fish-kill-leads-to-improved-reporting-p/nL3C9/.

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EPA admits that current monitoring practices are very unlikely to detect the presence of endangered species. And even when impingement and entrainment sampling are carried out by experienced biologists, the early life stages of listed species (eggs, larvae) are frequently difficult or impossible to distinguish from closely related species and are not reported or are lumped into a single genera.

There is no reason to continue EPA's dependence on such limited data. With the dramatic advances in genetics and bioinformatics, and with the rapid and significant decreases in the cost, time, and complexity of shotgun sequencing, chip-based analysis, and related techniques, there has been an explosion in the use of metagenomic sampling. Today, researchers throughout the United States can sample environmental media for genetic markers (or whole genomes) of multiple species at the same time. The National Academy of Sciences has been heavily promoting the use of environmental metagenomic analyses for several years.[70] It is quite feasible at this point for any facility operating a cooling water intake to periodically collect water samples, as well as samples of entrained and impinged biomass, and have them tested to detect DNA sequences unique to listed species known to inhabit the area.

12. As a condition of any BiOp, the Services must demand that EPA's rule ensures that all NPDES permits authorizing operation of a cooling water intake state clearly that permitted facilities must obtain an Incidental Take Permit under Section 10 of the ESA if there are listed species or critical habitat in the vicinity of the facility that may be adversely affected by its operation.

EPA's Biological Evaluation repeatedly makes reference to the NPDES permitting process and the possibilities of protecting endangered species through that process. As discussed above, the NPDES process does not and cannot excuse EPA from complying with its obligations under Section 7 of the ESA. Before finalizing this rule, EPA, with the advice of the Services, must reasonably conclude that its rule is not likely to jeopardize the survival, recovery, or critical habitat of listed species. But the Endangered Species Act applies not just to EPA and the Services; it extends to private actors too.

Particularly where, as here, the information provided by EPA is so shoddy that it precludes any possibility of serious analysis, EPA cannot abuse the Section 7 consultation process in a way that would insulate future take of listed species or adverse modification of critical habitat from the protections of the Act. EPA must make clear to regulated entities that, however EPA chooses to fulfill its duties under Section 7 of the Act, nothing in this consultation process can eliminate the strict obligation imposed on industrial facilities by Section 9 of the Act not to take endangered species or harm their habitat.

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[70] *See, e.g.*, Committee on Metagenomics: Challenges and Functional Applications, National Research Council, *The New Science of Metagenomics*, National Academis Press (2007), *available at* http://www.nap.edu/catalog.php?record_id=11902.

Functionally, the way for the Services to accomplish this is to insist that, as a term or condition of any BiOp, EPA's rule must be amended to require that all NPDES permits authorizing operation of a cooling water intake include a clause stating that:

a. Compliance with a NPDES permit does not ensure compliance with the Endangered Species Act; and, therefore

b. NPDES permitted facilities that take in cooling water or discharge waste head must obtain an Incidental Take Permit under Section 10 of the ESA if there are listed species or critical habitat in the vicinity of the facility, because these species and habitat may be adversely affected by operation of the cooling system.

13. The Services must clarify how they will address the ongoing and rapid listing of hundreds of species and their critical habitats.

The FWS is under judicially enforceable deadlines to clear hundreds of species from the ESA listing backlog this year and in the coming two years. On May 10, 2011, the FWS entered into a Stipulated Settlement Agreement in the case of *WildEarth Guardians v. Salazar*, in the United States District Court for the District of Columbia; and on July 12, 2011, the FWS entered into a Stipulated Settlement Agreement in the case of *Center for Biological Diversity v. Salazar*, also in the United States District Court for the District of Columbia. These agreements require FWS to make listing decisions on more than 250 species by certain dates, including listing decisions on more than 150 species by September 30, 2013. The ESA requires that concurrent critical habitat designations be made on those dates as well. *See* 16 U.S.C. §1533(a)(3)(A) and (b)(6)(C).

Commenters are concerned that EPA's inadequate BE became outdated as soon as it was printed and that the same will be true of any BiOps that the Services issue for EPA's proposed rule in the next few months. In light of the unprecedented, rapid and ongoing expansion of the number of listed species and their critical habitats, EPA and the Services must explain how they intend to review the impacts of EPA's proposed cooling water intake regulations on these species and critical habitats.

14. NMFS has additional responsibilities under the Marine Mammal Protection Act and the Essential Fish Habitat provisions of the Magnuson-Stevens Act.

NMFS' oversight responsibilities with respect to EPA's regulation of cooling water intakes are broader than the Section 7 consultation process. Under the Marine Mammal Protection Act (16 U.S.C. 1361 et seq.), NMFS is responsible for ensuring that marine mammals are not taken through EPA's action and that any impact on them from EPA's rule is negligible. The Biological Evaluation does not discuss marine mammals in a significant manner, although EPA does note generally that more than a dozen listed species of marine mammals may be

harmed through impingement (sea otters and pinnipeds), thermal discharge (manatees), and indirectly by cooling water intakes (all of the preceeding, plus whales). *See* BE at 32-33, 50-52.

EPA concluded that it lacks sufficient data to evaluate how marine mammals are affected by cooling water intakes. Without sufficient data, however, neither EPA nor NMFS can conclude that the impact on these species from regulated cooling water intakes is always negligible. The Biological Evaluation discusses circumstances in which cooling water intakes may have an important impact on marine mammals. For example, the Biological Evaluation recounts how many groups of West Indian Manatees have become dependent on power plant thermal discharges to provide overwintering habitat in areas outside their historic winter range. EPA writes that, "due to the high degree of seasonal exposure to the thermal plume of the power plants and threat of cold shock should the power plant go off-line suddenly, it was judged that the manatee would be susceptible to thermal and chemical alterations in their immediate environment." BE at 51.

The Commenters are concerned that this inadequate BE constitutes the sum total of EPA and NMFS's information gathering efforts under the MMPA. We ask that NMFS please clarify how the Biological Evaluation and the ESA Section 7 consultation process relate to NMFS' oversight responsibilities under the MMPA, and what other research and analysis activities NMFS is planning to complete in order to fulfill its MMPA duties.

Similarly, under Section 305 of the Magnuson-Stevens Fisheries Act and its implementing regulations, NMFS must "coordinate with and provide information to other Federal agencies to further the conservation and enhancement of essential fish habitat." 16 U.S.C. § 1855(b)(1)(D). Correspondingly, EPA must "consult with the Secretary with respect to any action authorized, funded, or undertaken, or proposed to be authorized, funded, or undertaken, by such agency that may adversely affect any essential fish habitat." *Id.* § 1855 (b)(2). EPA's regulation governs the continued operation of numerous cooling water intakes located in essential fish habitats. These intakes kill fish in and dramatically alter the ecosystems of these habitats.

Like the ESA, the Magnuson-Stevens Act also requires EPA and NMFS to "use the best scientific information available regarding the effects of the action on EFH and the measures that can be taken to avoid, minimize, or offset such effects." 50 C.F.R. § 600.920(d). And EPA is required to provide NMFS with a written assessment of the rule's effects on essential fish habitat. *See id.* §600.920(e)(1). But the Biological Evaluation includes barely any information or analysis related to the endangered species that it is supposed to focus on; it makes no mention at all of the hundreds of billions of other fish killed by cooling water intakes every year, including the many billions killed in essential fish habitats. EPA has not provided a written assessment of the impact that its rule will have on these habitats, on fish populations, or on regulated fisheries. EPA's Biological Evaluation is not even adequate to meet its original purpose of assessing impacts on listed species; it certainly cannot double as a written assessment of impacts to essential fish habitat.

Cooling water intakes have notorious and substantial adverse effects on commercial and recreational fisheries and essential fish habitat. To take just two examples, the Delaware Estuary in the vicinity of the Salem Nuclear Generating Station is designated essential fish habitat for sixteen species of fish.[71] The Salem Nuclear Generating Station withdraws billions of gallons of cooling water from this essential fish habitat every day, killing more than 800 million "age one equivalent" fish – i.e., billions of actual fish, eggs, and larvae – every year.[72] Similarly, the Hudson River is also designated as essential fish habitat for numerous species. In the 1990s and early 2000s, five power plants on the Hudson River (Indian Point, Bowline, Roseton, Lovett and Danskammer),[73] caused year-class reductions estimated to be as much as 79 percent, depending on fish species.[74] The generators' 2000 analysis of three of these plants predicted year-class reductions of up to 20 percent for striped bass, 25 percent for bay anchovy, and 43 percent for Atlantic tomcod, even without assuming 100 percent entrainment mortality.[75] New York State has concluded that these losses could seriously deplete any reserve or compensatory capacity needed to survive unfavorable environmental conditions.[76]

Because the intakes regulated under EPA's new rule have such substantial adverse effects, the only appropriate form of essential fish habitat consultation under the Magnuson-Stevens Act is expanded consultation. *See* 50 C.F.R. § 600.920(i). And this expanded consultation must be initiated at least 90 days prior to a final EPA decision on the proposed 316(b) rule. *See id.* §600.920(i)(4). NMFS makes textual and GIS descriptions of essential fish habitats widely available. As a starting point, EPA should have submitted to NMFS a list of all essential fish habitats overlapping regulated intakes and thus affected by this rule. Commenters are disappointed that EPA has not taken even this basic first step, yet somehow seeks to conclude its consultation with NMFS and issue a final rule shortly.

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[71] U.S. Nuclear Regulatory Commission, Essential Fish Habitat Assessment for the Proposed License Renewal for the Salem Nuclear Generating Station and Hope Creek Generating Station 16-17 (2011), *available at* pbadupws.nrc.gov/docs/ML1103/ML110320664.pdf.

[72] Versar, *Technical Review and Evaluation of Thermal Effects Studies and Cooling Water Intake Structure Demonstration of Impact for the Salem Nuclear Generating Station* at § VI-4 (Revised Final Report) (1989) (reported on an "equivalent adult" basis). Thiry (30) million pounds of bay anchovy and weakfish are lost each year due to entrainment and impingement at Salem compared to 6.8 million pounds of yearly commercial landings between 1975-1980.

[73] The Lovett plant has since closed, Danskammer has announced closure in the near future.

[74] 67 Fed. Reg. at 17,138, citing John Boreman and Phillip Goodyear, *Estimates of Entrainment Mortality for Striped Bass and Other Fish Species Inhabiting the Hudson River Estuary*, American Fisheries Society Monograph 4:152-160, 1988

[75] *Id.*, citing Consolidated Edison Company of New York, Draft environmental impact statement for the state pollutant discharge elimination system permits for Bowline Point, Indian Point 2 & 3, and Roseton steam electric generating stations (2000).

[76] *Id.*

Please explain how, and on what timeline, NMFS and EPA intend to comply with their respective obligations under the Magnuson-Stevens Fishery Act and the Marine Mammal Protection Act.

15. Request for meeting

The Services' Section 7 consultation handbook states that the action agency and the Services should involve other interested parties in discussions related to the consultation, including to the development of reasonable and prudent alternatives to the proposed rule and reasonable and prudent measures to mitigate the impacts of incidental take. *See* Handbook at 4-7. Commenters respectfully request an opportunity to meet with the Services and EPA to discuss the issues raised in this letter and our concerns related to this consultation.

16. Conclusion

We hope that the data referred to in this letter and the attached documents are helpful to the Services in this consultation process. Despite the shortcomings of EPA's submission, it is arbitrary and capricious and not in accordance with the Endangered Species Act for the Services to issue or for EPA to rely on a BiOP that does not draw on the best available scientific and commercial data. *See, e.g., Conner v. Burford*, 848 F.2d 1441, 1454 (9th Cir. 1988). The attached information is just a small sample of the available data that Commenters were able to assemble on a short timeline and with limited resources. We hope that this submission assists the Services in delineating the large volume of available data that is far better than what EPA provided in its Biological Evaluation and supporting materials, and we also hope that the Services are able to establish a research process that collects and makes use of that information.

In the absence of better information about the status of hundreds of endangered species affected by intakes, however, the benefit of the doubt must be given to endangered species. "Congress has spoken in the plainest of words, making it abundantly clear that the balance has been struck in favor of affording endangered species the highest of priorities, thereby adopting a policy which it described as 'institutionalized caution.'" *Tennessee Valley Authority v. Hill,* 437 U.S. 153, 194 (1978).

Given the volume of information available about the lethal effects of cooling water systems on endangered species, the fact that EPA's rule will achieve, at best, only a modest reduction in impingement and little or no reduction in entrainment and thermal discharge, the significant risk that EPA's rule will in fact increase both entrainment and thermal discharge, and the lack of any data to suggest that populations of threatened and endangered species are recovering despite these impacts, it is difficult to see how the Services can avoid a finding of jeopardy if they insist on issuing a BiOp based on the presently available information. Alternatively, we believe that the Services must demand that EPA make a sincere effort to provide the Services with the best available data about the effects of its action and the listed species harmed by it.

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We also hope to hear from you soon with regard to MMPA and Magnuson-Stevens Act compliance and our request to meet with the Services. Thank you for your consideration of these comments.

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Electric System Reliability and EPA's Clean Power Plan: Tools and Practices

Analysis Group

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February 2015

Acknowledgments

This report provides a primer on various reliability issues facing the electric industry as it looks ahead to implementation of the Clean Power Plan, as proposed by the U.S. Environmental Protection Agency on June 2, 2014.

Taking into consideration the many comments of various parties filed on EPA's proposal, the report addresses issues that the nation and the electric industry need to address in order to simultaneously meet electric system reliability and carbon-emissions reduction obligations.

This is an independent report by the authors at the Analysis Group, supported by funding from the Energy Foundation.

The report, however, reflects the analysis and judgment of the authors only.

About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

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APPENDIX

Public Comments on EPA's Proposed Clean Power Plan: Summary of Concerns relating to Electric System Reliability Issues Appendix - 1

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Executive Summary

Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability.

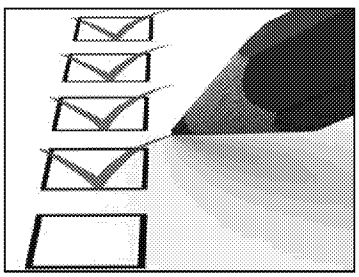
Such warnings are common whenever there is major change in the industry, and play an important role in focusing the attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.

Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan.

In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.

The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed.

The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out.



http://imgkid.com/checklist-icon.shtml

Among other things, these "business-as-usual" procedures include:

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- Assigning specific roles and responsibilities to different organizations, including regional reliability organizations, grid operators, power plant and transmission owners, regulators, and many others;
- Planning processes to look ahead at what actions and assets are needed to make sure that the overall system has the capabilities to run smoothly;
- Maintaining secure communication systems, operating protocols, and real-time monitoring processes to alert participants to any problems as they arise, and initiating corrective actions when needed; and
- Relying upon systems of reserves, asset redundancies, back-up action plans, and mutual assistance plans that kick in automatically when some part of the system has a problem.

http://www.bls.gov/ooh/installation-maintenance-and-repair/line-installers-and-repairers.htm

As proposed by EPA, the Clean Power Plan provides states and power plant owners a wide range of compliance options and operational discretion (including various market-based approaches, other means to allow emissions trading among power plants, and flexibility on deadlines to meet interim targets) that can prevent reliability issues while also reducing carbon pollution and cost.

EPA's June 2014 proposal made it clear that the agency will entertain market-based approaches and other means to allow emissions trading within and across state lines. Examples include emissions trading among plants (e.g., within a utility's fleet inside or across state lines), or within a Regional Transmission Organization (RTO) market. In this respect, the Clean Power Plan is fundamentally different from the Mercury and Air Toxics Standard (MATS) and is well-suited to utilize such flexible and market-based approaches. Experience has shown that such approaches allow for seamless, reliable implementation of emissions-reduction targets. In its final rule, EPA should clarify acceptable or standard market-based mechanisms that could be used to accomplish both cost and reliability goals.

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Moreover, EPA has stated repeatedly that it will write a final rule that reflects the importance of a reliable grid and provides the appropriate flexibility.[1] We support such adjustments in EPA's final rule as needed to ensure both emissions reductions and electricity reliability.

Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding *in parallel*.

Some of the cautionary comments are just that: calls for timely action. Many market participants have offered remedies (including readiness to bring new power plant projects, gas infrastructure, demand-side measures, and other solutions into the electric system where needed).[2] Indeed, this dynamic interplay is one reason why a recent survey of over 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and either supported EPA's proposed current emissions reduction targets or would make them more stringent.[3]

We note many concerns about electric system reliability can be resolved by the addition of new load-following resources, like peaking power plants and demand-side measures, which have relatively short lead times.[4] Other concerns are already being addressed by ongoing work to improve market rules, and by infrastructure planning and investment. A recent Department of Energy (DOE) report found that while a low-carbon electric

[1] See, for example, the January 6, 2015 blog post of Janet McCabe, EPA's Acting Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/. Also, see EPA's October 2014 Notice of Data Availability (NODA) that sought comments on, among other things, the potential to change the phase-in of emissions reductions to accommodate, for example, any constraints in natural gas distribution infrastructure, or how states could earn compliance credits for actions taken between 2012 and 2020.

[2] Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided through planning and infrastructure – we do note that serious questions have been raised about the assumptions used in recent reliability assessments performed by the North American Reliability Corporation (NERC). For example, Brattle Group's February 2015 report found that NERC failed to account for how industry is likely to respond to market and operational changes resulting from the Clean Power Plan. See Jurgen Weiss, Bruce Tsuchida, Michael Hagerty, and Will Gorman, "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," The Brattle Group, February 2015.

[3] The same survey found that utility executives believe that distributed energy resources offer the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, "2015 State of the Electric Utility Survey Results," January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned and municipal utilities, and electric cooperatives.

[4] Our report provides typical timelines for various types of resource additions in Section II.

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system may significantly increase natural gas demand from the power sector, the projected incremental increase in natural gas pipeline capacity additions is modest (lower than historic pipeline expansion rates), and that the increasingly diverse sources of natural gas supply reduces the need for new pipeline infrastructure.[5]

Some other comments raise the reliability card as part of what is – in effect – an attempt to delay or ultimately defeat implementation of the Clean Power Plan. We encourage parties to distinguish between those who identify issues and offer solutions, and those who (incorrectly) suggest that reducing carbon pollution through the Clean Power Plan is inconsistent with electric system reliability.

In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

Entities with roles to play as part of ensuring electric system reliability and timely compliance with EPA's Clean Power Plan	
Electric Reliability Entities	Federal Energy Regulatory Commission (FERC)
	North American Electric Reliability Corporation (NERC)
	Regional Reliability Organizations
	Electric System Operators and Balancing Authorities
Other public entities	Environmental Protection Agency (EPA)
	States (air agencies, public utility commissions, energy offices, state legislatures)
	Other federal agencies (Department of Energy, Energy Information Administration)
Entities involved with markets, resource planning, procurements	Wholesale market administrators
	Electric utilities (investor-owned, municipal utilities, cooperatives, joint action agencies
Other organizations that have a role to play	Non-utility generating companies and providers of other technologies
	Interstate natural gas pipeline companies (and storage suppliers)
	North American Energy Standards Board (NAESB)
	Energy efficiency program administrators
	Others

There are many capable entities focused on ensuring electric system reliability, and many things that states and others can do to maintain a reliable electric grid.

First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has for decades successfully relied on to maintain reliability, even in the face of sudden changes in industry structure, markets and policy.

Second, states should take advantage of the vast array of tools available to them and the flexibility afforded by the Clean Power Plan to ensure compliance is obtained in the most reliable and efficient manner possible. Given the interstate nature of the electric system, we encourage states

[5] U.S DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," February 2015.

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to rely upon mechanisms that facilitate emission trading between affected power plants in different states. Doing so will increase flexibility of the system, mitigate many electric system reliability concerns, and lower the overall cost of compliance for all.[6]

In this report we identify a number of actions that the Federal Energy Regulatory Commission (FERC), grid operators, states, and others should take to support electric system reliability as the electric industry transitions to a lower-carbon future. We summarize our recommendations for these various parties in tables at the end of our report.

In the end, the industry, its regulators and the States are responsible for ensuring electric system reliability while reducing carbon emissions from power plants as required by law. These responsibilities are compatible, and need not be in tension as long as all parties act in a timely way and use the many reliability tools at their disposal.

We observe that, too often, commenters make assertions about reliability challenges that really end up being about cost impacts. Although costs matter in this context, we think it is important to separate reliability considerations from cost issues in order to avoid distracting attention from the actions necessary (and feasible) to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers.

Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs. There is no reason to think that cost and reliability objectives cannot be harmonized within a plan to reduce carbon pollution.

[6] As we will discuss in a series of regional reports, others have already identified that regional strategies will minimize overall compliance costs. For example, the Midcontinent Independent System Coordinator (MISO) estimated that a regional carbon constraint approach could save up to $3 billion annually relative to a sub-regional or individual state approach. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014. See also, "Statement of Michael J. Kormos, Executive Vice President – Operations, PJM Interconnection, FERC Docket No. AD15-4-000, Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure," February 19, 2015.

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This paper is designed to:

- Describe the changes underway in the industry which set the stage for the continued evolution of reliability tools and practices;
- Provide a "reliability 101" primer to describe what "electric reliability" means to system planners and operators, and why specific standard practices are so important to assuring electric reliability;[7]
- Summarize reliability concerns expressed by various stakeholders;
- Explain the ways that standard operating procedures can address these concerns; and,
- Recommend actions that can be taken by various actors in the electric industry to assure that the Clean Power Plan's goals do not undermine reliable power supply.

Our recommendations can be found in tables following the Executive Summary.

[7] This report also includes a glossary of acronyms used in our report.

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Recommendation Tables

Table 1
Key Players in the Clean Power Plan and Available Tools

Entities	Roles and Responsibilities
Entities with direct responsibility for electric system reliability	- FERC (under the Federal Power Act (FPA)) - NERC (as the FERC-approved Electric Reliability Organization under the FPA) - Regional Reliability Organizations (RROs) - System operators and balancing authorities (including Regional Transmission Organizations (RTOs) and electric utilities) - States (for resource adequacy)

Other public agencies with direct and indirect roles in the Clean Power Plan	- U.S. Environmental Protection Agency (EPA)
	- State executive branch agencies:
	  - Air offices and other Environmental Agencies
	  - Public Utility Commissions (PUCs)
	  - Energy Offices
	  - Public authorities (e.g., state power authorities)
	- State governors and legislatures
	- U.S. Department of Energy (DOE)
	- Energy Information Administration (EIA)

Owners of existing power plants covered by 111(d) of the Clean Air Act	- Electric utilities
	  - investor-owned utilities
	  - municipal utilities
	  - electric cooperatives
	  - joint action agencies
	- Non-utility power plant owners

Markets and Resource Planning/ Procurement Organizations	- Organized markets administered by RTOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP).
	- Electric utilities with supply obligations & subject to least-cost planning processes:
	  - Many utilities (including joint action agencies) operate under requirements to use a combination of planning and competitive procurements (with or without self-build opportunities
	  - Transmission owners also have transmission planning requirements
	- Private investors (including non-utility companies) responding to market signals and seeking to develop/permit/construct/install/operate new resources (including new power plant projects, demand-response companies, merchant transmission companies, rooftop solar PV installation companies, etc.)

Others	- North American Energy Standards Board (NAESB) for setting electric & gas standards - Administrators/Operators of CO_2 allowance-trading systems - Administrators/Operators of energy efficiency programs - Fuel supply and delivery companies (gas pipeline and/or storage companies; gas producers; coal producers; coal transporters) - Energy marketing companies - Emerging technology providers – including, e.g., storage system providers, companies providing advanced communications and "smart" equipment, etc.

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Table 2
FERC, NERC, and RROs' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
FERC: - Adoption of federally-enforceable reliability requirements and standards - Oversight of NERC and all bulk power system operators - Oversight of interstate natural gas pipeline owners/operators, with authority to approve interstate pipeline expansions - Authority over transmission planning, tariffs, open-access - In organized markets, authority over market rules (including capacity markets, provision of ancillary services providing various attributes to system operators) - Interagency coordination with EPA, DOE	Consider: - Requiring NERC, RROs, and system operators/balancing authorities to periodically assess potential reliability impacts of CPP with geographic scope appropriate to the reliability entity. The assessments could identify specific concerns, and develop backstop solutions – Preliminary assessments starting at end of 2015/early 2016, to inform state action taking into account known policy, practices, resources in the relevant area – Reliability assessments at the time of proposed state plans – Reliability assessments annually up through early 2020s - Continuing to evaluate the adequacy of current FERC gas/electric coordination policies in light of *incremental* changes resulting from CPP relative to trends already underway in the industry - Eliciting filings from RTOs and other transmission companies about any new planning tools, notice provisions for potential retirements, information reporting, new products, minimum levels of capability with various attributes - Inquiring into new natural gas policies to support wider interdependence with electric system reliability (e.g., incentives for development of gas delivery/storage infrastructure) - Working with states to consider mechanisms to afford bulk-power system grid operators' greater visibility into generating and demand-side resources on the distribution system - Providing guidance outlining compliance strategies that would require approvals of the FERC under the FPA (versus approaches that might not require such)
NERC – Reliability Standards, compliance assessment, and enforcement – Annual & seasonal reliability assessments – Special reliability assessments	Consider: – Continuing to conduct special assessments of impact of CPP on reliability (as it periodically does for other developments in the industry) – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+) – Assess whether any new standards relating to Essential Reliability Services need to be modified in light of electric system changes occurring as part of the industry's response(s) to CPP
Regional Reliability Organizations – Annual & seasonal reliability assessments – Special reliability assessments – Coordination with neighboring RROs	Consider: – Conducting special assessments of impact of CPP on reliability – Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016) – Final assessments upon finalization of State Plans (2016+)

Table 3
Grid Operators' Potential Actions to Address Reliability Issues

Electric Reliability Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

System Operators and Balancing Authorities
– On-going annual & seasonal reliability assessments, including transmission planning
– Special reliability assessments
– Coordination with neighboring systems
 	
Note: Some of these entities also fulfill market, resource planning and procurement functions (described further below)
	Consider
	– Conducting special assessments of impact of CPP on system reliability
	  – Preliminary assessments in parallel with final rule development (in 2015) and development of State Plans (2015/2016)
	  – Final assessments upon finalization of State Plans (2016+)
	– Identifying specific areas of concern (e.g., notice period for potential unit retirements; need for more routine anticipatory analyses in transmission planning to explore "what if" changes occur on the system; identification of zones with violations of reliability requirements and any specific units needed for reliability pending resolution of the violation)
	– Working with stakeholders (including environmental agencies in relevant states) to develop proposals for reliability safety value to ensure mechanism to fully offset CO_2 emission impacts when use of a safety valve is triggered
	– Working with counterparts in natural gas industry to harmonize business practices, develop improved inter-industry forecasting tools, coordinate operating days/market timing, share information, identify specific natural gas infrastructure needs
	– Refreshing policies and practices to assure technology-neutral and competitively neutral means for providing reliability services (both resource adequacy and system operations)
	  - Technology neutrality should recognize the different attributes needed for essential reliability services, but be supportive of generation, transmission and demand-side solutions for providing such attributes
	– Working with state officials and distribution utilities within their relevant geographies to explore ways to expand the visibility (e.g., through communications and information systems) of the system operator into distribution system resource operations (i.e., distributed variable resources such as solar PV); incorporate into planning activities
	– Continuing to improve meteorological forecasting capabilities

Table 4
Other Federal Agencies' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

EPA
- **Issuing the final Clean Power Plan regulation**
- **Responsibility for finalizing standards for new power plants (Section 111(b))**
- **Responsibility for administering federal air, water, and waste pollution standards**
	Consider:
	- Clarifying acceptable standard market mechanisms that could be used to accomplish emission-reduction and reliability goals in economically efficient ways
	- Providing guidance on allowing one or more forms of a reliability safety valve, *with the condition* that overall emissions over the interim period (e.g., 2020-2029) are equal to or better than the plan without a triggering of the reliability safety valve. Examples might include:
	  - Allowing the reliability safety valve as proposed by the RTO/ISO Council (with the noted CO_2 emissions offset condition)
	  - Requiring/allowing temporary exemptions/modifications of timing/quantity requirements in State Plans
	  - Providing guidance about how states may propose to alter compliance deadlines/requirements where needed for reliability, should such issues arise over time
	- Requiring States to include reliability assessments in final State Plans (not for EPA to review/approve, but rather to ensure that such studies are conducted)

Other federal agencies - **DOE** - **EIA**	Consider: - Investigating additional reporting requirements by members of the industry - Conducting studies and analyses that examine physical capabilities of more integrated gas and electric system - Identifying CPP compliance issues as qualifying for DOE Critical Congestion Areas and Congestion Areas of Concern, and/or "national interest electric transmission corridors" under the Energy Policy Act of 2005

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Table 5
States' Potential Actions to Address Reliability Issues

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

States
– Air agency:
  – obligation to submit State Plans to EPA
  – reviewing/approving any modification to air permits of affected generating units
– Executive and legislative responsibility for energy, environmental laws and regulations
– Oversight over regulated electric and natural gas utilities (public utility commissions) – including ratemaking, programs (e.g., energy efficiency), planning and resource procurement
– Coordination with neighboring states
– Engagement in regional planning, operational, and market rules and procedures
– Siting/permitting of electric energy infrastructure and local gas distribution facilities
	Consider:
	– Proactively (i.e., now) engaging with state utilities and state/regional system operators in evaluation of potential CPP reliability impacts, and identification of reliability solutions (including supporting preliminary assessments in parallel with development of State Plans (2015/2016), and final assessments upon finalization of State Plans (2016+))
	– Establishing as part of the State Plan an annual state reliability evaluation, and identification of/commitment to take steps and measures in the future in response to any identified reliability concerns. This could include a framework for allowing compliance waivers and extensions in the early years in the event that reliability issues arise circa 2020, combined with requirements on state and/or compliance entities for provisional CO_2 reductions over transition period to make up for waivers/extensions in early years (e.g., to arrive at same cumulative emissions over the period)
	- Incorporating conditions in air permits to reflect operating limits (e.g., total emissions within an annual period)
	- Creating flexible implementation plans (e.g., mass-based models) and multi-state programs (e.g., regional cap/trade) to mitigate potential reliability impacts and operational flexibility across regions that reflect the normal operations of interconnected electric system
	  - State or regional cap and trade programs
	  - "Bubbling" of requirements across units owned by common owner (e.g., within one state or across states through bilateral state agreements/MOUs)
	– Developing statewide policies and measures for compliance that support reliability (energy-efficiency/renewable energy programs, including measures beyond Investor Owned Utility funded programs), for example:
	  – Clean energy standards
	  – Investment in emerging or early-stage technologies (*e.g.*, storage), public-private partnerships, tax and investment credits
	  – Protocols for counting Energy Performance Savings Contracts in State Plans
	– Reviewing need to modify permitting/siting regulations to accommodate dual-fuel capability of gas-fired power plants
	– Reviewing need to modify administrative or procedural measures to expedite siting, zoning, permitting of needed energy infrastructure (renewables, other power plants, transmission, LNG storage)
	– Instituting new entities (e.g., natural-gas buying authorities) to serve as contracting entity to support long-term commitments that may be necessary for gas system expansion
	– Requiring longer advance notice of power plant retirements

Table 6
Organized Markets' & Electric Utilities Potential Actions to Address Reliability Issues

Entities Involved with Markets, Resource Planning, and Procurements	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)

Wholesale Market Administrators (Generally, Bulk Power System (BPS) Operators in Competitive Market Regions)
– **Markets designed and administered to minimize costs *subject to the constraint* that all reliability requirements of the system are met**
	Consider:
	– Adding technology-neutral and competitively neutral market rules/products to add incentives for new reliability attributes.
	  – Local (zonal/load pocket) capacity and energy market pricing; changes to scarcity pricing
	  – Reliability attributes for system security (greater quantities of spinning or non-spinning reserves; AGC; ramping/load-following; reactive power; on-site fuel; frequency response; black start capability)
	– Establishing or clarifying, where necessary, expectations around unit performance during shortage or scarcity conditions
	– Clarifying how normal dispatch processes incorporate current restrictions on unit operations (including emissions limits, ramping periods, etc.), and how similar operational restrictions (if any) resulting from Clean Power Plan compliance would be incorporated in system operations
	– Establishing or clarifying, where needed, provisions for the creation of reliability must run (RMR) contracts for generators needed for reliability that would otherwise retire – conditioned upon permit restrictions that account for CO_2 emissions offsets
	– Establishing or clarifying, where needed, procedures to minimize duration of RMR contracts through development of utility or market responses (generation, transmission)
	– Identifying any changes in forward capacity markets for the period starting in 2020

Vertically-Integrated Utilities, Cooperatives, Municipal Light Companies
– **Long-term resource planning**
– **Obligation and opportunity to develop and obtain cost recovery for necessary demand, supply, and transmission investments and expenses**
– **Obligation to maintain power system reliability**
– **In some states, integrated resource planning and/or resource need/procurement processes**
– **Coordinated operation of systems with neighboring utilities**
	Consider:
	– Conducting forward-looking assessments of potential impacts on system reliability of CPP implementation
	  – Preliminary assessments prior to and during final rule development and SIP implementation
	  – Final assessments upon finalization of SIP
	– Developing or expanding long-term integrated resource planning processes for timely and practical incorporation of CPP compliance requirements
	– Incorporating all potential short- and long-term measures (supply and demand; generation and transmission) to address significant changes during CPP transition period
	– Engaging in coordination with neighboring utilities around local reliability concerns tied to CPP implementation

Table 7
Other Organizations' Potential Actions to Address Reliability Issues

Other Organizations that have a Role To Play in Assisting in Reliable and Effective Industry Compliance	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
Non-Utility Generating Companies	Consider: - Responding to signals in organized wholesale markets and in response to competitive solicitations by electric utilities
Interstate Natural Gas Pipeline Owners/Operators – Coordination among NGP owners/operators – Coordination with BPS operators – Development of new pipeline capacity	Consider: – Improving coordination with system operators – e.g., harmonize standards and practices, coordinate operating days/market timing, share information, etc.
NAESB - Working with industry stakeholders to develop standards for operations in electric and gas industry	Consider: – Periodically convening industry sector discussions about continuing need to harmonize standards in the electric and gas industries
Administrators of Allowance Trading Programs (e.g, RGGI, California, new ones)	Consider: - Establishing new "plug and play" programs that allow states to join with relatively administrative ease
Administrators of Energy Efficiency Programs	Consider: - Establishing products to offer to generating companies to 'purchase' program credits to offset emissions, subject to strict measurement and verification
Energy Service Companies (ESCos)	Consider: · Working with State agencies to develop mechanisms to incorporate energy-savings-performance contracts into State Plans

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I. Context

In June 2014, the U.S. Environmental Protection Agency (EPA) issued its proposed Clean Power Plan, designed to reduce carbon dioxide (CO_2) emissions from existing fossil-fuel power plants in the United States. The final rule, which is now anticipated to come out in mid-2015, will require each of the 49 states with covered power plants to prepare and submit plans for how they propose to reduce emissions from the plants in their state. Although the features of the final regulation will undoubtedly change in light of the many comments filed, EPA's current proposal requires states and affected electric generating units (EGUs) to demonstrate progress to reduce emissions starting in 2020, with subsequent reductions thereafter. This new policy will eventually affect over half of the nation's generating capacity and all but the smallest fossil fuel generating units.[8]

In light of the broad scope of the regulation, many stakeholders have raised concerns about whether EPA's proposal will jeopardize the reliability of the electric system. In Washington, in state capitols, in media alerts, in comments filed at the EPA, and elsewhere, many public officials, electric utilities, industry reliability organizations, and others have been demanding

[8] An affected electric generating unit (EGU) is defined broadly, as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input and (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system (Proposed Rule, Federal Register, Vol. 79, No. 117, June 18, 2014, page 34854). Generating units estimated to be subject to EPA's Clean Power Plan:

SNL Financial (as of 2-2015)	Generating Units Likely to be Directly Covered by Section 111(d)*		Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as Share of Total Capacity (%)
	(# Units)	Summer Capacity (GW)	Summer Capacity (GW)	Summer Capacity (GW)
Coal	922	300	303	99%
Gas	2,137	334	464	72%
Oil	62	17	39	44%
Total Fossil	3,121	651	806	81%
All Capacity			1,151	57%

* Includes all existing or under development steam turbines and combined cycle units greater than 25 MW, and any natural gas combustion turbines with generation greater than 219,000 MWh.
Source: SNL Financial, Power Plant Unit Database.

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that the changes introduced by the Clean Power Plan not come at the expense of electric reliability.[9]

For many decades, such cautions have appeared whenever major events – such as major new environmental regulations affecting power plants or structural changes to introduce competition in the electric industry – occur that could affect electric system reliability.[10]

Indeed, well before the EPA issued its proposal, various reliability organizations had already begun to anticipate how changes underway in the electric industry would necessitate modifications in traditional ways to plan for and operate the electric system. For example, the North American Electric Reliability Corporation (NERC) – the nation's electric reliability standards organization – issued a "concept paper" in October 2014, in which NERC describes the many ways that today's reliability procedures will need to evolve to keep ahead of the changing character of the electric "resources" that connect with the grid.[11]

NERC's paper, which was in development well before the EPA issued its Clean Power Plan (and is different from NERC's November 2014 assessment relating to the EPA proposal), begins by recognizing that the

> North American BPS [bulk power system] is experiencing a transformation that could result in significant changes to the way the power grid is planned and operated. These changes include retirements of baseload generating units; increases in natural gas generation; rapid expansion of wind, solar, and commercial solar photovoltaic (PV) integration; and more prominent uses of Demand Response (DR) and distributed generation…. As the overall resource mix changes, all the aspects of the ERSs [Electric Reliability Services] still need to

[9] See discussion in Section III and the Appendix to this paper. Note that even the leadership of the EPA and the President of the United States have insisted upon design and implementation of the Clean Power Plan in ways consistent with electric system reliability. See, for example: President Obama's Presidential Memorandum ("Power Sector Carbon Pollution Standards," June 25, 2013), in which the President directed the EPA to issue regulations to control CO_2 emissions from the power sector, and included the following instructions: "In developing standards, regulations, or guidelines … [EPA] shall ensure, to the greatest extent possible, that you: …(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses…" Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards

Also, see: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; and the January 6, 2015 blog post of Janet McCabe, EPA's Acting Assistant Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/.

[10] Notably, this has occurred in conjunction with: the EPA "NO_x SIP call" which affected 23 states in the 1990s; state and federal policies related to electric industry restructuring in the 1990s: the Cross-State Air Pollution Rule (CSAPR) and MATS rule; and with on-going increases in the amount of distributed energy resources and intermittent/non-dispatchable resources on the grid.

[11] NERC, "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability," October 2014. Hereinafter referred to as "NERC Essential Reliability Services Report".

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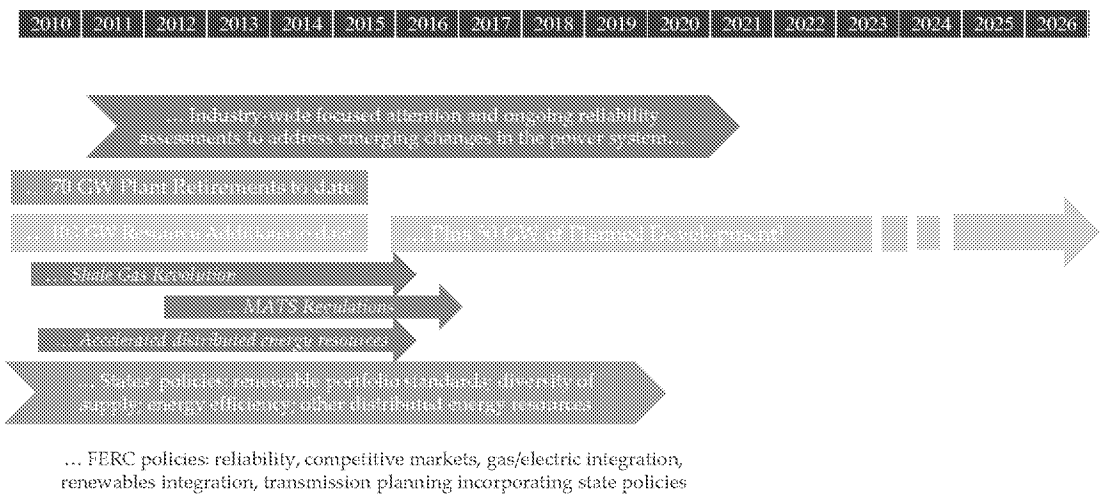
be provided to support reliable operation. ERSs are technology neutral and must be available regardless of the resource mix composition.[12]

Those transformations have been in the works for years – in part as a result of the shale gas revolution, changes in the relative prices of fossil fuels, state policies and federal laws encouraging greater use of renewable energy and energy efficiency, declines in wind and solar technology costs, retirements of old and highly polluting coal plants, retirements of a handful of nuclear plants (in some cases for safety reasons, and others for economic reasons), and strong interest by many customers in exploring ways to better manage their own energy use.[13] We depict these changes occurring in parallel in Figure 1, below.

Figure 1
Timeline of Changes Underway in the Electric Industry



[1] Includes retirements/additions announced for 2015 and units that are mothballed or out of service. Planned units include those under construction or in advanced development. Source for MW of retirements and planned additions: SN Financial, Accessed February 2015

As always, grid operators and utilities have implemented and adjusted long-standing planning and operational practices to stay abreast of, understand, and adapt practices to address reliability issues related to such changes in the industry. Given the multiple pressures on the electric power sector, such actions would be needed today even if EPA had not proposed to control carbon pollution in the Clean Power Plan.

[12] NERC Essential Reliability Services Report, page iii. The scope of work for this report was adopted by NERC in March of 2014, before the EPA Clean Power Plan was issued in proposed form in June, 2014.

[13] See, for example: Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 8, 2014, pages 23-46.

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Indeed, many organizations besides NERC have also been flagging the need to address reliability issues as the industry undergoes significant change. For example:

- The Federal Energy Regulatory Commission's (FERC) attention to gas-electric coordination as the two industries become increasingly dependent on each other,[14] and transmission companies and Regional Transmission Organizations (RTOs) plan for integration of variable generating resources and transmission requirements driven by public policies of state and local governments;[15]
- Studies by the Midcontinent ISO (MISO) of gas infrastructure,[16] and MISO's support for policies addressing transmission implications of the region's growing quantities of wind and other renewable resources;[17]
- ISO-New England's (ISO-NE) continuing analysis of that region's deepening reliance on gas-fired generating facilities, near-term generator retirements, and need to integrate deepening amounts of renewable resources;[18]

[14] FERC Commissioner Philip Moeller first requested comments on gas-electric coordination in February 2012. Since that time, the FERC has held nine regional conferences to address the issue. See FERC "Natural Gas – Electric Coordination." Available: http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp for additional detail. In 2013, FERC Chairman Cheryl LaFleur and Commissioner Moeller testified before Congress on "The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges". The Commissioners noted that gas-electric coordination was and is a growing and important trend due to falling natural gas prices and substantial domestic supplies. FERC receives quarterly updates from its staff on the status of developments in the industry regarding gas/electric coordination issues. http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp. Note too that in response to a directive from FERC, the North American Energy Standards Board (NAESB) undertook a process to develop some new standards for both electric and natural gas industries, which were described in a report submitted to FERC on September 29, 2014.

[15] On July 21, 2011, FERC issued Order 1000 (Docket No. RM10-23-000), in which the agency required, among other things, that each public utility transmission provider: (1) participate in a regional transmission planning process that produces a regional transmission plan; and (2) consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs. FERC Fact Sheet, Order 1000, http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf. On June 22, 2012, FERC issued the final rule in its docket (RM10-11-000) on Integration of Variable Energy Resources, in which it ordered a number of changes in interconnection agreements, transmission tariffs and cost recovery for regulation reserves to better accommodate renewables reliably and efficiently. 139 FERC ¶ 61,246, FERC Order No. 764.

[16] MISO released its first gas-electric interdependence study in February 2012; it reviewed existing gas pipeline capacity to serve existing electric generation and additional capacity that could be added in the future, and signaled to the MISO and stakeholders that an increase in gas-fired generation will require an "improved collaborative process between pipelines, power generators, and regulators to coordinate natural gas infrastructure projects." Gregory L. Peters, "Gas and Electric Infrastructure Interdependency Analysis," Prepared for the Midwest Independent Transmission System Operator, February 22, 2012, page. 12.

[17] MISO's "Multi-Value Project Portfolio Analysis" of transmission projects will support delivery of up to 41 million MWh of wind energy. Available: https://www.misoenergy.org/PLANNING/TRANSMISSIONEXPANSIONPLANNING/Pages/MVPAnalysis.aspx

[18] ISO-NE first identified these issues in 2010. In 2013, ISO-NE's Chief Executive Officer, Gordon van Welie, stated: "It is clear that resolving these challenges will not be simple, and it will take several years to realize the benefits of the solutions… It is important to remember that, often, the best ideas are born out of necessity. Today the power system faces significant and formidable obstacles. But tomorrow, it will be smarter, stronger, and more environmentally sound because of our collective efforts." ISO-NE, "2013 Regional Electricity Outlook," January 31, 2013, page 8.

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- Starting in 2010, calls by the American Public Power Association (APPA) to pay greater attention to the impacts of distributed generation and increased natural gas demand for power generation;[19]
- The Electric Reliability Council of Texas' (ERCOT) ongoing analysis of wind integration as part of its bi-annual Long Term System Assessment;[20]
- The review by the five major electric utilities in California of the implications of a potential significant increase in the state's renewable portfolio standard,[21] and the California ISO's (CAISO) solicitation of more flexible resources to support integration of renewables;[22]
- PJM Interconnection's (PJM) recent capacity performance proposal, in response to concerns raised by unavailable conventional generation capacity during the 2013-2014 polar vortex;[23] and
- New York ISO's (NYISO) ongoing evaluation of reliability needs, including scenarios that account for environmental regulations, increasing penetration of renewable resources, and natural gas fuel availability.[24]

These studies and activities – and others like them – illustrate that our electric system operators, planners, regulators, and others are stepping up to the plate (as they typically do) to grapple with ways to make sure that the future electric system is as reliable as the one we count on today. And their analyses reflect the reality that these trends are occurring as a result of economic, policy and regulatory forces that are independent of EPA's Clean Power Plan.

The value of such "reliability alerts" is that they identify ways in which changes in policy, economics, technology, and law affecting the electric industry intersect with the physics and engineering of interconnected electric systems. All parts of the system must pay attention to certain imperatives of the others.

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[19] See, for example, Aspen Environmental Group, "Implications of Greater Reliance on Natural Gas for Electricity Generation," prepared for American Public Power Association, July 2010.; and American Public Power Association, "Distributed Generation: An Overview of Recent Policy and Market Developments", November 2013.

[20] See, for example, ERCOT, "Long-Term System Assessment for the ERCOT Region," December 2012, which examined the implications of introducing significant wind generation and new gas-fired power plants on to the ERCOT Texas system.

[21] Energy+Environmental Economics, "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

[22] California Independent System Operator Corporation Reply Comments on Workshop issues, before the Public Utilities Commission of the State of California, In the Matter of "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations." Rulemaking 11-10-023, April 5, 2013.

[23] PJM Staff Proposal, "PJM Capacity Performance Proposal", August 20, 2014.

[24] NYISO conducts a detailed "Reliability Needs Assessment" every two years. See, for example, NYISO, "2014 Reliability Needs Assessment," Final Report, September 16, 2014.

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Certainly, the shale gas 'revolution' has introduced significant quantities of domestically supplied natural gas at prices which compete with coal, the historically dominant domestic fossil fuel for power generation. This new reality presents economic opportunities to the power system, with cost and environmental benefits for households and businesses. At the same time, however, lower-cost natural gas introduces new issues that must be addressed in the standards, business practices and regulation of both the electric and gas industries: for example, there are new issues surrounding ensuring adequate fuel-transportation and storage arrangements. States' policies to rely more heavily on domestic wind and solar generation also introduce new challenges: grid operators must plan to operate their systems reliably with greater reliance on less dispatchable resources (or in some cases resources that cannot be 'seen' on the system by grid operators, when the resources are behind the meters of customers).

Reliability organizations and grid operators (including NERC, Regional Transmission Organizations (RTOs), electric utilities, and others) are already facing the implications of these trends. They are doing what we count on them to do: looking ahead to see what's on the horizon and identifying reliability-related issues that require adjustments to planning, markets, or operations. They are identifying issues that arise from economic, technological, legal or policy changes. They are developing new analytic tools to better understand how factors like the weather (or wind or sun/cloud-cover conditions) affect power system operations. They are identifying possible, if not likely, changes in power supplies, and indicating where and when new resources might be needed in the years ahead. They are working with transmission owners, power plant companies, government regulators, reliability coordination organizations, consumer representatives, and others to identify changes that may be required in operating standards, market products, and practices.

This is standard operating procedure in an industry with a history with strong legal, cultural, and organizational incentives to do what it takes to make sure that a world-class reliable electric system remains a bedrock of the American economy and society. Recent calls for action to ensure that the Clean Power Plan does not jeopardize electric system reliability should be viewed in that context: people are doing their jobs, not necessarily trying to impede the Clean Power Plan.

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II. What Do We Mean by "Electric System Reliability"?

What is reliability, and why does it matter?

http://www.dailymail.co.uk/news/article-2226399/Sandy-Vast-majority-ConEd-wont-power-10-days--Manhattan-hopes-lit-Saturday.html

Most electricity users think of reliability in terms of how often their power shuts off and how long it takes to get it back on. These familiar reliability annoyances typically result from events affecting the local distribution system, such as a snowstorm or hurricane knocking out power lines or a car hitting a power pole.

While critically important to electricity users,[25] such events are not the main concern of observers considering the implications of EPA's Clean Power Plan. What they worry about is whether the overall electric system can do its job, day in and day out, even if one neighborhood or another loses its power.

This other kind of reliability is known as "bulk power system"[26] reliability (and what we call "system reliability" and what insiders sometimes call "BPS" reliability). Outages due to system failures differ from local outages in fundamental ways: in how they can arise; in the geographic scope of power interruptions; in the process and timing of power restoration; in the magnitude of adverse consequences; and, in terms of the parties responsible to fix the problems. The sheer scale of potential human health, safety, and economic impacts is what separates system reliability from local reliability, and dictates a high degree of vigilance on the part of regulators and the industry to avoid system-reliability failures.[27]

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[25] Electricity consumers are acutely aware of how inconvenient and costly outages can become, and of course may not care whether an outage is local or system-wide, in terms of the disruptive impacts on their lives. At the state level, maintaining reliable service is a fundamental obligation of every local utility, and state public utility commissions (PUCs) measure the performance of local utilities in maintaining local reliability over time through measurements that track the frequency and duration of outages. In many states, utilities can be fined heavily for poor reliability performance tied to local distribution-system outages. In contrast, system power failures – which are far less common – generally involve events affecting power plants and transmission lines and a wider geographic area of the grid, with reliability enforcement subject to the jurisdiction of FERC under then Federal Power Act (FPA).

[26] A Bulk Power System (BPS) generally covers a wide geographic region, and includes the generating resources, transmission lines, and associated equipment and systems used to operate the integrated electric system within the region. BPSs generally do not include the lower-voltage distribution systems of local utilities, which deliver power from the BPS to end-use customers.

[27] This is not to say that local distribution system circumstances can never create system reliability challenges. Given that the electric system has to maintain customer demand (load) and supply in balance at all times, a major storm that causes local lines to

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For this reason, multiple entities (including those in Table 8) constantly monitor conditions on the overall power system to assure that the overall system operates with a high degree of reliability. System planners, reliability organizations, power companies and regulators look many years ahead, to analyze changing conditions and flag issues on the horizon that need attention. From one season to the next, they review whether there will be enough resources to meet peak demand. Closer to real time, system operators monitor whether power plants are out for maintenance, whether temperature conditions will produce higher than expected demand, and myriad other conditions so that they can get ready for the next day's operations. And in real time, on a second-by-second basis, grid operators have to monitor, and manage the "balance" of the system so that supply equals demand within tolerable operating limits (i.e., "frequency"). Thus, across very different time frames, many actors in the industry work to assure that the system performs with impeccable reliability levels.

Table 8
Entities Responsible for Electric System Reliability

Organization	Roles and Responsibilities
Federal Energy Regulatory Commission (FERC)	- Federal agency responsible for enforcement of electric sector reliability requirements, including oversight of the ERO (NERC)
North American Electric Reliability Corporation (NERC)	- Designated as the Electric Reliability Organization (ERO) by FERC; responsible for developing, assessing and enforcing reliability standards
Regional Reliability Organizations (RROs)	- Members of the NERC that ensure regional operations are reliable, adequate and secure. Includes: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First (RF), SERC, Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electric Coordinating Council (WECC)
Grid and System Operators, and Balancing Authorities	- Responsible for the reliability functions in specific geographic areas. In addition to many electric utilities, there are other organizations serving this function in wide geographic areas, including Regional Transmission Organizations (the New York System Operator (NYISO), PJM Interconnection, New England Independent System Operator (ISONE), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)

Those responsible range from: the federal regulators at the FERC, which has statutory authority relating to system reliability; to NERC, the nation's "Electric Reliability Organization" (ERO), authorized by FERC to set reliability standards for grid operators, utilities and other power companies; to Regional Reliability Organizations (RRO) which ensure that the system is reliable, adequate and secure within the geographic footprint for which they're responsible; to grid operators (also known as "balancing authorities" or "system operators") with the operational responsibility in smaller areas.[28] Each

go down can cause a rapid loss of demand with the immediate need to address that big imbalance on the overall system in order to avoid a bigger problem affecting many other areas of the grid. Similarly, high penetrations of distributed resources (e.g., rooftop solar panels on customers' premises) connected to the local distribution system are emerging as a reason to increase the BPS grid operator's "visibility" into what is happening at the distribution system level because of the interrelationships between the two systems. In fact, several areas with significant current or expected installation of distributed resources (e.g., Hawaii, California) have begun to evaluate potential system-wide challenges associated with such developments.

[28] NERC's Glossary of Terms formally defines the various entities, along with various terminologies that described their responsibilities. NERC, "Glossary of Terms Used in NERC Reliability Standards," January 29, 2015, available: http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf

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one has different responsibilities, as shown in Table 8.

These entities monitor system reliability using time-tested, well-developed industry analytic tools. For longer-term assessments, the standard methods take into consideration a vast array of potential future infrastructure scenarios and system operational contingencies (e.g., sudden loss of generation, transmission or load). Annually and seasonally, system operators and reliability planners conduct reliability assessments to evaluate system changes, flag areas of concern that need to be addressed within different time frames, and identify plans to address any reliability concerns that may arise over the planning period. In addition, special assessments are periodically carried out in response to any industry or policy changes that have the potential to affect system reliability.

Thus it should not be surprising that EPA's proposed Clean Power Plan is being (and will continue to be) evaluated for potential reliability impacts in future years. We have seen such reliability evaluations exercised regularly over decades in the face of other major industry changes, as noted previously.[29] In every case, the prospect of change has led to reliability assessments and the waving of cautionary flags to call attention to the new challenges ahead.

How could electric system reliability be affected by the Clean Power Plan?

The Clean Power Plan will not lead to more cars hitting distribution poles, nor will it affect the frequency, location, or severity of storms that lead to local outages. The more relevant questions are how controls on power plant CO_2 emissions will affect power system components and operations. As highlighted in Section III (which summarizes stakeholder concerns around the Clean Power Plan's potential impacts on system reliability), concerns primarily relate to impacts these pollution controls will have on availability of existing power plants. Will plants

[29] There are many examples where changes in conditions have led to questions about whether the electric industry (and its supply chains) could respond in a sufficiently timely and effective way to avoid reliability problems. This occurred, for example, with: (1) prior EPA and state regulations governing human health and environmental impacts, including the CAA Title IV sulfur dioxide cap-and-trade program contained in the 1990s; the changes in National Ambient Air Quality Standards (NAAQS) and Clean Water Act (CWA) requirements; the more recent CSAPR and MATS regulations; and the proposals under 316(b) of the CWA. (2) Changes to the structure of the electric industry over the past several decades, involving major changes in the regulation of and the incentives for investment and operation; transfers of ownership and management of existing generation and transmission system elements; and the formation of RTOs and associated wholesale markets for energy, capacity and ancillary services. (3) Fundamental shifts in the economics of generating power from coal or from natural gas, driven initially by changes in technology costs (e.g., large-scale steam generators versus combined-cycle technologies) and more recently by the emergence of low-priced domestic shale gas resources; the growing strain in some regions on the capacity of interstate natural gas delivery and storage systems to meet combined demand from heating and electricity generation uses during peak winter conditions; and different business practices, and operational protocols and standards in two industries (the natural gas industry and the electric industry) that might need to be better aligned as the two industries become more interdependent. (4) The ongoing displacement of traditional generation resources by grid-connected and customer-sited variable renewable resources, in some cases dramatically changing the shape of net load that must be followed by system operators. (5) Questions about the ability of some wholesale electricity markets to provide sufficient financial incentives for suppliers to continue to operate and/or to enter the market.

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retire and, if so, which ones and when? Which new ones will be added, over what time period? Will gas pipelines and other fuel-delivery infrastructure be in place in time to fuel a power system that depends more upon natural gas? Will the electric transmission system be capable of moving power generated in new locations relative to customer demand?

Insights and answers to these various questions fall into two basic categories, differentiated by time scales. One focuses on long-term planning considerations, and is called "resource adequacy": Will there be enough (adequate) resources in place when system operators need to manage the system to meet demand in the future? The other focuses on short-term operations, and is called "system security": Will the operators be able to run the system in real time in a secure way to keep the system in balance, with all that that entails technically?[30]

Resource Adequacy

First, the interconnected electric grid must have resource adequacy – that is, there must be sufficient electric supply to meet electric demand at the time of annual peak consumption, taking into account the expectation that some parts of the system will not be able to operate for one reason or another. The system must have some additional quantity of capacity above the annual peak load value (the reserve margin) to cover the possibility that in highest-demand hours some resources may be out of service due to planned or unplanned outages.[31] In some regions and sub-regions (or "zones"), constraints on the ability of the transmission system to move power from one location to another mean that some portion of the demand within the zone must be met by generating resources within that same zone.

Ensuring resource adequacy is generally accomplished through two steps. First, the expected system peak demand and energy requirements over a long-term period (e.g., ten years) are established through a comprehensive forecasting effort. Forecasting processes for this purpose use well-established economic and industry modeling tools and data, are conducted frequently, and typically involve input by utilities, grid operators, public officials, consumer advocates, and

[30] The U.S. Energy Information Administration (EIA) defines electric system reliability as the "degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service." U.S. EIA, "Glossary," available at http://www.eia.gov/tools/glossary/index.cfm?id=E.

[31] Reserve margins are generally in the range of 10 to 20 percent of system peak load. The actual reserve margin varies from region to region as a function of many factors (e.g., the mix and expected performance of assets on the system, operational and emergency procedures, the availability of demand response/load curtailment, and contributions that may come from neighboring regions).

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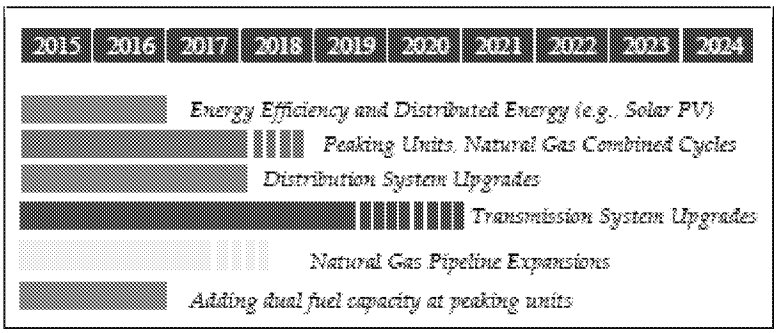
many other market participants and stakeholders. This step occurs in both wholesale energy markets and through integrated resource planning conducted by electric utilities.

Second, to the extent that identified long-term needs exceed resources expected to be on the system (due, for example, to growth in demand over time, and/or the retirement of existing resources), the deficit is met through the addition of new infrastructure (power plants or transmission lines) and/or demand resources (such as energy efficiency or demand-response measures). The ways in which new resources are added varies around the country, depending on the structure of the electric industry and the regulatory approach in place in a given state, along with other aspects of the market (including FERC-regulated RTOs in many regions). In wholesale market regions like PJM and NYISO, identified needs are met through market structures designed to provide financial incentives for investment in new capacity. In other regions (like most of the West), vertically integrated utilities, cooperatives and municipal electric companies add needed capacity by proposing and building their own project and/or through soliciting offers from other competitive suppliers. In any event, the overall resource need is forecasted (and, if relevant, a local/zonal requirement is further identified), and some combination of regulated and/or market process brings forth proposals to satisfy the need.

These processes are designed to accommodate the lead times necessary to bring a new project or resource into operation. They typically involve sufficient advance notification of need to allow for: (1) initial development stages and associated studies around project feasibility, interconnection, etc.; (2) administration of the markets or competitive procurement processes (and regulatory approvals of them); (3) zoning, permitting, and siting approvals for specific facility projects; (4) construction of the power plant and associated infrastructure (e.g., transmission interconnection/upgrades and – if needed – fuel delivery such as natural gas pipeline connections). Lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades. Figure 2 provides a conceptual depiction of lead times for planning, developing and installing

Figure 2
Typical Lead Times for Different Electric Resources



Source: Analysis Group

different types of infrastructure to support electric resource options.

The processes outlined above rarely occur in a sequential fashion.[32] Ten-year assessments take into account time periods that extend well beyond the number of years it typically takes to develop, permit, finance, and construct a new power plant.[33] As one developer is starting to scope out where to site a new power plant in anticipation of hoping to get approvals and enter the market four years in the future, another already has its approvals and has commenced construction. Installation of demand-response measures take much shorter time periods altogether. Many steps occur concurrently across many different types of resources that are being planned and put in place to meet resource adequacy requirements.

In practice, there are exceptionally few instances where industry has failed to provide for resource adequacy, where – due to a lack of installed capacity – the grid operator had to implement emergency protocols (such as lowering voltage (sometimes known as rolling brownouts) or curtailing service to customers (sometimes known as rolling blackouts)).[34] Although there have been rare occasions where a relatively near-term resource adequacy problem has been identified, regulators, market participants, grid operators, customers and reliability organizations have taken the steps needed to assure that the lights stayed on. There are well-known examples from around the country where the industry (including its regulators) did what was necessary to keep power flowing to consumers.[35] In large part, this track record

[32] For example, often initial market development of a new generating resource – e.g., site identification and control, technology selection, fuel and transmission infrastructure studies, fatal flaw analyses, even some initial siting and permitting efforts – happen in advance of or concurrent with resource need specification or market/utility procurement. Similarly, engineering, construction, and fuel contracts may be established (on a contingent basis) prior to final resource selection or final regulatory approval. Successful resource development teams effectively manage the flow of steps needed to take a new power plant from concept to operation so as to balance the stages of investment risk against the process of procurement and approval.

[33] Typically, lead times for a new natural gas power plant involve 2 years for development and permitting and another 2 years for construction. A peaking unit typically takes less time: from 2 to 3 years. Demand-response and other distributed energy resources can be brought to market in 1 to 2 years. Some generating additions may further require transmission or distribution system upgrades. These can range in time from as little as 2 to 3 years for local distribution upgrades to 5 to 6 years or longer for more extensive transmission system upgrades, but such permitting and construction activities are carried out coincident with power plant permitting and construction. Lead and development times are in part, flexible, depending on the system need and critically, it is possible to move faster when needed. For example, following the California Energy Crisis in the early 2000's, the state added thousands of MWs of new generation using a set of emergency 21-day, 4-month, and 6-month citing procedures. These emergency responses helped establish a set of best practice siting procedures that can be used by other states in similar situations. Susan F. Tierney and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[34] A notable exception is the well-known California electricity crisis of 2000-2001, which resulted from a combination of actions (including market manipulation through actions in the electric and natural gas markets, as well as caps on retail electricity prices). To our knowledge, there has never been a resource adequacy event (e.g., a brownout or blackout) due to implementation of an environmental regulation.

[35] Examples include:

- ERCOT's slim reserve margins in recent summers, including for example, in 2012, when nearly 2,000 MW of mothballed capacity was returned to service. Commissioner Anderson Jr., Public Utilities Commission of Texas, "Resource Adequacy in

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reflects the existence of the many resource-adequacy processes outlined above, the presence of multiple early warning systems, the ability of policy makers to take action to address challenges when urgent action is needed,[36] and a strong mission orientation of the industry and its regulators.[37]

System Security

Even assuming that these resource adequacy processes end up ensuring there are enough megawatts of capacity in place when needed to meet aggregate load requirements, actual

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ERCOT," Update #4, January 30, 2013. Available: https://www.puc.texas.gov/agency/about/commissioners/anderson/pp/analysis_ercot_capacity_reserve_margin_013013.pdf.

- Reliability must run (RMR) contracts to keep plants operating, for example:
  - The retention of operations of the Potomac Generating Station until completion of the Pepco transmission lines; see, Paul J. Hibbard, Pavel G. Darling, and Susan F. Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011);
  - A delay in Exelon's proposed retirement of the Eddystone and Cromby generating stations in Pennsylvania after PJM determined that in the absence of transmission upgrades, retirements of those units would lead to violations of security standards, with a reliability must run agreement between PJM and Exelon and state air regulators so that the plant could remain on line pending those transmission upgrades, but with limits on the units' dispatch to only those times when the units were needed for operational reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President of Federal Regulatory Affairs and Policy, Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011.
- Construction of peaking units on a fast-track basis by the New York Power Authority: "We increased our generating capacity by about 450 megawatts during summer 2001 when we began operating small, clean natural gas-powered generating plants at six sites in New York City and one on Long Island. We had launched a crash program in late August 2000 to install these PowerNow! plants in response to warnings from officials in the public and private sectors that the New York City metropolitan area could face power shortages in the summer of 2001. Similar warnings were repeated throughout the 10 months it took to obtain, site, design and install the units—a process that normally would require more than two years." New York Power Authority, "Small Clean Power Plants," Available: http://www.nypa.gov/facilities/powernow.htm.
- Requests by ISO-NE for demand-response resources in Connecticut on a fast-track basis: "On December 1, 2003, ISO New England Inc. (ISO-NE) issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut (SWCT) for the period 2004 to 2008. The purpose for acquiring these resources was to improve the electric system reliability in SWCT through the summer of 2007, when the 345 kV transmission loop is planned for completion." J.E. Platts, ISO-NE, "Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability, 2004-2008," October 4, 2004, page iii.
- New York State's contingency planning efforts (including consideration of new transmission projects) to prepare for a possible shutdown of the Indian Point nuclear plant, shutdown as early as 2018, depending on the outcome of its re-licensing with NRC. See the New York Department of Public Service Commission Case No. 12-E-0503, "Proceeding on Motion to Review Generation Retirement Contingency Plans." Available: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0503&submit=Search+by+Case+Number

[36] Susan F. Tierney, and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

[37] For example, FERC/EPA processes under the MATS regulation introduced a Reliability Safety Valve and related procedures to ensure that identified reliability challenges could be addressed, while allowing some flexibility with the eventual MATS timeline. As discussed below, the ISO/RTO council has proposed a similar reliability safety valve for the Clean Power Plan and the EPA has also acknowledged potential reliability concerns in its most recent Notice of Data Availability memorandum.

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'delivered' reliability also depends on making sure that the system operates in real time with high technical integrity.

System reliability is affected in real time by several things:

- The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
- The variations in system conditions (e.g., building lights turned on, or a power plant tripping off line unexpectedly, or sudden storm-related outages, or shifts in windiness) that change on a second-to-second, minute-to-minute, hour-to-hour, and day-to-day basis; and
- The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.

System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or "contingencies" – such as sudden and unexpected loss of generation, transmission, or load.[38] System planners and operator must ensure that the mix of resources on the system is capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system – such as a cascading outage covering one or more regions – that can come from unacceptable variations in system voltage and frequency. Blackouts can damage electrical equipment on the grid and on customers' premises, and create wide-ranging safety and health impacts.

To assure system security, the system as a whole must have certain attributes allowing it to provide "essential reliability services," as summarized in Table 9. These include two functional categories:

- *Voltage support*, meaning the ability of system resources to maintain real power across the transmission grid, through the use of reactive power sources such as generators connected to the system, capacitors, reactors, etc. Voltage on the system must be

[38] NERC describes certain features of the bulk power system needed to meet system security requirements – e.g., voltage control, frequency control – as Essential Reliability Services, or ERS. NERC Essential Reliability Services Report.

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maintained within an acceptable voltage bandwidth in normal operations and following a contingency on the system.[39]

- *Frequency Management*, meaning the ability of the system to maintain a system frequency within a technical tolerance at all times.[40] Frequency is a function of the match between generation output and load on the system, and requires constant balancing, or following of load by resources that can increase and decrease output instantaneously.

Importantly, system security, or operational reliability, is not a "yes" or "no" condition. To maintain it, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis.[41] The difficulty of this task largely results from several things. First, the

[39] Voltage support is local in nature, can change rapidly, and depends in part on the type and location of generators connected to the transmission system. Typically, voltage control is maintained by system planners and operators. Acceptable power factors for voltage support are maintained, in part, through the use of reactive power devices (or power factor control) that inject or absorb reactive power from the bulk power system. Reactive power can be provided by synchronous thermal generators and through capacitors and other devices, as well as by 'adequately designed' variable energy resources (including wind and solar) and storage technology. Voltage disturbance performance is the ability to maintain voltage support and voltage control after a disturbance event. NERC Essential Reliability Services Report, pages 1, 10-11.

[40] Frequency must typically be maintained within tens of mHz of a 60 Hz target. Higher frequencies indicate greater supply, while lower frequencies typically indicate greater demand. Frequency management includes: (1) Operating reserves, which are used to balance minute to minute differences in load and demand, load following capabilities to respond to intra- and inter-hour changes in load fluctuations, and reserves, which are used to restore system synchronization following generator or transmission outages; (2) Active Power Control, including ramping capability to quickly bring generators online in response to operator needs, often in ten minutes or less; (3) Inertia, or stored rotating energy that is used to arrest declines in frequency following unexpected losses. Historically, inertia has been supplied by large coal-fired generators, although NERC notes that new 'synthetic' inertia is available through the operation of variable energy resources supported by energy storage devices; and (4) Frequency Distribution Performance, which similar to voltage distribution performance, is the ability to maintain operations during and after an unplanned disturbance. NERC Essential Reliability Services Report, pages 3-5, 8-9.

[41] System operators manage voltage and frequency as load changes over time, and in response to contingency events, through the posturing and management of the resources on the system across several time scales:

- On a second-by-second basis through automatic generation control (AGC) systems on resources that will automatically adjust generation up or down in response to system frequency signals.
- On the time scale of minutes through tens of minutes through accessing "spinning reserves," including operating resources with the ability to ramp output up or down quickly, and resources that can connect to the system within several minutes.
- On the timescale of tens of minutes through accessing longer-term reserve resources that can turn on and connect to the system in less than an hour (typically on the order of 15 to 30 minutes).
- On the time scale of hours or days by committing sufficient operating and reserve resources to manage *expected* swings in net system load (that is, system load net of variable resource output). Note that load varies in relatively 'normal' ways over the course of the days, weeks, and months, and is predictable with a relatively high degree of accuracy by system operators. This allows for the commitment and availability of enough system resources to meet reliability objectives. However, the proliferation of distribution-level, behind-the-meter (BTM) generation with variable output (e.g., distributed wind and solar PV) complicates the forecasting of "net load" visible to system operators – that is, the normal variation in load net of variable BTM output that comes and goes with the sun and wind.
- On an as-needed basis for voltage control by adjusting reactive power injected into or absorbed from the system by on-line generators, capacitors, reactors, and system var compensators.

Source: NERC Essential Reliability Services Report, generally.

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operator has, in effect, a particular set of assets on the system at any time, which reflects the operational attributes of the various resources on the system at that time. These include things like: power plants with different operating profiles (e.g., start-up time, limits on output under different temperature conditions, availability to fuel supply); transmission systems that allow or limit power flows in various directions; 'smart' controls and communications devices that allow (or not) visibility into and/or management of power flows; demand response; storage systems; and so forth.

Table 9

System Security Needs and "Essential Reliability Services"

Services	Components		Description	Consequences of Failure
Voltage Support	*Voltage Control*		Support system load; maintain transmission system in a secure and stable range	· Loss of Load · Equipment Failure · Cascading Losses
	Voltage Disturbance Performance		Ability to maintain voltage support after a disturbance	
Frequency Management	*Operating Reserves*	Regulation	Minute-to-minute differences between load and resources	· Loss of Generation · Load Shedding · Interconnection Islanding · Overload Transmission Facilities · Damage Equipment and lead to Power System Collapse
		Load Following	Intra- and inter-hour load fluctuations	
		Reserves	Includes Spinning, Non-Spinning, and Supplemental; Used for synchronization and respond to generator or transmission outages in 10 min or greater time frames	
	Inertia		Stored rotating energy; Used to arrest decline in frequency following unexpected losses	
	Frequency Distribution Performance		Ability of a plant to stay operational during disturbances and restore frequency to BPS	
	Active Power Control	Frequency Control	Real-time balance between supply and demand	
		Ramping (Curtailment) Capability	Ability to increase/decrease active power, in response to operator needs. Measured in MW/min basis	

Notes and Sources:

[1] Adapted from NERC (2014) "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability".

[2] NERC (2014) notes that these Essential Reliability Services are functionally equivalent to the Interconnected Operations Service (IOS) definitions, with Voltage Support covering Reactive Power Supply from Generation Sources and Frequency Support covering Frequency Response, Regulation, Load Following, and Contingency Reserves.

[3] NERC notes that many of these ESRs are already defined as ancillary services in the OATT of many system operators. Ancillary services are "those services necessary to support the transmission of electric power form seller to purchaser", considering reliability needs. Therefore, NERC considers ancillary services to be a subset of ESRs.

Second, the operator must maintain frequency and voltage on the system at all times. This means, for example, starting up plants as backup resources ("reserves") to quickly replace another plant that trips off line or dips in its output (e.g., due to changes in wind conditions or power plant failure), or adjusting power output up and down with little notice to meet swings in load.

Third, the operator maintains and draws on a diverse set of operational procedures to manage system performance – such as committing or "posturing" resources that may be needed, allowing minor variations in system voltage, calling on resources from neighboring regions,

disconnecting variable generation, signaling to 'demand-response' providers to curtail their loads within short periods of time, and other procedures (including, as a last resort, isolated involuntary disconnection of load – or "rolling blackouts").

Reliability is by nature a technology-neutral concept. That said, not all of a system's resources are equal when it comes to the attributes they provide to system operators to manage system security. Historically, power systems' needs for voltage support, inertia, frequency control, and contingency-response capability have been met through operator actions in conjunction with their commitment of the types of technologies on the system: traditional thermal steam units (e.g., coal, nuclear, oil plants, natural gas and combined heat and power units) providing baseload service around the clock; cycling and load-following technologies (e.g., combined cycle plants operating on natural gas); quick-start fossil-fired peaking plants; and dispatchable hydro power supplies.

As the technologies on the system change – which is happening to different extents in different regions as a result of various forces, with or without the Clean Power Plan (as described above in Section I) – steps are being taken to ensure that the suite of essential reliability services is available to supply the frequency/voltage control and contingency-reserve needs of the system. NERC has characterized the challenge as one of filling gaps in services as they arise or widen over time.

Notably, system planners across the country are dealing constantly – and so far successfully – with the new and emerging reliability challenges from changing technology mixes. For example, the CAISO and California electric utilities have identified the need to add greater ramping capability to handle an increased variability in intra-day loads introduced from increasing amounts of 'variable energy resources' (VERs) necessary to meet increasingly higher renewable portfolio standards.[42] In general, load following is typically accomplished through the dispatch of fast-ramping combustion turbines and natural gas combined cycle (NGCC), although load following can also be met through well-designed and cost-effective storage, optimized energy efficiency programs, demand response, and devices (such as smart inverters) being added to wind farms.

[42] California is on track to meet its renewables portfolio standard target, such that by 2020, 33 percent of its total energy comes from renewable resources. The state is considering whether to adopt a 50-percent goal by 2030. Behind-the-meter solar and wind supplies are projected to significantly decrease net load during the middle of the day, while leaving significant shoulder peaks in the morning and evening, resulting in what is commonly called the "duck curve." A recent analysis found that this will require a significant increase in fast ramping, flexible dispatchable generation resources (along with other technologies, including storage). See Energy+Environmental Economics (E3), "Investigating a Higher Renewables Portfolio Standard in California," January 2014.

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III. What Concerns are Commenters Raising About Reliability Issues Associated with EPA's Clean Power Plan?

Summary of comments

To date, the EPA has received more than 3 million comments on the proposed Clean Power Plan. Many comments have raised concerns about electric system reliability. These comments have come from a wide range of stakeholders, including: owners of affected power plants (including vertically integrated utilities, merchant generators, municipal electric utilities, cooperatives); state officials, including public utility commissions, air pollution regulators, energy offices, as well as governors, attorneys general, and consumer advocate offices, and associations representing these various groups of public officials; system operators, regional reliability organizations; trade associations with business, public health, environmental, fossil-fuel supply and delivery organizations; members of the public; and others.[43]

The many comments received on reliability issues reflect the importance of thinking clearly about the potential impacts of the Clean Power Plan on system reliability. We summarize the types of reliability-related comments in Table 10, below, and provide more information about these public comments in the Appendix. Notably, EPA has made it clear that system reliability needs to be maintained as the Clean Power Plan is finalized and implemented.[44]

[43] Among the latter include various electric industry organizations (e.g., the Edison Electric Institute; the APPA; the National Rule Electric Cooperative Association; the Electric Power Supply Organization; the Clean Energy Group); business associations (e.g., the Chamber of Commerce); gas industry organizations (e.g., the Interstate Natural Gas Association (INGAA)); coal-industry groups (e.g., the Coal Utilization Research Council); non-energy trade groups (e.g., Water Associations such as the American Water Works Association, National Association of Water Companies and the National Association of Clean Water Agencies), and environmental organizations (e.g. Natural Resources Defense Council and Environmental Defense Fund); NERC; various individual RTOs (MISO, PJM, NYISO); FERC Commissioner Philip Moeller; Senator Dan Coats and 22 other senators. This is not intended to be a comprehensive or exhaustive list of comments or commenters, but rather represent the broad cross-section of types of organizations with an interest in Clean Power Plan reliability issues. Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[44] For example, see both the Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Federal Register, Vol. 79, No. 117, June 18, 2014. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf, and the Technical Support Document: Resource Adequacy and Reliability Analysis. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-resource-adequacy-and-reliability-analysis

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Table 10
Summary of Reliability Concerns Raised in Public Comments and Which Need to be Addressed as the EPA's Proposed Clean Power Plan is Implemented

Summary of Comments Submitted on Reliability Issues Related to the EPA Clean Power Plan		
Category	**Description**	**Potential Reliability Considerations – Which Need to be Addressed**
Resource Adequacy	Retirements of baseload power plants are presenting on-going challenges in some regions	May tighten planning reserve margins in some regions and require timely replacement of capacity on a 1-to-1 basis
		Requires additional transmission planning and analyses, with transmission solutions typically having longer lead times (~10 years) than generation additions
Resource Mix and Operational Security	Retirement of coal-fired capacity and restrictions on output at coal plants, combined with greater use of gas-fired capacity, will result in less fuel diversity in various regions	Some coal units will/may be cycled more frequently, ending up with lower overall capacity factors and adversely impacting relevant heat rates (and emissions per MWh)
		Operating gas plants at higher output will depend upon having adequate gas delivery capability, including firm supply and delivery contracts
		Increased reliance on variable and non-dispatchable resources (like wind and solar) will mean the need for greater quantities of operating reserves and ramping capability
		Loss of baseload generation requires additional voltage and frequency Support, including Inertia
Planning and Regulatory Coordination	The interim goals established in the Clean Power Plan do not provide adequate time for planning and development of adequate resources, for state and regional coordination, or for market solutions	Lead times for new transmission and power plants (including planning, siting, permitting, and construction time lines) extend beyond 2020 and the interim deadlines)
		Successful resolution of various gas-electric coordination issues will be needed to support greater reliance on natural gas in many regions
		RTO/ISO rules and practices regarding security-constrained economic dispatch may need to be reviewed and/or updated, depending upon how states design their plans to incorporate emissions controls
		Greater reliance on demand response and energy efficiency may require new rules and forecasting capabilities in wholesale energy and capacity markets
		Allocation (or reassignment) of transmission rights may be needed to accommodate changing power flows following power plant retirements or to accommodate greater reliance on underutilized gas-fired capacity and/or renewable resources.
Market Impacts and Market Responses	Uncertainty surrounding final regulations and state plans make it hard for markets to respond with concrete proposals in timely fashion	Uncertainty surrounding the regulatory treatment of new gas-fired combined cycles (under 111(b)) may chill development.
		Increased reliance on gas-fired power plants may depend upon new investment in pipeline capacity, with need for new mechanisms to support long-term commitments in some regions (e.g., organized markets)
		Increased reliance on natural gas may accelerate retirements of nuclear units prior to the end of their operating licenses.
		Reliability must-run contracts may be needed to retain some units needed for reliability, but with potential adverse impacts on wholesale market efficiency
		Uncertainty surrounding how states will plan for ensuring new capacity additions in regional organized markets, in light of buyer-side mitigation and other federal wholesale market rules

Many observers' concerns that the Clean Power Plan could jeopardize *resource adequacy* are tied primarily to questions around timing: Does the sequence of steps implied by EPA's proposal – starting with the June 2014 proposal, then taking into account the timing of EPA's final rule, the development of State Plans, the approval of plans by the EPA, and then through compliance

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decisions and actions by owners of affected power plants – allow sufficient time for everything that needs to be done by states, reliability planners, grid operators, planning and procurement processes, market responses, and so forth to ensure resource adequacy? Or, where that is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing resource adequacy?

Concerns voiced about whether Clean Power Plan implementation could jeopardize *system security* are tied primarily to anxiety over how and when state compliance activity will alter the diversity of resources on the system, and thus the mix of resource capabilities needed to meet system security requirements. In particular, will the economic signals and compliance obligations provided through state implementation of the Clean Power Plan cause the retirement of resources that are needed for system security, and/or will replacement capacity provide the needed operational capabilities? If a significant portion of existing coal-fired capacity retires and is replaced (in part) by gas-fired capacity, will regional interstate pipeline systems be robust enough to ensure reliable delivery of fuel in all hours of the year? If state compliance activities significantly increase the proliferation of grid- and distribution-level variable resources, how much more difficult will it be for system operators to manage the variability in net load on a real-time basis? Or, where this is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing system security concerns?

Other commenters portray the readiness of the industry to step up with solutions to these reliability issues. For example, INGAA described the capability of the natural gas pipeline industry to add new infrastructure.[45] Calpine stated its readiness (along with other market participants) to add new gas-fired generation (and to offer under-utilized capacity already existing on the system).[46] The Clean Energy Group provided suggestions about how the design of policies supporting flexibility and market-based approaches can substantially mitigate reliability concerns.[47] State energy offices (through their national association (NASEO)) noted the ability of a wide variety of well-tested energy efficiency measures (beyond utility-provided programs) to avoid CO_2 emissions from power plant operations.[48] The National Association of Regulatory Commissioners (NARUC) pointed to the ability to reap cost-effective savings in the

[45] Comments of INGAA, filed December 1, 2014.

[46] Comments of Calpine Corporation, filed November 26, 2014.

[47] Comments of the Clean Energy Group (CEG), filed December 1, 2014.

[48] Comments of the National Association of State Energy Officials (NASEO), filed December 1, 2014.

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electricity used for water treatment and delivery by introducing measures on the water utility system – thus affording water savings and avoiding CO_2 emissions on the power system.[49]

We also point out many ways to address the reliability issues raised in comments in Section IV of our report, with our suggestions organized around the different entities with some direct or indirect role to play in system reliability.

Reliability safety value concept

The ISO/RTO Council (IRC) has proposed that EPA include a "Reliability Safety Valve" provision as part of the final rule, to help with resolve multi-state issues that may arise due to the Proposed Rule and impact grid reliability.[50] In the view of the IRC, a Reliability Safety Value would provide a regulated and reviewed backstop solution with a defined process for modifying State Plans to ensure reliability against unforeseen issues. As part of this process, the IRC has recommended that the EPA include a specific requirement in the final rule that State Plans must include a detailed reliability assessment. By requiring reliability assessments ahead of final plans, according to the IRC, the Reliability Safety Valve would only be used in situations that could not be addressed ahead of time and that arise solely from dynamic, unplanned changes in the grid. As proposed by the IRC, a Reliability Safety Value would allow relief from compliance schedules if specific units are deemed necessary for reliability considerations.[51] The Reliability Safety Value has been supported by numerous organizations and RTOs, who point out that the concept has been successfully implemented as part of the MATS compliance policy.

We note – as an important element in considering the particular Reliability Safety Valve proposed by the IRC – that there are key differences between the regulatory frameworks of Clean Power Plan and the MATS rule. In particular, the latter assigns emissions-reductions targets on each affected fossil-fuel generating unit, and does not allow any emission averaging across generating stations or across time. As we noted previously in this report, there is much more flexibility in the design of the Clean Power Plan.[52] In particular, the opportunity for states

[49] Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed November 19, 2014.

[50] For example, see comments filed by the ISO/RTO Council (IRC), December 1, 2014.

[51] This process is analogous to RMR contracts that are often available in organized ISO/RTO markets. These contracts provide for time-limited, out-of-market payments to generators that have provided notification of retirement but are necessary for reliability reasons (e.g., local voltage support). Once alternative resources (transmission or generation) solving the reliability need are in place, the RMR contracts cease and the units may retire. By way of example, the IRC suggests that the Reliability Safety Value and a mandatory reliability assessment could help identify reliability issues arising from an individual State Plan, such as a state requirement for reduced utilization at a fossil unit needed for transmission security and voltage support on a transmission network that crosses a state line. ISO/RTC Comments, filed December 1, 2014.

[52] EPA is relying on a portion of the Clean Air Act– Section 111(d) – in its Clean Power Plan. "Section 111(d)'s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to

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to rely upon market-based mechanisms that allow emission trading across power plants within states and across wide regions is a compelling basis for thinking differently about the need for a reliability safety value in this instance. The wider the region in which emission trading might occur, the less likely that reliability issues will be introduced by the Clean Power Plan.

NERC's initial reliability assessment of the Clean Power Plan

NERC published its own "Initial Reliability Review" of the Proposed Rule in November 2014.[53] NERC flagged a number of "significant reliability challenge[s], given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed [Clean Power Plan]."[54] NERC notes that the primary purpose of the paper was to "provide the foundation for the range of reliability analyses" that will be required for stakeholders to work together. Notably, NERC recommended that coordinated regional and multi-regional planning and analysis should start immediately to identify specific areas of concern and that the EPA should consider a more timely approach to resolving any known reliability concerns.

NERC noted that the accelerated retirement of fossil units will stress already declining reserve margins, and that time will be a major constraint, particularly for facility planning, permitting, and construction. NERC identifies transmission upgrades as potentially being needed to successfully integrate variable energy resources anticipated as part of various states' plans, as well as to support reliability concerns regarding voltage and frequency support associated with extensive re-dispatch of NGCC. NERC also suggested that pipeline capacity constraints will

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other recent federal regulatory initiatives applicable to the electric industry.... In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources. By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance... And in its [State Plan], each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach. This language "supports the use of market-based mechanisms" and other alternatives in ways that are not possible under the statutory language governing MATs, which required each affected generating station to have emissions at or below the allowed emissions rates. If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another." Source: Susan F. Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 2014, pages 3-4.

[53] NERC has stated that its November report, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review," November 2014 (Hereinafter referred to as "NERC CPP IRR") is the first in a series of reliability assessments that NERC plans to conduct. NERC says it plans to release two additional studies in 2015 that will include a detailed evaluation of generation and transmission adequacy and a preliminary assessment of state SIPs.

[54] NERC CPP IRR, page 2.

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exacerbate the strain on essential reliability services from relying more heavily on gas. While a full review of the NERC study is beyond the scope of this paper, we note again that these issues have been emerging in markets for a number of years, well before the introduction of the Clean Power Plan. Indeed, NERC covered these "emerging trends" in California, Hawaii, ERCOT, and other regions in its October primer on "Essential Reliability Services."

Many comments in turn, have cited and expanded on the NERC Review. While reliability has been a common theme of these comments, for the most part the NERC report and the public's comments on the Clean Power Plan do not point to specific, modeled reliability problems that have been identified at known points on the bulk power system. Rather, both the report and the comments focus on generalized concerns about potential reliability issues that may arise due to the operational challenge of meeting both the interim and final-goal targets, generally assuming little in the way of the compliance flexibility built into the proposed rule and available to states. While these are valid concerns, it is critical to recognize the numerous strategies, policies, markets and organizations in place that have successfully dealt with these similar operational challenges in the past, and will going forward, as we discuss further below.

Moreover, the Clean Power Plan proposed rule, like all proposed EPA rules, is a "first draft" that is designed to elicit data and comments. EPA has already signaled that it is evaluating stakeholder concerns about the timing and glide path for meeting interim and final targets, and will evaluate this information as it writes the final rule.

Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided and addressed in time through planning and infrastructure – we do note recent critiques (e.g., Brattle Group's February 2015 report) of the assumptions used in NERC's recent reliability assessments, which do not take into consideration industry responses to market and reliability signals. This is a significant reason to view the NERC as only having set the table with respect to potential reliability concerns, and to recognize that NERC and many other parties will step up with their important contributions to implementation of the CPP within the electric system reliability context.

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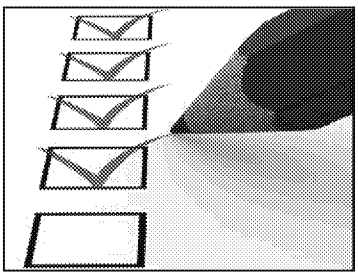
IV. Options for Assuring Electric System Reliability in Conjunction with Implementing the Clean Power Plan

The reliability check list

The many comments on the proposed Clean Power Plan submitted to EPA serve as a reminder of the broadly-understood condition that pursuing CO_2 emission reductions in the power sector has to occur in an environment that respects the reliability rules of the game. Like the check list at the start of any endeavor, the comments point out a number of potential items to consider adding to the "to do" list that the electric industry routinely uses to ready itself for reliable system operations.



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Fortunately, that check list is already robust. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations, placing the country in a good starting position as of the start of 2015. Many of the reliability issues identified in public comments are not new – the industry has responded successfully and effectively to similar challenges in the past. And for several years, some of the trends that commenters note must now be addressed in response to the Clean Power Plan are actually developments that have been underway for many years – and that are currently being addressed. Examples include the FERC's policies addressing: transmission planning taking into account infrastructure needs arising from state-policy (such as renewable portfolio standards); integration of variable electric resources; market designs to assure efficient entry of capacity with attributes needed for reliable system operations; and directives to modify standards and policies so as to better harmonize operations of the electric and gas markets. Other examples include the many studies conducted by RTOs, electric utilities, national laboratories (like the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), research institutions (such as the Electric Power Research Institute, university research centers, and think tanks) , and the Department of Energy.

These many studies are already pointing out that some of the tools and checklists needed for reliability may need to be enhanced as a result of the many changes underway in the industry. In many respects, the shift towards natural gas-fired generation (driven in large part by fundamental economic forces), the proliferation of variable resources due to economic and policy factors, and the growth in distributed resources in some regions will drive changes in industry planning and operations over a schedule largely coincident with implementation of the Clean Power Plan.

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In the end, we think that even if sometimes exaggerated, the reliability "alerts" are actually a good thing: It is appropriate that people are paying attention to reliability issues, so that potential problems can be avoided – and they can be addressed in time through proper planning and appropriate responses. Even if some of the existing tools need to be sharpened or even new ones added, past experience, the capabilities of the industry, the attention of regulators, and the inherent flexibility of Clean Power Plan implementation strongly suggest that the task is manageable. As always, careful planning and advance work is necessary to make sure that there are not inefficient trade-offs between the two core objectives.

The Reliability Toolkit: Which ones to use here?

The U.S. electric system performs so reliably because it includes both clearly defined and clearly assigned roles and responsibilities to particular actors, and also relies upon markets and regulated planning processes to provide an array of workable solutions. This is a very sturdy toolkit to build upon. Our suggestions aim to make it even better by pointing out some extra steps that responsible parties might take to make the toolkit as strong as possible for supporting the changes underway in the industry, including Clean Power Plan implementation.

For this reason, we organize our discussion of tools by identifying those in the hands of "reliability organizations" (like grid operators, FERC, NERC, the states, and others) and those in others' hands (including power plant owners, the markets, and many additional players, including the EPA itself). While the latter may not be "reliability organizations" in the same ways that the institutions in the first group are, they still have significant opportunities (if not genuine responsibility) to take actions to help ensure reliable pathways to compliance with CO_2 emission reductions required from the power sector.

In Table 1 at the beginning of our report, we categorize parties into the following groupings:

- Entities with direct responsibility for critical reliability functions;
- Other public agencies with direct or indirect roles in the Clean Power Plan;
- Owners of existing power plants covered by Section 111(d) of the CAA;
- "Markets" and resource planning/procurement organizations; and
- Other entities with inevitable roles to play in ensuring a reliable system in conjunction with enabling effective and timely compliance with the Clean Power Plan.

Note that in some cases, some parties (e.g., a vertically integrated utility which is a balancing authority and also conducts resource/planning and procurements) may fall into one or more categories.

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Then we use those groupings not only to identify the normal, business-as-usual responsibilities of those parties, but also to make a number of suggestions for things that those different players might do in anticipation of heading off potential reliability problems before they arise, or in mitigating impacts if they do. Table 2 makes suggestions for what FERC, NERC, the Regional Reliability Organizations, with Table 3 providing suggestions for System Operators/Balancing Authorities might do, in terms of institutionalizing new studies, reporting requirements, and so forth. Table 4 then focuses on things that other federal agencies can do, with Table 5 suggesting actions by state government entities. Table 6 identifies potential actions that might be considered/adopted as part of organized markets to send appropriate and timely signals for investment, and in parallel, what electric utilities might do within their own resource planning/procurement processes to accomplish reliable outcomes in their geographic footprint. Finally, Table 7 provides a number of suggestions about things that other players might do in their own zones of influence.

In the end, the industry, its reliability regulators and the States have a wide variety of existing and modified tools at their disposal to help as they develop, formalize, and implement their respective State Plans. These two responsibilities – assuring electric system reliability while taking the actions required under law to reduce CO_2 emissions from existing power plants – are compatible, and need not be in tension with each other as long as parties act in timely ways.

This is not to suggest that electricity costs to consumers do not also matter in this context; of course they do. But we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution, precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

This array of tools is of course subject to important and beneficial social constraints and must be exercised to serve the interests of ratepayers. There is no reason to think that these dual objectives cannot be harmonized within a plan to reduce carbon pollution.

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V. Conclusion

In this report we identify the many rules, regulations, institutions, and organizations – in effect, the industry's *standard operating procedures* – for ensuring that EPA's design and administration of the Clean Power Plan in no way jeopardizes or compromises the high level of power system reliability we are used to. Such reliability is essential for the strength of our economy and the public health and safety of our citizens.

In the end, of course, it is a good thing that the industry is paying close attention to reliability issues, so that any potential problems can be avoided – and can be addressed in time through planning and appropriate responses. This is do-able, based on past experience and the capabilities of the industry. As always, careful planning and advance work is necessary to make sure that there are not trade-offs between the two.

Having reviewed the broad range of comments received by EPA with a focus on power system reliability, and the potential reliability challenges posed by Clean Power Plan administration, we find that many of these comments tend to assume inflexible implementation and present worst case scenarios, with an exaggerated cause-and-effect relationship. Moreover, many comments (including those from NERC itself) tend to assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. The history of the electric system and its ability to respond to previous challenges including industry deregulation and previous Clean Air Act regulations such as the NO_x SIP call, SO_2 rule, CSAPR, and MATS prove that this is highly unlikely. These challenges will be solved by the dynamic interplay of regulators and market forces with many solutions proceeding *in parallel*.

Indeed, this dynamic interplay is one reason why a recent survey of more than 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and felt that EPA should either hold to its current emissions reduction targets or make them more aggressive.[55] Similarly, other market participants announced a willingness and ability to help meet system demand for new natural gas supplies[56] and gas-fired generation, in

[55] The same survey found that those utility executives believed that distributed energy resources offered the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, 2015 State of the Electric Utility Survey Results, January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned, municipal, and electric cooperatives.

[56] See, for example, comments filed by INGAA, December 1, 2014. ("INGAA is confident that … the natural gas pipeline industry can respond to demand for the natural gas pipeline capacity that may be necessary to enable compliance with the Clean Power Plan."). INGAA noted that the existing natural gas pipeline system is already supporting national gas-fired combined-cycle utilization rates of 60 percent during peak periods, which are the same periods when distribution constraints are most likely.

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support of the Clean Power Plan.[57] This is in addition to the expanded and innovative solutions and strategies for incremental energy efficiency and distributed energy resources identified by State Regulators and Energy Officials.

There are a number of things states and others can (and, in our view, should) do as part of developing their State Plans to further ensure reliability. First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has relied on to maintain reliability for decades – in the face of both normal operations and sudden changes in markets and policy. These procedures flow from a comprehensive set of laws, rules, protocols, organizations, and industry structures that focus continuously on what is needed to maintain electric reliability.

Second, states should give due consideration to the vast array of tools available to them and the flexibility afforded by the Clean Power Plan in order to ensure compliance is obtained in the most reliable and efficient manner possible. In particular, given the interstate nature of the electric system, we encourage states to enter into agreements with other states or add provisions to state plans that facilitate emission trading between affected power plants in different states; doing so will increase flexibility of the system, mitigate electric system reliability concerns, and lower the overall cost of compliance for all.

[57] See, for example, the comments of Calpine Corporation, filed November 26, 2014. ("With our modern, flexible, and efficient generating fleet, Calpine is prepared to facilitate the successful implementation of the Proposed Clean Power Plan. We are confident that by working constructively with the states and EPA as we have always done, the Clean Power Plan can be a success.")

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APPENDIX:
Public Comments on EPA's Proposed Clean Power Plan: Summary of Concerns Relating to Electric System Reliability Issues

As of February 8, 2015, 3.83 million comments have been filed on the EPA's proposed Clean Power Plan.[58] Many organizations have compiled lists and summaries of comments filed by various parties.[59] Most of the comments focus on stringency of the proposed emissions reductions targets, the reasonableness of (and legal bases for) the "building block" methodology used by EPA is setting state targets, the timing of emissions reductions in two periods (interim: 2020-2029); and final (2030 and beyond); the ability of states to develop their State Plans with enough time; and other comments.[60],[61]

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[58] Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602.

[59] See, for example: Bipartisan Policy Center (http://bipartisanpolicy.org/wp-content/uploads/2015/02/Comments_Map_Static.pdf); National Association of State Energy Offices (http://111d.naseo.org/); Advanced Energy Economy (http://blog.aee.net/epa-ghg-regs-we-read-the-comments-so-you-dont-have-to-part-1-state-federal-regulator-association); Institute for 21st Century Energy (U.S. Chamber of Commerce); (http://www.energyxxi.org/eparule-stateanalysis; http://www.energyxxi.org/eparule-stateanalysis).

[60] See, for example, comments filed by APPA, December 1, 2014; Business Roundtable, December 1, 2014; Class of '85 Regulatory Response Group, December 1, 2014; CEG, December 1, 2014; CURC, December 1, 2014; Coalition for Innovative Climate Solutions, December 1, 2014; Edison Electric Institute (EEI), December 1, 2014; Electric Power Supply Institute, December 1, 2014; ERCOT, November 17, 2014; Environmental Defense Fund, December 1, 2014; Georgetown Climate Center (with state officials from California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington), December 1, 2014; INGAA, December 1, 2014; NARUC, November 19, 2014; NASEO, December 1, 2014; NRDC, December 1, 2014; National Rural Electric Cooperative Association, July 29, 2014; Nuclear Energy Institute (NEI), December 1, 2014; NYISO, November 17, 2014; PJM Interconnection, December 1, 2014; RTO/ISO Council, December 1, 2014; Sierra Club, December 1, 2014; Southern States Energy Council, September 29, 2014; and Western Electricity Coordinating Council (WECC), November 25, 2014.

[61] Even before the final December 1st, 2014 deadline for filing comments, the EPA and other regulators had acknowledged these many public statements and the comments that had been submitted in advance of the deadline. Specifically, in October of 2014, EPA issued a Notice of Data Availability (NODA) that sought comments on three core issues, which we summarize below:

- *Compliance trajectory of emissions reductions from 2020 to 2029*, and in particular, if or how reductions related to building block 2 could be phased in over time (for example, to accommodate constraints in natural gas distribution infrastructure, or how the book life of existing assets could be used to define an alternative glide path) or how states could earn compliance credits for actions taken between 2012 and 2020;
- *Technical assumptions in the building block methodologies for 2 and 3*, including how to consider new gas-fired combined cycle (NGCC) units in state goals, the role of natural gas co-firing at coal plants as a compliance strategy, and if states with little to no existing NGCC capacity should achieve a minimum target of new NGCC generation; and with respect to renewable energy, how or if the EPA could consider alternative goal setting strategies that account for state or regional economic potential of renewables as opposed to relying on existing RPS; and the role of nuclear units in building block 3; and
- *Methodologies for setting State-specific goals*, including the feasibility of using a multi-year baseline (2010-2012) for goal setting, to what extent renewable and energy efficiency goals should be assumed to displace existing fossil generation – as opposed to displacing or avoiding future fossil generation.

The formal NODA is available through Regulations.Gov in Docket No. EPA-HQ-OAR-2013-0602 and informally, through the EPA, here: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-notice-data-availability.

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Our own review of submissions from the public and various organizations has focused on issues related to system reliability. These commentaries include concerns raised about one or another aspect of the proposal's impact on the power system's performance. Many comments make suggestions for changes in EPA's proposal, and steps that other entities might take to address reliability issues in the context of compliance with the Clean Power Plan.

A common reliability-related comment is that the EPA did not consider – or seek out the expertise – for how the assumptions it used in setting states' emission reduction targets (i.e., the four "building blocks") may change the operations of the electric grid and how those changes in turn can affect the ability to meet state targets.[62] A similar theme is that the individual state targets do not account for the regional nature of electric grid reliability. Finally, a common concern is that the proposed timeframes for compliance, combined with the interim targets for emissions reductions commencing in 2020, do not provide adequate time for states to develop regional compliance plans or for RTOs to incorporate State Plan provisions into the regional long-term planning frameworks or existing market rules for economic dispatch.

That said, a wide range of regulators and other organizations have committed to working with the EPA and the states to manage these challenges, and in turn, leverage their detailed knowledge of the electric system. As discussed later in this report, many regional coordinators and state regulators already have planning policies and procedures in place that can proceed in parallel with the development of SIPs to ensure the timely development of generation, transmission, and distribution infrastructure needs.[63]

Although the comments do not point to specific known, localized reliability problems identified by a specific commenter, many observers caution that if a state elects not to (or cannot, for one reason or another) accomplish the depth of emission reductions assumed by EPA in state

[62] For example, the EEI noted that "a significant portion of [it's] comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system." Comments filed December 1, 2014, at 12. Similarly, on December 22, 2014, Senator Murkowski (ranking member, Committee on Energy & Natural Resources), Representative Upton (Chairman, Committee on Energy & Commerce), and Representative Whitfield (Chairman, Subcommittee on Energy & Power) requested comment from the FERC Commissioners on their level of involvement and interaction with EPA staff when developing the Clean Power Plan and understanding reliability implications. Letter to FERC from Senator Murkowski, Representative Upton, and Representative Whitfield, December 22, 2014.

[63] Note for example, recent activities among the PJM states: the recent comments submitted to the FERC (Docket No. AD15-4-000: Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, February 19, 2015) by Michael Kormos, Executive Vice President for Operations, PJM: "PJM has begun this coordination process by engaging state commissions, state environmental regulators responsible for implementing the Clean Power Plan, and EPA starting last year. Recently, PJM has undertaken detailed analyses of scenarios and alternatives that were provided to us by OPSI. Those results have been reviewed with our members and with the states and are posted on our website at http://www.pjm.com/~/media/committeesgroups/committees/mc/20150120-webinar/20150120-item-05-carbon-rule-analysis.ashx.

targets, then the state will inevitably need to make additional cuts from other blocks which will increase the stress on remaining assets and strategies.

Comments on reliability issues thus tend to focus on challenges in system operation that may lead to reliability failures. The commentaries do, however, provide suggestions for how to mitigate the challenges for system reliability failures by building into State Plans alternative strategies for meeting those same targets beyond those incorporated into EPA's target-setting assumptions. For example, comments by both NARUC and NASEO discuss the extensive potential for additional CO_2 savings from energy efficiency projects at the interface of the energy-water nexus and other energy-efficiency initiatives outside of conventional programs administered by electric utilities. Additional guidance or clarification from the EPA on how to account for these programs in State Plans could unleash and incentivize a broad swath of carbon reduction strategies beyond the narrow four building blocks.

Many comments focused on the implications of greater utilization of natural gas-fired power plants on changes in system dispatch and the interdependence of interim and final state goals.[64] Achieving a system-wide 70-percent capacity factor for existing natural-gas combined cycle (NGCC) units, for example, would transition a set of power plants now used largely as intermediate and load-following resources to become base-load capacity resources. Baseload coal-fired generators in place at the end of the 2010s would feel the effects, through either greater cycling of these units, or retention of the units to operate only occasionally if needed to remain on the system for resource adequacy purposes, or retirements. Observers note that cycling such coal-fired units more frequently will decrease their efficiency (i.e., increase their heat rates), as plants use additional energy to overcome the inertia inherent in these units. Commenters' cautions that such impacts will increase the overall fleet average emission profile. The observation is that such interactions will mean that states will need to find additional carbon reductions elsewhere. To the extent that the shift includes greater reliance on renewable energy penetration, then the system operators will need to adjust how they operate the resources on their system to maintain reliability. These variable energy resources do not offer system operators the same level of control (e.g., some may be behind the meter and therefore not even "visible" to operator) for frequency or voltage support nor can they be relied upon to meet load in all hours of the day. In the absence of significant new storage capability on the system, this will increase the need for load-following, fast-ramping resources to respond to

[64] The U.S. Chamber of Commerce Institute for 21st Century Energy reviewed and summarized State comments and found that 35 states raised issue with Building Block 2. This was more than any other category identified by the report. Institute for 21st Century Energy, U.S. Chamber of Commerce. "In Their Own Words: A Guide to States' Concerns Regarding the Environmental Protection Agency's Proposed Greenhouse Gas Regulations for Existing Power Plants", January 22, 2015, page 14.

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sudden drops in renewable generation. Traditionally, gas-fired combined cycles or natural gas combustion turbines have met this need. But gas-fired plants that begin to operate more in baseload mode may not be able to perform that load-following function. As described in Section II, Figure 2 above, lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades.

These changes are already underway in part due to the shale gas revolution, state and federal policies supporting renewable energy, other environmental policies. According to some observers, the Clean Power Plan will accelerate such trends. Either way, grid operators will need to address the potential diminishing reservoir of voltage support and inertia that has historically been supplied by coal-fired thermal units with their rotating mass of equipment.

Also, the successful operation of natural gas combustion turbines to balance and integrate intermittent and variable renewable supplies will depend, in turn, on the availability and access to fuel when needed for dispatch. Commenters have suggested, and rightly so, that a significant increase in gas-fired generation will require new gas delivery infrastructure. (We note the recent report published by the U.S. DOE that found, among other things, that the amount of incremental gas infrastructure needed is less than what has been put in place by the industry in the recent past.[65]

> Diverse sources of natural gas supply and demand will reduce the need for additional interstate natural gas pipeline infrastructure. The combination of a geographic shift in regional natural gas production—largely due to the expanded production of natural gas from shale formations—and growth in natural gas demand is projected to require expanded natural gas pipeline capacity. However, the rate of pipeline capacity expansion in the scenarios considered by this analysis is lower than the historical rate of natural gas pipeline capacity expansion. …
>
> (2) Higher utilization of existing interstate natural gas pipeline infrastructure will reduce the need for new pipelines. The U.S. pipeline system is not fully utilized because flow patterns have evolved with changes in supply and demand. …
>
> (3) Incremental interstate natural gas pipeline infrastructure needs in a future with an illustrative national carbon policy are projected to be modest relative to the Reference Case. While a future carbon policy may significantly increase natural gas demand from

[65] U.S. DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015, http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf. After modeling interactions between the gas and electric industries, the report's key findings (at iv-v).

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the electric power sector, the projected incremental increase in natural gas pipeline capacity additions is modest relative to the Reference Case.

(4) While there are constraints to siting new interstate natural gas pipeline infrastructure, the projected pipeline capacity additions in this study are lower than past additions that have accommodated such constraints."

It will take time – in some cases several years – to build this infrastructure, and unlike transmission planning that is coordinated by a central planning authority, expansion of the gas delivery and storage system is driven by market economics. But significant amount of pipeline expansion is already in advanced planning and permitting. Thus, while typically, gas pipeline companies require long-term commitments from 'anchor' gas shippers before receiving permitting approval and proceeding to break ground, there is no reason to believe that the system will be short of capacity as a result of the Clean Power Plan. Indeed, such commitments have and can be made in many regions (notably, in Colorado, as part of the state's approval of Xcel's decision to replace parts of its coal fleet with gas-fired plants, or in the Midwest, where DTE Energy has committed to support pipeline expansion to access gas supplies in the Marcellus). In some organized wholesale electric markets, however, there may need to be changes in some market rules and/or new institutional commitments to induce new investment in firm pipeline expansion to make gas available to non-utility generators.

Another issue raised in many comments relates to the current uncertainty that exists with regard to how states may/should/will count *new* gas-fired combined cycle power plants in their overall planning. Because such new plants fall under a different part of the Clean Air Act (i.e., Section 111(b)) than existing power plants (i.e., Section 111(d)), EPA has suggested that states will have the option to determine whether to fold in new plants into their overall framework for controlling emissions of then-existing power plants, or to keep those new plants regulated under a separate regime. What states will do remains a critical unknown, and could affect the operations of the overall power system, as well as emissions from the plants now covered under the Clean Power Plan.[66]

Beyond regional concerns and detailed technical criticisms, the most frequent reliability-related comments focus on the implications of the interim targets and the timelines for compliance.[67]

[66] For example, states with an emission rate goal less than 1,000 lbs/MWh may meet such a target through extensive renewable resources. The use and reliance on new NGCC units (with an emission rate equal to 1,000 lbs/MWh) to provide significant quantities of energy when renewables are off-line may actually increase net total emissions.

[67] The current rule includes two compliance options: a 2030 final goal with an interim compliance goal for average emissions between 2020 and 2029, and a second option, with lower total goals and no interim goals, to be achieved by 2025. Under option 1, States are required to file their SIP by June 30, 2016, with one year extensions available for single states and two years for multi-state plans. EPA has committed to reviewing and approving all SIPs within one year of receipt. Therefore, final SIPs will take effect

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Commenters point out that the compliance timeline presents at least two challenges. The first is the added pressure on resource adequacy in light of pending retirements, particularly of economically marginal coal units facing difficult retrofit decisions for compliance with ongoing air regulations such as the MATS.[68] The second is the asserted lack of time for states to develop regional plans for compliance, which could easily require multi-year time frames to coordinate necessary staff in legislative departments, PUCs, and state energy and air offices.

Others have raised the issue that the timelines will result in significant stranded costs for ratepayers.[69] While not a reliability issue per-se, these stranded costs carry a true economic cost in that those monies may have been better spent on other programs in support of the Clean Power Plan project. However, as we discussed we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be "lower cost" options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such 'solutions' as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

between June 30, 2017 and June 30, 2019. Interim compliance goals for each state are set for the 2020 to 2029 period, in what is commonly referred to as the "glide path" of emission reductions to the 2030 target. The interim compliance goals assume that states can achieve the full quantity of reductions equal to estimates from Building Block 1 and Building Block 2. The "glide" in the interim targets, then, is due to the steady increase in carbon reductions from avoided fossil fuel generation in the 2020-2029 period from increasing levels of renewable energy and energy efficiency deployment.

[68] For example, MISO estimated that between 10 -12 gigawatts of coal-fired capacity will retire by 2016 to meet the MATS rule. An additional 14 gigawatts of coal-fired generation (25 percent of the remaining supply) is further at risk of retirement by 2020. MISO conservatively estimates that it will take a minimum of six years for the necessary generation and transmission infrastructure to replace these retirements. Assuming that all state plans are finalized and approved by 2018, necessary infrastructure would not be in place until 2024 – leaving a four year gap of increased reliability risk. MISO, "Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units," November 2014.

[69] For example, Ameren estimated that the 2020-2029 interim timelines could cost Missouri ratepayers an additional $4 billion compared to its existing Integrated Resource Plan (IRP). Ameren noted that its existing IRP assumes the full retirement of coal units at the end of their useful lives by 2034. The early retirements would move forward the in-service date for proposed NGCC and require additional capacity than would otherwise be needed by 2034. See Comments of Ameren, filed December 1, 2014, at 3.

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Acronyms

Acronym	Definition
APPA	American Public Power Association
BPS	Bulk Power System
BTM	Behind the Meter
CAA	Clean Air Act
CAISO	California Independent System Operator
CPP	Clean Power Plan
CO_2	Carbon Dioxide
CSAPR	Cross State Air Pollution Rule
CURC	Coal Utilization Research Council
CWA	Clean Water Act
EEI	Edison Electric Institute
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERSs	Essential Reliability Services
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
MATS	Mercury and Air Toxics Standard
MISO	Midcontinent Independent System Operator
NAAQS	National Ambient Air Quality Standards
NASEO	National Association of State Energy Officials
NARUC	National Association of Utility Regulatory Commissioners
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NODA	Notice of Data Availability
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection
PUC	Public Utility Commission
RPS	Renewable Portfolio Standard
RSV	Reliability Safety Valve
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SIPs	State Implementation Plans
SPP	Southwest Power Pool
VER	Variable Energy Resources (e.g., wind and solar)
WECC	Western Electric Coordination Council

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Attachment 6

STATE OF SOUTH CAROLINA

South Carolina Electric & Gas Company's Integrated Resource Plan (IRP)

BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

COVER SHEET

DOCKET
NUMBER: 2014 - ____ - E

(Please type or print)

Submitted by: K. Chad Burgess
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NOTE: The cover sheet and information contained herein neither replaces nor supplements the filing and service of pleadings or other papers as required by law. This form is required for use by the Public Service Commission of South Carolina for the purpose of docketing and must be filled out completely.

DOCKETING INFORMATION (Check all that apply)

☐ Emergency Relief demanded in petition ☐ Request for item to be placed on Commission's Agenda expeditiously

☐ Other:

INDUSTRY (Check one)	NATURE OF ACTION (Check all that apply)		
☒ Electric	☐ Affidavit	☐ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certificatio
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigatior
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☒ Other:
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	Integrated Resource Plan
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☐ Report	

K. Chad Burgess
Associate General Counsel

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February 28, 2014

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: South Carolina Electric & Gas Company's 2014 Integrated Resource Plan
Docket No. 2014-____-E

Dear Ms. Boyd:

In accordance with S.C. Code Ann. § 58-37-40 (Supp. 2013) and Order No. 98-502 enclosed you will find the 2014 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G 2014 IRP"). This filing also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann § 58-33-340.

By copy of this letter, we are also serving the South Carolina Office of Regulatory Staff and the South Carolina Energy Office with a copy of the SCE&G 2014 IRP and attach a certificate of service to that effect.

If you have any questions or concerns, please do not hesitate to contact us.

Very truly yours,

K. Chad Burgess

KCB/kms
cc: John W. Flitter
Jeffery M. Nelson, Esquire
Ashlie Lancaster
(all via electronic and U.S. First Class Mail)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2014-___-E

IN RE:

South Carolina Electric & Gas Company's Integrated Resource Plan	)	**CERTIFICATE OF SERVICE**

This is the certify that I have caused to be served this day one (1) copy of the **2014 Integrated Resource Plan of South Carolina Electric & Gas Company** via electronic mail and U.S. First Class Mail to the persons named below at the address set forth:

Jeffrey Nelson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
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John Flitter
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Karen M. Scruggs

Cayce, South Carolina
This 28th day of February 2014

2014

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

Introduction

This document presents South Carolina Electric & Gas Company's ("SCE&G" or "Company") Integrated Resource Plan ("IRP") for meeting the energy needs of its customers over the next fifteen years, 2014 through 2028. This document is filed with the Public Service Commission of South Carolina ("Commission") in accordance with S.C. Code Ann. § 58-37-40 (Supp. 2013) and Order No. 98-502 and also serves to satisfy the annual reporting requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-430 (Supp. 2013). The objective of the Company's IRP is to develop a resource plan that will provide reliable and economically priced energy to its customers while complying with all environmental laws and regulations.

I. Demand and Energy Forecast for the Fifteen-Year Period Ending 2028

Total territorial energy sales on SCE&G's system are expected to grow at an average rate of 1.6% per year over the next 15 years, while firm territorial summer peak demand and winter peak demand will increase at 1.6% and 1.7% per year, respectively, over this forecast horizon. The table below contains these projected loads. By convention winter follows summer.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2014	4,786	4,496	22,648
2015	4,849	4,557	22,732
2016	4,968	4,632	22,944
2017	5,073	4,713	23,423
2018	5,166	4,814	23,765
2019	5,245	4,894	24,279
2020	5,319	4,967	24,683
2021	5,385	5,057	25,065
2022	5,458	5,152	25,533
2023	5,540	5,249	26,032
2024	5,623	5,349	26,514
2025	5,705	5,447	27,007
2026	5,789	5,541	27,481
2027	5,867	5,636	27,935
2028	5,943	5,731	28,397

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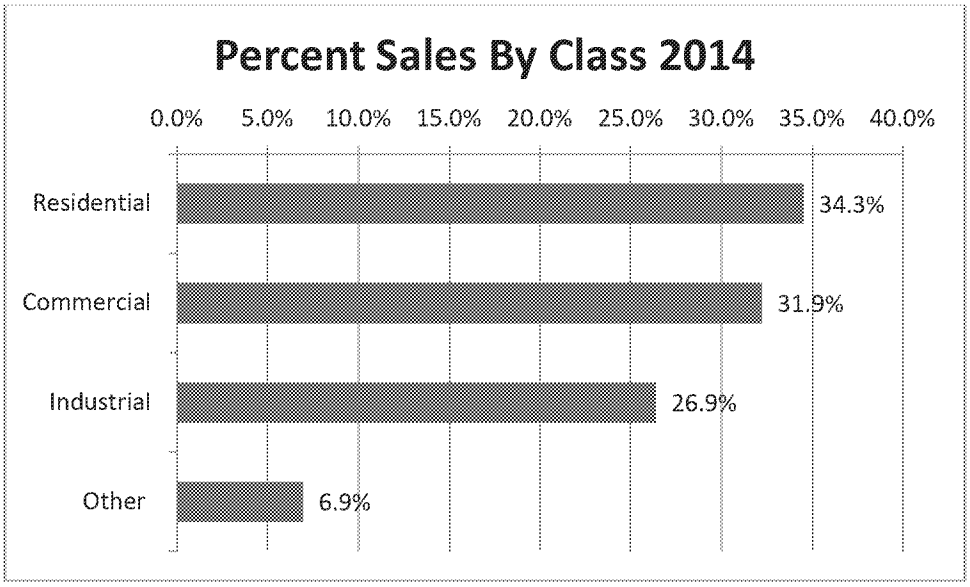
The energy sales forecast for SCE&G is made for over 30 individual categories. The categories are subgroups of our seven classes of customers. The three primary customer classes - residential, commercial, and industrial - comprise just over 93% of our sales. The following bar chart shows the relative contribution to territorial sales made by each class. The "other" class in the chart below includes street lighting, other public authorities, municipalities and electric cooperatives.



SCE&G's forecasting process is divided into two parts: development of the baseline forecast, followed by adjustments for energy efficiency impacts. A detailed description of the short-range baseline forecasting process and statistical models is contained in Appendix A of this report. Short-range is defined as the next two years. Appendix B contains similar information for the long-range methodology. Long range is defined as beyond two years. Sales projections for each group are based on statistical and econometric models derived from historical relationships.

1. System Peak Demand: Summer vs. Winter

SCE&G usually peaks in the summer as seen in the chart below. This is reasonable for several reasons. First, the climate in SCE&G's service area is generally hotter in the summer than colder in the winter relative to a given base temperature. Second, the penetration of air-conditioners among SCE&G's customers approaches 100% since there are no real substitutes for

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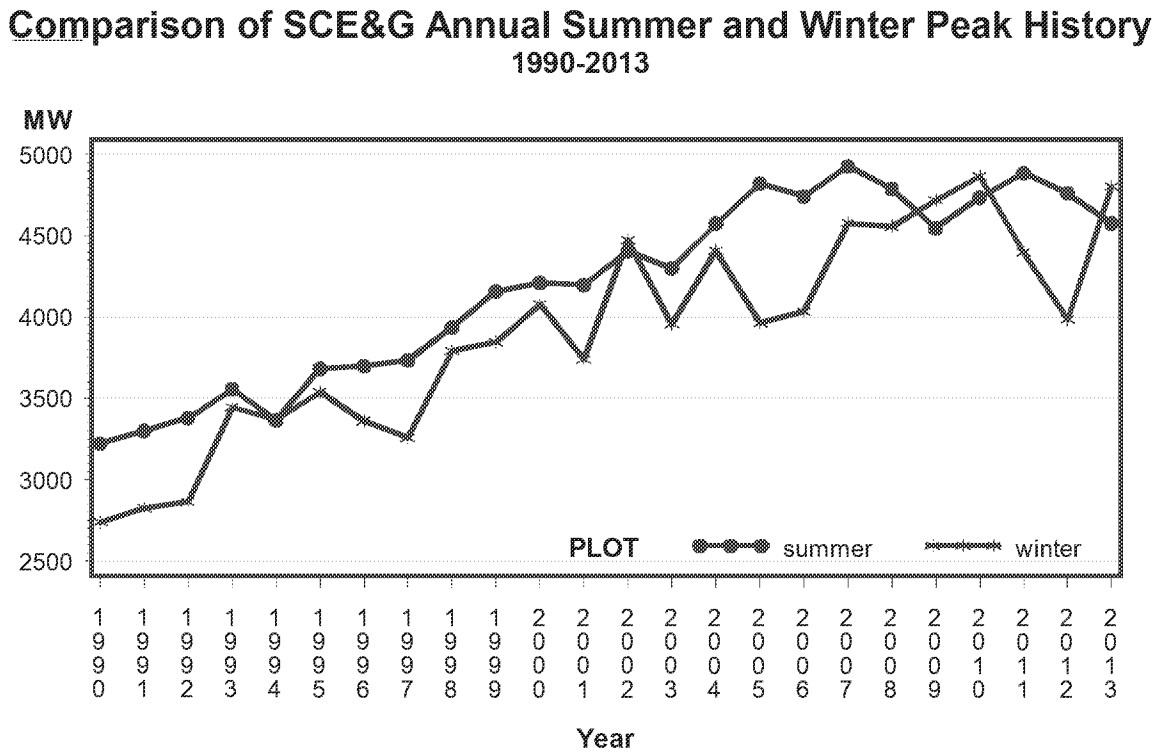
electric air-conditioners at present. Finally, a large number of residential and gas customers heat their homes and businesses with natural gas. Results of the peak demand forecast methodology used herein show that the general pattern of higher summer peaks relative to winter peaks will continue.

The following charts shows SCE&G's experience with summer versus winter peaking. By industry convention, the winter period is assumed to follow the summer period. In 19 of the past 24 years, SCE&G peaked in the summer. One other notable feature of the peak demand chart is the greater variability in winter peak demand.



The forecast of summer peak demand is developed by combining the load profile characteristics of each customer class collected in the Company's Load Research Program with forecasted energy. The winter peak demand is projected through its correlation with annual energy sales and winter degree-day departures from normal.

2. DSM Impact on Forecast

SCE&G expects its energy efficiency ("EE") programs to reduce retail sales in 2014 by 84,627 MWH or approximately 85 GWH. Retail sales after this EE impact are expected to be 22,035 GWH. Therefore, the EE programs are expected to reduce retail sales by 0.384% from

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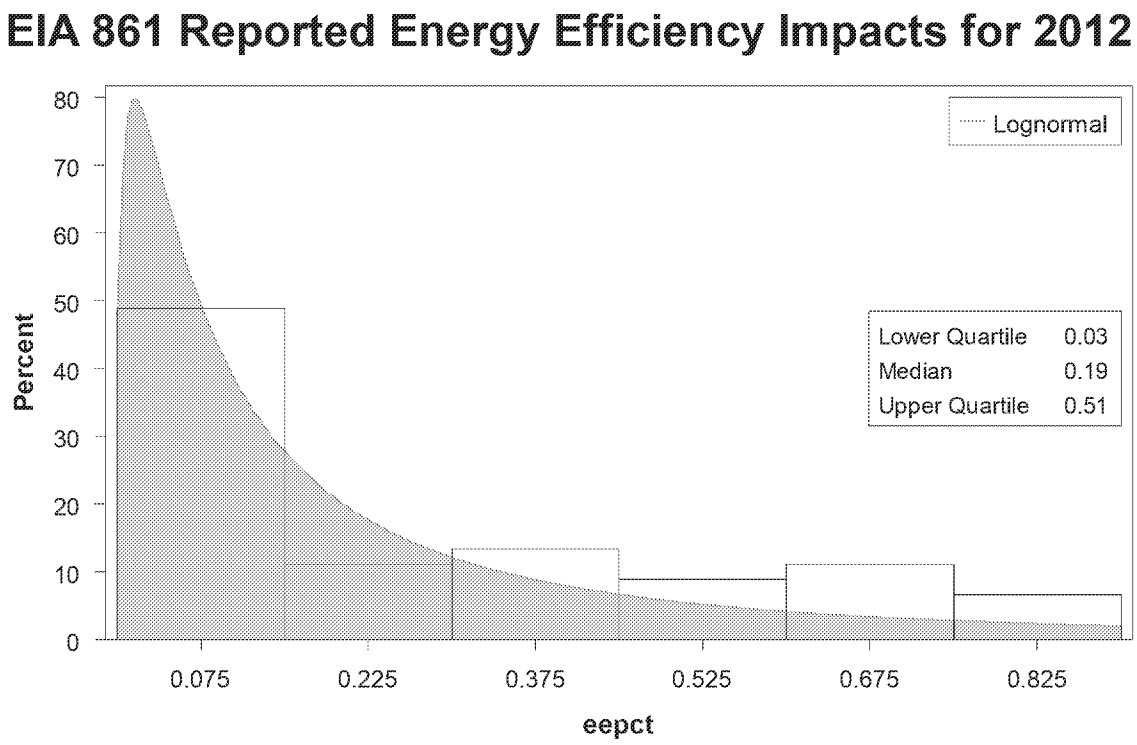
what they would have been. To gauge how its EE programs compared to other companies in the Southeast, SCE&G analyzed the EE impacts filed with the U.S. Energy Information Administration ("EIA") in 2012, the latest year available. There were 47 companies filing from the Southeast, in particular, from the NERC regions of SERC and FRCC. Two companies were dropped from the analysis for bad data. The chart below shows graphically the distribution of reported results. The median EE impact was 0.19%. Thus half the companies showed results higher and half lower than this median value. SCE&G's expectation for 2014 is twice this median value placing it in the top half of the distribution and almost into the top quartile. Clearly SCE&G's EE programs compare favorably with other companies in the Southeast.



As part of the forecast development, the 0.38% EE savings was divided into a residential and commercial component. In addition, savings due to lighting efficiencies were removed from the class numbers and combined with lighting efficiency effects due to federally mandated measures. This was necessary to produce a consistent forecast of lighting efficiency effects. After this adjustment, the annual EE percentages used to produce the forecast were determined to be 0.31% and 0.13% for the residential and commercial sectors, respectively. The table below illustrates the calculation of the EE reductions. The far right-hand column labeled "Cumulative

Reductions" is the sum of the residential and commercial cumulative reductions and represents the "SCE&G DSM Programs" column shown in a subsequent forecast summary table.

Derivation of Annual EE Savings									
	Baseline Residential (GWH)	Cumulative Reductions (GWH)	Incremental Reductions (GWH)	Inc. %	Baseline Commercial (GWH)	Cumulative Reductions (GWH)	Incremental Reductions (GWH)	Inc. %	Cumulative Reductions (GWH)
2014	7,883	-	-	-	7,247	-	-	-	-
2015	7,919	-	-	-	7,257	-	-	-	-
2016	8,053	-25	-25	-0.31	7,437	-10	-10	-0.13	-35
2017	8,192	-50	-25	-0.31	7,615	-20	-10	-0.13	-70
2018	8,318	-76	-26	-0.31	7,777	-30	-10	-0.13	-106
2019	8,511	-103	-26	-0.31	8,042	-40	-10	-0.13	-143
2020	8,697	-129	-27	-0.31	8,300	-51	-11	-0.13	-180
2021	8,877	-157	-28	-0.31	8,544	-62	-11	-0.13	-219
2022	9,054	-185	-28	-0.31	8,783	-73	-11	-0.13	-259
2023	9,242	-214	-29	-0.31	9,041	-85	-12	-0.13	-299
2024	9,420	-243	-29	-0.31	9,288	-97	-12	-0.13	-340
2025	9,602	-273	-30	-0.31	9,540	-110	-12	-0.13	-382
2026	9,777	-303	-30	-0.31	9,782	-122	-13	-0.13	-425
2027	9,947	-334	-31	-0.31	10,015	-135	-13	-0.13	-469
2028	10,120	-365	-31	-0.31	10,257	-149	-13	-0.13	-514

3. Energy Efficiency Adjustments

Several adjustments were made to the baseline projections to incorporate significant factors not reflected in historical experience. These were increased air-conditioning and heat pump efficiency standards and improved lighting efficiencies, both mandated by federal law, and the addition of SCE&G's energy efficiency programs. The following table shows the baseline projection, the energy efficiency adjustments and the resulting forecast of territorial energy sales.

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	Baseline Sales (GWH)	Energy Efficiency: SCE&G DSM Programs (GWH)	Energy Efficiency: Federal Mandates (GWH)	Energy Efficiency: Total EE Impact (GWH)	Territorial Sales (GWH)
2014	22,773	0	-125	-125	22,648
2015	22,919	0	-187	-187	22,732
2016	23,446	-35	-467	-502	22,944
2017	23,999	-70	-506	-576	23,423
2018	24,415	-106	-544	-650	23,765
2019	25,011	-143	-589	-732	24,279
2020	25,565	-180	-702	-882	24,683
2021	26,103	-219	-819	-1,038	25,065
2022	26,633	-259	-841	-1,100	25,533
2023	27,195	-299	-864	-1,163	26,032
2024	27,740	-340	-886	-1,226	26,514
2025	28,297	-382	-908	-1,290	27,007
2026	28,836	-425	-930	-1,355	27,481
2027	29,355	-469	-951	-1,420	27,935
2028	29,883	-514	-972	-1,486	28,397

Baseline sales are projected to grow at the rate of 2.0% per year. The impact of energy efficiency, both from SCE&G's DSM programs and from federal mandates, causes the ultimate territorial sales growth to fall to 1.6% per year as reported earlier.

Since the baseline forecast utilizes historical relationships between energy use and driver variables such as weather, economics, and customer behavior, it embodies changes which have occurred between them over time. For example, construction techniques which result in better insulated houses have had a dampening effect on energy use. Because this process happens with the addition of new houses and/or extensive home renovations, it occurs gradually. Over time this factor and others are captured in the forecast methodology. However, when significant events occur that impact energy use but are not captured in the historical relationships, they must be accounted for outside the traditional model structure.

The first adjustment relates to federal mandates for air-conditioning units and heat pumps. In 2006, the minimum Seasonal Energy Efficiency Ratio ("SEER") for newly manufactured appliances was raised from 10 to 13, which means that cooling loads for a house that replaced a 10 SEER unit with a 13 SEER unit would decrease by 30% assuming no change

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in other factors. The last mandated change to efficiencies like this took place in 1992, when the minimum SEER was raised from 8 to 10, a 25% increase in energy efficiency. Since then air-conditioner and heat pump manufacturers introduced much higher-efficiency units, and models are now available with SEERs over 20. However, overall market production of heat pumps and air-conditioners is concentrated at the lower end of the SEER mandate. The 2006 minimum SEER rating represented a significant change in energy use which would not be fully captured by statistical forecasting techniques based on historical relationships. For this reason an adjustment to the baseline was warranted.

A second reduction was made to the baseline energy projections beginning in 2013 for savings related to lighting. Mandated federal efficiencies as a result of the Energy Independence and Security Act of 2007 took effect in 2013 and will be phased in through 2015. Standard incandescent light bulbs are inexpensive and provide good illumination, but they are extremely inefficient. Compact fluorescent light bulbs ("CFLs") have become increasingly popular over the past several years as substitutes. They last much longer and generally use about one-fourth the energy that incandescent light bulbs use. However, CFLs are more expensive and still have some unpopular lighting characteristics, so their large-scale use as a result of market forces was not guaranteed. The new mandates will not force a complete switchover to CFLs, but they will impose efficiency standards that can only be met by them or newly developed high-efficiency incandescent light bulbs. Again, this shift in lighting represents a change in energy use which was not fully reflected in the historical data.

The final adjustment to the baseline forecast was to account for SCE&G's new set of energy efficiency programs. These energy efficiency programs along with the others in SCE&G's existing DSM portfolio are discussed later in the IRP. In developing the forecast it was assumed that the impacts of these programs were captured in the baseline forecast for the next two years but thereafter had to be reflected in the forecast on an incremental basis.

4. Load Impact of Energy Efficiency and Demand Response Programs

The Company's energy efficiency programs ("EE") and its demand response programs ("DR") will reduce the need for additional generating capacity on the system. The EE programs implemented by our customers should lower not only their overall energy needs but also their power needs during peak periods. The DR programs serve more directly as a substitute for peaking capacity. The Company has two DR programs: an interruptible program for large

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customers and a standby generator program. These programs represent over 200 megawatts ("MW") on our system. The following table shows the impacts of EE from the Company's DSM programs and from federal mandates as well as the impact from the Company's DR programs on the firm peak demand projections.

Territorial Summer Peak Demands (MWs)							
		Energy Efficiency					
Year	Baseline Trend	SCE&G Programs	Federal Mandates	Total EE Impact	System Peak Demand	Demand Response	Firm Peak Demand
2014	5,046	0	-3	-3	5,043	-257	4,786
2015	5,112	0	-4	-4	5,108	-260	4,848
2016	5,270	-11	-26	-37	5,233	-267	4,966
2017	5,406	-21	-38	-59	5,347	-275	5,072
2018	5,525	-33	-48	-81	5,444	-279	5,165
2019	5,631	-44	-59	-103	5,528	-283	5,245
2020	5,735	-55	-74	-129	5,606	-286	5,320
2021	5,829	-67	-89	-156	5,673	-289	5,384
2022	5,920	-79	-92	-171	5,749	-292	5,457
2023	6,021	-91	-96	-187	5,834	-296	5,538
2024	6,125	-104	-100	-204	5,921	-299	5,622
2025	6,228	-116	-103	-219	6,009	-303	5,706
2026	6,331	-129	-107	-236	6,095	-306	5,789
2027	6,429	-143	-110	-253	6,176	-310	5,866
2028	6,525	-157	-113	-270	6,255	-313	5,942

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II. SCE&G's Program for Meeting Its Demand and Energy Forecasts in an Economic and Reliable Manner

A. Demand Side Management

Demand Side Management (DSM) can be broadly defined as the set of actions that can be taken to influence the level and timing of the consumption of energy. There are two common subsets of Demand Side Management: Energy Efficiency and Load Management (also known as Demand Response). Energy Efficiency typically includes actions designed to increase efficiency by maintaining the same level of production or comfort, but using less energy input in an economically efficient way. Load Management typically includes actions specifically designed to encourage customers to reduce usage during peak times or shift that usage to other times.

Energy Efficiency

SCE&G's Energy Efficiency programs include Customer Information Programs, Web-Based Information and Services Programs, Energy Conservation and the Demand Side Management Programs. A description of each follows:

1. **Customer Information Programs:** SCE&G's customer information programs fall under two headings: the **Annual Energy Efficiency Campaigns** and **Web-based Information Initiatives**. The following is an overview of each.

   Annual Energy Efficiency Campaigns

   a. **Customer Insights and Analysis:** In 2013, SCE&G continued to proactively educate its customers and create awareness on issues related to energy efficiency and conservation. To help maximize the effectiveness of our campaigns, ongoing customer feedback is used to ensure marketing and communications efforts are consistent with what customers value most. Key insights gained through SCE&G's Brand Health Study and Voice of the Customer Panels are integrated to ensure we are communicating in a consistent manner that customers will understand.

      As a result, SCE&G continues to highlight programs/services that reflect three main categories identified by our customers as offering the best opportunity to

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save energy and money. These areas include rebates and incentives, in-home services and education.

b. **Media/Channel Preferences:** Placement of all marketing and advertising is carefully reviewed, taking into consideration the customers' preferred methods of receiving information about SCE&G's energy efficiency programs and services. Priority channels include television (local news and select cable stations); online banner advertising, radio, electronic/print newsletters, direct mail, bill inserts and newspapers (major daily and weekly minority publications). SCE&G's statewide business office locations also serve as a distribution point for sharing information with customers. In addition, SCE&G has also incorporated social media, e.g. Twitter and Facebook, into its communications strategy. Key South Carolina markets covered, with all marketing communications, include Columbia, Charleston, Aiken and Beaufort.

c. **Public Affairs/News Media/Speakers Bureau:** Furthermore, SCE&G understands the value of public affairs as an integral part of a well-rounded energy efficiency communication strategy and actively engages news media (broadcast and print) for coverage of key programs and services that will benefit our customers now and in the future. Public Affairs and Marketing staff also provide support with securing company experts to address a variety of organizations through a formal Speakers' Bureau, extending our outreach to church groups, senior citizen and low-income housing communities, civic organizations, builder groups and homeowner associations.

d. **Special Events:** Another key component to SCE&G's annual marketing initiatives include participation in a variety of events that offer the opportunity to further extend customer education and outreach of energy information. SCE&G's 2013 schedule included a solid mix of special events to include the Home Builders Association ("HBA") Home Improvement Show and Tour of Homes in Columbia and Black Expos in Columbia and Charleston.

e. **EnergyWise Communications:** Brand positioning of SCE&G's energy efficiency programs and services with all marketing and advertising initiatives falls under the EnergyWise umbrella – an SCE&G registered trademark in South

Carolina and encompasses **general awareness education** as well as **program specific offerings**.

General Awareness Education: Last year's advertising included messaging on a wide range of topics such as year-round and seasonal energy efficiency tips that are practical for customers to manage on their own or that have a no-cost, low-cost factor to them. Examples include thermostat settings, checking air filters monthly, water heater settings and unplugging appliances that are sometimes perceived to be "energy vampires" (lights, TV's, computers, cell phone chargers, etc.).

Program Specific Offerings: In 2013, SCE&G continued to heavily promote its portfolio of residential electric rebate/incentive programs under its Demand Side Management (DSM) department – many of which were featured in our general awareness advertising schedule. Specific programs included ENERGY STAR Lighting, our free Home Energy Check-up, Home Performance with ENERGY STAR and Residential Heating & Cooling and Water Heating Equipment.

2. **Web-Based Information and Services Programs:** SCE&G's online offerings can be broken into four components: Customer Awareness Information, the Energy Analyzer, free online Energy Audit and EnergyWise e-newsletter. Altogether, there have been more than 5.1 million visits to SCE&G's website in 2013. Customers must be registered to use the interactive tools Energy Analyzer and Energy Audit. There are over 350,000 customers registered for this access. Descriptions of the four categories listed above follows:

    a. **Customer Awareness Information:** The SCE&G website, www.sceg.com, supports all communication efforts to promote energy savings information – both general awareness tips and program-specific overviews, tools and resources – all through a section called "Be EnergyWise and Save". Energy savings information includes detailed information on each of the Demand Side Management programs for residential and commercial/industrial customers, as well as how-to videos on insulation, thermostats and door and windows.

    b. **Energy Analyzer:** The Energy Analyzer, in use since 2004, is a 24-month bill analysis tool. It uses complex analytics to identify a customer's seasonal

usages and target the best ways to reduce demand. This Web-based tool allows customers to access their current and historical consumption data and compare their energy usage month-to-month and year-to-year -- noting trends, temperature impact and spikes in their consumption. There were a little over 106,000 visits to the Energy Analyzer tool in 2013.

c. **Online Energy Audit:** The Online Energy Audit tool leads customers through the process of creating a complete inventory of their home's insulation and appliance efficiency. The tool allows customers to see the energy and financial savings of upgrades before making an investment. Over 7,000 customers used the Energy Audit tool in 2013.

d. **SCE&G EnergyWise E-Newsletter:** SCE&G's web-based information and services included ongoing management of its EnergyWise e-newsletter to support customer demand for additional information on ways to help them save energy. A total of 2,464 customers are registered for the e-newsletters distributed in 2013.

3. Energy Conservation

Energy conservation is a term that has been used interchangeably with energy efficiency. However, energy conservation has the connotation of using less energy in order to save rather than using less energy to perform the same or better function more efficiently. The following is an overview of each SCE&G energy conservation offering:

a. **Energy Saver / Conservation Rate**: The Rate 6 (Energy Saver/Conservation) rewards homeowners and homebuilders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provides for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive which is beneficial to all of our customers and trade allies. Homes built to this standard have improved comfort levels and increased re-sale value over homes built to the minimum building code standard, which is also a significant benefit to participants. Information on this program is available on our website and by brochure.

b. **Seasonal Rates**: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

4. **Demand Side Management Programs**

In 2013, SCE&G completed a comprehensive evaluation of the existing DSM programs with the specific intention of updating programs and introducing new programs to the DSM portfolio. In May 2013, the Company presented the new portfolio to the Commission and received approval in November 2013. The Commission approved a suite of eleven (11) DSM programs, which includes nine programs targeting SCE&G's residential customer classes and two programs targeting SCE&G's commercial and industrial customer classes. A description of each program follows:

a. **Residential Home Energy Reports** provides customers with free monthly/bi-monthly reports comparing their energy usage to a peer group and providing information to help identify, analyze and act upon potential energy efficiency measures and behaviors.

b. **Residential Energy Information Display** provides customers with an in-home display that shows information from the customer's meter regarding current energy usage and cost, and the approximate use and cost to date for the month. The displays were distributed to targeted customers, upon their request, at a discounted price.

c. **Residential Home Energy Check-up** program provides customers with a visual energy assessment performed by SCE&G staff at the customer's home. At the completion of the visit, customers are offered an energy efficiency kit containing simple measures, such as compact fluorescent light bulbs ("CFL"), water heater wraps and/or pipe insulation. The Home Energy Check-up is provided free of charge to all residential customers who elect to participate.

d. **Residential Home Performance with ENERGY STAR®** program promotes a comprehensive energy efficiency audit of the home by trained contractors. SCE&G provides incentives to customers for implementing specific measures based on the audit findings.

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e. **Residential ENERGY STAR® Lighting** program incentivizes residential customers to purchase and install high-efficiency ENERGY STAR® qualified lighting products by providing discounts to the manufacturers and retailers.

f. **Residential Heating & Cooling and Water Heating Equipment** program provides incentives to customers for purchasing and installing high efficiency HVAC equipment and non-electric resistance water heaters in new and existing homes.

g. **Residential Heating & Cooling Efficiency Improvements** program provides residential customers with incentives to improve the efficiency of existing AC and heat pump systems through HVAC tune-ups (system optimizer), complete duct replacements, duct insulation and duct sealing. The system optimizer was discontinued in May 2013.

h. **Residential ENERGY STAR® New Homes** program provides incentives to customers and builders who are willing to commit to ENERGY STAR® standards in new home construction.

i. **Neighborhood Energy Efficiency Program (NEEP)**, approved by the Commission in April 2013, provides qualifying customers energy education, an on-site energy survey of the dwelling, and direct installation of low-cost energy saving measures at no additional cost to the customer. The program is delivered in a neighborhood door-to-door sweep approach and offers customers who are eligible and wish to participate a variety of direct installation energy efficiency measures.

j. **Commercial and Industrial Prescriptive** program provides incentives to non-residential customers to invest in high-efficiency lighting and fixtures, high efficiency motors and other equipment. To ensure simplicity, the program includes a master list of measures and incentive levels that are easily accessible to commercial and industrial customers on the website.

k. **Commercial and Industrial Custom** program provides custom incentives to commercial and industrial customers based on the calculated efficiency benefits of their particular energy efficiency plans or construction proposals. This program applies to technologies and applications that are more complex and

customer-specific. All aspects of this program fit within the parameters of both retrofit and new construction projects.

5. **Load Management Programs**

The primary goal of SCE&G's load management programs is to reduce the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

a. **Standby Generator Program:** The Standby Generator Program for wholesale customers provides about 25 megawatts of peaking capacity that can be called upon when reserve capacity is low on the system. This capacity is owned by our wholesale customers and through a contractual arrangement is made available to SCE&G dispatchers. SCE&G has a retail version of its standby generator program in which SCE&G can call on 20 or more customers to run their emergency generators. This retail program provides about 17 MWs of additional capacity as needed.

b. **Interruptible Load Program:** SCE&G has over 150 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCE&G is short of capacity.

c. **Real Time Pricing ("RTP") Rate:** A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in the market, the RTP program sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.

d. **Time of Use Rates:** Our time of use rates contain higher charges during the peak usage periods of the day and lower charges during off-peak periods. This encourages customers to conserve energy during peak periods and to shift energy consumption to off-peak periods. All SCE&G customers have the option of purchasing electricity under a time of use rate.

SCE&G's resource plan shows the need for additional capacity in the future to continue providing reliable electric service to its customers. As SCE&G evaluates how to satisfy this need, the Company will consider, among other things, demand response technologies.

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B. Supply Side Management

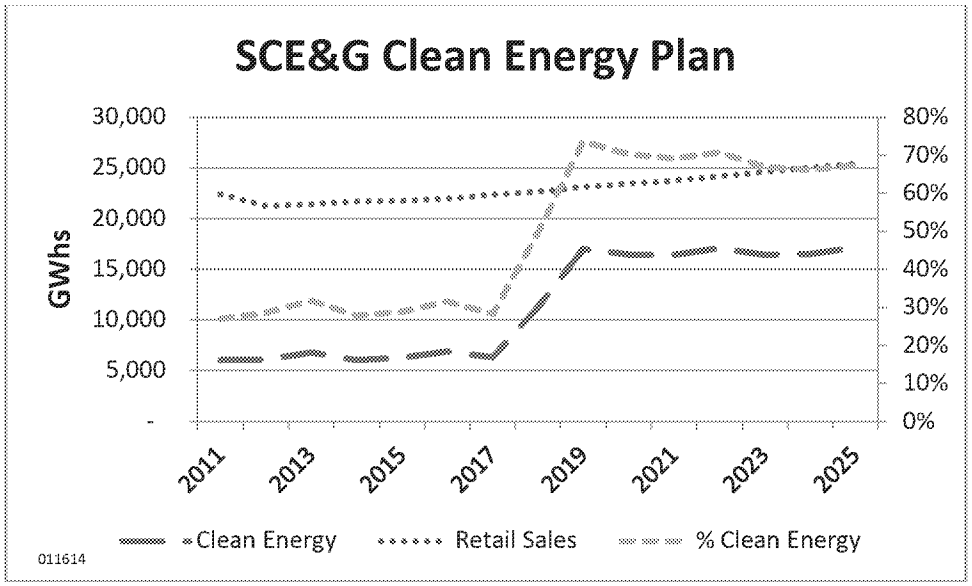
Clean Energy at SCE&G

Clean energy includes energy efficiency and clean energy supply options like nuclear power, hydro power, combined heat and power and renewable energy.

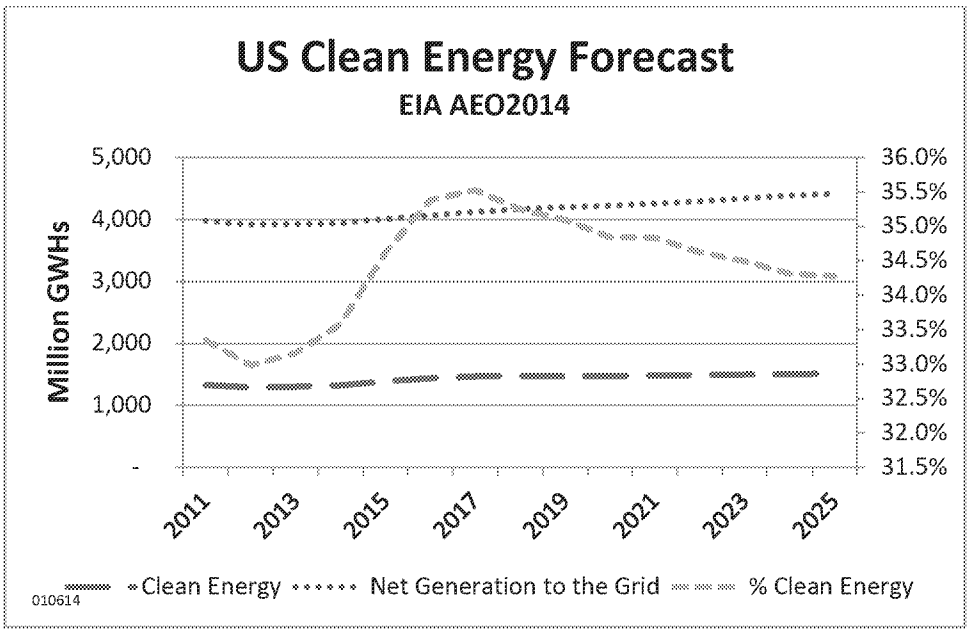
1. Existing Sources of Clean Energy

SCE&G is committed to generating more of its power from clean energy sources. This commitment is reflected: in the amount of current and projected generation coming from clean sources, in the certified renewable energy credits that the Company generates each year, in the Company's net metering program, and in the Company's support for Palmetto Clean Energy, Inc. Below is a discussion of each of these topics.

a. Current Generation: SCE&G currently generates clean energy from hydro, nuclear, solar and biomass. The following chart shows the current and expected amounts of clean energy in GWH and as a percentage of retail sales.



As seen in the chart above, SCE&G currently generates a little over 30% of its retail sales from clean energy sources but by 2019 it expects to generate about 74% from clean energy. According to the EIA, the U.S. as a nation currently generates about 33% of its retail sales as clean energy and it expects this percentage to increase slightly over the next ten years or so. The following chart graphs EIA's forecast for US clean energy.



SCE&G compares very favorably to the nation in its clean energy plans since by 2019 it should be meeting about twice as much of its retail sales with clean energy on a relative basis compared to the nation.

b. Renewable Energy Credits: The SCE&G-owned electric generator, located at the KapStone Charleston Kraft LLC facility, generates electricity using a mixture of coal and biomass. KapStone Charleston Kraft, LLC, produces black liquor through its Kraft pulping process and produces and purchases biomass fuels. These fuels which are used to produce renewable energy and the electricity generated qualify for Renewable Energy Certificates ("REC") as approved by Green-e Energy, a leading national independent certification and verification program for renewable energy administered by the Center for Resource Solutions, a nonprofit company based in San Francisco, California. The nearby table shows the MWHs of renewable energy generated by the Kapstone generator, formerly known as the Cogen South generator:

Year	MWh	% of Retail Sales
2007	371,573	1.7%
2008	369,780	1.7%
2009	351,614	1.7%
2010	346,190	1.5%
2011	336,604	1.5%
2012	414,047	1.9%
2013	385,202	1.8%

c. Boeing Solar Generator: In 2011, SCE&G installed approximately 10 acres of thin-film laminate panels (18,095 individual panels) on the roof of Boeing's North Charleston assembly plant. The PV system, having an alternating current peak output of 2.35 MW, began generating in October 2011. All RECs and energy generated by the roof top solar system are provided to

Boeing for onsite use. At the time of completion this was the largest roof-top solar generator in the Southeast. Over the last two years the Boeing solar plant has generated the following amounts of energy:

Year	MWh
2012	3,513
2013	3,410

d. Net Metering Rates and the PR-1 Rate: Protecting the environment includes encouraging and helping our customers to take steps to do the same. Net metering provides a way for residential and commercial customers interested in generating their own renewable electricity to partially power their homes or businesses and sell the excess energy back to SCE&G. For residential customers, the generator output capacity cannot exceed the annual maximum household demand or 20 KW, whichever is less. For small commercial customers, the generator output capacity cannot exceed the annual maximum demand of the business or 100 KW, whichever is less. Under its PR-1 rate for qualifying facilities, the Company will pay the qualifying customer for any power generated and transmitted to the SCE&G system. The PR-1 rate is developed using SCE&G's avoided costs.

e. Palmetto Clean Energy, Inc.: Palmetto Clean Energy, Inc. ("PaCE") is a non-profit, tax exempt organization formed by SCE&G, Duke Energy, Progress Energy, the South Carolina Office of Regulatory Staff ("ORS") and the S.C. Energy Office for the purpose of promoting the development of renewable power in South Carolina. Customers make a tax deductible contribution to PaCE and PaCE uses the funds collected to pay renewable generators a financial incentive for their power.

2. Future Clean Energy

SCE&G is participating in activities seeking to advance renewable technologies in the future. Specifically the Company is involved with off-shore wind activities in the state, co-firing with biomass fuels, building solar generation, studying smart grid opportunities and distribution automation. These activities are set forth in more detail below.

a. New Renewable Projects: SCE&G's customers and other South Carolina stakeholders have expressed a desire for solar energy in the State, and SCE&G is looking for ways to integrate

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additional solar into the system in the most economical way possible while beginning to grow a new energy economy in South Carolina based on a diverse portfolio of generation. SCE&G currently has approximately 4 megawatts of solar generation on the system, and plans to build new solar farms that will add up to 20 megawatts of renewable energy to our system. We have created an experienced team focused on research, design, and implementation of renewable energy resources (solar, wind, and biomass). In 2014-2016, we plan to install several solar farms on the system. These solar farms will be built in various locations throughout the system and will include opportunities for research, education, and expansion of the energy economy in S.C.

b. Off-Shore Wind Activities: SCANA/SCE&G is a founding member of the Southeastern Coastal Wind Coalition and participates in the Utility Advisory Group of that organization. The mission of Southeastern Coastal Wind Coalition is to advance the coastal and offshore wind industry in ways that result in net economic benefits to industry, utilities, ratepayers, and citizens of the Southeast. The focus is three fold:

1. Research and Analysis – objective, transparent, data-driven, and focused on economics.
2. Policy / Market Making – exploring multistate collaborative efforts and working with utilities, not against them.
3. Education and Outreach – website, communications, and targeted outreach.

SCE&G participated in the Regulatory Task Force for Coastal Clean Energy. This task force was established with a 2008 grant from the U.S. Department of Energy. The goal is to identify and overcome existing barriers for coastal clean energy development for wind, wave and tidal energy projects in South Carolina. Efforts included an offshore wind transmission study; a wind, wave and ocean current study; and creation of a Regulatory Task Force. The mission of the Regulatory Task Force was to foster a regulatory environment conducive to wind, wave and tidal energy development in state waters. The Regulatory Task Force was comprised of state and federal regulatory and resource protection agencies, universities, private industry and utility companies.

SCANA/SCE&G participated in discussions to locate a 40 MW demonstration wind farm off the coast of Georgetown. This effort, known as Palmetto Wind, includes Clemson University's Restoration Institute, Coastal Carolina University, Santee Cooper, the S.C. Energy

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Office and various utilities. Palmetto Wind has been put on hold due to the high cost of the project.

SCE&G invested $3.5 million in the Clemson University Restoration Institute's wind turbine drive train testing facility at the Clemson campus in North Charleston. This new facility is dedicated to groundbreaking research, education, and innovation with the world's most advanced wind turbine drive train testing facility capable of full-scale highly accelerated mechanical and electrical testing of advanced drive train systems for wind turbines.

c. Co-firing with Biomass: SCE&G continues to investigate and evaluate the co-firing of biomass and other engineered waste products in our existing coal burning facilities. The goal of the project is to determine the operational practicality as well as the economic and fuel supply implications of co-firing in existing coal units. Co-firing of biomass fuel in our existing units represents an opportunity to include additional renewable fuels in our production mix without having to build new facilities or spend significant capital on existing facilities. Results are evaluated by the Fossil Hydro department to determine the feasibility for a future course of action.

d. Smart Grid Activities: SCE&G currently has approximately 9,300 AMI meters that are installed predominately on our medium to large commercial customers as well as our smaller industrial customers. Other applications where this technology is deployed include all time-of-use accounts and all accounts with customer generation (net metering). These meters utilize public wireless networks as the communication backbone and have full two-way communication capability. Register readings and load profile data are remotely collected daily from all AMI meters. In addition to traditional metering functions, the technology also provides real-time monitoring capability including power outage/restoration, meter/site diagnostics, and power quality monitoring. Load profile data is provided to customers daily via web applications enabling these customers to have quick access to energy usage allowing better management of their energy consumption. Moving forward, this technology will also enable more sophisticated DSM offerings that may be attractive to a variety of customer classes.

e. Distribution Automation: SCE&G is continuing to expand the penetration of automated Supervisory Control and Data Acquisition ("SCADA") switching and other intelligent devices

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throughout the system. We have approximately 850 SCADA switches and reclosers, most of which can detect system outages and operate automatically to isolate sections of line with problems thereby minimizing the number of affected customers. Some of these isolating switches can communicate with each other to determine the optimal configuration to restore service to as many customers as possible without operator intervention. We are continuing to evaluate systems that will help these automated devices communicate with each other and safely reconfigure the system in a fully automated fashion.

f. Environmental Mitigation Activities: In order to reduce NO_X emissions and to meet compliance requirements, SCE&G installed Selective Catalytic Reduction ("SCR") equipment at Cope Station in the fall of 2008. The SCR began full time operation on January 1, 2009, and has run well since that time. It is capable of reducing NO_X emissions at Cope Station by approximately 90%. SCE&G is also utilizing the existing SCRs at Williams and Wateree Stations along with previously installed low NO_X burners at the other coal-fired units to meet the Clean Air Interstate Rule ("*CAIR*") requirements for NO_X which are in effect while the Cross State Air Pollution Rule is under a court-ordered stay. Additionally, SCE&G has installed flue gas desulfurization ("FGD") equipment, commonly known as wet scrubbers, at Williams and Wateree Stations to reduce SO_2 emissions. The in-service dates for Williams and Wateree Stations were February 25, 2010, and October 12, 2010, respectively. Scrubber performance tests at both stations met the SO_2 designed removal rate of 98%. Mercury emission control has also been realized in the industry via the operation of FGD equipment. Consequently, the continued operation of the FGD equipment will contribute to SCE&G's strategy for meeting the impending requirements of the US EPA's Mercury and Air Toxics Standard ("*MATS*") that will become effective on April 16, 2015. The Chem-Mod fuel additive being used at McMeekin Station, Cope Station, and Williams Station will similarly contribute to SCE&G's efforts in stack emission control for mercury, as well as for NO_X and SO_2.

In response to the US EPA's impending *MATS*, the last coal-fired boiler at Urquhart Station, Unit 3, was converted to natural gas. Decommissioning of the plant's former coal handling facilities is in progress. Also in response to MATS Canadys Station ceased operations on November 6, 2013, and decommissioning efforts are in progress.

In an effort to cease bottom ash sluicing to the Wateree Station's ash ponds, SCE&G installed two remote submerged flight conveyors that dewater boiler bottom ash sluice and

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recycle the overflow back to the boiler for reuse. This retrofit was completed for Units 1 and 2 during October 2012. The bottom ash is then marketed as an ingredient in the manufacture of pre-stressed concrete products.

g. Nuclear Power in the Future – Small and Modular: Small Modular Reactor ("SMR") technology continues to be developed. DOE has awarded two grants, totaling $452 million, for SMR development. At about a third, or less, of the size of current nuclear power plants, SMRs could make available, for a smaller capital investment, a modular design for specific generation needs. SCE&G will continue to evaluate this technology as it develops.

3. Summary of Proposed and Recently Finalized Regulations

The EPA has either proposed or recently finalized 6 regulations and modified one additional regulation. These are Cross-State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), Greenhouse Gases, Cooling Water Intake Structures, Coal Combustion Residuals, Effluent Limitation Guidelines, and a new 1-hour sulfur dioxide National Ambient Air Quality Standard ("NAAQS").

a. Cross-State Air Pollution Rule ("CSAPR")

On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued a stay delaying implementation of CSAPR pending the outcome of a legal appeal. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR and left CAIR in place. The federal court ordered the EPA to continue administering the previously promulgated CAIR. On October 5, 2012, the EPA filed a petition for rehearing of the order. On January 24, 2013, the United States Court of Appeals for the D.C. Circuit denied EPA's petition for rehearing. The Court ordered EPA to continue to enforce the 2005 CAIR until CSAPR could be re-issued. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013, the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G has already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR if reinstated.

CSAPR, which was intended to replace CAIR, was initially finalized in July 2011 under the Clean Air Act and would affect 27 states including South Carolina, requiring reductions in

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sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions beginning in 2012, with stricter reductions in 2014. The rule established an emissions cap for SO_2 and NO_X and limited the trading region for emission allowances by separating affected states into two groups with no trading between the groups.

SCE&G Fossil Hydro generation is in compliance with emission limits set by CSAPR and CAIR.

b. Mercury and Air Toxics Standards ("MATS")

Proposed under the Clean Air Act, this rule sets numeric emission limits for mercury, particulate matter as a surrogate for toxic metals, and hydrogen chloride as a surrogate for acid gases. The final rule also revises new source performance standards for power plants to address emissions of particulate matter, sulfur dioxide and nitrogen oxides. The rule would replace the court-vacated Clean Air Mercury Rule. MATS was proposed in May 2011, and the final rule was issued on December 21, 2011.

The rule became effective on April 16, 2012. Compliance with MATS is required within three years. A 1-year extension may be granted by the state permitting authorities if additional time is needed for units that are required to run for reliability purposes which would otherwise be deactivated, or which, due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay. It is expected that coal-fired generators will need to have a combination of flue gas desulfurization, selective catalytic reduction and fabric filters in order to comply with the standards. A second year of extension may also be possible for reliability critical units that qualify for an Administrative Order at the end of the 1-year extension. All extension requests must be supported by the written concurrence of the appropriate Planning Authority and will be considered by EPA on a case-by-case basis, supplemented by consultation with FERC and/or other entities with relevant reliability expertise as appropriate.

SCE&G applied for and received a 1-year extension from DHEC for both McMeekin and Canadys. With the retirement of Canadys in the 4th quarter of 2013, only McMeekin has a waiver that will allow the continued use of coal until April 2016.

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c. Greenhouse Gases

The EPA's rule addressing the emission of greenhouse gases was proposed under the Clean Air Act and would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. This action will amend the new source performance standards ("NSPS") for electric generating units ("EGU") and will establish the first NSPS for greenhouse gas ("GHG") emissions. The Rule essentially requires all new fossil fuel-fired power plants to meet the carbon dioxide ("CO_2") emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal plants can be constructed without carbon capture and sequestration ("CCS") capabilities. The first part of this rule, related to new generation sources, was released in April 2012 and was expected to become final in March 2013.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA issued a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The April 2012 rule was withdrawn by EPA and the new rule, which became final on January 8, 2014, still requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal fired units in the near future.

The Presidential Memorandum also directed EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any.

SCE&G's new nuclear generation will mitigate CO_2 concerns going forward. The following chart shows that SCE&G's CO_2 emissions will fall well below its 1995 level after the next several years.

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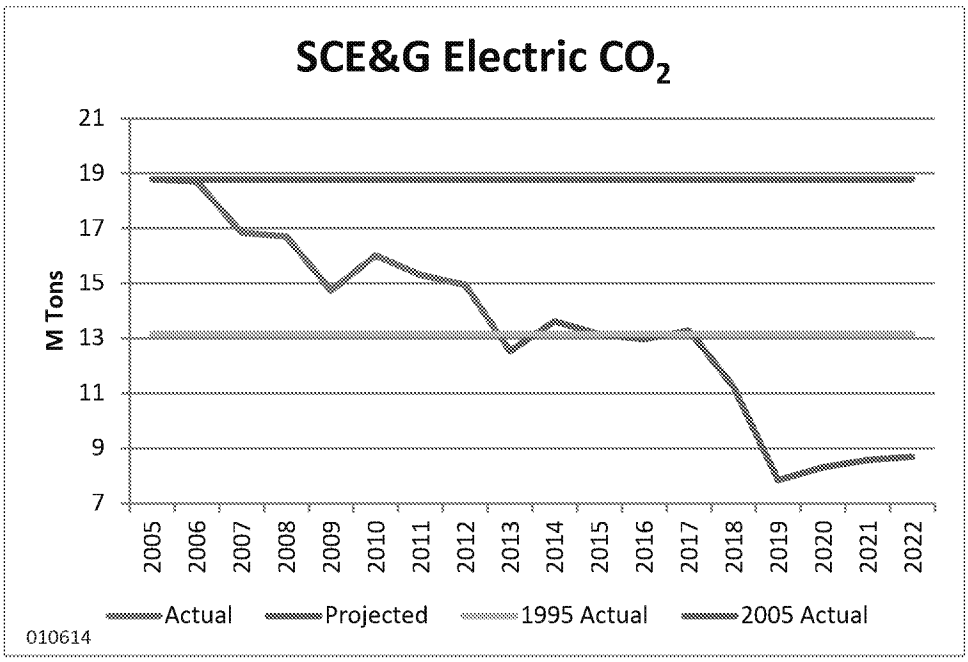

d. Cooling Water Intake Structures

Proposed under section §316(b) of the Clean Water Act, this rule is intended to reduce damage to aquatic life through impingement, when organisms are trapped against inlet screens, and entrainment, when they are drawn into the generator's cooling water system. Facilities that withdraw at least 2 million gallons per day would be subject to a limit on the number of fish that can be killed through impingement. Facilities that withdraw at least 125 million gallons per day and new units at existing facilities may be subject to more stringent restrictions. The rule was proposed in April 2011, and a final rule is now expected by April 17, 2014.

There is considerable uncertainty regarding when the regulations would be effective and the steps that would have to be taken in order to meet them. Facilities must comply with Best Available Technology Standards within 8 years, but many required submittals are due much earlier, as early as six months after rule promulgation. Compliance actions range from enhanced screening and reconfiguration of water intake systems to installation of cooling towers to reduce the flow rate. On SCE&G's system, Jasper, Cope and Wateree Stations have closed cycle cooling towers installed and should not be significantly affected by these regulations. The Company is currently conducting studies and is developing or implementing compliance plans for these initiatives.

e. Coal Combustion Residuals

In response to concerns over the potential structural failure of coal ash impoundment facilities instigated by the December 2008 failure that occurred at a Tennessee Valley Authority facility, EPA has proposed changing the classification of coal combustion residuals from its current status of an exempt waste. Two options were proposed under the Resource Conservation and Recovery Act: (1) list residuals as special hazardous wastes when destined for disposal in landfills or surface impoundments or (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010 and comments were received through November 2010. EPA has not issued the rule as yet and has not specified when a final rule will be issued. The effective date is believed to be dependent on which option is selected. If coal combustion residuals are classified as non-hazardous wastes, the rule would be effective six months after promulgation. A special hazardous waste designation would likely push compliance out until about 2021 when the state adopts the rule. Timing will vary from state to state.

On January 18, 2012, several environmental groups, led by Earthjustice, filed a notice of intent to sue the EPA to force the agency to finalize its proposed rule determining how coal combustion residuals (commonly referred to as "coal ash") will be categorized. On January 22, 2013, the Court in the coal combustion residuals ("CCR") deadline litigation postponed the status conference in the case until April 26, 2013. On October 29, a federal district judge ordered EPA to file by December 29, 2013, a timeline for the completion of this rule. However, because environmental groups and coal ash recyclers are in settlement negotiations concerning the timeline, in December, the district court accepted a motion to give EPA additional time (until late January) to file the timeline. In January, a consent decree was filed that sets forth EPA's obligation to sign, by December 19, 2014, a notice for publication in the Federal Register taking final action on the Agency's rule for CCR.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

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f. Effluent Limitation Guidelines

The Clean Water Act ("CWA") establishes the basic structure for regulating discharges of pollutants into the waters of the United States. It provides EPA and the States with a variety of programs and tools to protect and restore the nation's waters. These programs and tools generally rely either on water quality-based controls, such as water quality standards and water quality-based permit limitations, or technology-based controls such as effluent guidelines and technology-based permit limitations. The EPA is currently developing a proposed rule to amend the effluent guidelines and standards for the Steam Electric Power Generating category. Once issued, the Steam Electric effluent guidelines and standards will be incorporated into State administered wastewater permits known as National Pollutant Discharge Elimination System ("NPDES") permits. EPA's decision to proceed with a rulemaking was announced on September 15, 2009, following completion of a preliminary study.

EPA reviewed wastewater discharges from power plants and the treatment technologies available to reduce pollutant discharges. EPA believes that the current regulations, which were last updated in 1982, do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades. EPA's main reason for this concern is that the air pollution control technologies that have been retrofitted to power plants in order to reduce air emissions put a majority of those contaminants into the wastewater discharge. In 2010, EPA submitted an Information Collection Request ("ICR") to all electric utilities to aid in their review of plant operations, pollution control technologies, and current wastewater discharges. Consequently, SCE&G expended considerable time and resources to answer a 213-page questionnaire for each of its electric generating facilities.

Under the CWA, compliance with applicable limitations is achieved under State-issued National Permit Discharge Elimination System (NPDES) permits. As a facility's NPDES permit is renewed (every 5 years) any new effluent limitations would be incorporated. New federal effluent limitation guidelines for steam electric generating units (the ELG Rule) were published in the Federal Register on June 7, 2013. Comments were due by September 20, 2013, and the rule is expected to be finalized May 22, 2014. EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Once the rule becomes effective, the State environmental regulators will modify the NPDES permits to match more restrictive standards thus requiring utilities to retrofit each facility with new wastewater treatment technologies. Based on the

proposed rule, SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree at a minimum.

g. NAAQS 1-hour SO_2

In June 2010, EPA revised the primary SO_2 standard by establishing a new 1-hour standard at a level of 75 parts per billion ("ppb"). The EPA revoked the two existing primary standards of 140 ppb evaluated over 24-hours, and 30 ppb per hour averaged over an entire year. The new form is the 3-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations. EPA also required states to install new monitors by January 1, 2013. Compliance requires both monitoring and refined dispersion modeling of SO_2 sources to meet the new standard.

The new 1-hour national ambient air quality standard ("NAAQS") for SO_2 presents new challenges and is driving strategic planning for large SO_2 emitters around the country. For this new standard, EPA is requiring the unusual step of using air quality modeling for criteria pollutant attainment designations. EPA released its draft guidance for this State Implementation Plan ("SIP") modeling and the states prepared for designation modeling efforts. However, later guidance issued during June 2012 indicated that EPA would back off of the modeling requirement.

Historically, ambient air monitoring data has provided the basis for attainment designations. The shift to using models instead of ambient data poses significant challenges. For example, due to the stringent nature of the short term SO_2 standards, the conservative nature of the models and use of conservative inputs in the model (short-term emission limits), the results can significantly overstate reality. Also there are likely to be surprises for historically grandfathered sources or even new well-controlled sources.

During 2013, EPA deferred designations for South Carolina for future action. On January 7, 2014, EPA made available two updated draft documents that provide technical assistance for states implementing the 2010 health-based, sulfur dioxide (SO_2) standard. These documents provide technical advice on the use of modeling and monitoring to determine if an area meets the 2010 SO_2 air quality standard. In a future rule expected in 2014, the EPA will establish requirements for characterizing SO_2 air quality in priority areas, focusing on areas with sources that have emissions higher than a threshold amount. The EPA expects to establish these thresholds taking population into account. States will have the flexibility to characterize air

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quality using modeling of actual emissions or using appropriately sited existing and new monitors. These data would be used in two future rounds of designations in 2017 (based on modeling) and 2020 (based on new monitoring). EPA expects to issue a Data Requirements Rule for implementing the 1-Hour SO_2 standard during 2014. Air quality control installations that SCE&G and GENCO have already completed and planned retirements of older coal-fired units are expected to allow the Company to comply with the 1-Hour SO_2 standard.

4. Supply Side Resources at SCE&G

a. Existing Supply Resources

SCE&G owns and operates six (6) coal-fired fossil fuel units, one (1) gas-fired steam unit, eight (8) combined cycle gas turbine/steam generator units (gas/oil fired), sixteen (16) peaking turbine units, four (4) hydroelectric generating plants, and one Pumped Storage Facility. In addition, SCE&G receives the output of 85 MWs from a cogeneration facility. The total net non-nuclear summer generating capability rating of these facilities is 4,590 MWs in summer and 4,764 MWs in winter. These ratings, which are updated at least on an annual basis, reflect the expectation for the coming summer and winter seasons. When SCE&G's nuclear capacity (647 MWs in summer and 661 MWs in winter), a long term capacity purchase (25 MWs) and additional capacity (20 MWs) provided through a contract with the Southeastern Power Administration are added, SCE&G's total supply capacity is 5,282 MWs in summer[1] and 5,470 MWs in winter. This is summarized in the table on the following page.

[1] This supply capacity does not include the Company's solar generator with a DC nominal rating of 2.6 MWs which lies behind a customer's meter.

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Existing Long Term Supply Resources

The following table shows the generating capacity that is available to SCE&G in 2014.

	In-Service Date	Summer (MW)	Winter (MW)
Coal-Fired Steam:			
McMeekin – Near Irmo, SC	1958	250	250
Wateree – Eastover, SC	1970	684	684
*Williams – Goose Creek, SC	1973	605	610
Cope - Cope, SC	1996	415	415
Kapstone – Charleston, SC	1999	85	85
Total Coal-Fired Steam Capacity		2,039	2,044
Gas-Fired Steam:			
Urquhart – Beech Island, SC	1953	95	96
Nuclear:			
V. C. Summer - Parr, SC	1984	647	661
I. C. Turbines:			
Hardeeville, SC	1968	9	9
Urquhart – Beech Island, SC	1969	39	48
Coit – Columbia, SC	1969	28	38
Parr, SC	1970	60	73
Williams – Goose Creek, SC	1972	40	52
Hagood – Charleston, SC	1991	128	145
Urquhart No. 4 – Beech Island, SC	1999	48	49
Urquhart Combined Cycle – Beech Island, SC	2002	458	484
Jasper Combined Cycle – Jasper, SC	2004	852	924
Total I. C. Turbines Capacity		1,662	1,822
Hydro:			
Neal Shoals – Carlisle, SC	1905	3	4
Parr Shoals – Parr, SC	1914	7	12
Stevens Creek - Near Martinez, GA	1914	8	10
Saluda - Near Irmo, SC	1930	200	200
Fairfield Pumped Storage - Parr, SC	1978	576	576
Total Hydro Capacity		794	802
Other: Long-Term Purchases		25	25
SEPA		20	20
Grand Total:		5,282	5,470

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and is operated by SCE&G. Not reflected in the table is a solar PV generator owned by SCE&G with a nominal direct current rating of 2.6 MWs nor a purchase of 300 MWs of firm capacity for the years 2014-2015.

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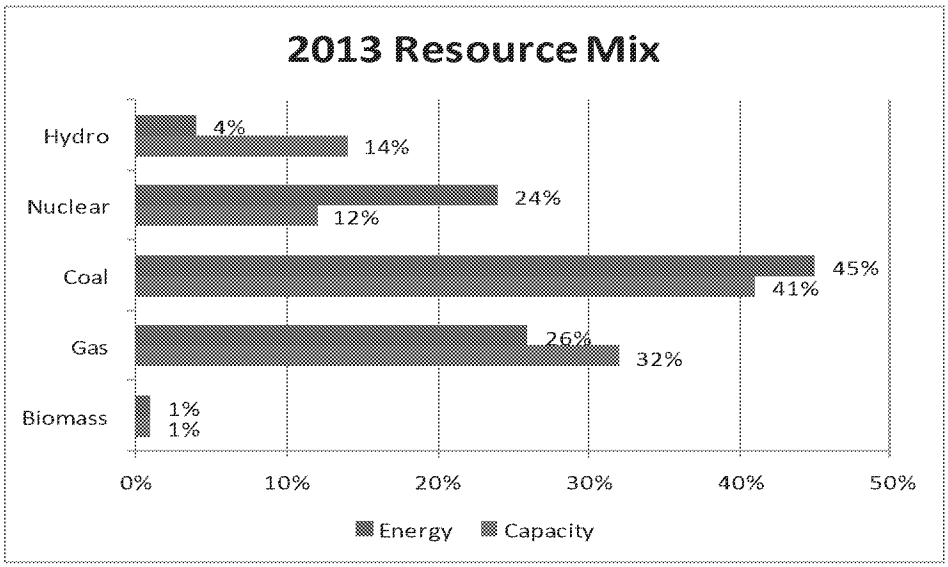
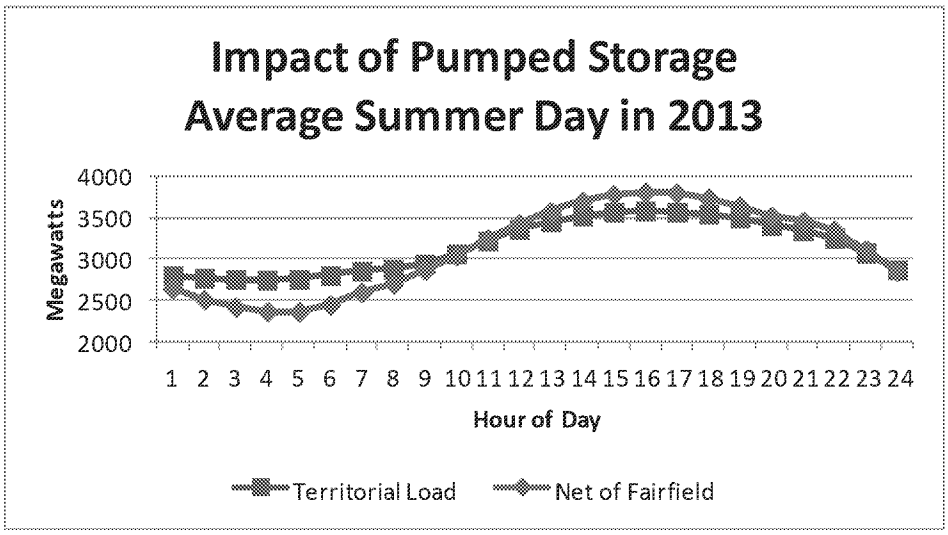
The bar chart below shows SCE&G's actual 2013 relative energy generation and relative capacity by fuel source.



b. DSM from the Supply Side

SCE&G is able to achieve a DSM-like impact from the supply side using its Fairfield Pumped Storage Plant. The Company uses off-peak energy to pump water uphill into the Monticello Reservoir and then displaces on-peak generation by releasing the water and generating power. This accomplishes the same goal as many DSM programs, namely, shifting use to off-peak periods and lowering demands during high cost, on-peak periods. The following graph shows the impact that Fairfield Pumped Storage had on a typical summer weekday.



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In effect the Fairfield Pumped Storage Plant was used to shave about 218 MWs from the daily peak times of 2:00pm through 6:00pm and to move about 2.4% of customer's daily energy needs off peak. Because of this valuable supply side capability, a similar capability on the demand side, such as a time of use rate, would be less valuable on SCE&G's system than on many other utility systems.

c. Planning Reserve Margin and Operating Reserves

The Company provides for the reliability of its electric service by maintaining an adequate reserve margin of supply capacity. The appropriate level of reserve capacity for SCE&G is in the range of 14 to 20 percent of its firm peak demand. This range of reserves will allow SCE&G to have adequate daily operating reserves and to have reserves to cover two primary sources of risk: supply risk and demand risk.

Supply reserves are needed to balance the "supply risk" that some SCE&G generation capacity may be forced out of service or its capacity reduced on any particular day because of mechanical failures, fuel related problems, environmental limitations or other force majeure/unforeseen events. The amount of capacity forced-out or down-rated will vary from day-to-day. SCE&G's reserve margin range is designed to cover most of these days as well as the outage of any one of our generating units.

Another component of reserve margin is the demand reserve. This is needed to cover "demand risk" related to unexpected increases in customer load above our peak demand forecast. This can be the result of extreme weather conditions or other unexpected events.

The level of daily operating reserves required by the SCE&G system is dictated by operating agreements with other VACAR companies. VACAR is the organization of utilities serving customers in the Virginia-Carolinas region of the country who have entered into a reserve sharing agreement. These utilities are members of the SERC Reliability Corporation, a nonprofit corporation responsible for promoting and improving the reliability of the bulk power transmission system in much of the southeastern United States. While it can vary by a few megawatts each year, SCE&G's pro-rata share of this capacity is always around 200 megawatts.

To analyze these three components of reserve and establish a reserve margin target range, SCE&G employs three methodologies: 1) the component method which analyzes separately each of the three components mentioned above; 2) the traditional and industry standard technique of "Loss of Load Probability," or LOLP, using a range of LOLP from 1 day per year to

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1 day in 10 years; and 3) the largest unit out method. The results of this analysis are summarized in the following table and support a reserve margin target range of 14% to 20%.

	Low MWs	Low %	High MWs	High %
Component Method	766	16.0%	1016	21.3%
LOLP	721	14.4%	1171	23.5%
Largest Unit	644	13.5%	966	20.2%
	644		1171	
Reserve Policy		14.0%		20.0%

By maintaining a reserve margin in the 14 to 20 percent range, the Company addresses the uncertainties related to load and to the availability of generation on its system. It also allows the Company to meet its VACAR obligation. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

d. New Nuclear Capacity

On May 30, 2008, SCE&G filed with the Commission a Combined Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity and for a Base Load Review Order for the construction and operation of two 1,117 net MW nuclear units to be located at the V.C. Summer Nuclear Station near Jenkinsville, South Carolina. Following a full hearing on the Combined Application, the Commission issued Order No. 2009-104(A) granting SCE&G, among other things, a Certificate of Environmental Compatibility and Public Convenience and Necessity.

On March 30, 2012, the United States Nuclear Regulatory Commission issued a combined Construction and Operation License ("COL") to SCE&G for each unit. Both units will have the Westinghouse AP1000 design and use passive safety systems to enhance the safety of the units.

On January 27, 2014, SCE&G and Santee Cooper agreed to increase SCE&G's ownership share from 55% to 60% in three stages. SCE&G will acquire an additional 1% of the 2,234 MWs of capacity when Unit #2 achieves commercial operation which is expected around December 2017 or the first quarter of 2018. An additional 2% will go to SCE&G one year later

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and another 2% one year after that. By December 2019 or the first quarter of 2020, SCE&G will own 60% of both units (670 MWs each) while Santee Cooper will own 40%.

e. Retirement of Coal Plants

When the EPA promulgated its Mercury and Air Toxics Standards ("MATS") on December 21, 2011, SCE&G had six small coal-fired units in its fleet totaling 730 MWs ranging in age from 45 to 57 years that could not meet the emission standards without further modifications to the units. Those six units are displayed in the following table.

Plant Name	Capacity (MW)	Commercialization Date
Canadys 1	90	1962
Canadys 2	115	1964
Canadys 3	180	1967
Urquhart 3	95	1955
McMeekin 1	125	1958
McMeekin 2	125	1958

After a thorough retirement analysis, the Company decided that these six units would be retired when the addition of new nuclear capacity was available as a replacement.[2] As part of this retirement plan the Company has retired Canadys' Units #1, 2 and 3 and has converted Urquhart #3 to be fired with natural gas while dismantling the coal handling facilities at this unit. The capacity (250 MWs) of the remaining two coal-fired units, McMeekin 1&2, is required to maintain system reliability until the new nuclear capacity is available. Under the MATS regulations but with a one year waiver granted by South Carolina Department of Health and Environmental Control ("SCDHEC") these units cannot run on coal after April 15, 2016. The Company is currently looking at ways to bridge, with dispatchable resources, the gap between the MATS compliance date and the availability of the new nuclear capacity.

[2] In announcing its plans to retire the units in its 2012 Integrated Resource Plan, the Company was careful to note that its retirement plans were subject to change if circumstances changed. See SCE&G's 2012 Integrated Resource Plan, at 29 (May 30, 2012) ("Although today's reference resource plan calls for the retirement of the six coal-fired units, the Company will continue to monitor, among other things, developments in environmental regulation and will continue to analyze its options and modify the plan as needed to benefit its customers.").

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f. Renewable Resources

SCE&G continues to monitor the development of renewable sources of energy and looks for economic opportunities to include them in its resource plan.

1. Busbar Costs of Renewable Resources

The following charts show the busbar cost of renewable resources compared to other potential resource additions. The busbar cost is shown in terms of $/MWh at various capacity factors. It is assumed that the overnight capital costs of solar PV and off-shore wind are $3,873 per KW and $6,230 per KW respectively. The capital cost for a combined cycle facility and a combustion turbine facility are $1,023 per KW and $676 per KW respectively. Solar PV and off shore wind can be seen as more costly than traditional sources of power.

There are four charts shown on the next page. The two charts on the left side of the page show the busbar costs with and without the federal investment tax credit ("ITC"). As an approximation it is assumed that the ITC will reduce the capital cost of solar and wind by 30%. The two charts on the right side of the page show the same information but with the vertical axis truncated at $500/MWh thereby displaying more granularity at higher capacity factors.

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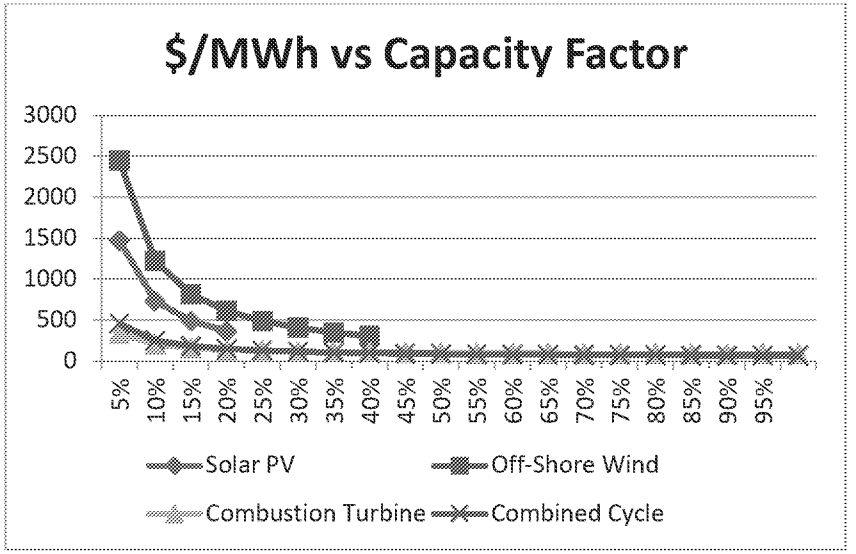

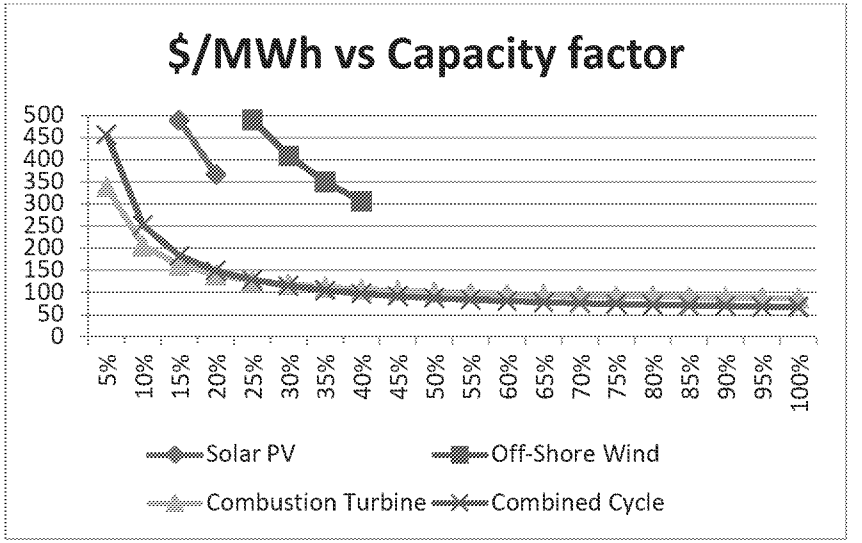

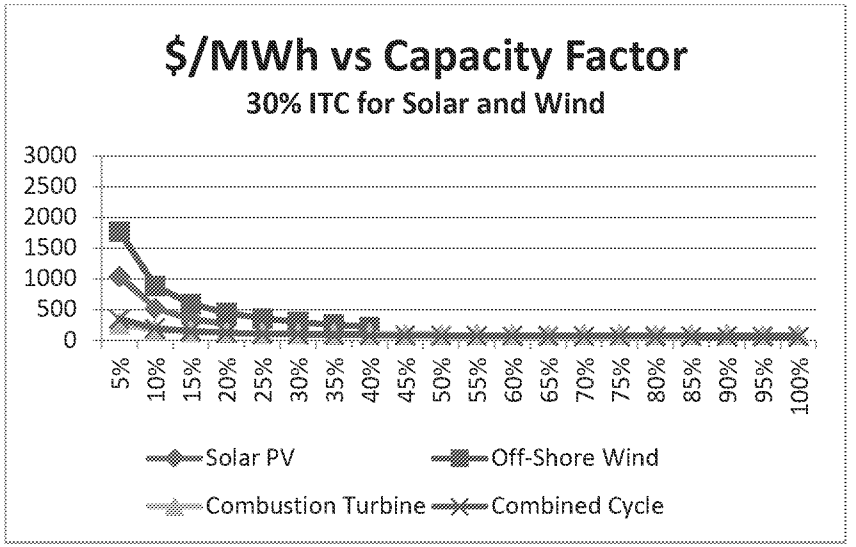

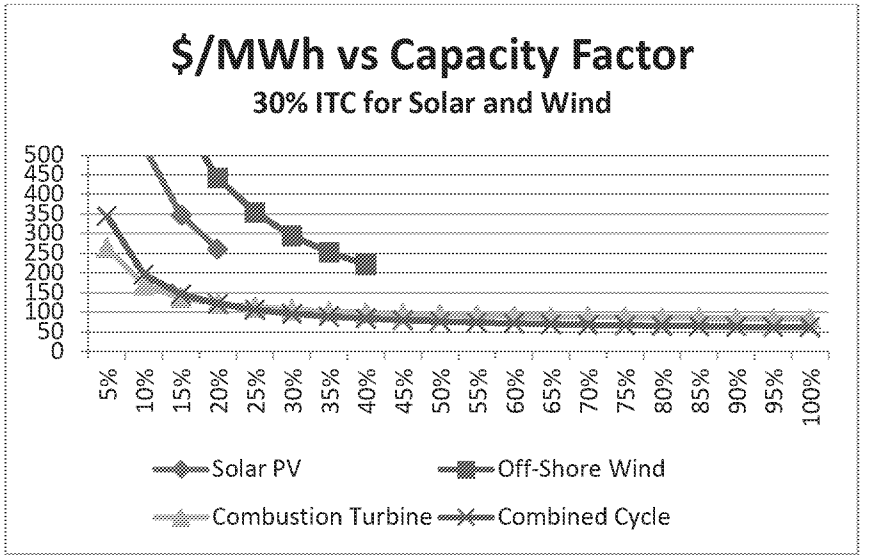

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2. CO_2 Emissions and Renewable Resources

The following table compares several types of generation to SCE&G's new nuclear capacity in terms of CO_2 output, both emitted and avoided, assuming that half gas and half coal generation is being displaced.

Equivalent Avoided CO_2 Emissions to SCE&G's New Nuclear Capacity				
Type	**Avoided CO_2 Emissions**	**Output MWh**	**Capacity MW**	**CO_2 Emissions Tons**
New Nuclear	6,756,327	10,564,560	1,340	0
Solar PV	6,756,327	10,564,560	7,354	0
Offshore Wind	6,756,327	10,564,560	3,260	0
Combined Cycle	6,756,327	25,316,685	3,613	9,434,389

To avoid the same number of tons of CO_2 as 1,340 MWs of nuclear capacity, you would need more than 5 times that capacity in solar PV capacity or almost 2.5 times that capacity in off shore wind capacity or more than 2.5 times that capacity in gas fired combined cycle capacity.

3. The Projected Cost of Distributed Solar Photovoltaic Energy

The National Renewable Energy Laboratory ("NREL") has produced and made available to the public a financial calculator to evaluate renewable technologies. The NREL model known as the System Advisor Model ("SAM") was used to estimate the level cost of solar energy ("LCOE") in South Carolina under several scenarios. See https://sam.nrel.gov for more information on the SAM model. The following table shows the LCOE for a commercial customer seeking a power purchase agreement ("PPA"). The LCOE is reduced by both a federal and a state investment tax credit ("ITC") and by the use of accelerated depreciation, in particular, 5 year MACRS. It assumes the project is financed with 80% debt at 7% interest with a target internal rate of return ("IRR") of 15%. Since the capital cost of a solar PV installation are size and site specific and since the costs continue to change each year, the LCOE is shown for several levels of capital cost.

Levelized Cost of Solar Energy for a Commercial Installation			
Size 2000 KW		Size 200 KW	
Capital Cost $/watt	L.C.O.E. $/MWh	Capital Cost $/watt	L.C.O.E. $/MWh
$3.00	$102.50	$4.00	$121.80
$2.50	$88.30	$3.00	$93.40
$2.00	$74.00	$2.50	$79.20

The following table shows similar results for a residential installation.

Levelized Cost of Solar Energy for a Residential Installation	
Size 5 KW	
Capital Cost $/Watt	L.C.O.E. $/MWh
$6.00	$193.70
$5.00	$155.00
$4.00	$116.30
$3.00	$77.50

4. Potential Impact of Solar PV on the Resource Plan

It is difficult to pinpoint how much and how fast solar photovoltaic energy resources will develop in SCE&G's service territory, but it is evident that these resources will play a role in SCE&G's energy supply in the coming years. The cost of solar panels and associated equipment has been decreasing over the past years. Much of the ongoing and future cost reduction of solar farms is likely to be driven by efficiencies in design and construction, and the pace of reductions is likely to slow, but how far and how fast the costs will drop in the future is not certain. Federal and state tax incentives encourage the installation of solar facilities, but the level of support is likely to change in the future. Finally solar development is encouraged through the policy of net energy metering ("NEM") whereby all solar energy generated at a customer's site is valued at the customer's retail rate. Since much of the utility's fixed costs are recovered through a volumetric, per kWh charge, utilities generally claim that this policy is not sustainable. Conversely, particular solar installations may bring value to the system that is unaccounted for under current rate designs. SCE&G is working to better understand the costs and benefits of solar energy resources on its system so that costs and value are appropriately accounted for. The

following table shows the impact of solar generation when its DC capacity is set to 2% of SCE&G's firm system peak. Approximately 56% of the DC rating of solar capacity will be generating on a summer afternoon and contribute to reducing the summer peak demand. There will be no solar generation at the time of SCE&G's winter peak demand which usually occurs between 7 and 8 am.

Impact When Solar DC Capacity Set to 2% of System Peak						
Year	System Peak MW	Solar DC MW @1%	Summer Peak Impact	Winter Peak Impact	Solar Energy MWH	Percent of Retail Sales
2014	4,786	96	54	0	134,161	0.6%
2015	4,849	97	54	0	135,927	0.6%
2016	4,968	99	56	0	139,263	0.6%
2017	5,074	101	57	0	142,234	0.6%
2018	5,166	103	58	0	144,813	0.6%
2019	5,246	105	59	0	147,056	0.6%
2020	5,319	106	60	0	149,102	0.6%
2021	5,385	108	60	0	150,952	0.6%
2022	5,458	109	61	0	152,999	0.6%
2023	5,540	111	62	0	155,297	0.6%
2024	5,623	112	63	0	157,624	0.6%
2025	5,704	114	64	0	159,895	0.6%
2026	5,790	116	65	0	162,305	0.6%
2027	5,867	117	66	0	164,464	0.6%
2028	5,942	119	67	0	166,566	0.6%

g. Projected Loads and Resources

SCE&G's resource plan for the next 15 years is shown in the table labeled "SCE&G Forecast Loads and Resources - 2014 IRP " on a subsequent page. The resource plan shows the need for additional capacity and identifies, on a preliminary basis, whether the need is for peaking/intermediate capacity or base load capacity.

On line 10 the resource plan shows decreases in capacity which relate to the retirement of coal units as previously discussed. The resource plan shows the addition of peaking capacity on line 8 and the need for any firm one year capacity purchases on line 12. The Company has secured the purchase of 300MWs in the years 2014 through 2016. Capacity is added to maintain the SCE&G's planning reserve margin within the target range of 14% to 20%. The resource plan

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thus constructed represents one possible way to meet the increasing demand of our customers. Before the Company commits to adding a new resource, it will perform a study to determine what type resource will best serve our customers.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with alternatives in the market.

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SCE&G Forecast of Summer Loads and Resources - 2014 IRP

	YEAR	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Load Forecast																
1	Baseline Trend	5046	5113	5272	5407	5525	5632	5734	5830	5921	6023	6125	6227	6332	6430	6525
2	EE Impact	-3	-4	-37	-58	-80	-103	-129	-156	-171	-187	-203	-220	-236	-253	-270
3	Gross Territorial Peak	5043	5109	5235	5349	5445	5529	5605	5674	5750	5836	5922	6007	6096	6177	6255
4	Demand Response	-257	-260	-267	-275	-279	-283	-286	-289	-292	-296	-299	-303	-306	-310	-313
5	Net Territorial Peak	4786	4849	4968	5074	5166	5246	5319	5385	5458	5540	5623	5704	5790	5867	5942
System Capacity																
6	Existing	5282	5287	5290	5293	5293	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753
	Additions															
7	Solar Plant (20 MWs DC)	5	3	3												
8	Peaking/Intermediate										93	93	93	93	93	93
9	Baseload					625	669	46								
10	Retirements						-345									
11	Total System Capacity	5287	5290	5293	5293	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753	6846
12	Firm Annual Purchase	300	300	375	500											
13	Total Production Capability	5587	5590	5668	5793	5918	6242	6288	6288	6288	6381	6474	6567	6660	6753	6846
Reserves																
14	Margin (L13-L5)	801	741	700	719	752	996	969	903	830	841	851	863	870	886	904
15	% Reserve Margin (L14/L5)	16.7%	15.3%	14.1%	14.2%	14.6%	19.0%	18.2%	16.8%	15.2%	15.2%	15.1%	15.1%	15.0%	15.1%	15.2%
16	% NERC Res.Mrgn L14/(L5-L4)	15.9%	14.5%	13.4%	13.4%	13.8%	18.0%	17.3%	15.9%	14.4%	14.4%	14.4%	14.4%	14.3%	14.3%	14.5%

Note: L17 shows the reserve margin calculated according to NERC's new definition. See the following link for details:
http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

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III. Transmission System Assessment and Planning

SCE&G's transmission planning practices develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the system. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for our customers while meeting SCE&G and industry transmission performance standards.

SCE&G has an ongoing process to determine the current and future performance level of the SCE&G transmission system. Numerous internal studies are undertaken that address the service needs of our customers. These needs include: 1) distributed load growth of existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers and 3) customers who use only transmission services on the SCE&G system.

SCE&G has developed and adheres to a set of internal Long Range Planning Criteria which can be summarized as follows:

> *The requirements of the SCE&G "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*
>
> *a. Loss of any bus and associated facilities operating at a voltage level of 115kV or above*
> *b. Loss of any line operating at a voltage level of 115kV or above*
> *c. Loss of entire generating capability in any one plant*
> *d. Loss of all circuits on a common structure*
> *e. Loss of any transmission transformer*
> *f. Loss of any generating unit simultaneous with the loss of a single transmission line*
>
> *Outages more severe are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.*

Furthermore, SCE&G subscribes to the set of mandatory Electric Reliability Organization ("ERO"), also known as the North American Electric Reliability Corporation ("NERC"),

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Reliability Standards for Transmission Planning, as approved by the NERC Board of Trustees and the Federal Energy Regulatory Commission ("FERC").

SCE&G assesses and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC website http://www.nerc.com/.

The SCE&G transmission system is interconnected with Duke Energy Progress, Duke Energy Carolinas, South Carolina Public Service Authority ("Santee Cooper"), Georgia Power ("Southern Company") and the Southeastern Electric Power Administration ("SEPA") systems. Because of these interconnections with neighboring systems, system conditions on other systems can affect the capabilities of the SCE&G transmission system and also system conditions on the SCE&G transmission system can affect other systems. SCE&G participates with other transmission planners throughout the southeast to develop current and future power flow and stability models of the integrated transmission grid for the NERC Eastern Interconnection. All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, SCE&G evaluates its current and future transmission system for compliance with the SCE&G Long Range Planning Criteria and the NERC Reliability Standards.

To ensure the reliability of the SCE&G transmission system while considering conditions on other systems and to assess the reliability of the integrated transmission grid, SCE&G participates in assessment studies with neighboring transmission planners in South Carolina, North Carolina and Georgia. Also, SCE&G on a periodic and ongoing basis participates with other transmission planners throughout the southeast to assess the reliability of the southeastern integrated transmission grid for the long-term horizon (up to 10 years) and for upcoming seasonal (summer and winter) system conditions.

The following is a list of joint studies with neighboring transmission owners completed over the past year:

1. SERC NTSG Reliability 2013 Summer Study
2. SERC NTSG Reliability 2013/2014 Winter Study
3. SERC LTSG 2017 Summer Peak Study
4. SERC NTSG OASIS 2013 January Studies (13Q1)
5. SERC NTSG OASIS 2013 April Studies (13Q2)
6. SERC NTSG OASIS 2013 July Studies (13Q3)
7. SERC NTSG OASIS 2013 October Studies (13Q4)
8. SERC DSG 2014 Summer Peak/Shoulder/Light Load/Winter Peak, 2015 Summer Peak, and 2019 Summer Peak/Light Load/Winter Peak Dynamics Studies

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9. ERAG 2018 Summer Transmission System Assessment
10. CTCA 2019 Summer Study
11. CTCA 2024 Carolinas Wind Study
12. SCRTP 2014 Summer Peak, 2013/2014 Winter Peak, 2018 Summer Peak, and 2023 Summer Peak Transfer Studies
13. EIPC 2018 & 2023 Roll-Up Integration Studies

where the acronyms used above have the following reference:

SERC - SERC Reliability Corporation
NTSG - Near Term Study Group of SERC
LTSG - Long Term Study Group of SERC
OASIS - Open Access Same-time Information System
DSG - Dynamics Study Group
ERAG - Eastern Interconnection Reliability Assessment Group
CTCA - Carolinas Transmission Coordination Arrangement
SCRTP - South Carolina Regional Transmission Planning
EIPC - Eastern Interconnection Planning Collaborative

These activities, as discussed above, provide for a reliable and cost effective transmission system for SCE&G customers.

Eastern Interconnection Planning Collaborative (EIPC)

The Eastern Interconnection Planning Collaborative ("EIPC") was initiated by a coalition of regional Planning Authorities. These Planning Authorities are entities listed on the NERC compliance registry as Planning Authorities and represent the entire Eastern Interconnection. The EIPC was founded to be a broad-based, transparent collaborative process among all interested stakeholders:

- State and Federal policy makers
- Consumer and environmental interests
- Transmission Planning Authorities
- Market participants generating, transmitting or consuming electricity within the Eastern Interconnection

The EIPC provides a grass-roots approach which builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities. This approach provides coordinated interregional analysis for the entire

Eastern Interconnection guided by the consensus input of an open and transparent stakeholder process.

The EIPC purpose is to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders. This work builds upon, rather than replaces, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes are informed by the EIPC analysis efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various policy options.

FERC Order 1000 – Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order 1000 - Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities. With respect to transmission planning, this Final Rule: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from FERC-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Also, this Final Rule requires that each public utility transmission provider participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures required by this Final Rule. Each cost allocation method must satisfy six cost allocation principles.

On October 11, 2012, SCE&G filed with the FERC its proposed actions to achieve compliance with the Regional requirements of Order 1000. On April 18, 2013, FERC conditionally accepted SCE&G's filing subject to SCE&G providing more clarity and adding greater detail to SCE&G's compliance plans. On October 15, 2013, SCE&G submitted a second

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filing addressing these points. FERC is currently reviewing SCE&G's second filing. SCE&G worked with its neighboring planning region (Southeastern Regional Transmission Planning "SERTP") to develop actions to achieve compliance with the interregional requirements of Order 1000. On July 10, 2013, SCE&G filed with the FERC its proposed actions to achieve compliance with the Interregional requirements of Order 1000. FERC is currently reviewing SCE&G's Interregional compliance filing.

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Appendix A

Short Range Methodology

This section presents the development of the short-range electric sales forecasts for the Company. Two years of monthly forecasts for electric customers, average usage, and total usage were developed according to Company class and rate structures, with industrial customers further classified into SIC (Standard Industrial Classification) codes. Residential customers were classified by housing type (single family, multi-family, and mobile homes), rate, and by a statistical estimate of weather sensitivity. For each forecasting group, the number of customers and either total usage or average usage was estimated for each month of the forecast period.

The short-range methodologies used to develop these models were determined primarily by available data, both historical and forecast. Monthly sales data by class and rate are generally available historically. Daily heating and cooling degree data for Columbia and Charleston are also available historically, and were projected using a 15-year average of the daily values. Industrial production indices are also available by SIC on a quarterly basis, and can be transformed to a monthly series. Therefore, sales, weather, industrial production indices, and time dependent variables were used in the short range forecast. In general, the forecast groups fall into two classifications, weather sensitive and non-weather sensitive. For the weather sensitive classes, regression analysis was the methodology used, while for the non-weather sensitive classes regression analysis or time series models based on the autoregressive integrated moving average (ARIMA) approach of Box-Jenkins were used.

The short range forecast developed from these methodologies was also adjusted for federally mandated lighting programs, new industrial loads, terminated contracts, or economic factors as discussed in Section 3.

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Regression Models

Regression analysis is a method of developing an equation which relates one variable, such as usage, to one or more other variables which help explain fluctuations and trends in the first. This method is mathematically constructed so that the resulting combination of explanatory variables produces the smallest squared error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. Several statistics which indicate the success of the regression analysis fit are shown for each model. Several of these indicators are R^2, Root Mean Squared Error, Durbin-Watson Statistic, F-Statistic, and the T-Statistics of the Coefficient. PROC REG of SAS[1] was used to estimate all regression models. PROC AUTOREG of SAS was used if significant autocorrelation, as indicated by the Durbin-Watson statistic, was present in the model.

Two variables were used extensively in developing weather sensitive average use models: heating degree days ("HDD") and cooling degree days ("CDD"). The values for HDD and CDD are the average of the values for Charleston and Columbia. The base for HDD was 60° and for CDD was 75°. In order to account for cycle billing, the degree day values for each day were weighted by the number of billing cycles which included that day for the current month's billing. The daily weighted degree day values were summed to obtain monthly degree day values. Billing sales for a calendar month may actually reflect consumption that occurred in the previous month based on weather conditions in that period and also consumption occurring in the current month. Therefore, this method more accurately reflects the impact of weather variations on the consumption data.

The development of average use models began with plots of the HDD and CDD data versus average use by month. This process led to the grouping of months with similar average use patterns. Summer and winter groups were chosen, with the summer models including the

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months of May through October, and the winter models including the months of November through April. For each of the groups, an average use model was developed. Total usage models were developed with a similar methodology for the municipal customers. For these customers, HDD and CDD were weighted based on Cycle 20 distributions. This is the last reading date for bills in any given month, and is generally used for larger customers.

Simple plots of average use over time revealed significant changes in average use for some customer groups. Three types of variables were used to measure the effect of time on average use:

1. Number of months since a base period;
2. Dummy variable indicating before or after a specific point in time; and,
3. Dummy variable for a specific month or months.

Some models revealed a decreasing trend in average use, which is consistent with conservation efforts and improvements in energy efficiency. However, other models showed an increasing average use over time. This could be the result of larger houses, increasing appliance saturations, lower real electricity prices, and/or higher real incomes.

ARIMA Models

Autoregressive integrated moving average ("ARIMA") procedures were used in developing the short range forecasts. For various class/rate groups, they were used to develop customer estimates, average use estimates, or total use estimates.

ARIMA procedures were developed for the analysis of time series data, i.e., sets of observations generated sequentially in time. This Box-Jenkins approach is based on the assumption that the behavior of a time series is due to one or more identifiable influences. This method recognizes three effects that a particular observation may have on subsequent values in the series:

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1. A decaying effect leads to the inclusion of autoregressive (AR) terms;

2. A long-term or permanent effect leads to integrated (I) terms; and,

3. A temporary or limited effect leads to moving average (MA) terms.

Seasonal effects may also be explained by adding additional terms of each type (AR, I, or MA).

The ARIMA procedure models the behavior of a variable that forms an equally spaced time series with no missing values. The mathematical model is written:

$$Z_t = u + Y_i \ (B) X_{i,t} + q(B)/ f(B) a_t$$

This model expresses the data as a combination of past values of the random shocks and past values of the other series, where:

t	indexes time
B	is the backshift operator, that is $B(X_t) = X_{t-1}$
Z_t	is the original data or a difference of the original data
f(B)	is the autoregressive operator, $f(B) = 1 - f_1 B - \ldots - f_1 B^p$
u	is the constant term
q(B)	is the moving average operator, $q(B) = 1 - q_1 B - \ldots - q_q B^q$
a_t	is the independent disturbance, also called the random error
$X_{i,t}$	is the ith input time series
$y_i(B)$	is the transfer function weights for the ith input series (modeled as a ratio of polynomials)
$y_i(B)$	is equal to $w_i(B)/ d_i(B)$, where $w_i(B)$ and $d_i(B)$ are polynomials in B.

The Box-Jenkins approach is most noted for its three-step iterative process of identification, estimation, and diagnostic checking to determine the order of a time series. The autocorrelation and partial autocorrelation functions are used to identify a tentative model for univariate time series. This tentative model is estimated. After the tentative model has been

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fitted to the data, various checks are performed to see if the model is appropriate. These checks involve analysis of the residual series created by the estimation process and often lead to refinements in the tentative model. The iterative process is repeated until a satisfactory model is found.

Many computer packages perform this iterative analysis. PROC ARIMA of (SAS/ETS)[2] was used in developing the ARIMA models contained herein. The attractiveness of ARIMA models comes from data requirements. ARIMA models utilize data about past energy use or customers to forecast future energy use or customers. Past history on energy use and customers serves as a proxy for all the measures of factors underlying energy use and customers when other variables were not available. Univariate ARIMA models were used to forecast average use or total usage when weather-related variables did not significantly affect energy use or alternative independent explanatory variables were not available.

Footnotes

1. SAS Institute, Inc., SAS/STAT™ Guide for Personal Computers, Version 6 Edition. Cary, NC: SAS Institute, Inc., 1987.

2. SAS Institute, Inc., SAS/ETS User's Guide, Version 6, First Edition. Cary, NC: SAS Institute, Inc., 1988.

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Electric Sales Assumptions

For short-term forecasting, over 30 forecasting groups were defined using the Company's customer class and rate structures. Industrial (Class 30) Rate 23 was further divided using SIC codes. In addition, twenty-eight large industrial customers were individually projected. The residential class was disaggregated into several sub-groups, starting first with rate. Next, a regression analysis was done to separate customers into two categories, "more weather-sensitive" and "less weather sensitive". Generally speaking, the former group is associated with higher average use per customer in winter months relative to the latter group. Finally, these categories were divided by housing type (single family, multi-family, and mobile homes). Each municipal account represents a forecasting group and was also individually forecast. Discussions were held with Industrial Marketing and Economic Development representatives within the Company regarding prospects for industrial expansions or new customers, and adjustments made to customer, rate, or account projections where appropriate. Table 1 contains the definition for each group and Table 2 identifies the methodology used and the values forecasted by forecasting groups.

The forecast for Company Use is based on historic trends and adjusted for Summer 1 nuclear plant outages. Unaccounted energy, which is the difference between generation and sales and represents for the most part system losses, is usually between 4-5% of total territorial sales. The average annual loss for the three previous years was 4.6%, and this value was assumed throughout the forecast. The monthly allocations for unaccounted use were based on a regression model using normal total degree-days for the calendar month and total degree-days weighted by cycle billing. Adding Company Use and unaccounted energy to monthly territorial sales produces electric generation requirements.

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TABLE 1
Short-Term Forecasting Groups

Class Number	Class Name	Rate/SIC Designation	Comment
10	Residential Less Weather-Sensitive	Single Family Multi Family	Rates 1, 2, 5, 6, 8, 18, 25, 26, 62, 64 67, 68, 69
910	Residential More Weather-Sensitive	Mobile Homes	
20	Commercial Less Weather-Sensitive	Rate 9	Small General Service
		Rate 12	Churches
		Rate 20, 21	Medium General Service
		Rate 22	Schools
		Rate 24	Large General Service
		Other Rates	3, 10, 11, 14, 16, 18, 25, 26 29, 62, 67, 69
920	Commercial Space Heating More Weather-Sensitive	Rate 9	Small General Service
30	Industrial Non-Space Heating	Rate 9	Small General Service
		Rate 20, 21	Medium General Service
		Rate 23, SIC 22	Textile Mill Products
		Rate 23, SIC 24	Lumber, Wood Products, Furniture and Fixtures (SIC Codes 24 and 25)
		Rate 23, SIC 26	Paper and Allied Products
		Rate 23, SIC 28	Chemical and Allied Products
		Rate 23, SIC 30	Rubber and Miscellaneous Products
		Rate 23, SIC 32	Stone, Clay, Glass, and Concrete
		Rate 23, SIC 33	Primary Metal Industries; Fabricated Metal Products; Machinery; Electric and Electronic Machinery, Equipment and Supplies; and Transportation Equipment (SIC Codes 33-37)
		Rate 23, SIC 99	Other or Unknown SIC Code*
		Rate 27, 60	Large General Service
		Other	Rates 18, 25, and 26
60	Street Lighting	Rates 3, 9, 13, 17, 18, 25, 26, 29, and 69	
70	Other Public Authority	Rates 3, 9, 20, 21, 25, 26, 29, 65 and 66	
92	Municipal	Rate 60, 61	Three Individual Accounts

*Includes small industrial customers from all SIC classifications that were not previously forecasted individually. Industrial Rate 23 also includes Rate 24. Commercial Rate 24 also includes Rate 23.

TABLE 2
Summary of Methodologies Used To Produce
The Short Range Forecast

Value Forecasted	Methodology	Forecasting Groups
Average Use	Regression	Class 10, All Groups Class 910, All Groups Class 20, Rates 9, 12, 20, 22, 24, 99 Class 920, Rate 9 Class 70, Rate 3
Total Usage	ARIMA/ Regression	Class 30, Rates 9, 20, 99, and 23, for SIC = 91 and 99 Class 930, Rate 9 Class 60 Class 70, Rates 65, 66
	Regression	Class 92, All Accounts Class 97, One Account
Customers	ARIMA	Class 10, All Groups Class 910, All Groups Class 20, All Rates Class 920, Rate 9 Class 30, All Rates Except 60, 99, and 23 for SIC = 22, 24, 26, 28, 30, 32, 33, and 91 Class 930, Rate 9 Class 60 Class 70, Rate 3

Appendix B

Long Range Sales Forecast

Electric Sales Forecast

This section presents the development of the long-range electric sales forecast for the Company. The long-range electric sales forecast was developed for six classes of service: residential, commercial, industrial, street lighting, other public authorities, and municipals. These classes were disaggregated into appropriate subgroups where data was available and there were notable differences in the data patterns. The residential, commercial, and industrial classes are considered the major classes of service and account for over 93% of total territorial sales. A customer forecast was developed for each major class of service. For the residential class, forecasts were also produced for those customers categorized into two groups, more and less weather-sensitive. They were further disaggregated into housing types of single family, multi-family and mobile homes. In addition, two residential classes and residential street lighting were evaluated separately. These subgroups were chosen based on available data and differences in the average usage levels and/or data patterns. The industrial class was disaggregated into two digit SIC code classification for the large general service customers, while smaller industrial customers were grouped into an "other" category. These subgroups were chosen to account for the differences in the industrial mix in the service territory. With the exception of the residential group, the forecast for sales was estimated based on total usage in that class of service. The number of residential customers and average usage per customer were estimated separately and total sales were calculated as a product of the two.

The forecast for each class of service was developed utilizing an econometric approach. The structure of the econometric model was based upon the relationship between the variable to be forecasted and the economic environment, weather, conservation, and/or price.

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Forecast Methodology

Development of the models for long-term forecasting was econometric in approach and used the technique of regression analysis. Regression analysis is a method of developing an equation which relates one variable, such as sales or customers, to one or more other variables that are statistically correlated with the first, such as weather, personal income or population growth. Generally, the goal is to find the combination of explanatory variables producing the smallest error between the historic actual values and those estimated by the regression. The output of the regression analysis provides an equation for the variable being explained. In the equation, the variable being explained equals the sum of the explanatory variables each multiplied by an estimated coefficient. Various statistics, which indicate the success of the regression analysis fit, were used to evaluate each model. The indicators were R^2, mean squared Error of the Regression, Durbin-Watson Statistic and the T-Statistics of the Coefficient. PROC REG and PROC AUTOREG of SAS were used to estimate all regression models. PROC REG was used for preliminary model specification, elimination of insignificant variables, and also for the final model specifications. Model development also included residual analysis for incorporating dummy variables and an analysis of how well the models fit the historical data, plus checks for any statistical problems such as autocorrelation or multicollinearity. PROC AUTOREG was used if autocorrelation was present as indicated by the Durbin-Watson statistic.

Prior to developing the long-range models, certain design decisions were made:

- The multiplicative or double log model form was chosen. This form allows forecasting based on growth rates, since elasticities with respect to each explanatory variable are given directly by their respective regression coefficients. Elasticity explains the responsiveness of changes in one variable (e.g. sales) to changes in any other variable (e.g. price). Thus, the elasticity coefficient can be applied to the forecasted growth rate of the explanatory variable

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to obtain a forecasted growth rate for a dependent variable. These projected growth rates were then applied to the last year of the short range forecast to obtain the forecast level for customers or sales for the long range forecast. This is a constant elasticity model, therefore, it is important to evaluate the reasonableness of the model coefficients.

- One way to incorporate conservation effects on electricity is through real prices or time trend variables. Models selected for the major classes would include these variables, if they were statistically significant.
- The remaining variables to be included in the models for the major classes would come from four categories:
  1. Demographic variables - Population.
  2. Measures of economic well-being or activity: real personal income, real per capita income, employment variables, and industrial production indices.
  3. Weather variables - average summer/winter temperature or heating and cooling degree-days.
  4. Variables identified through residual analysis or knowledge of political changes, major economics events, etc. (e.g., the gas price spike in 2005 attributable to Hurricane Katrina and recession versus non-recession years).

Standard statistical procedures were used to obtain preliminary specifications for the models. Model parameters were then estimated using historical data and competitive models were evaluated on the basis of:

- Residual analysis and traditional "goodness of fit" measures to determine how well these models fit the historical data and whether there were any statistical problems such as autocorrelation or multicollinearity.
- An examination of the model results for the most recently completed full year.

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- An analysis of the reasonableness of the long-term trend generated by the models. The major criteria here was the presence of any obvious problems, such as the forecasts exceeding all rational expectations based on historical trends and current industry expectations.
- An analysis of the reasonableness of the elasticity coefficient for each explanatory variable. Over the years a host of studies have been conducted on various elasticities relating to electricity sales. Therefore, one check was to see if the estimated coefficients from Company models were in-line with others. As a result of the evaluative procedure, final models were obtained for each class.
- The drivers for the long-range electric forecast included the following variables.

Service Area Housing Starts
Service Area Real Per Capita Income
Service Area Real Personal Income
State Industrial Production Indices
Real Price of Electricity
Average Summer Temperature
Average Winter Temperature
Heating Degree Days
Cooling Degree Days

The service area data included Richland, Lexington, Berkeley, Dorchester, Charleston, Aiken and Beaufort counties, which account for the vast majority of total territorial electric sales. Service area historic data and projections were used for all classes with the exception of the industrial class. Industrial productions indices were only available on a statewide basis, so forecasting relationships were developed using that data. Since industry patterns are generally

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based on regional and national economic patterns, this linking of Company industrial sales to a larger geographic index was appropriate.

Economic Assumptions

In order to generate the electric sales forecast, forecasts must be available for the independent variables. The forecasts for the economic and demographic variables were obtained from Global Insight, Inc. and the forecasts for the price and weather variables were based on historical data. The trend projection developed by Global Insight is characterized by slow, steady growth, representing the mean of all possible paths that the economy could follow if subject to no major disruptions, such as substantial oil price shocks, untoward swings in policy, or excessively rapid increases in demand.

Average summer temperature or CDD (Average of June, July, and August temperature) and average winter temperature or HDD (Average of December (previous year), January and February temperature) were assumed to be equal to the normal values used in the short range forecast.

After the trend econometric forecasts were completed, reductions were made to account for higher air-conditioning efficiencies, DSM programs, and the replacement of incandescent light bulbs with more efficient CFL or LED light bulbs. Industrial sales were increased if new customers are anticipated or if there are expansions among existing customers not contained in the short-term projections.

Peak Demand Forecast

This section describes the procedures used to create the long-range summer and winter peak demand forecasts. It also describes the methodology used to forecast monthly peak demands. Development of summer peak demands will be discussed initially, followed by the construction of winter peaks.

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Summer Peak Demand

The forecast of summer peak demands was developed with a load factor methodology. This methodology may be characterized as a building-block approach because class, rate, and some individual customer peaks are separately determined and then summed to derive the territorial peak.

Briefly, the following steps were used to develop the summer peak demand projections. Load factors for selected classes and rates were first calculated from historical data and then used to estimate peak demands from the projected energy consumption among these categories. Next, planning peaks were determined for a number of large industrial customers. The demands of these customers were forecasted individually. Summing these class, rate, and individual customer demands provided the forecast of summer territorial peak demand. Next, savings identified from SCE&G's demand-side management programs were removed. Finally, the incremental reductions in demand resulting from the Company's standby generator and interruptible programs were subtracted from the peak demand forecast. This calculation gave the firm summer territorial peak demand, which was used for planning purposes.

Load Factor Development

As mentioned above, load factors are required to calculate KW demands from KWH energy. This can be seen from the following equation, which shows the relationship between annual load factors, energy, and demand:

$$\textit{Load Factor} = \textit{Energy}/(\textit{Demand} \times 8760)$$

The load factor is thus seen to be a ratio of total energy consumption relative to what it might have been if the customer had maintained demand at its peak level throughout the year. The value of a system coincident load factor will usually range between 0 and 1, with lower values indicating more variation in a customer's consumption patterns, as typified by residential users with

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relatively large space-conditioning loads. Conversely, higher values result from more level demand patterns throughout the year, such as those seen in the industrial sector.

Rearrangement of the above equation makes it possible to calculate peak demand, given energy and a corresponding load factor. This form of the equation is used to project peak demand herein. The question then becomes one of determining an appropriate load factor to apply to projected energy sales.

The load factors used for the peak demand forecast were not based on one-hour coincident peaks. Instead, it was determined that use of a 4-hour average class peak was more appropriate for forecasting purposes. This was true for two primary reasons. First, analysis of territorial peaks showed that all of the summer peaks had occurred between the hours of 2 and 6 PM. However, the distribution of these peaks between those four hours was fairly evenly spread. It was thus concluded that while the annual peak would occur during the 4-hour band, it would not be possible to say with a high degree of confidence during which hour it would happen.

Second, the coincident peak demand of the residential and commercial classes depended on the hour of the peak's occurrence. This was due to the former tending to increase over the 4-hour band, while the latter declined. Thus, load factors based on peaks occurring at, say, 2 PM, would be quite different from those developed for a 5 PM peak. It should also be noted that the class contribution to peak is quite stable for groups other than residential and commercial. This means that the 4-hour average class demand, for say, municipals, was within 2% of the 1-hour coincident peak. Consequently, since the hourly probability of occurrence was roughly equal for peak demand, it was decided that a 4-hour average demand was most appropriate for forecasting purposes.

The effect of system line losses were embedded into the class load factors so they could be applied directly to customer level sales and produce generation level demands. This was a convenient way of incorporating line losses into the peak demand projections.

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Energy Projections

For those categories whose peak demand was to be projected from KWH sales, the next requirement was a forecast of applicable sales on an annual basis. These projections were utilized in the peak demand forecast construction. In addition, street light sales were excluded from forecast sales levels when required, since there is no contribution to peak demand from this type of sale.

Combining load factors and energy sales resulted in a preliminary, or unadjusted peak demand forecast by class and/or rate. The large industrial customers whose peak demands were developed separately were also added to this forecast.

Derivation of the planning peak required that the impact of demand reduction programs be subtracted from the unadjusted peak demand forecast. This is true because the capacity expansion plan is sized to meet the firm peak demand, which includes the reductions attributable to such programs.

Winter Peak Demand

To project winter peaks actual winter peak demands were correlated with three primary explanatory factors: total territorial energy, customers, and weather during the day of the winter peak's occurrence. Other dummy variables were also included in the model to account for unusual events, such as recessions or extremely cold winters.

The logic behind the choice of these variables as determinants of winter peak demand is straightforward. Over time, growth in total territorial load is correlated with economic growth and activity in SCE&G's service area, and as such may be used as a proxy variable for those economic factors, which cause winter peak demand to change. It should be noted that the winter peak for any given year by industry convention is defined as occurring after the summer peak for that year. The winter period for each year is December of that year, along with January and February of the following year. For example, the winter peak in 1968 of 962 MW occurred on December 11, 1968,

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while the winter peak for 1969 of 1,126 MW took place on January 8, 1970. In addition to economic factors, weather also causes winter peak demand to fluctuate, so the impact of this element was measured by two variables: the average of heating degree days (HDD) experienced on the winter peak day in Columbia and Charleston and the minimum temperature on the peak day. The presence of a weather variable reduces the bias which would exist in the other explanatory variables' coefficients if weather were excluded from the regression model, given that the weather variable should be included. When the actual forecast of winter peak demand was calculated, the normal value of heating degree-days over the sample period was used. Although the ratio of winter to summer peak demands fluctuated over the sample period, it did show an increase over time. A primary cause for this increasing ratio was growth in the number of electric space heating customers. Due to the introduction and rapid acceptance of heat pumps over the past three decades, space-heating residential customers increased from less than 5,000 in 1965 to almost 217,000 in 2004, a 10.2% annual growth rate. However, this growth slowed dramatically in the 1990's, so the expectation is that the ratio of summer to winter peaks will change slowly in the future.

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Message

From: Care2 [petitionquestions@care2team.com]
on behalf of Joseph Wissman [info@care2.com]
Sent: 10/25/2014 4:08:56 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Save Monarch Butterflies From Monsanto!

Oct 25, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

The Monarch butterfly population in North America has been shrinking at an alarming rate because a significant portion of their breeding habitat is being destroyed by herbicides used on genetically engineered (GE) crops. Milkweeds are critical to the Monarch's survival because they are the only plants Monarch larvae will eat, but they are being decimated by the rampant use of Roundup (glyphosate) used in conjunction with Monsanto's Roundup Ready (TM) GE crops.

To protect Monarchs, we must protect their critical habitat. I urge President Obama to direct the Environmental Protection Agency and the Department of Agriculture to protect Monarch butterflies by stopping the approval of Monsanto's Roundup Ready (TM) and other glyphosate-resistant and pesticide-promoting genetically engineered crops.

Sincerely,

Mr. Joseph Wissman
[redacted] Meramec
Ex. 6 Personal Privacy (PP)

Message

From: EUEC [pdayal@euec.ccsend.com]
on behalf of EUEC [pdayal@euec.com]
Sent: 8/23/2016 2:05:12 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Call for Abstracts - EUEC 2017: San Diego, CA - DEADLINE APPROACHING

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Talen Energy Corp
Unpacking the Latest Portfolio Developments

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Still looking to add plants, but expect nominal share repurchase with 3Q

Given the significant decline in shares in 3Q we see mgmt as posed to announce a modest buyback w/ 3Q results on 11/5 (likely ~small) to placate shareholder demands. We continue to see execution on further portfolio power transactions as critical (mgmt has expressed interest in both AEP and EFH). Sparkspread has also recently noted that Engies' US power portfolio is on the market; TLN mgmt confirmed it is open to this predominantly gas portfolio (~11GW) as well. Transformation to reduce operational risk remains key, beyond just reaping potential SG&A benefits of a combined portfolio.

Selling 399MW CP Crane coal plant in MD for immaterial proceeds

TLN announced its latest divestment package sale, formalizing the sale of CP Crane asset to affiliate of Avenue Capital for immaterial proceeds, consistent with our expectations of value for the asset, which has likely till ~2020 left prior to implementation of new MD NO_x regulations. The value of the plant would appear to be principally driven by the potential for outsized energy revenue in volatile winter months in the coming ~4-year period (see our projections below). The announcement follows AES' decision to retire its Beaver Valley coal plant in Western PA following an inability to find a new offtaker for the project (and opting against gas conversion too).

Pulling the debt deal to await better times – using revolver liquidity for now

TLN mgmt opted to pull its $400Mn term loan B debt capital raise Friday due to market conditions (initial pricing was L+350). The company will opt to make use of its existing $1.85 Bn credit facility in the near-term. The deal was contemplated as a portion of the $1.175Bn MACH Gen acquisition announced in July. Timing of Holtwood/Ironwood divestiture proceeds is expected by 1Q16, whereas the MACH Gen acquisition is expected to close by YE15.

Valuation: Maintain $11 PT; near-term pressure could be Riverstone lockup

Beyond 3Q repurchase update with 3Q results, we suspect the next point of pressure could emerge around the Nov 30th Riverstone lockup expiration (35% of shares). We flag that its pending petition before FERC remains to approve its 'Option 3' divestment package. We think shares will trade as a function of power fluctuations (a potential headwind given 3Q update of MtM guidance) as well as expectations around execution of a deal. Valuation is based on 2017E sum-of-the-parts.

How do we think about TLN and Dealmaking

We see a repurchase as simply to appease shareholders, but expect management to expound on the merits of strategic repoisitioning of the company, rather than buying back shares almost no matter how cheap the company. The need to dilute down the concentrated asset risk in the TLN portfolio is unique in the power & utility space, requiring management to continue to add assets beyond those pending acquisition as part of the MachGEN deal. Despite its recent underperformance, we see the underperformance as warranted from doing simple commodity adjustments for MtM moves in power and gas in the quarter, with a positive offset from the latest asset sales of its Hydro and CCGT assets at a premium to market expectations.

How does the Crane sale look?

Talen divested 399MW of coal with immaterial proceeds.

On Friday Talen disclosed that it was selling its 399MW C.P. Crane coal plant to an unnamed affiliate of Avenue Capital for an undisclosed sum that management believes is immaterial. For context, in June Talen announced the sale of its renewable segment and did not disclose a transaction price in the press release; however, did not call the proceeds immaterial. In its second quarter 10Q the renewable transaction value was disclosed as $116Mn.

Crane has environmental compliance uncertainty in ~2020 as disclosed by management.

We estimate that Crane will generate ~$30Mn in gross cash flow (pre-capex) in 2016-2019 and see environmental regulations as potentially compelling retirement in 2020. As a result we believe the ultimate sales price is modestly below $50Mn, sending a negative signal for PJM assets (3x 2017E EV / EBITDA) even when considering the environmental uncertainties. Specifically Crane has SNCR technology which management believes could require additional "controls or operational changes" to comply in 2020. Talen also points towards modifications necessary to meet 316(b) intake water compliance and has previously stated that it can burn ultra-low sulfur Adaro coal for carbon compliance with MATS.

Key considerations around the plant also include whether TLN can take advantage of portfolio averaging across its portfolio still as part of the MD NO_x regulations and what liabilities have been transferred with the sale?

Figure 1: C.P. Crane Mini Model – limited EBITDA and FCF

C.P. Crane Mini Model	2014A	2015	2016	2017	2018	2019
Capacity (MW)	399	399	399	399	399	399
Capacity Factor, UBSe	14.6%	20.0%	20.0%	20.0%	20.0%	20.0%
PJM-West Peak ($/MWh), Bias for Super-Peak	$56.8	$57.9	$54.1	$51.9	$50.0	$50.6
Variable Cost (Coal & Dispatch) ($/MWh)	($26.9)	($27.8)	($28.6)	($28.6)	($28.6)	($28.6)
Energy Margin ($MWh)	$29.80	$30.16	$25.53	$23.28	$21.41	$22.03
Generation (TWh)	0.5	0.7	0.7	0.7	0.7	0.7
Energy Margin ($Mn)	$15.2	$21.1	$17.8	$16.3	$15.0	$15.4
PJM SWMAAC Capacity Payment ($/MW-day)	$174	$155	$148	$144	$159	$50
Capacity Revenue ($Mn)	$22	$19	$18	$18	$20	$6
O&M ($/kW-yr), UBSe	60	60	60	60	60	60
O&M ($ Mn)	23.9	23.9	23.9	23.9	23.9	23.9
EBITDA	**12.7**	**16.3**	**12.2**	**10.2**	**10.7**	**(2.3)**
	16.3			10.2	9.94	(2.01)

Source: Company Filings, Platts, SNL Energy, and UBS Estimates

Management also stated that the asset's net income, adjusted EBITDA, and cash flow was expected to be immaterial in FY16; we provide our mini-model estimates above. The transaction is expected to close in 1Q15. As a reminder, Talen has requested that the FERC approve its motion to create a third option for its required Riverstone/PPL Supply market power mitigation divestitures.

Sum-of-the-Parts Valuation

Valuation remains based on 2017E sum-of-the-parts. We have adjusted for the latest transactions including (1) accretion on the Ironwood/Holtwood sales and (2) value from MACH Gen portfolio purchase.

Figure 2: Talen Valuation: Unchanged PT $11/sh

Talen Energy - 2017E	UBS	EV/EBITDA Multiples			Valuation Cases		
	EBITDA	Low	Base	High	Low	Base	High
PPL Supply: Wholesale	308	6.0x	7.0x	8.0x	$1,847	$2,155	$2,463
Less: Ironwood & Hydro	(126)	6.0x	7.0x	8.0x	($757)	($884)	($1,010)
PPL EnergyPlus: Market & Trading	32	4.0x	5.0x	6.0x	$128	$160	$192
Total PPL Supply	214	5.7x	6.7x	7.7x	$1,217	$1,431	$1,644
Raven, Jade, Sapphire, Power	154	6.0x	7.0x	8.0x	$926	$1,080	$1,234
Less: Crane, Wagner 2, & Bayonne	(35)	6.0x	7.0x	8.0x	($210)	($245)	($280)
Net RJS (Riverstone)	119	6.0x	7.0x	8.0x	$716	$835	$954
Synergies and Other	195	6.0x	7.0x	8.0x	$1,172	$1,367	$1,563
Total Unregulated EV	**528**	**5.9x**	**6.9x**	**8.2x**	**$3,105**	**$3,633**	**$4,319**
Net Debt							
PPL Supply					$2,859	$2,839	$2,897
RJS					$1,171	$1,136	$1,110
Plus: Crane, Wagner 2, & Bayonne FCF NPV					($92)	($92)	($92)
Plus: Net Proceeds from Divestitures					($1,160)	($1,160)	($1,160)
Cash and 2015/2016E FCF					($475)	($459)	($458)
Total Net Debt					**$2,303**	**$2,264**	**$2,296**
Net Debt / Adj. EBITDA					*5.1x*	*4.3x*	*4.3x*
Total Equity Value					**$802**	**$1,370**	**$2,022**
Implied FCF Yield (EBITDA - Capex - Interest Exp - Taxes)					20%	11%	8%
Shares Outstanding					128.5	132.8	134.9
Standalone Talen (TLN) Valuation					**$6.24**	**$10.31**	**$15.00**
Accretion on MACH Gen					**($2.00)**	**$0.21**	**$2.31**
Talen (TLN) Valuation					**$4.00**	**$11.00**	**$17.00**
Upside/(Downside)					**-62%**	**4%**	**61%**

Source: UBS estimates

The Engie Portfolio in the US

For context, we also include the total list of plants for Engie in the US, breaking out the 6.3GW of CCGT across various markets.

Figure 3: Engie (formerly GDF Suez) US Portfolio

Power Plant Name	Owned Existing Capacity (MW)	Operating Ownership (%)	Prime Mover	Fuel Type	Year First Unit In Service	ISO(s)	State/ Province
Colorado Energy Nations Company	40.0	100.00	Steam Turbine	Bituminous Coal	1976	-	CO
Troy Energy IC	14.0	100.00	Internal Combustion	Distillate Fuel Oil	2014	PJM	OH
Tunnel CT	21.8	100.00	Jet Engine	Jet Fuel	1969	New England	CT
Armstrong County	676.0	100.00	Gas Turbine	Natural Gas	2002	PJM	PA
Ashtabula CC	14.6	51.00	Combined Cycle	Natural Gas	2001	PJM	OH
Astoria Energy Facility	271.5	44.80	Combined Cycle	Natural Gas	2006	New York	NY
Astoria Energy II (AE2)	183.6	30.00	Combined Cycle	Natural Gas	2011	New York	NY
Bellingham	532.1	100.00	Combined Cycle	Natural Gas	2002	New England	MA
Bellingham Cogeneration	168.0	50.00	Combined Cycle	Natural Gas	1991	New England	MA
Blackstone	514.6	100.00	Combined Cycle	Natural Gas	2001	New England	MA
Calumet Energy Team	330.0	100.00	Gas Turbine	Natural Gas	2002	PJM	IL
Ennis Tractebel Power Project	392.9	100.00	Combined Cycle	Natural Gas	2002	ERCOT	TX
Freeport Power (Oyster Creek Unit VIII)	215.0	50.00	Combined Cycle	Natural Gas	1994	ERCOT	TX
Hays Energy Project	937.0	100.00	Combined Cycle	Natural Gas	2002	ERCOT	TX
Hopewell Cogeneration	399.0	100.00	Combined Cycle	Natural Gas	1990	PJM	VA
Midlothian Energy Project	1474.0	100.00	Combined Cycle	Natural Gas	2000	ERCOT	TX
Milford Power CC	169.8	100.00	Combined Cycle	Natural Gas	1993	New England	MA
Millennium Hawkins Point	9.0	100.00	Gas Turbine	Natural Gas	2000	PJM	MD
Millennium Hawkins Point ST	1.0	100.00	Steam Turbine	Natural Gas	2000	PJM	MD
Nassau Energy Corporation	57.0	100.00	Combined Cycle	Natural Gas	1991	New York	NY
Newgulf CT	84.5	100.00	Gas Turbine	Natural Gas	1984	ERCOT	TX
Pleasants County	323.9	100.00	Gas Turbine	Natural Gas	2002	PJM	WV
Sayreville Cogeneration	166.5	50.00	Combined Cycle	Natural Gas	1991	PJM	NJ
Troy Energy	676.0	100.00	Gas Turbine	Natural Gas	2002	PJM	OH
Waterbury Power	98.0	98.00	Gas Turbine	Natural Gas	2009	New England	CT
West Windsor	107.6	96.08	Combined Cycle	Natural Gas	1996	Ontario	Ontario
Wise County	734.0	100.00	Combined Cycle	Natural Gas	2004	ERCOT	TX
Metro Wastewater Reclamation CT	6.2	100.00	Gas Turbine	Other Biomass Gas	2000	-	CO
Almonte Solar Project (Beckwith)	4.0	40.00	Photovoltaic	Solar	2014	Ontario	Ontario
Brockville Solar Farm	4.0	40.00	Photovoltaic	Solar	2013	Ontario	Ontario
Northfield Mountain Solar Project	1.9	100.00	Photovoltaic	Solar	2011	New England	MA
Coleto Creek	635.0	100.00	Steam Turbine	Subbituminous Coal	1980	ERCOT	TX
Northeastern Power Cogeneration Facility	52.0	100.00	Steam Turbine	Waste Coal	1989	PJM	PA
Bulls Bridge	8.4	100.00	Hydraulic Turbine	Water	1903	New England	CT
Cabot	61.8	100.00	Hydraulic Turbine	Water	1915	New England	MA
Falls Village	11.1	100.00	Hydraulic Turbine	Water	1914	New England	CT
Northfield Mountain	1146.0	100.00	Pumped Storage	Water	1972	New England	MA
Rocky River (CT)	29.4	100.00	Pumped Storage	Water	1928	New England	CT
Scotland Dam	2.2	100.00	Hydraulic Turbine	Water	1937	New England	CT
Shepaug	42.6	100.00	Hydraulic Turbine	Water	1955	New England	CT
Stevenson	28.9	100.00	Hydraulic Turbine	Water	1919	New England	CT
Taftville	2.0	100.00	Hydraulic Turbine	Water	1906	New England	CT
Tunnel Hydro	2.2	100.00	Hydraulic Turbine	Water	1919	New England	CT
Turners Falls	6.4	100.00	Hydraulic Turbine	Water	1905	New England	MA
Blue Sky Wind Farm	-	-	Wind Turbine	Wind	2013	Ontario	Ontario
Cape Scott Wind Farm Project (Knob Hill Wind)	39.6	40.00	Wind Turbine	Wind	2014	-	British Columbia
Caribou Mountain Wind	19.8	20.00	Wind Turbine	Wind	2009	New Brunswick	New Brunswick
Clear Creek Wind Farm	4.0	40.00	Wind Turbine	Wind	2008	Ontario	Ontario
Cultus Wind Farm	4.0	40.00	Wind Turbine	Wind	2008	Ontario	Ontario
East Lake St. Clair Wind	39.6	40.00	Wind Turbine	Wind	2013	Ontario	Ontario
Frogmore Wind Farm	4.0	40.00	Wind Turbine	Wind	2008	Ontario	Ontario
Harrow I Wind Farm	4.0	40.00	Wind Turbine	Wind	2010	Ontario	Ontario
Harrow II Wind Farm	4.0	40.00	Wind Turbine	Wind	2010	Ontario	Ontario
Harrow III Wind Farm	4.0	40.00	Wind Turbine	Wind	2010	Ontario	Ontario
Harrow IV Wind Farm	4.0	40.00	Wind Turbine	Wind	2010	Ontario	Ontario
Hetherton/Wareham (Plateau II) Wind	3.6	40.00	Wind Turbine	Wind	2012	Ontario	Ontario
Lake Erieau Wind Farm	39.6	40.00	Wind Turbine	Wind	2013	Ontario	Ontario
Maxwell Wind (Plateau I)	3.6	40.00	Wind Turbine	Wind	2012	Ontario	Ontario
Mohawk Point Wind Farm	4.0	40.00	Wind Turbine	Wind	2008	Ontario	Ontario
Norway Wind Park	3.6	40.00	Wind Turbine	Wind	2007	-	Prince Edward Island
Pointe Aux Roches	48.6	100.00	Wind Turbine	Wind	2011	Ontario	Ontario
Snrigley (Plateau III) Wind	3.6	40.00	Wind Turbine	Wind	2012	Ontario	Ontario
Silcote Corners Wind Project	-	-	Wind Turbine	Wind	-	Ontario	Ontario
West Cape Wind Farm	39.6	40.00	Wind Turbine	Wind	2007	-	Prince Edward Island
Pinetree Power Bethlehem	15.0	100.00	Steam Turbine	Wood Waste Solids	1986	New England	NH
Pinetree Power Fitchburg	16.0	100.00	Steam Turbine	Wood Waste Solids	1992	New England	MA
Pinetree Power Tamworth	20.0	100.00	Steam Turbine	Wood Waste Solids	1987	New England	NH
Ryegate Power Station	13.4	67.00	Steam Turbine	Wood Waste Solids	1992	New England	VT
Viking Energy of Lincoln	16.3	100.00	Steam Turbine	Wood Waste Solids	1989	MISO	MI
Viking Energy of McBain	16.3	100.00	Steam Turbine	Wood Waste Solids	1988	MISO	MI
Viking Energy of Northumberland	16.2	100.00	Steam Turbine	Wood Waste Solids	1988	PJM	PA
Grand Total	11041.9						
Total COGT	6337.2						

Source: SNL and UBS estimates

For additional context, please refer links to relevant recent reports below:

10/9/15 Extracting Top Dollar on Divestments

9/18/15 Capacity Auction Misses The Mark

8/18/15 Tapping Into Gas Conversions

8/7/15 Traveling on Calmer Waters (Upgrade to Neutral)

7/21/15 Deploying The War Chest

7/20/15 Opening The War Chest?
6/4/15 Initiation: Choppy Waters on the Susquehanna
5/22/15 The 10 Key Talen Debates

More Background

What to expect for the quarter?

Quarter is challenging to forecast following the recent June 2015 public spin.

We forecast TLN reporting adjusted 3Q15 EBITDA of **$307Mn**; however, caution that a quarterly earnings walk for the company is particularly challenging as the company was formed in June 2015 and lacks historical disclosures. We estimate that the company's adjusted EBITDA would be roughly flat YoY with expected lower earnings at RJS (particularly the Topaz Texas fleet) offset by synergies.

Figure 4: TLN 3Q15 EBITDA Walk

Talen 3Q15 Earnings Walk	EBITDA
PPL Supply	$224
RJS	$74
3Q14E Adjusted EBITDA	$298
PPL Supply	$222
RJS	$57
Parent & Other	$28
3Q15E Adj EBITDA	**$307**
YoY Change	$9
3Q15 Consensus	$303
2015 Guidance	**935-1,085**
2015 UBSe	**$987**
2015 Consensus	**$976**

Source: Company Filings, ThomsonReuters, and UBSe

What's new with TLN?

We show our estimates of the transaction economics with actual sales prices and UBSe adjusted EBITDA for the facilities. Mgmt disclosed that it will paydown the $42Mn Ironwood debt which we round-up to $50Mn to account for a pre-payment premium.

- **Divesting three PA assets for net $1.2Bn, implying 12x gross EV/EBITDA multiple:** TLN agreed to sell its Ironwood combined-cycle gas plant (704MW) to a subsidiary of TransCanada for $654M and couple of its hydroelectric projects, Wallenpaupack and Holtwood (combined capacity of 292MW) to Brookfield Renewable Energy partners for $860Mn. Talen guides to $140Mn 2016 EBITDA ($150Mn UBSe) but we forecast this stepping-down to $115Mn by 2018E based upon the declining power curve. Based on UBSe EBITDA we estimate that Ironwood was sold for ~8x EV / EBITDA, largely in-line with expectations, but the hydro transacted at 18x EV / EBITDA (~$2,945/kW), likely ~$200mn ahead of Street expectations. After factoring in tax obligation on the sale we see the transaction as adding +$2/sh in value assuming debt paydown (4.3x net debt/adjusted EBITDA). Both the transactions are expected to close in 1Q16.

Figure 5: Summary of Ironwood, Holtwood, and Wallenpaupack Divestiture

Ironwood, Holtwood, and Wallenpaupack Divestiture							
	EBITDA	Low	Base	High	Low	Base	High
PPL Ironwood	80	7.2x	8.2x	9.2x	$576	$656	$736
Holtwood and Wallenpaupack	46	17.6x	18.6x	19.6x	$814	$860	$906
Gross Sales Price	**126**	**11.0x**	**12.0x**	**13.0x**	**$1,390**	**$1,516**	**$1,642**
Less: Taxes Payable	20% of Proceeds					($306)	
Net Sales Price						$1,210	
Less: Debt Assumed (Ironwood)						($50)	
Total Net Proceeds						**$1,160**	

Source: Company Filings and UBS Estimates. EBITDA is UBSe

- **Valuation on the hydro assets significantly higher than expected:** The sales multiple for the ~15-year old efficient CCGT is not surprising but the implied multiple and $/kW for the hydro transactions came in well above our expectations. Below we present a summary of recent hydro sales showing an average of ~$2,000/kW. The first three transactions involved Brookfield Renewables as the company clearly sees value in PJM hydrogeology assets. The PPL Montana sales was to NorthWestern Corp (NWE).

Figure 6: Summary of Ironwood, Holtwood, and Wallenpaupack Divestiture

Hydro Transactions	MW	$/kW	Price ($Mn)
Holtwood and Wallenpaupack	293	$2,935	$860
Safe Harbor (LS Power)	138	$2,202	$303
Safe Harbor (Exelon)	279	$2,194	$613
PPL Montana Hydro	633	$1,422	$900
Average	336	$1,993	$669

Source: Company Filings and UBS Estimates. EBITDA is UBSe

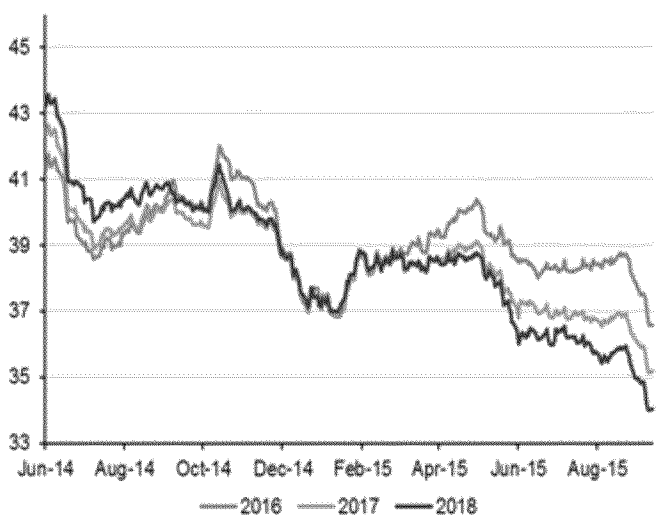
- **If FERC petition is successful, substantially completes required divestiture:** The divestitures are part of the requirement to comply with FERC's order made in December 2014 regarding formation of Talen Energy. Talen has filed a motion with the FERC requesting to modify the divestiture packages to avoid transacting on the Sapphire portfolio given inability to divest the Bayonne asset due to difficulty renewing the land lease. If Talen's request is approved (requested action by November 30th) and it pursues the new Option 3, it would only have to divest the C.P. Crane coal asset in PJM-SWMAAC, likely a small value figure either way given potential MD state regs.
- **Long-term use of proceeds the focus: Will mgmt buyback shares and do M&A?:** TLN intends to use the total net proceeds of $1.16B to retire pre-payable and maturing debt currently rather than repurchase shares. In our recent meeting with management they downplayed repurchases but we would not be surprised to see a small announcement w/ 3Q, reflecting the recent pullback in shares and investor demands (akin to pressures on NRG). TLN has publicly stated its desire to diversify via M&A and reducing leverage today provides further latitude to add debt on a potential acquisition.

EBITDA Estimates: Further commodity weakness hits Talen particularly hard

Talen is among the most sensitive IPPs to changes in natural gas and power prices. For example, prior to the MACH Gen acquisition and latest divestitures management disclosed the following sensitivities in June on a hedged basis:

- -$0.50/mmBtu change in gas drives -$240Mn margin
  - This represents 27% of management's 2016E adjusted EBITDA guidance
- -$5/MWh change in power drives -$200Mn margin decline
  - This represents 23% of management's 2016E adjusted EBITDA guidance

Figure 7: PJM-West ATC ($/MWh)



Source: Platts

Figure 8: TETCO Natural Gas ($/mmBtu)

Source: Platts

Our estimates continue to exclude the contribution from the pending MACH Gen transaction (displayed illustratively) but include the full portfolio of divestiture assets.

Figure 9: TLN Adjusted EBITDA Estimates

Talen Energy EBITDA Summary	2015	2016	2017	2018	2019
PPL Supply	$693	$605	$340	$380	$415
Raven Power	$127	$110	$117	$119	$113
Sapphire Power	$48	$39	$31	$33	$9
Topaz/Jade Power	$14	$4	$6	-$5	-$2
Subtotal	$882	$757	$494	$527	$535
Synergies and Other	$123	$153	$195	$190	$193
Total Adjusted EBITDA	**$1,005**	**$909**	**$689**	**$718**	**$728**
Standalone Guidance	*935-1,085*	*885*			
UBS Prior	*987*	*960*	*766*	*795*	*805*
Consensus	*976*	*972*	*876*	*880*	*863*
UBSe Pro-Forma For MACH Gen	*1,005*	*1,054*	*809*	*823*	*835*

MACH Gen EBITDA Summary	2015	2016	2017	2018	2019
MACH Gen EBITDA					
Athens	$116	$110	$89	$77	$72
Harquahala	($3)	($8)	($10)	($9)	($8)
Millennium Power	$32	$17	$26	$39	$40
Total EBITDA	**$145**	**$119**	**$106**	**$107**	**$103**
Guidance		*$120*			

Source: Company Filings, FactSet, and UBS Estimates

Below we present additional details on the latest with the divestiture process and other recent items of focus for Talen:

- **Inability to find buyer for Bayonne drives alternate proposed divestiture package:** On September 28th Talen filed a new motion regarding the mitigation plans, specifically requesting permission to consider an 'Option 3' of assets from the previous divestiture Options 1 & 2. Management believes that the Option 3 involves greater market power mitigation and "provides greater flexibility for potential buyers to bid on units they value most."

Figure 10: Summary of Possible Divestiture Packages

Divestiture Package #1								
Power Plant Name	Owner	Owned	Fuel Type	Plant Type	Year First	ISO(s)	State	'17E EBITDA
Bayonne Cogeneration	Sapphire Power Holdings LLC	174	Natural Gas	Natural Gas	1988	PJM - PS North	NJ	6
Camden Cogeneration	Sapphire Power Holdings LLC	151	Natural Gas	Natural Gas	1993	PJM - PSEG	NJ	6
Elmwood Park Plant	Sapphire Power Holdings LLC	73	Natural Gas	Natural Gas	1989	PJM - PS North	NJ	1
Newark Bay Cogeneration	Sapphire Power Holdings LLC	129	Natural Gas	Natural Gas	1993	PJM - PS North	NJ	7
Pedricktown Cogeneration Plant	Sapphire Power Holdings LLC	132	Natural Gas	Natural Gas	1992	PJM - EMAAC	NJ	4
York Cogeneration	Sapphire Power Holdings LLC	52	Natural Gas	Natural Gas	1988	PJM - MAAC	PA	1
PPL Ironwood	PPL Newco	660	Natural Gas	Natural Gas	2001	PJM - MAAC	PA	80
Total Divestiture Package #1		1,371						95

Divestiture Package #2								
Power Plant Name	Owner	Owned	Fuel Type	Plant Type	Year First	ISO(s)	State	'17E EBITDA
C.P. Crane	Raven Power Holdings	385	Subbituminous Coal	Coal	1961	PJM - SWMAAC	MD	16
C.P. Crane CT	Raven Power Holdings	14	Distillate Fuel Oil	Fuel Oil	1967	PJM - SWMAAC	MD	
Bayonne Cogeneration	Sapphire Power Holdings LLC	174	Natural Gas	Natural Gas	1988	PJM - PS North	NJ	6
Camden Cogeneration	Sapphire Power Holdings LLC	151	Natural Gas	Natural Gas	1993	PJM - PSEG	NJ	6
Elmwood Park Plant	Sapphire Power Holdings LLC	73	Natural Gas	Natural Gas	1989	PJM - PS North	NJ	1
Newark Bay Cogeneration	Sapphire Power Holdings LLC	129	Natural Gas	Natural Gas	1993	PJM - PS North	NJ	7
Pedricktown Cogeneration Plant	Sapphire Power Holdings LLC	132	Natural Gas	Natural Gas	1992	PJM - EMAAC	NJ	4
York Cogeneration	Sapphire Power Holdings LLC	52	Natural Gas	Natural Gas	1988	PJM - MAAC	PA	1
Holtwood Hydroelectric Plant	PPL Generation LLC	249	Water	Renewable	1910	PJM - MAAC	PA	39
Wallenpaupack	PPL Generation LLC	44	Water	Renewable	1926	PJM - MAAC	PA	7
Total Divestiture Package #2		1,403						95

Divestiture Package #3								
Power Plant Name	Owner	Owned	Fuel Type	Plant Type	Year First	ISO(s)	State	'17E EBITDA
PPL Ironwood	PPL Newco	660	Natural Gas	Natural Gas	2001	PJM - MAAC	PA	80
C.P. Crane	Raven Power Holdings	385	Subbituminous Coal	Coal	1961	PJM - SWMAAC	MD	16
C.P. Crane CT	Raven Power Holdings	14	Distillate Fuel Oil	Fuel Oil	1967	PJM - SWMAAC	MD	
Holtwood Hydroelectric Plant	PPL Generation LLC	249	Water	Renewable	1910	PJM - MAAC	PA	39
Wallenpaupack	PPL Generation LLC	44	Water	Renewable	1926	PJM - MAAC	PA	7
Total Divestiture Package #3		1,352						143

Source: Company Filings and UBS Estimates

Talen has requested a 21-day comment period on the motion with Commission action by **November 30th**. At a recent conference management stated that it anticipated an announcement on the plant divestitures in the upcoming 'few weeks'. Talen has also

commented that it has not seen material weakness in the asset market as it tries to sell these divestiture assets despite the sharp contraction in valuations for public IPPs.

Figure 11: 2018/2019 PJM Capacity Auction Results

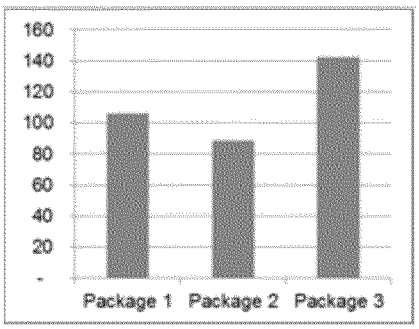
2018/2019 Capacity Auction							
Core Assets	**CP MW**	**Base MW**	**Uncleared MW**	**CP Price**	**Base Price**	**Uncleared Price**	**Revenue ($Mn)**
BGE	1,682	99	270	$164.77	$149.98	$50.00	$112
EMAAC	-		-	$225.42	$210.63	$50.00	$0
MAAC	1,575		-	$164.77	$149.98	$50.00	$95
PPL	4,913	6	1,382	$164.77	$75.00	$50.00	$321
PSEG	-			$225.42	$210.63	$50.00	$0
PS-North	-			$225.42	$210.63	$50.00	$0
Total	**8,170**	**105**	**1,652**				**$527**
Portfolio Split	**82%**	**1%**	**17%**	**$MW/Day Average**		**$145.47**	
Divestiture Assets	**CP MW**	**Base MW**	**Uncleared MW**	**CP Price**	**Base Price**	**Uncleared Price**	**Revenue ($Mn)**
BGE	0	0	361	$164.77	$149.98	$50.00	$7
EMAAC	0	0	109	$225.42	$210.63	$50.00	$2
MAAC	631	0	45	$164.77	$149.98	$50.00	$39
PPL	34	246	0	$164.77	$75.00	$50.00	$9
PSEG	0	0	142	$225.42	$210.63	$50.00	$3
PS-North	103	0	59	$225.42	$210.63	$50.00	$10
Total	768	246	716				$68
Portfolio Split	**44%**	**14%**	**41%**	**$MW/Day Average**		**$108.12**	
Grand Total	**8,938**	**351**	**2,368**				**$595**
Portfolio Split	**77%**	**3%**	**20%**	**$MW/Day Average**		**$139.93**	

Source: Company Filings and UBS Estimates

Based on the five assets in divestiture package Option 3 and management's granular disclosures for 2018/2019 PJM auction, we believe the assets cleared as follows:

- **PPL Ironwood (660MW): 631MW MAAC Capacity Performance**
  - As the largest asset in the divestiture package, this is the only logical category that the asset could have cleared.
- **C.P. Crane (399MW): 361MW BGE Uncleared**
  - This is the only Raven BGE-interconnected asset in the divestiture packages.
- **Holtwood and Wallenpaupack Hydroelectric Plants (293MW): 246MW**
  - In the PPL zone 246MW cleared as the base product versus 34MW which cleared as Capacity Performance.

Figure 12: UBSe EBITDA Contribution from Three Divestiture Options



Source: Company Filings and UBS Estimates

Talen reports that "negotiations proved futile" to extend the lease with Macquarie; the last negotiation occurred February 11, 2015.

On the negative side, if Talen retains the Sapphire assets which seemingly did not clear in the 2018/2019 auction, there is more uncertainty about the incremental auction. At a recent conference management stated that it sees more upside from bidding into the incremental auctions and via bilaterals for its EMAAC (Pedricktown), PSEG (Camden), and PS-North (Elmwood) assets but this

strategy differs from peers. We apply a $50/MW-day placeholder for uncleared capacity in our analysis.
Further analyses of the auctions are available in our latest report 'Capacity Auction Misses The Mark'.
Prior to this latest motion, Talen filed with FERC to retain its ~160MW Bayonne Cogeneration plant in New Jersey through the life of the land lease (October 31, 2018) given challenges finding a purchaser for the asset without a lease extension secured. Macquarie Infrastructure (MIC) owns the neighboring Bayonne Energy Center and owns the real estate for Talen's unit. Macquarie has publicly stated that it does not intend to extend the land lease but would be interested in purchasing the plant "at a reasonable price" with the intention of building a new plan or upgrading the existing unit.
Per Talen's previous FERC petition, "based on its final assessment since the close of the Transaction, **Talen Energy has determined that divesting the Bayonne facility is not currently a realistic possibility**." Riverstone (owner of Bayonne prior to the PPL Supply/Riverstone spin to create Talen) made the deactivation requests for Bayonne in 2014 without market power issues raised and has cleared in the 2015/2016-2017/2018 capacity auctions (i.e. capacity payments end May 31, 2018). Talen commented in the filing that when Riverstone first initiated a bidding process for the Sapphire portfolio it had multiple interested parties. Furthermore, Talen does not see a suitable substitute in its portfolio that could be divested instead of Bayonne. In that original motion management requested an order by **November 15th** (as mentioned the new relevant date is November 30th).
Assuming that Bayonne cleared in the PJM Capacity Performance transition auctions we estimate $16Mn of adjusted EBITDA for Bayonne through October 2018. The transition auction uplift is relatively subdued given its premium location in PS-North.

Figure 13: Bayonne Cogen Mini Model – Assuming Retirement in October 2018

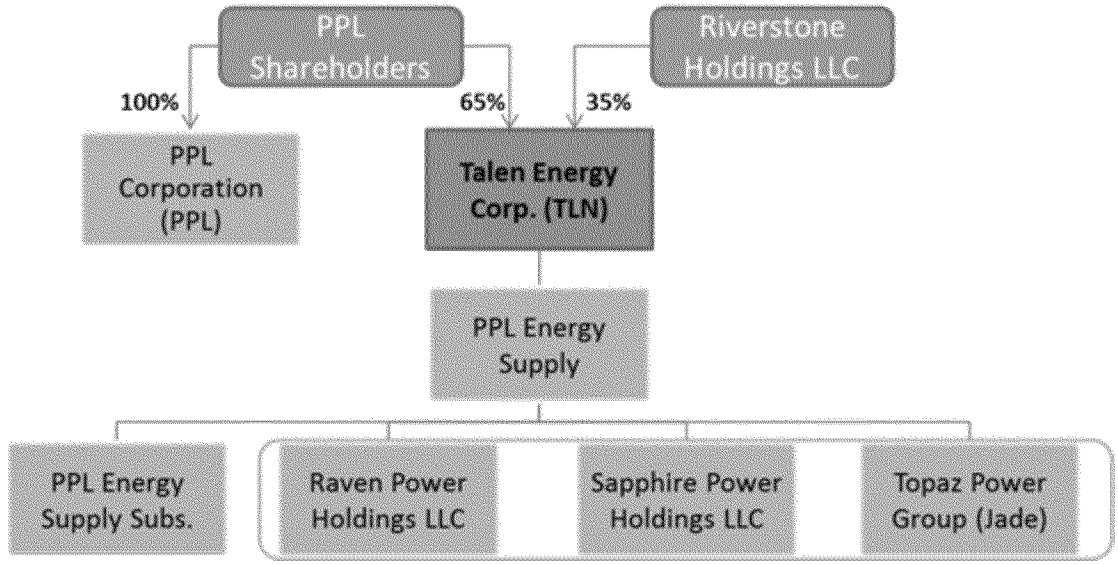
Bayonne Cogen Mini Model	2014A	2015	2016	2017	2018
Capacity (MW)	165	165	165	165	165
Capacity Factor, UBSe	30.0%	30.0%	30.0%	30.0%	25.0%
PJM-West On-Peak ($/MWh)	$45	$46	$43	$42	$40
Heat Rate, UBSe	5,733	8,857	8,857	8,857	8,857
Variable Cost ($/MWh)	($24)	($25)	($25)	($28)	($29)
Energy Margin ($MWh)	$22	$22	$19	$14	$11
Generation (TWh)	0.4	0.4	0.4	0.4	0.4
Energy Margin ($Mn)	$9	$9	$8	$6	$4
EMAAC Capacity Payment ($/MW-day)	$182	$155	$148	$144	$152
Capacity Revenue ($Mn)	$10	$8	$8	$8	$3
O&M ($/kW-yr), UBSe	45	45	45	45	45
O&M ($ Mn)	7.4	7.4	7.4	7.4	7.4
EBITDA	**11.7**	**10.4**	**8.7**	**6.4**	**0.0**

Source: Company Filings, Platts, SNL Energy, and UBS Estimates

Investors should not read too much into Talen's filing to register Riverstone's shares – this is an ordinary course of business event.

- **TLN: Beginning Riverstone Process:** Talen filed an S-1 on September 18th to initiate the registration process for the 44.975Mn shares owned by Riverstone (35% of Talen) as part of the PPL Supply/Riverstone spin that created Talen. Riverstone has a 180-day lock-up period on its shares (~November 30th). This filing does not indicate that Riverstone intends to sell its entire stake but simply that it is eligible to begin reducing its position. Riverstone could utilize its Talen ownership as a way to gain exposure to further power M&A but we would naturally expect the private equity firm to reduce its position over time, particularly given its relative size. With shares down ~50% through early October we would anticipate some monetization but it is unclear what Riverstone ultimately plans.

Figure 14: Pro-Forma Talen Corporate Structure



Source: Company Filings

- **MACH Gen closing possibly ahead of schedule:** Talen recently disclosed that it saw the MACH Gen transition closing within a few weeks from the end of September, pointing towards the earlier portion of the 4Q15 guidance. When the deal was announced on July 20th Talen indicated that FERC and New York PSC review could take 3-4 months, indicating completion by late October/November. Talen placed a contingency on that NY timeline indicating that the review process could double to 6-8 months in the absence of a change of control waiver from MACH Gen lenders.

Constitution slow to launch: Part of the upside thesis for the MACH Gen portfolio is premised on the Athens asset gaining access to cheap Marcellus natural gas via the Constitution pipeline but in-service for the pipeline has been delayed. Williams previously estimated that it would have received regulatory approval for Constitution by Summer 2015. We suspect this is more of a 1H17 project.

Regards,

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Sell	FSR is > 6% below the MRA.	12%	20%
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Source: UBS. Rating allocations are as of 31 March 2015.
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This issue of EUEC's ENERGYNews features presentations on SMART GRID & RISK MANAGEMENT made in Track D at EUEC 2015

SMART GRID & RISK MANAGEMENT

D4.1 GRID MODERNIZATION & THE SMART UTILITY - Anthony Barazza, Grid Automation, Schneider Electric; Adam Caballero

D4.2 ELECTRIC RATE IMPACTS DUE TO ENVIRONEMENTAL REGULATIONS - Mike Borgstadt, Manager - Business Consulting, Burns & McDonnell Engineering Co.

D4.3 WHAT HAPPENS DURING A COLD SNAP - Stephen Slocomb, Associate, Epsilon Associates

D4.4 MARGINAL ENERGY EMISSION RATES FOR THE EVOLVING ENERGY LANDSCAPE - Jessica Lau, Engineer, ISO New England; Peter Wong

D4.5 WHO'S CONTRIBUTING TO GRID STABILITY? - Roger Clarke-Johnson, Western Region Manager, American Governor

D8.1 ENERGY INDUSTRY VIEW ON CLIMATE CHANGE RISK, ADAPTATION AND ECOSYSTEM RISK MANAGEMENT - Sarah Ball, Manager, Environmental Affairs, Edison Electric Institute

D8.2 MANAGING ECOSYSTEM RISK: ENGINEERING ECO-SOLUTIONS TO CLIMATE CHANGE ADAPTATION - John B. Christopher, Water/Wastewater Manager, Louis Berger

D8.3 CLIMATE CHANGE IMPACTS TO ELECTRICAL DISTRIBUTION NETWORKS: MANAGING RISKS, ENHANCING RESILIENCE - Claire Bonham-Carter, Principal, AECOM; Allan Klindworth & Chee Chan

D8.4 IRRATIONAL GREEN: REVEALING TODAY'S GREAT, GREEN DECEPTIONS - Randy Hughes, Manager, Independence Power & Light

D8.5 AMMONIA FUEL FROM RENEWABLE-SOURCE ELECTRICITY, WATER, & AIR: TECH OPTIONS & ECONOMICS MODELING - Bill Leighty,

TECHNICAL TRACKS (view abstracts)

SMART GRID
ESP, PM, CEMS
BIOFUELS
111 (D), NSR, NAAQS
ENERGY POLICY
RE: SOLAR & PV
RENEWABLE ENERGY
316 (B) WATER
MERCURY CONTROL
Hg (DCI and ACI)
CCS & CCR
CEMS & HCL
PERMITS COMPLIANCE
OPERATIONS & MGMT
ALT FUEL EV FLEETS
BATTERY & STORAGE
FGD ZLD WASTEWATER
EHS EMIS RISK MGMT

D7.1 FACILITATE INVESTMENTS IN NATURAL GAS INFRASTRUCTURE - CASE STUDIES OF TWO REGION - Hua Fang, Technical Director, ICF International

D7.2 NATURAL GAS MARKET DRIVERS: IMPLICATIONS FOR POWER GENERATORS - Ken Ditzel , Managing Director, FTI Consulting

D7.3 THE SAFETY, RELIABILITY & ECONOMIC LAYERS OF NATURAL GAS CONVERSION PROJECTS - Ajay Kasarabada, Project Manager, Black & Veatch; Steve Williams

D7.4 COAL TO NATURAL GAS CONVERSIONS, WHAT YOU NEED TO KNOW - Joe Brown, Product Manager, Mitsubishi Hitachi Power Systems

D7.5 ANALYZING CARBON POLICY & PRICING EFFECTS ON GLOBAL NATURAL GAS MARKETS: CONSUMERS & PRODUCERS - Hakob Avetisyan, Assistant Professor, California State University

D2.1 INSPIRING AMERICA'S NEXT SOCIAL ENTREPRENEURS - Drew Beal, CEO, Kill the Cup

D2.2 DESIGNING FOR THE POST-CARBON ECONOMY: IT'S ZERO OR NOTHING - Eric Corey Freed, Founding Principal, organicARCHITECT

D2.3 WORKPLACE & OCCUPATIONAL SUSTAINABILITY: THINKING OUTSIDE THE BOX - Bapanaiah Penugonda, Dentist/Associate Professor, NYU College of Dentistry; Katie Baron

D2.4 ENVIRONMENTAL EVALUATION OF SIX BUILDING SHEARING LAYERS FOR THE ALLOCATION OF GREEN POINTS - Svetlana Pushkar, Lecturer, Ariel University; Oleg Verbitsky

D2.5 OPPORTUNITIES & COSTS FOR ENERGY CONSERVATION IN THE UK BUILDING STOCK - Reza Arababadi, PhD Student, ASU; Érika Mata, Angela Sasic Kalagasidis & Filip Johnsson, Chalmers University of Technology

SCR & CONTROL TECH

CLEAN POWER PLAN

SOx & NOx CONTROL

WATER MANAGEMENT

DECOMMISSIONING of POWER PLANTS

CEMS, AQ & MATS

MERCURY CONTROL

Ameren's Alternative to EPA's GHG RULES

U.S. EPA's McCabe Details Clean Power Plan at EUEC

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Preliminary Program

Directors

U.S. Department of Energy	Edison Electric Institute	EPRI	Clean Tech
Mitchell Baer	John Kinsman	Bryan Hannegan	Prabhu Dayal

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What is EUEC?

EUEC2013: 16TH ANNUAL ENERGY, UTILITY & ENVIRONMENT CONFERENCE
USA's Largest Professional Networking & Educational Event of its kind

NETWORK WITH 2,000 DELEGATES IN 200 COMPANY EXHIBIT AREA
with 9 networking lunches, receptions & breaks

600 SPEAKERS MAKE PRESENTATIONS IN 10 TRACK PROGRAM

REGISTRATION COST	Sept 1	Oct 1	Nov 1	Dec 1	Jan 1	On-Site
Attendee Full	$695	$795	$895	$995	$1095	$1,395
Speaker/Gov't/VIP	$595	$695	$795	$895	$995	$1,295
3-Day Conference	$395	$495	$595	$695	$795	$1,095

Full/Speaker/Gov't/ VIP Registration includes:

- 8 networking meals served buffet style in exhibit area
- Attend all 600 technical presentations in 3 days
- EUEC Flash Drive with 600 presentations with audio

3-Day Conference Registration includes:

- Network at 8 functions (without meals)
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Who should attend?

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- RENEWABLE ENERGY ENTREPRENEURS
- BUSINESS DEVELOPMENT PROFESSIONALS
- UTILITY AND ENERGY EXECUTIVES
- LAWYERS, ACCOUNTANTS AND CONSULTANTS
- U.S. LEGISLATORS, GOVERNMENT AGENCIES
- SCIENTISTS AND RESEARCHERS

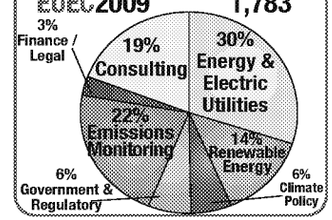
INVESTORS:

- COMMERCIAL & INVESTMENT BANKS
- VENTURE CAPITALISTS AND PRIVATE EQUITY
- CORPORATE AND INSTITUTIONAL INVESTORS
- DEAL LAWYERS AND CONSULTANTS
- PROJECT DEVELOPERS

DECISION MAKERS:

- ELECTRIC UTILITIES
- ELECTRIC VEHICLES
- ARCHITECTS/ENGINEERS/SCIENTISTS
- CO-GENERATORS/SELF-GENERATORS
- CNG (COMPRESSED NATURAL GAS)
- FUEL SUPPLIERS
- INDEPENDENT POWER PRODUCERS
- EQUIPMENT MANUFACTURERS
- POWER INDUSTRY CONSULTANTS
- DESIGNERS AND CONSULTANTS
- PROJECT DEVELOPERS
- RESEARCH AND DEVELOPMENT ORGANIZATIONS
- HUMAN RESOURCE MANAGERS AND RECRUITERS
- CONTINOUS EMISSION MONITORS AND SPECIALISTS

Year	Delegates
EUEC2012	2,037
EUEC2011	1,830
EUEC2010	2,345
EUEC2009	1,783



Directors

U.S. DEPARTMENT OF ENERGY

Mitchell Baer - Director, Office of Oil and Gas Analysis, U.S. Department of Energy

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Power by Association

John Kinsman - Senior Director, Environment, Edison Electric Institute

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EPRI ELECTRIC POWER RESEARCH INSTITUTE

Bryan Hannegan - Vice President, Electric Power Research Institute

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CARBON TRADE

www.ctrade.org

Prabhu Dayal - President, C Trade

C TRADE is a global renewable energy project development company that has constructed nine turnkey Clean Development Mechanism (CDM) biogas to energy projects using waste manure and biomass to capture methane biogas to produce electricity and finance using carbon credits in the Philippines and India.

Exhibit Schedule

EXHIBIT SET UP

Sunday Jan 27th 1 pm to 7 pm

SHOW TIMES

Mon. Jan 28th - 11 am to 7 pm
Tue. Jan 29th - 9 am to 7 pm
Wed. Jan 30th - 9 am to 12 pm

EXHIBIT TEAR DOWN

Wed. Jan 30th - 12 to 4 pm

Conference Schedule

Sunday | January 27, 2013

7:00 am - 7:00 pm	Registration
7:30 am - 1:00 pm	Golf Tournament
1:00 pm - 5:00 pm	Pre-Conference Workshops
1:00 pm - 7:00 pm	Exhibitor Set-Up

Monday | January 28, 2013

7:00 am - 7:00 pm	Registration
8:00 am - 11:00 am	Plenary Session
11:00 am - 7:00 pm	Exhibit Hall Open
11:00 pm - 1:00 pm	Networking Lunch - Exhibit Area
1:00 pm - 3:00 pm	Technical Session - 1
3:00 pm - 3:30 pm	Networking Break - Exhibit Area
3:30 pm - 5:30 pm	Technical Session - 2
4:00 pm - 7:00 pm	Exhibitor Invited Guests
5:00 pm - 7:00 pm	Networking Reception- Exhibit Area

Tuesday | January 29, 2013

7:30 am - 9:30 am	Technical Session - 3
9:00 am - 7:00 pm	Exhibit Hall Open
9:30 am - 10:00 am	Networking Break - Exhibit Area
10:30 am - 12:00 pm	Technical Session - 4
12:00 pm - 1:00 pm	Networking Lunch - Exhibit Area
1:00 pm - 3:00 pm	Technical Session - 5
3:00 pm - 3:30 pm	Networking Break - Exhibit Area
3:30 pm - 5:30 pm	Technical Session - 6
4:00 pm - 7:00 pm	Exhibitor Invited Guests
5:00 pm - 7:00 pm	Networking Reception - Exhibit Area

Wednesday | January 30, 2013

7:30 am - 9:30 am	Technical Session - 7
9:00 am - 12:00 pm	Exhibit Hall Open
9:30 am - 10:00 am	Networking Break - Exhibit Area
10:00 am - 12:00 pm	Technical Session - 8
12:00 pm - 4:00 pm	Exhibit Tear-Down
1:00 pm - 3:00 pm	Technical Session - 9

Preliminary Program

Keynote

Monday, January 28th, 8:00 AM - 11:00 AM
Phoenix Convention Center | 100 N. 3rd St. | Phoenix, AZ 85004

U.S. DEPARTMENT OF ENERGY

NATURAL GAS IN AMERICA'S CLEAN ENERGY ECONOMY
Chris Smith | Deputy Assistant Secretary | U.S. DOE

EPA United States Environmental Protection Agency

EPA REGULATORY UPDATE FOR POWER PLANTS
Gina McCarthy | Assistant Administrator | U.S. EPA (invited)

AEP AMERICAN ELECTRIC POWER

REGULATORY CHALLENGES, TECHNOLOGY SOLUTIONS
Mike Morris | Chairman | AEP

anga

DEVELOPMENT OF NORTH AMERICA'S OIL AND GAS RESOURCES
Regina Hopper | CEO | America's Natural Gas Alliance (invited)

EPRI ELECTRIC POWER RESEARCH INSTITUTE

IMPACTS OF ENVIRONMENTAL CONTROLS ON THE GENERATION FLEET
Bryan Hannegan | Vice President | Electric Power Research Institute

EDF ENVIRONMENTAL DEFENSE FUND

NATURAL GAS: A CLEAN, LOW CARBON ALTERNATIVE?
Mark Brownstein | Chief Counsel | Environmental Defense Fund

EUEC

EUEC: LOOKING AHEAD AFTER 15 YEARS OF SUCCESS
Prabhu Dayal | Chairman | EUEC

Mission Statement

EUEC facilitates information exchange and fosters cooperation between industry, government, regulators, academia and stake-holders for the protection of our environment and energy security.

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At-A-Glance

EUEC 2013 Format | All Speakers limited to 20 minutes using PowerPoint
Each session is 2 hours with 6 Speakers

Track	A	B	C	D	E	F	G	H	I	J
Sessions	Air Policy & Regulations	Pollution Monitoring & Modeling	Mercury Multi-Pollutant Control	Natural Gas & Energy Security	Renewable Energy	Operations & Mgmt	GHG, Carbon Mgmt & CCS	Biofuels & Biomass	Sustainability & Water	Energy Efficiency
1	Regulatory Update I	CEMS & MATS	Hg Control Demonstrations	CNG & Shale Gas	Small Scale Renewable & Electric Utilities	Economic Energy & Cybersecurity	Carbon Footprint	Algae	Energy Sustainability	Energy Efficiency
2	Regulatory Update II	HCL Monitoring	Hg Control & Bromine	Fracking & Sustainable Development	Distributed Generation	Compliance Technologies & Strategies	Tailoring Rule/NSR/ GHG BACT	Biofuels / Ethanol	Sustainability Projects	Energy Mgmt.
3	NAAQS	PM, Opacity & Visability	Control Technologies I	Energy Policy	Renewable Development Analysis	Power Plant & Boiler Optimization	Planning & GHG	Biomass	Sustainability Reporting	Smart Grid
4	NSR	Mercury Measurement	Control Technologies II	CNG: Alternative Fuel & Fleet Mgmt	Renewable Project Development	EHS & EMIS	Corporate Strategies & Risk Mgmt.	Bio & Waste Energy	316b	Energy Efficiency & Mgmt. I
5	Compliance Stratagies	Emission Testing & Monitoring	MATS	State, Regional & Infrastructure	IP & New Technology	EHS & Risk Management	California Cap & Trade	Landfill Gas to Energy	Water Sustainability	Energy Efficiency & Mgmt. II
6	MACT	Monitoring & Reporting	Dry Sorbent Injection	Clean Transportation Policy	Solar & PV	ASH / CCP	GHG Stratagies	Cofiring in Power Plants	Water & Electric Utilities	Energy Conservation & Storage
7	Permits & Compliance	Modeling	Activated Carbon	Energy & Climate	Wind	Operations & Management	CCS: Carbon Capture & Storage		Water - Regulatory Updates	Demand Response
8	Clean Air Policy	CEMS	Advanced Control Technologies	Managing Risk & Project Mgmt.	EV-PHEV, CPV & Batteries	Natural Resource Mgmt. - HCP	CCS II		Sustainability Green	
9	Regulatory Compliance - URS									

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A1. REGULATORY UPDATE I

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WINSTON & STRAWN LLP

Jay Holloway

Burns & McDonnell

Block Andrews

A1.1 REPORT FROM THE SCENE OF THE TRAIN WRECK -- UPDATE ON THE IMPACT OF NEW EPA RULES & ACTIONS ON ELECTRIC UTILITY GENERATION
Jay Holloway, Partner, Winston & Strawn LLP

A1.2 CLEAN AIR ACT ABACK - THE MACT CONUNDRUM
Peter Belmonte, Sr. Partner, Environmental Resources Management; Robert Fraser

A1.3 RECENT REGULATORY DEVELOPMENTS AFFECTING PERMITTING OPTIONS
Thomas Echikson, Partner, LeClairRyan

A1.4 UTILITY REGULATORY UPDATE: IMPLICATIONS & STRATEGIC CONSIDERATIONS FOR COMPLIANCE
Block Andrews, Strategic Environmental Solutions Director, Burns & McDonnell

A1.5 UTILITY REGULATORY UPDATE: IMPLICATIONS & STRATEGIC CONSIDERATIONS FOR COMPLIANCE
Mike Borgstadt, Manager - Resource Planning, Burns & McDonnell Engineering Co.

A1.6 THE NEXT FOUR YEARS: HOW THE OUTCOME OF THE ELECTION WILL IMPACT THE CLEAN AIR ACT AGENDA
Roger Martella, Attorney, Sidley Austin LLP

John Kinsman - Invited

A2. REGULATORY UPDATE II

Session Sponsor and Co-Chair

A2.1 STARTUP & SHUTDOWN ALLOWANCES - A CASE STUDY ON UNIT START UP
Patrick Leming, Software Services Manager, Babcock & Wilcox Power Generation Group; John Downs

A2.2 EPA PROPOSAL TO REVISE MATS EMISSION LIMITS FOR NEW ELECTRIC GENERATING UNITS
Ralph Roberson, President, RMB Consulting & Research

A2.3 IS FEDERALISM ALIVE UNDER THE CLEAN AIR ACT?
Bill Wehrum, Partner, Hunton & Williams LLP

A2.4 UPDATE TO COAL UNIT RETIREMENTS & GRID RELIABILITY
M. Gary Helm, Sr. Market Strategist, PJM Interconnection

A2.5 REGULATORY UPDATE & IMPLICATIONS OF THE PM2.5 NATIONAL AMBIENT AIR QUALITY STANDARD
Robert McCann, Principal- Director, Air Resources, Golder Associates Inc.

A2.6 FIRST CAIR, THEN CSAPR. WHAT'S NEXT?
Daniel Chartier, Director - Environmental Markets & Air Quality Programs, Edison Electric Institute

A3. NAAQS

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A3.1 COMPLIANCE CHALLENGES POSED BY THE NAAQS FOR SO2, NO2, & PM2.5
Robert Paine, Technical Director, AECOM; David Heinold & Robert Iwanchuk

A3.2 THE STATE OF THE NAAQS
Kurt Kissling, Attorney at Law, Pepper Hamilton LLP

A3.3 RECENT HAPPENINGS REGARDING THE EXCEPTIONAL EVENT RULE
Samuel Lofland, Attorney, Ryley Carlock & Applewhite; James Sanderson

A3.4 AMBIENT SO2 STANDARD: NONATTAINMENT, UNCLASSIFIABLE, MODELING, MAINTENANCE (OR INFRASTRUCTURE) SIP, . . WHERE ARE WE?
Harold Robbins, President, Bison Engineering Inc.

A3.5 HOW ELECTRIC POWER COMPANIES CAN BEST DEAL WITH THE CHALLENGES OF STATES DEVELOPING SIPS TO DEMONSTRATE ATTAINMENT OF THE 1-HOUR SO2 NAAQS
Howard Ellis, President, Enviroplan Consulting; Dr. Allen Dittenhoefer & Michael Hirtler, CCM

A4. NSR

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A4.1 EPA'S REGIONAL HAZE PROGRAM - A NEW AGENDA FOR VISIBILITY
Norman Fichthorn, Partner, Hunton & Williams LLP; Aaron Flynn

A4.2 NEW SOURCE REVIEW SETTLEMENTS IN A CHANGING REGULATORY CLIMATE
Liz Williamson, Partner, Winston & Strawn LLP

A4.3 THE UTILITY NEW SOURCE REVIEW ENFORCEMENT INITIATIVE -- MORE THAN A DECADE OLD & IT KEEPS GOING, & GOING, & GOING.
Makram Jaber, Partner, Hunton & Williams

A4.4 CAUSALITY & EFFECT: EMISSIONS ANALYSES IN RETROSPECTIVE NSR CASES
Marc Chupka, Principal, The Brattle Group

A4.5 WEAKENING OF THE PSD/NSR HAMMER
Karl Karg, Partner, Latham & Watkins LLP

A4.6 RECENT DEVELOPMENTS IN NSR
Gary McCutchen, Principal, RTP Environmental Associates, Inc.

A4.7 EXPERIENCES WITH GHG PERMITTING UNDER NSR
David Jordan, Partner, ERM

A5. COMPLIANCE STRATEGIES

Session Sponsor and Co-Chair

A5.1 PRACTICAL OPERATING PERMIT COMPLIANCE
George Lipka, Consulting Engineer, Tetra Tech EC

A5.2 PRACTICAL COMPLIANCE EXPERIENCE
Maureen Gannon, Executive Director of Environmental Services, PNM Resources Inc.

A5.3 PRACTICAL CONSIDERATIONS FOR ENVIRONMENTAL COMPLIANCE STRATEGY DEVELOPMENT
Brian Toth, Climate & Renewable Strategy Manager, Southern Company

A5.4 EPA'S CROSS STATE RULE, THE LITIGATION, IMPLEMENTATION COMPLIANCE
Dave Tripp, Partner, Stinson Morrison Hecker, LLP; Daniel R. Wilkus, Westar Energy

A5.5 PRACTICAL NSR COMPLIANCE
Mack McGuffey, Partner, Troutman Sanders LLP

A5.6
Randy Brogdon, Partner/Environmental Practice Group Leader, Troutman Sanders LLP

A6. MACT

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A6.1 MACT COMPLIANCE TECHNOLOGIES
Scott Bayon, Director of Sales, Anguil Environmental Systems, Inc.

A6.2 OVERVIEW OF THE NON-HAZARDOUS SECONDARY MATERIAL RULE: IS YOUR FUEL A SOLID WASTE?
Melissa Hillman, Managing Consultant, Trinity Consultants

A6.3 BOILER MACT ENERGY ASSESSMENTS
Dorothy Austin, Senior Project Manager, Golder Associates Inc.; Ying Ng

A6.4 INJECTION OF GAS-PHASE BROMINATED PAC UPSTREAM OF WET SCRUBBERS FOR HG CONTROL
Ron Landreth, Manager Customer Technical Service, Albemarle Environmental Division

A6.5 THE UTILITY MACT RULE: ONE YEAR LATER
Michael Rossler, Manager - Environmental Programs, EEI

A6.6 STATISTICS IN ENVIRONMENTAL POLICY MAKING & COMPLIANCE IN AIR QUALITY: SOURCE TEST DATA INTERPRETATION IN BOILER & UTILITY MACT
Joy Brooks, Senior Associate, ENVIRON International Corporation; Glenn England & Joe Hower

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A7. PERMITS & COMPLIANCE

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A7.1 CAN THIS PROPOSED POWER PROJECT BE BUILT?
(m)Eri Ottersburg, Senior Engineer, SLR International; Ray Hendricks, Portland General Electric

A7.2 PERMITTING OF NEW AIR QUALITY CONTROL EQUIPMENT ADDITIONS FOR "ALPHABET SOUP" COMPLIANCE: SUCCESSES & CAUTIONS
Steven Babler, Air Quality Engineer, Sega Inc.; Brian Petermann

A7.3 CONVERTING FROM COAL TO NATURAL GAS - CHANGES TO COMPLIANCE MONITORING
John Downs, Regulatory Manager, Babcock & Wilcox Power Generation Group; Mark Holt

A7.4 QUALITY ASSURANCE REQUIREMENTS OF MAKING METEOROLOGICAL ASSESSMENTS FOR PERMITTING A NEW POWER PLANT
Ping Wan, Senior Principal Engineer, Bechtel Power Corporation

A7.5 STREAMLINING THE PERMITTING PROCESS – CASE STUDIES FROM GAS-FIRED COMBUSTION TURBINE LICENSING
Anand Yegnan, Senior Consultant/Project Manager, ERM; John Sherwell, Maryland DNR; Julie Ross, Mark Garrison, & Jennifer Flannery, ERM

A7.6 DO I REALLY NEED TO MODEL?
Teresa Raine, Principal Consultant, ERM

A7.7 AIR PERMITTING FOR RECIPROCATING ENGINE PROJECTS FOR ELECTRICITY GENERATION
Mary Hauner-Davis, Manager, Air/Noise Department, Burns & McDonnell; Minda Nelson

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A8. CLEAN AIR POLICY

A8.1 WILL THE REFINING INDUSTRY SURVIVE THE CLEAN AIR ACT?(OR, WILL THE NEXT STRAW BREAK THE CAMEL'S BACK)
(m)Bill Smalling, Attorney at Law, C.William Smalling, Attorney at Law, PLLC.

A8.2 OBTAINING AN EXTENSION ON THE 18 MONTH CONSTRUCTION DEADLINE FOR YOUR PSD PERMIT
(m)Eri Ottersburg, Senior Engineer, SLR International; Ray Hendricks, Portland General Electric

A8.3 SUMMARY OF REGIONAL EMISSIONS & AIR QUALITY TRENDS, 1999-2010
Eugene Trisko, Attorney at Law, On behalf of ACCCE

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A9. REGULATORY COMPLIANCE

URS Workshop

B1. CEMS & MATS

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Tim Kuiken

B1.1 SOFTWARE CEMS & ALTERNATIVE TO HARDWARE
Joseph Miller, Technical Consultant - Environmental, Rockwell Automation

B1.2 MERCURY & AIR TOXICS STANDARDS (MATS) CEMS DESIGN & NEW MONITORING REQUIREMENTS
Tim Kuiken, Midwest Regional Sales Manager, Cemtek Environmental

B1.3 SO3 SOURCE EMISSION SAMPLING METHODOLOGIES
David Ostaszewski, Senior Managing Engineer, O'Brien & Gere Engineers

B1.4 CEMS SYSTEMS SPECIFICALLY FOR COMBINED CYCLE POWER PLANTS
Deborah Padwater, Strategic Industry Manager - Power, Sick Maihak GmbH

B1.5 MERCURY & AIR TOXICS STANDARD (MATS) EMISSION TESTING REQUIREMENTS, RECOMMENDATIONS & COST COMPARISONS
Jeff Burdette, Practice Leader, TRC Environmental Corporation

B1.6 FULL-SCALE MULTISITE EVALUATION OF THE MULTIELEMENT SORBENT TRAP SAMPLING (ME-ST) METHOD FOR HALOGEN
John Pavlish, Sr. Research Advisor, Energy & Environmental Research Center; Jeffrey Thompson

B2. HCL MONITORING

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B2.1 HCL EMISSIONS MEASUREMENTS USING FTIR
Sylvie Bosch-Charpenay, Senior Applications Scientist, MKS Instruments; Barbara Marshik, Peter Zemek

B2.2 HCL MONITORING - BEST PRACTICES & FIELD EXPERIENCE
Heimo Breton, Head of Corp. Solutions Center, SICK Process Automation

B2.3 MEASURING HCL USING HOT/WET EXTRACTIVE FTIR CEMS
Jim Cornish, Technical Sales & Support, Gasmet Technologies; Luc Sevrette

B2.4 FIELD TRIALS OF OPSIS TUNABLE DIODE LASER FOR HCL MONITORING
(m)James Wright, Director - Advanced Monitoring Solutions, Clean Air Engineering; J. Demkovich

B2.5 IN-DUCT HCL MONITORING
Charles Lockert, President, Breen Energy Solutions

B2.6 HCL CEMS
Seth Morrell. Sales & Marketing Coordinator, Altech Environment U.S.A.

B2.7 REQUIREMENTS OF PS-18 FOR FTIR MEASUREMENT OF HCL FOR UTILITY & CEMENT INDUSTRIES
Kevin Ramazan, Vice President, FTIR Operations, California Analytical Instruments, Inc.

B3. PM, OPACITY & VISIBILITY

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John Watson & Judi Chow

B3.1 AN UPDATED REVIEW OF PM SPIKING FOR PM CEMS CALIBRATION
Robert Baxter, President, B3 Systems, Inc.; Derrick Hinkle

B3.2 DIGITAL CAMERA BASED CONTINUOUS EMISSION MONITORING
Shawn Dolan, President, Virtual Technology LLC

B3.3 PM2.5 EMISSIONS TEST METHODS COMPARISON, LIMITATIONS & BENEFITS
Kevin Crosby, Technical Director, Avogadro Group; Craig Thiry

B3.4 APPLICATION OF MOBILE DEVICES FOR VISIBLE EMISSIONS
Sue Sung, Dir - EHS Technology, Trinity Consultants; Adam Williams & Nick Petro

B3.5 PM MONITORING OPTIONS UNDER THE UTILITY MATS RULE
Steve Norfleet, Project Manager, RMB Consulting & Research, Inc.; Jon Konings, We Engergies

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B4. MERCURY MEASUREMENT

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SICK

Dan Kietzer

B4.1 TECHNICAL ADVANCES IN HG CEM'S - UPDATE
Dan Kietzer, Business Development Manager, SICK Process Automation

B4.2 MERCURY SPECIATION MEASUREMENTS FROM BOILER TO STACK
(m)James Wright, Director - Advanced Monitoring Solutions, Clean Air Engineering; T. Rodak, J. McKeever

B4.3 ONGOING FIELD TEST EXPERIENCES WITH THE AUTOMATIC SORBENT TRAP MONITORING SYSTEM
Jurgen Reinmann, Branch Manager, Environnement S.A Deutschland; Seth Morrell, Altech Environmental USA

B4.4 MONITORING MERCURY & NON-MERCURY HAP METALS WITH A SINGLE CEMS
Douglas Barth, Business Development Manager, Pall Corporation; Krag Petterson & Marty Ladner

B4.5 ELEMENTAL MERCURY IN SOIL BY SEQUENTIAL EXTRACTION FOR COMPLIANCE WITH ILLINOIS RISK BASED CLEAN-UP
Don Cortes, Chief Scientific Officer / VP, STAT Analysis Corporation; Surendra Kumar

B4.6 RESULTS FROM A GOLD NANOPARTICLE MERCURY DETECTION SYSTEM
Jay James, Founder, Picoyune, Donald Lucas Ph.D., Lawrence Berkeley National Laboratory

B5. EMISSION TESTING & MONITORING

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B5.1 MEASURING ZERO POLLUTANTS
(m)Robert Davis, Vice President - Environmental Sustainablity, Airgas

B5.2 NEW RULES FOR EPA PROTOCOL GASES
(m)Robert Davis, Vice President - Environmental Sustainablity, Airgas

B5.3 FIELD TESTING OF AN IN SITU SO3/SO2/H2O CONTINUOUS REAL-TIME MONITOR
Curtis Laush, Senior Scientist, IMACC

B6. MONITORING & REPORTING

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B6.1 IMPINGEMENT MONITORING & MODELING AT 15 POWER PLANTS ON THE OHIO RIVER
Greg Seegert, Chief Ichthyologist, EA Engineering, Science, & Technology; Ron King, Joe Vondruska, Doug Dixon

B6.2 SF6 & DECOMPOSITION GAS ANALYSIS THROUGH NON DISPERSIVE INFRARED TECHNOLOGY
Vaughan Williams, International Sales Director, Energy Maintenance Technologies; Neil Kane, Kevin York

B6.3 MATS COMPLIANCE - HOW WILL EPA DETERMINE COMPLIANCE? HOW WILL YOUR DAHS DEMONSTRATE COMPLIANCE?
John Downs, Regualtory Manager, Babcock & Wilcox Power Generation Grp.; Joel Millard

B6.4 FUTURE CHALLENGES FOR CEMS DAHS SYSTEMS
Mark Shell, Chief Technology Officer, Environmental Systems Corporation

B7. MODELING

Session Sponsor and Co-Chair

B7.1 MODELING LAKE RECOVERY FOLLOWING MERCURY EMISSIONS CHANGES
Leonard Levin, Technical Executive, Electric Power Research Institute; Krish Vijayaraghavan, Environ

B7.2 EVALUATION OF MODELING RESULTS USING A REFINED TECHNIQUE FOR PREDICTING IMPACTS FROM PORTABLE OR TRANSIENT SOURCES (TRANSVAP)
Richard Hamel, Air Quality Meteorologist, AECOM; Thomas Damiana

B7.3 SOLUTIONS TO AERMOD PREDICTED NAAQS EXCEEDANCES DUE TO BUILDING WAKE EFFECTS
Ron Petersen, Vice President, CPP, Inc.

B7.4 FORECASTING FOR EMISSION COMPLIANCE VIA OPERATIONAL MODELING
Scott Tampke, Business Development Manager, Black & Veatch

B7.5 ADVANCED DISPERSION MODELING TECHNIQUES TO ASSIST WITH NAAQS COMPLIANCE
Robert Iwanchuk, Manager - Air Quality Engineering & Studies, AECOM; David Heinold, Richard Hamel & Robert Paine, AECOM; Eladio Knipping & Naresh Kumar, EPRI

B7.6 DOES EPA NEED MORE ADVANCED MODELS FOR SECONDARY FORMATION
Gale Hoffnagle, Air Quality Consutling Practice Leader, TRC Environmental Corporation

B7.7 A REAL-TIME MODEL FOR PERFORMANCE MONITORING USING EMISSIONS DATA
Sastry Munukutla, Emeritus Prof. of Mech. Engg., Tennessee Tech. Univ.

B8.

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B9.

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C1. HG CONTROL DEMONSTRATIONS

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C1.1 DEMONSTRATION OF TECHNOLOGY FOR ENHANCED HG CONTROL WITH SDA & CDS UNITS
Rebecca Stiles, Sr. Research Chemist, Nalco, an Ecolab Company; Bruce Keiser & Nicholas Ergang, Nalco Company; Steve Smokey, GRE Stanton Station

C1.2 APPLYING MONITOR & CONTROL STRATEGIES FOR HG EMISSIONS ACROSS WET FGD SCRUBBERS
Bruce Keiser, Research Fellow, Nalco, an Ecolab Company; Jianwei Yuan, Rebecca Stiles & John Meier, Nalco, an Ecolab Company; Stephen Potter, Duke Energy Corporation

C1.3 A NOVEL APPROACH TO MERCURY CONTROL FROM COAL FIRED POWER PLANTS
Jeff Kolde, Product Specialist, W.L. Gore & Associates, Inc.; John Darrow, Rich Gebert, Steve Hardwick, Stephen Stark, W.L. Gore and Associates, Inc.; Jonas Klingspor, Tom Machalek, Blake Stapper; URS Corporation; Ramsay Chang, EPRI

C1.4 PERMANENT SYSTEM INSTALLATION OF A NOVEL MERCURY REMOVAL STRATEGY
Philip Elliott, Engineering Services Manager, STEAG Energy Services LLC

C1.5 ADVANCED ACTIVATED CARBONS FOR EFFICIENT MERCURY REMOVAL
Brandon Looney, Principle Engineer, Southern Company; Jacqueline Cecil, Robert Huston & Joe Wong

C1.6 FULL SCALE & PILOT SCALE FIELD STUDIES USING NORIT'S CONCRETE COMPATIBLE CARBON
(m)Patton Adams, Developmental Engineer, Norit Inc.

C1.7 HG CONTROL WITH MICRO INJECTION OF BROMINATED PAC IN A SCRUBBED PRB PLANT
Jon Miller, Technical Service Engineer, Albemarle Corp.; Shane Bemis, CPS Energy

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C1.8 A NOVEL FOR APPROACH FOR MERCURY CAPTURE
Christopher Poling, Vice President, Mercury Capture Systems; Tom Lesniak

C2. HG CONTROL & BROMINE

C2.1 EMO™
Bobby Chen, Client Program Mgr., Shaw Environmental & Infrastructure Grp., Randall Moore

C2.2 INTERACTION OF HAPS, HG & BROMINATED ACTIVATED CARBON IN COMBUSTION FLUE GAS
Erik Rupp, Research Associate, Stanford Univ. Energy Resources Engineering; Jennifer Wilcox

C2.3 IN PURSUIT OF THE NEW-PLANT MATS HG CONTROL LIMIT: FULL SCALE TEST RESULTS USING ALSTOM'S KNXTM MERCURY CONTROL TECHNOLOGY WITH NORIT'S PAC PRODUCTS
Thomas Pearson, Principal Process Engineer, Alstom Power, Inc. Environmental Control Systems; Brad Donat & John David, Norit Americas Inc.

C2.4 ADVANTAGE OF ALBEMARLE GAS-PHASE BROMINATED ACTIVATED CARBON FOR MERCURY CONTROL IN DRY SCRUBBERS – SDA/CDS APPLICATIONS
Behrooz Ghorishi, R&D Director, Albemarle Corp.; Emma Zhou, John Parks & Will Pickrell

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C2.5 MAXIMIZING MERCURY CAPTURE UNDER CHALLENGING COMBUSTION SCENARIOS
Marcus Sylvester, VP of Sales, Midwest Energy Emissions Corporation

C2.6 ECONOMICAL, EFFICIENT AND PROVEN HG CONTROL TECHNOLOGY
Thomas Gale, Catalyst Manager, Southern Research Institute; George Blankenship

C2.7 THE INFLUENCE OF FUEL CHLORINE & BROMINE ON DIOXINS & FURANS IN THE STACK GAS OF WASTE INCINERATORS & COAL-FIRED POWER PLANTS
Bernhard Vosteen, President, Vosteen Consulting GmbH; Werner Funcke & Berthold Hülk

C3. CONTROL TECHNOLOGIES I

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C3.1 START UP & OPERATING EXPERIENCE NRG INDIAN RIVER NID DFGD
Mark Fiedler, Principal Process Engineer, Alstom Power

C3.2 THE FACT & FICTION OF SCR CATALYST REGENERATION
Mark Ehrnschwender, VP of Business Development, STEAG Energy Services LLC

C3.3 DESIGN, INSTALLATION, START-UP & OPERATION OF A 2720 MWE FGD & WASTE WATER TREATMENT SYSTEM
Natarajan Sekhar, Senior Consultant, CH2M Hill, Albert Leung, Chinla Light & Power, Hong Kong & Tom Higgins, CH2M Hill, USA

C3.4 MERCURY CONTROL & ITS INTERRELATION TO POWER PLANT OPERATION & OTHER AIR POLLUTION CONTROL TECHNOLOGY
Mark Sankey, Senior Engineering Specialist, Bechtel Power Corporation, Don Koza. Bechtel Power Corp; Michelle Golden, Bechtel Power Corp

C3.5 MERCURY CONTROL FOR UTILITY BOILERS THAT REQUIRE FLUE GAS CONDITIONING
David Young, Engineer III, ADA-ES, Inc., Ken Baldrey, Brian Donnelly, Greg Filippelli

C3.6 PERFORMANCE OF PERNOXIDE FOR NOX CONTROL ON A FULL SCALE TRIAL ON A UTILITY COAL FIRED BOILER
Robert Crynack, Manager - Air Pollution Control, FMC Environmental Solutions; Philip Block, FMC Environmental Solutions; James Jarvis & Sterling Gray, URS Corporation

C3.7 OPERATING A CIRCULATING DRY SCRUBBER AT LOW & VARIABLE BOILER LOADS
Terence Ake, Product Manager, Babcock Power, Inc.; Roderick Beittel & Anthony Licata

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C4. CONTROL TECHNOLOGIES II

C4.1 BASF MERCURY SORBENTS - UPDATE ON MINERAL BASED TECHNOLOGIES FOR MERCURY CAPTURE IN COAL-FIRED POWER PLANTS
William Hizny, Technical Projects Manager, BASF Corporation, Fabien Rioult, PhD - BASF Corporation; Xiaolin Yang, PhD - BASF Corporation

C4.2 GAME-CHANGING MULTI-POLLUTANT EMISSIONS CONTROL TECHNOLOGY
Kevin Crapsey, VP of Corporate Strategy & Development, Eco Power Solutions

C4.3 INITIAL OPERATION & PERFORMANCE OF THE INTEGRATED DFGD/WFGD FOR CLIFFSIDE 6
Raymond Gansley, Manager of Process Engineering, Alstom; Phil Rader & Dale Love

C4.4 CODEPENDENCE OF MULTIPOLLUTANT CONTROLS & THE AIR PREHEATER
John Guffre, Senior Research Scientist, Paragon Air Heater Technologies, Inc

NOL-TEC SYSTEMS
Michael Thiel

C4.5 EMISSIONS CONTROL SYSTEM UPGRADES FOR INDIAN RIVER UNIT 4
Steve Bjorklun, Senior Associate Process Engineer, Burns & McDonnell Engineering Company, Inc.; Gerry Hopper, NRG; Kristin Glikbarg & Paul Brandt, Burns & McDonnell

C4.6 EVALUATION OF MERCURY CONTROL TECHNOLOGIES WHILE OXY-FIRING A PRB COAL
Andrew Fry, Manager - Engineering R&D, Reaction Engineering International; Brydger Van Otten & Brad Adams, Reaction Engineering International; Jost Wendt, Geoff Silcox & Ignacio Preciado, University of Utah; Larry Bool, Praxair

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C5. MATS

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C5.1 HCL & MERCURY MITIGATION WITH DSI
Brent Tidemann, Chemical Engineer - Manager, Nol-Tec Systems; Michael Thiel

C5.2 MATS COMPLIANCE SOLUTION FOR UNSCRUBBED COAL-FIRED BOILERS
Jonas Klingspor, Vice President, URS Corporation; Tom Machalek, Blake Stapper, URS; Jeff Kolde, John Darrow, Richard Gebert, Stephen Stark, W.L. Gore and Associates, Inc.

C5.3 PREPARING FOR THE MERCURY AIR TOXICS STANDARD (MATS)
Martin Dillon, PE, PMP, Project Manager, ADA-ES, Inc.; Andrew Szafarz: Alliant Energy, Inc., Sharon Sjostrom, Greg Filippelli, Thomas Campbell, David Young, ADA-ES, Inc.

C5.4 ADDRESSING MATS & MERCURY RE-EMISSIONS WITH MULTI-POLLUTANT EMISSIONS CONTROL TECHNOLOGY
Peter Kawa, Senior Vice President-Sales, Eco Power Solutions

C5.5 UTILITY MATS COMPLIANCE W/ HCL LIMITATIONS & THE CHALLENGES FACING AGING EGUS
Paul Johnson, Project Manager, ADA-ES, Inc.; Andrea Taylor, Tennessee Valley Authority; David Young, John Schminky & Greg Filippelli, ADA-ES, Inc

C5.6 DECISION MAKING FOR MAT COMPLIANCE
Joel Millard, KVB-Enertec Regualtory Specialist, Babcock & Wilcox Power Generation Group; Bill Eberhardt

C5.7 FORGET ABOUT MERCURY RE-EMISSION -- HOW TO USE YOUR WET-FLUE-GAS DESULFURIZER AS A ROBUST & EFFECTIVE MERCURY ABSORBER
Joe Stuart, Director of Commercial Development, TDC, a division of Genesis Energy Limited

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C5.8 A SYSTEM EVALUATION APPROACH IN IMPLEMENTING DSI FOR MATS COMPLIANCE
Anthony Silva, Advisory Engineer, Babcock & Wilcox; T. Ruppelli, S. Kumar, & J. Knapik

C6. DRY SORBENT INJECTION(DSI)

C6.1 BENEFITS OF CONDITIONED AIR IN TRANSLOADING WHEN USING TRONA OR SBC FOR ACID GASES MITIGATION IN COAL FIRED UNITS FLUE GAS STREAM
Jarret McClendon, Applications Engineer, Natronx Technologies

C6.2 THE EFFECT OF DRY SORBENT INJECTION (DSI) REAGENTS ON COAL COMBUSTION BY-PRODUCTS
Jim Dickerman, Director FGT, Lhoist North America; Melissa Sewell

C6.3 DSI FOR SO2 SO3, HCL, & HG REMOVAL - ANSWERS TO COMMON QUESTIONS
Jon Norman, DSI Technology Manager, United Conveyor Corporation

C6.4 ACID GAS & MERCURY MATS COMPLIANCE THROUGH SORBENT INJECTION
Cody Wilson, Director of Engineering, ADA-ES, Inc.; Greg Filippelli, Cameron Martin & Robin Stewart, ADA-ES; Bill Caputo, BCSI

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C6.5 OPTIMIZATION OF DRY SORBENT INJECTION & PAC INJECTION FOR COST-EFFECTIVE MULTI-POLLUTANT CONTROL
Kevin Fisher, Senior Engineer, Element 1 Engineering, Inc.; Steve Smokey, Great River Energy

C6.6 STATUS OF THE DRY SORBENT INJECTION PROJECT AT BOARDMAN STATION
Bruce McCampbell, Project Manager, Shaw; Kenneth Fitzgerald & Christopher Wedig

C6.7 IS THERE A PLACE FOR DSI AT DETROIT EDISON?
William Rogers, Sr. Technological Specialist, DTE Energy; Robin Stewart, Andrew Bertelson, Jordan Copenhafer, Nathan Sonobe & Trent Lynch, ADA-ES, Inc.

C6.8 STRATIFICATION CONSIDERATION IN DSI OPTIMIZATION
Charles Lockert, President, Breen Energy Solutions

C6.9 A HIGH REACTIVE HYDRATED LIME FOR CHALLENGING DSI APPLICATIONS
Curt Biehn, Manager, Marketing & Technical Services, Mississippi Lime Compay; Mark DeGenova, Randy Griffard, Eric Van Rens & Richard Zhang

C7. ACTIVATED CARBON & SCR

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C7.1 RECENT INJECTION TRIALS OF MATS-PAC™ NON-HALOGENATED ACTIVATED CARBON IN COAL-FIRED POWER PLANT FLUE-GAS
William Naylor, VP Operations, Carbonxt, Inc.; Dr. David Mazyck, Carbonxt, Inc.; Dr. Heather Byrne, Dr. Ameena Khan, Jack Drwiega & Caitlin Gross, Clear Carbon Innovations

C7.2 SORBENT TESTING IN THE LAB AND FIELD
(m)John Kline Principal, John Kline Consulting; Anik Delagrave, Lafarge

C7.3 HOW TO GUARANTEE THE LOWEST COST ACTIVATED CARBON TREATMENT SOLUTION
Richard Mimna, Senior Research Associate, Calgon Carbon Corporation; Michell Lomago

C7.4 ACTIVATED CARBON MARKET SUPPLY & DEMAND
Rob Nebergall, Global Business Manager - Emissions Control Technologies, Norit Inc.

C7.5 RELEASE & TRANSFORMATION OF POISONS IMPLICATED IN SCR CATALYST DEACTIVATION
(m)Balaji Krishnakumar, Sr. Computational Analyst, Niksa Energy Associates LLC; Stephen Niksa, NEA LLC; Alejandro Jimenez, EPRI

C7.6 SCR CATALYST MANAGEMENT CONSIDERATIONS
Nick Pollack, Chief Technology Officer, CoaLogix; Randy Sadler

C7.7 SELECTIVE CATALYTIC REDUCTION SYSTEMS
Joe Smith, Business Development Manager, Peerless Mfg

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James Bays, Technology Fellow, CH2MHILL; Tom Higgins, Dana French, BT Thomas

C8.2 IN-FLIGHT MERCURY CAPTURE OF NORIT'S NONCARBON SORBENT VERSUS DARCO HG-LH
(m)Patton Adams, Developmental Engineer, Norit Inc.

C8.3 PARTICULATES & MERCURY REMOVAL USING KIMRE(TM) TECHNOLOGY
George C. Pedersen Jr. PE, CEO, KIMRE, INC.

C8.4 APPLICATION OF THE DRYFINING™ TECHNOLOGY AT EXISTING POWER UNITS FIRING LOW-RANK COAL
(m)Charles Bullinger, Senior Principle Engineer, Great River Energy; Vladimir Vaysman & Yixin Lu, WorleyParsons

C8.5 REACT MULTIPOLLUTANT SYSTEM - AN OPTION TO CONSIDER
Jim Peters, VP Business Development, Hamon

C8.6 POLLUTION CONTROL COST MINIMIZATION
Jerrold Radway, Chairman, Enerchem

C8.7 DEMONSTRATIONS OF AMENDED SILICATES FOR MERCURY CONTROL IN COAL FIRED GENERATING UNITS
Jim Butz, VP of Project Management, Novinda; Cliff Brown & Ben Bernardo

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C9.1 REGIONAL ENVIRONMENTAL REMEDIATION
(m)Gare Henderson, Director of R&D, Gravitational Systems Engineering, Inc.

C9.2 ANALYTICAL MGMT. OF SCR CATALYST LIFETIMES & MULTIPOLLUTANT PERFORMANCE
(m)Balaji Krishnakumar, Sr. Computational Analyst, Niksa Energy Associates LLC; Stephen Niksa, Niksa Eenrgy Associates LLC; Farrokh Ghoreishi & Corey Tyree, Southern Company

C9.3 MULTI-POLLUTANT CONTROL USING THE CHEM-MOD LLC TECHNOLOGY
Murray Abbott, Manager of Technical Support, Chem-Mod LLC; Sally Wasikowski & George Kotch, Chem-Mod LLC; Jay Gunderson, Energy & Environmental Research Center

C9.4 SNOXTM -THE ECONOMICAL WAY TO TURN HIGH-SULPHUR FUELS INTO POWER WITH REDUCED CO2 EMISSIONS
Peter Ibæk, Business Develpment Manager, Haldor Topsoe A/S

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Kelly Daly, Chair - Energy & Environmental Division, Stinson Morrison Hecker LLP

D1.2 THE EFFECT OF SHALE GAS ON NEW ENGLAND POWER MARKETS
Stephen Slocomb, Associate, Epsilon Associates

D1.3 OPTIONS FOR CAPTURING THE VALUE OF SHALE GAS: ENVIRONMENTAL, ECONOMIC & ENERGY SECURITY PERSPECTIVES
Joe Marriott, Lead Associate, Booz Allen Hamilton; Robert Murray, Jesse Goellner, & Gary Leatherman

D1.4 SHALE GAS & LNG EXPORT: REGULATION OF A REW PHENOMENON
Les Lo Baugh, Shareholder/Partner, Brownstein

D1.5 ENVIRONMENTAL & ECONOMIC IMPACT ASSESSMENT OF SHALE GAS PRODUCTION & RESOURCES
Sarah Jordaan, Project Manager, EPRI; Sean Bushart

D1.6 A SYSTEMWIDE MODEL TO MEET THE CHALLENGES & MAXIMIZE THE ECONOMIC POTENTIAL FROM SHALE GAS EXTRACTION IN SMALL TOWN COMMUNITIES
Sayan Chakraborti, Senior Program Manager, MRIGlobal; Mark Abashian & Larry Brown, MRIGlobal; Gregory Proctor, Prolific Technology

D2. FRACKING & SUSTAINABLE DEVELOPMENT

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D2.1 PUBLIC CONFIDENCE & HYDRAULIC FRACTURING: FINANCIAL RESPONSIBILITY AS AN ECONOMIC TOOL FOR RISK-SHARING
Kerry Schlichting, Senior Associate, ICF International; Libby McCullough

D2.2 FRACKING: ENVIRONMENTAL REGULATORY & POLICY UPDATE
Megan Roberts-Satinsky, Associate, Venable LLP

D2.3 FRACKING POLICY: WRONG POLICY COULD DERAIL GAS PRODUCTION OVERNIGHT INCREASING COSTS TO HOMEOWNERS & INDUSTRY
(m) Stephen Sewalk, Assistant Professor, University of Denver; Qionglin Dai

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D3.1 NATIONAL CAP & TRADE LEGISLATION- WHAT YOU NEED TO KNOW TO PREPARE
Larry Goldenhersh, CEO, Enviance

D3.2 IMPACTS OF POTENTIAL FUTURE RULES & REGULATIONS ON INVESTMENT DECISIONS TODAY
Sebastian Mankowski, Consultant, NERA Economic Consulting; Scott Bloomberg

D3.3 ENERGY POLICY IN THE WHITE HOUSE 2013 OBAMA VS. ROMNEY
Kelly Carnes, President, CEO, TechVision21

D3.4 ELPIPES AND BALLISTIC BREAKERS AS ENABLERS FOR AN UNDERGROUND SUPERGRID
Roger Faulkner, Founder & President, Electric Pipeline Corporation

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Byron Woertz, Senior Project Manager, Western Electricity Coordinating Council

D3.6 ELPIPES TO CREATE HIGH CAPACITY IRELAND-UK POWER LINKAGE
Joe Corbett, Head of Technical Services, Mainstream Renewable Power Ltd.; Roger Faulkner, Electric Pipeline Corporation

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Mitchell Baer, Director - Office of Oil and Gas Analysis, US DOE

D3.8 ENERGY AND ENVIRONMENT POLICY LEARNINGS FROM 'CASH FOR CLUNKERS'
Shoshannah Lenski, Associate, Strategy & Corporate Development, DTE Energy

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Vijayan Chomatil, Entrepreneur, Kanab Energy

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Rob Barnett, Energy Analyst, Bloomberg Government

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Barbara Sands, Managing Consultant, PA Consulting

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Michelle De Blasi, Attorney, Greenberg Traurig LLP; Christopher Davey, EnviroMission

D5.3 CUTTING THROUGH THE STATIC: INSIGHTS FOR IMPLEMENTING EFFECTIVE PUBLIC INVOLVEMENT PROGRAMS FOR ELECTRIC INFRASTRUCTURE DEVELOPMENT
Diann Strom, Principal, EnviroIssues; Diane Adams

D5.4 PRACTICING RISK-AWARE ELECTRICITY REGULATION
Dan Mullen, Senior Manager, Ceres; Ron Binz, Public Policy Consulting; Richard Sedano, Regulatory Assistance Project; Denise Furey, Regent Square Advisors

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Allison Wood, Partner, Hunton & Williams LLP

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Jeanette Pablo, President, Navitas Strategies

D7.3 ACHIEVING SIGNIFICANT CARBON EMISSION REDUCTIONS FROM COGENERATION THROUGH NEW MARKET-BASED INCENTIVES
Paul MacGregor, Senior Vice President, Nexant; Tom Flynn

D7.4 ADOPT A CARBON TAX WITH REINVESTMENT & CONVERT NATURAL GAS TO GASOLINE TO REDUCE EMISSIONS OVER 50% IN 20 YEARS
(m)Stephen Sewalk, Assistant Professor, University of Denver; Vincent Buscarello

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(m)Sloane Whiteley, Senior Business Consultant, AVEVA

D8.2 CHALLENGES OF SOFT TARGET SECURITY PROTECTION IN THE POWER & UTILITY SECTOR
Jeff Simmerman, Lieutenant Commander USCG (ret), Environmental Resources Management

D8.3 ENERGY PROJECTS- RISKS & MANAGEMENT
Lorne Sivertson, President, Sivertson & Associates Consulting Ltd.

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Mickey Landkof, Senior Sales Engineer, Enviance

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Nedia Miller, Principal, Miller CTA

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Peter Black, Director, Brant Renewable Energy

E1.2 COMPATIBILITY OF SMALL WIND TURBINES WITH DOD FACILITIES
Kelley MacDonald, Research Mechanical Engineer, USACE - CRREL; C. Ryerson, W. Stein & K. Knuuti, USACE - CRREL; LTC D. Mikolaities, NH ARGNG

E1.3 RENEWABLE ENERGY CERTIFICATES: DEMYSTIFYING THE CURRENCY OF US & STATE RENEWABLE ENERGY MARKETS
Alex Pennock, Manager, Green-e Energy - Center for Resource Solutions

E1.4 A NEW VISION FOR CONCENTRATED SOLAR
Zev Rosenzweig, CEO & President, AORA Solar Ltd

E1.5 HOW TO BUY & MARKET RENEWABLE ENERGY CREDITS & MEET STATE MANDATES IN NYISO, PJM & RGGI
Bert Spaeth, Senior Energy Engineer, RS Energy Solutions Inc.

E1.6 STATISTICAL OPTIMIZATION OF MEDIUM COMPONENTS AFFECTING FERMENTATIVE HYDROGEN PRODUCTION FROM CRUDE GLYCEROL BY THERMOTOLERANT KLEBSIELLA SP. TR17
Teera Chookaew, Ph.D Candidate, Prince of Songkla University

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Peter Lilienthal, CEO, HOMER Energy

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Craig Lewis, Executive Director, Clean Coalition

E2.3 SYNCING SCHEDULES FOR RENEWABLE GENERATION & TRANSMISSION INTERCONNECTION
Molly Cresto, Project Manager, CH2M HILL; Cary Roberts

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Terry Clapham, Distributed Generation Manager, California Center for Sustainable Energy

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George Miley, Professor Emeritus - University of Illinois; Xiaoling Yang, Kyu-Jung Kim, Tapan Patel, Erik Ziehm, James Madrigal, Bert Stunkard

E2.6 FEASIBILITY & CONSUMER BENEFITS OF MEETING THE RENEWABLE PORTFOLIO STANDARD FOR DISTRIBUTED GENERATION IN ILLINOIS
Jin H. Jo, Assistant Professor, Illinois State University; Jared Hayden & Sarah Noll

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(m)Margery Moore, Dir. EHS Strategic Alliances, Bloomberg BNA

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Marlys Palumbo, Partner, Van Ness Feldman

TE3.3 HE ROLE OF ADVANCED PUMPED STORAGE HYDRO TECHNOLOGIES IN PROVIDING GRID SERVICES & INTEGRATION OF VARIABLE ENERGY RESOURCES
Vladimir Koritarov, Project Manager, Argonne National Laboratory

E3.4 ANCILLARY SERVICES ISSUES FROM THE PERSPECTIVE OF A PROJECT DEVELOPER'S ATTORNEY
Karl Kumli , Shareholder/Vice President, Dietze and Davis, P.C.

E3.5 TECHNICAL POTENTIAL OF PV PROJECT DEVELOPMENT IN THE US
Milo Terzich, Project Development Director - Americas, Trina USA; Krishna Shah

E3.6 DEVELOPMENT OF A RENEWABLE ENERGY MEASUREMENT SYSTEM
Zelda Roberts, Senior Specialist, National Advisory Council on Innovation

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Robert Prohaska, Director, ESA

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Peter Richardson, Partner, Richardson & O'Leary, PLLC

E4.3 KEY CONSIDERATIONS FOR LANDFILL GAS TO METHANE PROJECTS
(m)Joel Cervelloni, Principal Consultant, PA Consulting; TBD

E4.4 TRES AMIGAS - CREATING A NATIONAL HUB FOR RENEWABLES
Laura Manz, Senior Vice President, Viridity Energy, on behalf of Tres Amigas

E4.5 ENVIRONMENTAL LITIGATION AGAINST RENEWABLE PROJECT DEVELOPMENT
Jim Wedeking, Staff Attorney, Sidley Austin LLP

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Carolyn Parrs, President & CEO, Mind Over Markets

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James McTarnaghan, Partner, Duane Morris

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Kevin Wedman, Vice President, Bureau Veritas

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(m)Kris Skrinak, President, adaptiveARC, Inc.

E5.2 MAPS: MAGLEV POWER STORAGE SYSTEM
Robert Coullahan, President, Readiness Resource Group Incorporated; James Powell, Gordon Danby & James Jordan, Maglev 2000; F.H. Griffis New York Polytechnic University

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Edward Hinders, Canyon West LLC; Patrick Kelly

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John Robbins, Senior Director of Sales - Americas, AREVA Solar, Inc.

E5.5 PATENT PROTECTION BEST PRACTICES IN THE WAKE OF THE AMERICA INVENTS ACT
Lee Huddleston, Partner, Osha Liang, LLP

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Judith Kim, Director, Sterne, Kessler, Goldstein & Fox; Katrina P. Quach

E5.7 CAPTURING VALUE THROUGH INTELLECTUAL ASSET MANAGEMENT
Thomas McGurk, President & Mgng Member, Advanced Biofuel Solutions/McGurk Intellectual Property Advisors

E5.8 SUSTAINABLY PRODUCING NATURAL GAS THROUGH BIOTECHNOLOGY
Bob Cavnar, CEO, Luca Technologies

E6. SOLAR & PV

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Lane S. Garrett, P.E., C.E.M., CEO, ULG Energy Solutions, Inc.

E6.2 OUTLOOK FOR PV DEMADN IN A LOW INCENTIVE MARKET
Paula Mints, Director, Navigant

E6.3 SUNBEAMS FROM SPACE MIRRORS FEEDING SOLAR FARMS ON THE GROUND AT DUSK & DAWN
Lewis Fraas, President, JX Crystals Inc.

E6.4 DELIVERING & MAINTAINING A SUCCESSFUL, PROFITABLE SOLAR SYSTEM
Mike Grunow, Marketing Director, Trina Solar

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Boris Schubert, CEO, Q.CELLS North America

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Troy Dalbey, North American Manager, Upsolar Group

E6.7 BEST PRACTICES FROM SCE'S SOLAR PV PROGRAM
Mark Nelson, Director of Generation Planning & Strategy, Southern California Edison

E6.8 NATIONAL UTILITY RATES DATABASE
David Loomis, Professor of Economics, Illinois State University

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Stan Rosinski, Program Manager, Electric Power Research Institute; John Lindberg

E7.2 FINANCING RENEWABLE ENERGY PROJECTS: THE ROLE OF EX-IM BANK
Craig O'Connor, Director - Office of Renewable Energy, Export-Import Bank of the US

E7.3 CREATION OF A JOINT VENTURE: THE PRELIMINARY LETTER OF INTENT
Michael Manuel, Principal, Goldberg Kohn Ltd.

E7.4 PROJECT FINANCING FOR RENEWABLE ENERGY PROJECTS
John Ravis, Principal, Scully Capital

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William Stark, Senior Consultant, SAIC Energy, Environment & Infrastructure

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John MacDonald, Project Manager, Tetra Tech, Inc.

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Rajshekar DasGupta, Vice President - Energy Storage, Electrovaya

E8.2 CHARGING, TESTING & MONITORING: EV BATTERY CHARGING SYSTEMS & TECHNOLOGY
Don Karner, President of ECOtality North America, ECOtality

E8.3 FEASIBILITY OF ENERGY STORAGE ON ITALIAN POWER EXCHANGES ANCILLARY MARKET
Francesco Vallone, CEO, Celertech; Faddy Ardian

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F1. ECONOMIC ENERGY & CYBERSECURITY

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Brian Lenane, Senior Principal, SRA International

F1.2 CONDUCTING A RISK BASED METHODOLOGY FOR COMPLIANCE & CYBER SECURITY REQUIREMENTS
(m)Jerome Farquharson, Practice Manager, Burns & McDonnell Engineering Company; Michael Welch

F1.3 EFFECTIVE REGULATORY APPROACHES TO SMART GRID CYBER SECURITY
Terry Jarrett, Commissioner, Missouri Public Service Commission

F1.4 DESIGNING AN EFFECTIVE SECURITY PROGRAM
Joachim Gloschat, Physical Security Specialist, Security Management Solutions, LLC

F1.5 CYBER THREATS TO INDUSTRIAL CONTROL SYSTEMS: FACT OR FICTION
Marty Edwards, Director - Control Systems Security Program; Department of Homeland Security

F2. COMPLIANCE TECHNOLOGIES & STRATEGIES

F2.1 ASSESSMENT OF GREENHOUSE GAS RETROFIT ISSUES FOR COAL FIRED POWER PLANTS
Joy Gloria, Engineer, Sargent & Lundy, LLC; David Bahr, Sargent & Lundy, LLC; John Chang, USEPA

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F2.2 LOWER RISK AND REDUCED COST - ESP TO PJFF CONVERSION
Mark Aldrich, Regional Executive, Hamon

F2.3 RE-ENGINEERING COAL-FIRED GENERATING PLANTS
Keith Moore, President, Castle Light Energy Corp

F2.4 STRATEGIES FOR PATENTING "GREEN" TECHNOLOGIES
Erica Lowthers, Patent Agent, Sim. IP Practice

F2.5 ADVANCES IN FUEL LEAN GAS REBURN
Charles Lockert, President, Breen Energy Solutions

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Robert Van Durme, P.E., Senior Account Manager, Lechler Inc.

F2.7 AIR PERMITTING OF IPL'S EAGLE VALLEY PROPOSED REPLACEMENT COMBINED CYCLE PLANT
Richard Benedict Director of Project Development, Indianapolis Power & Light Co. (IPL); Tom Rarick & Robert Fraser, Environmental Resources Management

F3. POWER PLANT & BOILER OPTIMIZATION

F3.1 USE OF CHLORINE DIOXIDE IN RO SYSTEMS FOR TREATMENT OF BOILER FEED WATER
Bob Mueller, Director - Process Chemicals, Airgas Specialty Gases

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F3.2 IN FURNACE LASER-BASED MEASUREMENTS SYSTEM TO OPTIMIZE COAL COMBUSTION ON 600MW COAL-FIRED BOILER
Scott Affelt, Vice President, Zolo Technologies

F3.3 RECAPTURING LOST MW & BOOSTING PLANT EFFICIENCY FROM LOWER RANK COALS
(m)Charles Bullinger, Senior Principle Engineer, Great River Energy

F3.4 IMPROVED HEAT TRANSFER MANAGEMENT THROUGH SOOTBLOWING OPTIMIZATION ON A CYCLONE FIRED UNIT
Jeremy Brown, Project & Applications Engineer, Babcock & Wilcox PGG

F3.5 COAL FLOW OPTIMIZATION WITH B&W PGG'S EVENFLOW SYSTEM
Tim Fuller, Technology Manager, Babcock & Wilcox Power Generation Group; Bijan Hosseininejad & Eric Fuller, B&W PGG; Alan Murkerson & Joe Krajna, Lakeland Electric; Dr. Harun Biligren, Lehigh University

F3.6 USE OF OXYGEN ENHANCED COMBUSTION TO ENHANCE BOILER OPERATIONS
Larry Bool; Sr. Development Professional, Praxair, Inc; Stefan Laux, David Thompson & Sho Kobayashi

F3.7 COMBUSTION OPTIMIZATION FOR DECREASED EMISSIONS & IMPROVED EFFICIENCY
David Earley, President, Combustion Technologies Corporation; Joe Estrada, Duke Energy

F3.8 IMPROVING BOILER PERFORMANCE AT XCEL'S COMANCHE STATION USING GE'S ZONAL COMBUSTION MONITORING SYSTEM
Antonio Marquez, Lead Engineer, General Electric; Neil Widmer, Santosh Nareddy & David Moyeda, General Electric; Gregory George, Xcel Energy

F3.9 VERSATILITY OF NEW GENERATION DS® LOW NOX BURNER
Joe Brown, Aftermarket Services Product Manager, Hitachi Power Systems America; Peter Jin

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EA Engineering, Science, and Technology, Inc.

Richard Waterman

F4. EHS & EMIS

F4.1 FLUE GAS CONTAMINANT MEASUREMENT FROM OXY-COMBUSTION IN A COAL-FIRED POWER PLANT
Kenneth Wong, Senior Staff Scientist, American Air Liquide; Morgane Riviere, Air Liquide France

F4.2 ENSURING REGULATORY COMPLIANCE IN A DECENTRALIZED ORGANIZATION
Sponsor & Co-Chair - Richard Waterman, Vice President, EA Engineering, Science, & Technology, Inc.; Kathy French, LS Power Development, LLC

F4.3 EMIS - INCIDENT REPORTING SYSTEM
Mark Chrisos, Director of HSE & Security, InterGen

F4.4 EHS GLOBAL AUDITING TRENDS
(m)Margery Moore, Dir. EHS Strategic Alliances, Bloomberg BNA

F4.5 LEVERAGING MODERN TECHNOLOGY FOR EMIS SUCCESS
Don Smith, Regional Director, Perillon Software

F4.6 THE SAFETY LEADERS BRAIN-HOW SAFETY LEADERS ARE WIRED DIFFERENTLY & WHY THIS MAKES ALL THE DIFFERENCE TO BUSINESS
Michelle Brown, Operations Manager, Sentis USA; Elizabeth Prazeres

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Johannes Swanepoel & David Hoffamn

F5. EHS & RISK MANAGEMENT

F5.1 OIL SPILL RISK EVALUATION FOR SUBSTATION OIL-FILLED EQUIPMENT
Kris Macoskey, Principal, Civil & Environmental Consultants, Inc.; Emory McLean

F5.2 RISK MANAGEMENT & ITS IMPACT ON ENVIRONMENTAL HEALTH & SAFETY
Tom Barlow, Channel Manager, EtQ; Glenn McCarty

F5.3 MANAGING AND REDUCING RISK: ENVIRONMENTALLY PREFERRED CHEMICALS IN YOUR COMPANY'S MAINTENANCE PROGRAM
Jim Collins, Business Development Mgr.- Energy Markets, CRC Industries

F5.4 ENVIRONMENTAL GREEN SHOP AWARD PROGRAM
Robert Trapani, Environmental Engineer, State of Arizona Department of Transportation

F5.5 IMPLEMENTING ISO 31000 INTO EHS
Johannes Swanepoel, Product Marketing Manager, Enablon

F5.6 MOVING FROM EHS COMPLIANCE TO PERFORMANCE
David Hoffman, Sustainable Supply Chain SME, Enablon

F5.7 REDUCING HUMAN HEALTH RISKS FROM CARBON DIOXIDE VENTING ASSOCIATED WITH CARBON CAPTURE OPERATIONS
John Shrock, Senior Scientist, ECT, Inc.

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F6. ASH / CCP

F6.1 UPDATE ON ASTM COAL ASH REUSE STANDARDS
A. Gwen Eklund, Director - Power Generation Services, TRC

F6.2 COAL ASH STORAGE & DISPOSAL - LITIGATION & REGULATORY DEVELOPMENTS
Nash Long, Partner, Winston & Strawn, LLP; May Wall

F6.3 COAL ASH MANAGEMENT -- THE CHANGING LEGAL LANDSCAPE
Jeffrey N. Martin, Partner, Hunton & Williams LLP

F6.4 COAL COMBUSTION RESIDUALS CASE STUDY: GHENT GENERATING STATION
Stephen Henson, Process Engineer, Kiewit Power; Raymond Eric Zbacnik, Kiewit Power; Scott Straight, LG&E and KU Energy

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F7. OPERATIONS & MANAGEMENT

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F7.1 TRUE GRIT: 7 CORE PRACTICES OF RESILIENT LEADERS
Autumn Krauss, Chief Scientist, Sentis; Kellie Lewis

F7.2 ENERGY BENCHMARKING IN NYC
David Ahrens, Managing Director, Energy Spectrum

F7.3 OUTAGE MANAGEMENT 101 – A GUIDE TO THE EFFECTIVE PLANNING, EXECUTION & CLOSE OUT OF GENERATING PLANT MAINTENANCE OUTAGES
Phil Webster, Project Manager, Black & Veatch Corporation; Stephen Nelson, Dominic DiBari & Mike Dammann

F7.4 MILL PRE-FIRE DETECTION SYSTEMS
Richard Hovan, Principal Consultant, EPA Systems, LLC

F7.5 PROACTIVELY PINPOINTING HAZARDOUS VEGETATION ON THE FRINGES OF POWER LINE RIGHT-OF-WAY CORRIDORS USING LIDAR AND IMAGERY DATA
Alex McCracken, Product Consultant, Exelis

F7.6 MANAGING ENVIRONMENTAL COMPLIANCE AND RESOURCE RECOVERY DURING TRANSMISSION & DISTRIBUTION SYSTEM CONSTRUCTION
Robert Ferrell, Sr. Manager, Business Development, URS Corporation; Lauren Andersen, Ray Hinkle

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F8. NATURAL RESOURCE MGMT. - HCP

F8.1 PROGRAMATIC PERMITTING FOR VEGETATION MANAGEMENT
Michael Warner, President - Project Manager, Transcon Environmental, Inc.

F8.2 AN INTEGRATED ECOLOGY & DESIGN APPROACH TO WETLAND RESTORATION
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F8.3 A STANDARDS BASED INFORMATION & OPERATIONS INTEGRITY MANAGEMENT MATURITY MODEL
(m)Sloane Whiteley, Senior Business Consultant, AVEVA

F8.4 RESILIENCE & ADAPTABILITY: WEIGHING THE RISKS & BENEFITS OF FISH CONSUMPTION IN RURAL ALASKA
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(m)Kris Hoellen, Director, The Conservation Fund

F8.6 PROJECT STREAMLINING & STEWARDSHIP BENEFITS OF PARTNERING WITH THIRD PARTY MITIGATION PROVIDERS
(m)Kris Hoellen, Director, The Conservation Fund

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G1.1 NATURAL VS ANTHROPOGENIC GHG EFFECT: A COMPENDIUM
Dejan Ristic, Pressure/Energy Systems Engineer-Group Leader, Argonne National Laboratory

G1.2 APPLICATION OF HESTIA METHODS TO THE CITY OF PHOENIX, USA
Igor Razlivanov, Postdoc, ASU; Kevin Gurney & Yang Song, ASU; Yuyu Zhou, Joint Global Change Research Institute, College Park,

G1.3 HIGH-RESOLUTION GLOBAL FOSSIL FUEL CO2 EMISSION INVENTORY FOR 1992 TO 2010 USING INTEGRATED IN-SITU & REMOTELY SENSED DATA IN A FOSSIL FUEL DATA ASSIMILATION SYSTEM
Salvi Asefi-Najafabady, Postdoctoral Scholar, Arizona State University; Peter Rayner, Jianhua Huang, Yang Song, Kevin Gurney

G1.4 VULCAN: NATIONAL SCALE HIGH RESOLUTION QUANTIFICATION OF FOSSIL FUEL CO2 EMISSIONS
Kevin Gurney, Associate Professor, Arizona State University; Yuyu Zhou, DOE; Daniel Mendoza, Purdue Univ; Vandhana Chandrasekaran& Igor Razlivanov, ASU

G1.5 "MASS PRODUCED" PRODUCT CARBON FOOTPRINTS TO FACILITATE BUSINESS DECICISONS & LCA EDUCATION IN LARGE COMPANIES
Christoph , Meinrenken, Associate Research Scientist, Columbia University, Klaus S. Lackner & Anthony N. Garvan

G1.6 IS WOOD BIOENERGY CARBON NEUTRAL?
Roger Sedjo, Senior Fellow, Resources for the Future; Xiaohui Tian, Ohio State University

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Tauna Szymanski, Senior Associate, Hunton & Williams LLP

G2.2 GHG BACT AS CO2 INJECTION FOR EOR
Mary Ellen Ternes, Attorney, McAfee & Taft

G2.3 BEST AVAILABLE CONTROL TECHNOLOGY FOR GREENHOUSE GASES
Deanne Dutton Hughes, Principal, Cardinal Engineering

G2.4 IMPLICATIONS OF THE EGU GHG NSPS ON GHG BACT DETERMINATIONS: WHAT DOES IT ALL MEAN?
Kate Graf, Senior Consultant, Geosyntec Consultants

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Angela Morrison, Attorney, Hopping Green & Sams, PA; Max Lee, Koogler and Associates, Inc.

G2.6 NSR APPLICABILITY UNDER TAILORING RULE, PART II
Max Lee Ph.D., P.E., President, Koogler and Associates, Inc.; Angela Morrison, Hopping Green & Sams

G2.7 HURDLES OF IMPLEMENTING THE TAILORING RULE AT LANDFILLS
David Thorley, Director of Air, Waste Management; Angela Morrison, Hopping Green & Sams, P.A.

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David Sumi, Executive Director, The Cadmus Group

G3.2 COMPILATION & ANALYSIS OF NEW MEXICO'S GHG EMISSIONS INVENTORY DATA 2008 - 2011
Michael Schneider, Environmental Scientist, State of New Mexico Environment Department Air Quality Bureau

G3.3 THE EMERGING POST-KYOTO CLIMATE POLICY FRAMEWORK AS EXPLAINED THROUGH NEW ENVIRO-ECONOMIC METRICS
(m) Stephen Sewalk, Assistant Professor, University of Denver; Vincent Buscarello

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G4. CORPORATE STRATEGIES & RISK MGMT

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G4.1 CREATING GREENHOUSE GAS EMISSIONS OFFSETS BY REDUCING NITROGEN FERTILIZER USE IN U.S. AGRICULTURAL CROP PRODUCTION
Adam Diamant, Technical Executive, EPRI; Neville Millar, Ph.D. & G. Philip Robertson, Ph.D., Michigan State University (MSU).

G4.2 SUMMARY OF RECENT OBSERVATIONAL STUDIES OF THE IMPACTS OF CLIMATE CHANGE & IMPLICATIONS FOR THE ELECTRIC UTILITY INDUSTRY
Howard Balentine Technical Leader - Air Quality, AECOM; Gregory Derevianko

G4.3 CARBON TAX OR "CAP-&-TRADE" SYSTEMS & ITS COST & PRICE EFFECT ON U.S. REFINING & MARKETING
(m)Bill Smalling, Attorney at Law, C. William Smalling, PLLC

G4.4 HESS CORPORATION'S NEXT GENERATION CLIMATE CHANGE STRATEGY
(m)Michal Pelzig, Senior Manager Reporting, Hess Corporation

G4.5 ENVIRONMENTAL & CARBON REPORTING & DISCLOSURE: A NEW PARADIGM
(m)John Fillo, Principal Consultant, Trinity Consultants Inc

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Gillian Marks, President, The Climate Advisor

G5.2 CARBON CREDIT CAPITAL - DECISION SUPPORT TOOL FOR COST EFFECTIVE COMPLIANCE TO AB-32 CAP-AND-TRADE
Luca Nencetti, Director of Engineering, Carbon Credit Capital, LLC

G5.3 KICK-OFF FOR CALIFORNIA'S AB 32: HOW WILL THE MARKET WORK?
Andrew Van Horn, Managing Director, Van Horn Consulting

G5.4 CARBON PROJECT TYPES TARGETED FOR CALIFORNIA COMPLIANCE MARKET PROTOCOLS
Dick Kempka, Vice President Business Development, The Climate Trust

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G6. GHG STRATEGIES

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Jagatheesan (Jack) Senthilvel, Project Manager, WorleyParsons; Joseph Takats

G6.2 DOE/NETL'S CARBON CAPTURE R&D PROGRAM
Timothy Fout, Project Manager, U.S. DOE/NETL; Lynn Brickett & Shailesh Vora

G6.3 CARBON FOOTPRINT OF A PRESIDENTIAL ELECTION
Art Samberg, Senior Consultant, Golder Associates Inc.

G7. CCS: CARBON CAPTURE & STORAGE

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G7.1 CARBON CAPTURE UTILIZATION & STORAGE (CCUS) KNOWLEDGE BASED TOOLS FROM THE DOE/NETL CARBON STORAGE
Brian Dressel, Project Manager, DOE/National Energy Technology Laboratory; John Litynski

G7.2 CO2 CAPTURE VIA SORBENT ENHANCED WATER GAS SHIFT
William Steen, Sr. Chemical Engineer, URS; Carl Richardson & Tom Machalek, URS; Yongqi Lu, Hong Lu & Massoud Rostam-Abadi, ISGS; Elaine Everitt, DOE

G7.3 ENZYMATIC TECHNOLOGY FOR LOW-COST CARBON DIOXIDE CAPTURE
Jonathan Carley, Vice-President - Business Development, CO2 Solutions Inc.; Dr. Luan Nguyen, Codexis, Inc.; Dr. Sylvie Fradette, CO2 Solution Technologies Inc.; Dr. Geert Versteeg, Procede Group BV

G7.4 A CASE STUDY OF PERFORMANCE, COST & FEASIBILITY OF A CO2 CAPTURE-READY COAL POWER PLANT
Eric Grol, Energy Analyst, U.S. Department of Energy/National Energy Technology Laboratory; Steve Herron & Paul Myles, Worley Parsons

G7.5 INTEGRATION OF SHALE GAS PRODUCTION WITH CCS
Jinsheng Wang, Research Scientist, CanmetENERGY, Natural Resources Canada; David Ryan, Edward J. Anthony, Andrew Wigston

G7.6 FUNDING MECHANISMS ADDRESSING THE LONG-TERM LIABILITY OF CCS ACTIVITIES
Terry Unger, Associate, ICF International; Kerry Schlichting

G7.7 EVALUATION OF ADVANCED SOLVENTS & OTHER COMPETING TECHNOLOGIES FOR CO2 CAPTURE FROM FOSSIL FUEL-FIRED SYSTEMS
Brandon Pavlish, Research Manager, Energy & Environmental Research Center University of North Dakota, Nathan Fiala & John Kay

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Travis Starns, Director of Projects, ADA-ES, Inc.; Holly Krutka, Martin Dillon, Sharon Sjostrom

G8.2 500 MTPD COAL-FIRED CO2 CAPTURE PROJECT UPDATE, INCLUDING MHI AMINE EMISSION REDUCTION TECHNOLOGY & HEAT INTEGRATION SYSTEM
Steven Holton, Dir. Business Development, Mitsubishi Heavy Industries America, Inc.; Steven Holton, Tatsuya Tsujiuchi, Takahito Yonekawa, & Paul Wood, MHIA; Takuya Hirata, Hiromitsu

G8.3 APPLICATION OF A NOVEL FROTH-BASED STRUCTURED PACKING FOR ABSORPTION BASED POST COMBUSTION CCS
Zhenshuo Liu, Sr. Staff Engineer, Westec Environmental Solution; William H. Hargrove, Frank Hubner

G8.4 INVESTING IN THE GHG CONSTRAINED FINANCIAL MARKETS IN THE LIGHT OF THE FINANCIAL REFORM LEGISLATION
Nedia Miller, Founder, MILLER, CTA

G8.5 CARBON CAPTURE & STORAGE AT NATURAL GAS COMBINED CYCLE POWER PLANTS IN CALIFORNIA
Julian Isham, Geology Manager, Shaw E&I

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G8.6 THE PLAINS CO2 REDUCTION (PCOR) PARTNERSHIP: A REGIONAL CARBON SEQUESTRATION PARTNERSHIP IN THE INTERIOR PLAINS OF NORTH AMERICA
Edward Steadman, Deputy Associate Director for Research, Energy & Environmental Research Center; J. Harju, C. Gorecki, L. Botnen, D. Daly, W. Peck, M. Jensen, S. Smith, J. Sorensen, J. Hamling, R. Klapperich & K. Anagnost

G8.7 EVALUATION OF CO2 CAPTURE FROM EXISTING COAL FIRED PLANTS BY HYBRID SORPTION USING SOLID SORBENTS (CACHYS™)
Nicholas Lentz, Associate Director for Energy Technology Applications, University of North Dakotal; Charles K. Thumbi, Daniel A. Laudal & Steven A. Benson, UND; Srivats Srinivasachar, Envergex LLC

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H1. ALGAE

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H1.1 RENEWABLE SOLAR BIOBUTANOL PRODUCTION UTILIZING CARBON DIOXIDE AS THE SOLE FEEDSTOCK
Bruce Dannenberg, CEO & Founder, Phytonix Corporation

H1.2 UTILIZATION OF LIQUID EFFLUENT FROM AN ANAEROBIC DIGESTER (DLE) AS A NUTRIENT SOURCE FOR ALGAE GROWTH
(m)Greg Karr, Program Manager, MRIGlobal; Jennifer Jackman, Scott Shore & Kristine Krebs

H1.3 WATER SUSTAINABILITY THROUGH THE USE OF AN ALGAE-BASED ADVANCED BIOLOGICAL TREATMENT
Rick Johnson, Director, Business Development, AlgEvolve

H1.4 ENERGY & WATER RESOURCE EFFICIENT PRODUCTION OF MICROALGAE LIPIDS
Kelsey Price, Student Researcher, University of New Hampshire; Ihab Farag

H1.5 ALGAE GROWTH IN PHOTOBIOREACTORS USING A REMOVABLE JACKET OF COLORED LEDS
Daniel Eltringham, Student Researcher, University of New Hampshire; Marian Elmoraghy & Ihab Farag

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EVALUATION OF AS-RECEIVED & PRETREATED NORTHEAST BIOMASS FOR PRODUCTION OF BIOFUELS & VALUE-ADDED PRODUCTS
Nii Ofei Mante, Research Associate - Thermochemical Conversion Research, Brookhaven National Laboratory; Thomas E. Amidon & Timothy A. Volk (1) & Suresh P. Babu (2)

CATALYTIC CONVERSION OF SYNTHESIS GAS INTO FUEL ETHANOL
Girish Srinivas, Principal Engineer, TDA Research, Inc.; Michael V. Mundschau, Erik W. Andersen, Steven D. Dietz, Brady J. Clapsaddle & Steven C. Gebhard

POST ELECTION POLITICS & CELLULOSIC ETHANOL DEVELOPMENT
Christopher Standlee, Executive Vice President, Abengoa Bioenergy

STATISTICAL OPTIMIZATION OF ENZYMATIC HYDROLYSIS OF OIL PALM TRUNK FOR PRODUCTION OF GLUCOSE, XYLOSE & ETHANOL
Pongsak Noparat, Student, Department of Industrial Biotechnology, Faculty of Agro-Industry, Prince of Songkla University; Sompong O-Thong, Poonsuk Prasertsan

UTILIZATION OF AN AIR BLANKET TO KEEP BIODIESEL DRY
Scott Grossbauer, Global Sales Manager, Donaldson Company

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EUCALYPTUS PLANTATIONS IN FLORIDA USA: ECONOMIC ANALYSIS OF BIO-ENERGY & CARBON SEQUESTRATION POTENTIAL
Jeff Wright, Manager, Hardwood Development, ArborGen Inc

INNOVATIONS IN FLUIDIZED BED TECHNOLOGY: IMPROVING EFFICIENCY WITH INBED HEAT TRANSFER & STAGED GASIFICATION
Patrick Travis, Business Development Manager, Outotec Energy Products

CFD MODELING OF BIOMASS COMBUSTION FOR A 500MW COAL-FIRED BOILER CONVERSION
Baiyun Gong, Staff Scientist, Nalco Mobotec; Guisu Liu, Liming Shi, Brian Higgins & Ed Pozzobon

PRODUCTION & PROPERTIES OF SOLID FUELS FROM HYDROTHERMAL CARBONIZATION (HTC) OF LIGNO-CELLULOSIC BIOMASS
S. Kent Hoekman, Research Professor, Desert Research Institute; Larry Felix, Gas Technology Institute; Grady Coble, Parker Towing Company

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PERMITTING A NEW AND INNOVATIVE WASTE CONVERSION TECHNOLOGY IN NEW JERSEY
Alan Sawyer, Managing Director, NRG Energy, Inc.; Greg Seher, Atlantic County Utilities Authority; Marcus Scrimgeour & Greg McCarran, SCS Engineers, PC

CARBON CAPTURE FROM CEMENT FLUE GAS AND CONVERSION OF CARBON TO NEW VALUE IN BIOPLASTICS
(m)John Kline, Principal, John Kline Consulting; Brian Sefton & Shannon LaGuardia, Oakbio Inc.

ENERGY FROM MUNICIPAL SOILD WASTE WITH ZERO CARBON EMISSION
Surendra Saxena, Professor, CleanHydro-Innovision

BRINGING BIOGAS TECHNOLOGY TO ORGANIC WASTE MARKETS IN THE US
Emily Viau, CEO, Bioenergy Frontiers, Inc

DISTRIBUTED-SCALE BIOMASS GASIFICATION POWER
Chris Zygarlicke, Deputy Associate Director for Research, Energy & Environmental Research Center

PARTNERING WITH COAL: PROGRESS, OPPORTUNITIES & CHALLENGES WITH MSW-DERIVED FUELS
Mark Hall, Executive Vice President, Lakeside Energy/Dongara; Melissa Hillman, Trinity Consultants

SUSTAINABILITY IN AN URBAN ENVIRONMENT THROUGH ANAEROBIC DIGESTION
John McDowell, Project Manager, Eisenmann Corporation

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BIOMETHANE VEHICLE FUEL
Harrison Clay, President, Clean Energy Renewable Fuels

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Brian Stuver, Client Service Manager, Joyce Engineering

LANDFILL GAS-TO-ENERGY: SOLUTION OR PROBLEM?
Mike Ewall, Director, Energy Justice Network

BIOCHAR. A SOLUTION FOR SOLID WASTE MANAGEMENT
Ricardo Aguirre, Director of Stormwater Engineering, CVL Consultants

BIOCHAR UTILIZATION IN AN INTEGRATED SYSTEM FOR BIOENERGY CROP PRODUCTION & CARBON SEQUESTRATION
(m)Greg Karr, Program Manager, MRIGlobal; Andrew Miller, Ryan Krause & Donnie Bowman, MRIGlobal; Nathan Nelson & Arthur Fink, Kansas State University

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LOW-CARBON CO-FIRING
Paula Calabrese, Senior Vice-President & Chief Strategy Officer, ReCommunity Energy LLC

ZERO WASTE POWER PLANTS USING PLASMA GASIFICATION TECHNOLOGY
Louis Circeo, Chief Scientist, Applied Plasma Arc Technologies, LLC

GIANT KING GRASS AS AN ENERGY CROP IN THE UNITED STATES
Carl Kukkonen, CEO, VIASPACE Inc.

COOL PLASMA GASIFICATION
(m)Kris Skrinak, President, adaptiveARC, Inc.

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I1. ENERGY SUSTAINABILITY

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RENEWABLE ENERGY - SHOW ME THE GREEN!
Greg Odegard, Consultant, GO Environmental

GREEN CAIMS & GREENWASHING - THE GRASS REALLY GREENER?
Charles Franklin, Senior Counsel, Akin Gump Strauss Hauer & Feld

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Lisa White, Environmental Engineer, Clifton Associates Ltd.; Bram Noble, University of Saskatchewan

OPTIMAL USE OF ALTERNATIVE ENERGY SOURCES FOR SUSTAINABLE ENERGY MANAGEMENT
Duane Rosa, Professor of Economics, West Texas A&M University

YESAB - THE YUKON WAY
Ken McKinnon, Executive Committee Member, Yukon Environmental & Socio-economic Assessment Board

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Ryan Mielke, Senior Marketing Manager, Lend Lease; John Karelis

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Edward Handl, Division Manager, JBR Environmental Consultants, Inc.; Jason Benson, NV Energy

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Warren Te Bruuge, CEO & Founder, Manzimvula Ventures, Inc.

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Devin Hodge, Sustainability Program Manager, Argonne National Laboratory

WIRE & CABLE EFFICIENCY
Evan Birenbaum, Program Manager, Southern California Edison; Carol Godfrey, Southwire

I3. SUSTAINABILITY REPORTING

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SUSTAINABILITY: MORE THAN "CHECKING THE BOX"
(m)Joel Cervelloni, Principal Consultant, PA Consulting, TBD

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Yolanda Pagano, Director, Sustainable Strategies & Solutions, O'Brien & Gere

RAISING THE BAR: NEW CHALLENGES FOR CORPORATE SUSTAINABILITY REPORTING
Jacob Kislevitz, Senior EHS&SR Specialist, Hess Corporation; Michal Pelzig

SUSTAINABILITY REPORTING & VERIFICATION: A SYMBIOTIC RELATIONSHIP
(m)John Fillo, Principal Consultant, Trinity Consultants, Inc.

I4. 316B

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David Bailey, Sr. Project Manager, EPRI

EPA'S PROPOSED EFFLUENT GUIDELINES AND 316(B) RULES – OPERATING IN THE MIDST OF UNCERTAINTY
Averil Edwards, Associate, Winston & Strawn LLP

A NEW LOOK AT THE 316(B) COOLING WATER INTAKE RULE - NOW WHAT?
Manitia Moultrie, U. S. Power Sector Leader, Golder Associates

WHAT DO EPA'S NEW 316(B) COOLING WATER INTAKE STRUCTURE REGULATIONS MEAN TO EXISTING POWER GENERATION
Stephen Petron, Global Ecosystem Services Director, CH2M HILL; Christopher Wiggins

STRATEGIES FOR COMPLIANCE WITH UPCOMING 316(B) REQUIREMENTS
Erik Heinen, Senior Scientist, Environmental Consulting & Technology; Mark Gerath & Steve Cibik, ECT

USE MUNICIPAL RECLAIM WATER & HIGH CYCLES OF CONCENTRATION FOR COOLING TOWERS - SAVE WATER & ENERGY - BUT WAIT, THERE'S MORE....
Ivan Cooper, Practice Leader, Golder Associates

I5. WATER SUSTAINABILITY

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Jessica Shi, Sr. Project Manager, Electric Power Research Institute; Sean Bushart

USE OF NON-DISINFECTED MUNICIPAL EFFLUENT
Charlie Nichols, Senior Technologist, CH2M HILL; John Oster

TAKING ZEEWEED® MBR TECHNOLOGY TO THE NEXT LEVEL
Brian Arntsen, Global Domain Leader UFMBR, GE Water & Process Technologies

COMMERICAL ENERGY EFFICIENT WASTEWATER TREATMENT & WATER REUSE - IMET TECHNOLOGY
Mehmet A. Gencer, CEO, IMET Corporation

ZERO LIQUID DISCHARGE FOR COMPLIANCE
Kristen Jenkins, Global Technology Lead - Industrial Water, CH2MHILL; Thomas Higgins

A NEW AERATOR FOR WASTE LAGOONS
Jim Dartez, President, Reliant Water Technologies

I6. WATER & ELECTRIC UTILITIES

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UNDERSTANDING THE ENERGY/WATER NEXUS & DEVELOPING CONSENSUS-BASED SOLUTIONS
Mary Doyle Kenkel, Executive Director, Center to Advance Energy & Water Management

MHI'S SIMPLE ZERO LIQUID DISCHARGE SYSTEM FOR WET FGD
Shintaro Honjo, Research & New Technologies Engineering Manager, Mitsubishi Heavy Industries America, Inc.; Motofumi Ito, Norikazu Inaba, & Satoru Sugita, Mitsubishi Heavy Industries America, Inc.; Tetsu Ushiku, Tatsuto Nagayasu, Toshihiro Fukuda & Seiji Kagawa, Mitsubishi Heavy Industries, Ltd.

AN OVERVIEW OF THE WATER RESEARCH CENTER
Jeff Wilson, Principal Research Engineer, Southern Company; Richard Breckinridge EPRI; Jay Wos SRI

DESIGN & OPERATIONAL CHALLENGES ASSOCIATED WITH CONDITIONING
Zachry Bahr, Mechanical Engineer, Burns & McDonnell

WATER RISK & OPPORTUNITY FOR ELECTRIC UTILITIES
Peter Flaherty, Sr. Engineer, ERM; Skelly Holmbeck

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I7. WATER - REGULATORY UPDATES

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BEYOND ASH PONDS
Thomas Higgins, Global Technology Leader - Power Water & Process, CH2M HILL; Dennis Fink & Dana French

CALIFORNIA STORM WATER & RENEWABLE ENERGY & ELECTRIFYING MIX
S. Wayne Rosenbaum, Partner, Stoel Rives LLP

ELECTRIC POWER RESEARCH INSTITUTE (EPRI) FISH PROTECTION R&D REVIEW: FINE MESH (≈2.0 MM) TRAVELING WATER SCREENS & FISH RETURN SYSTEM PERFORMANCE
Douglas Dixon, Technical Executive, Electric Power Research Institute; Jon Black, Alden Research Laboratory

COMPARISON OF ENTRAINMENT AT ADJACENT INTAKES WITH & WITHOUT LARGE SLOT-WIDTH WEDGE-WIRE SCREENS: A CASE FOR WEDGE-WIRE SCREENS TO REDUCE ENTRAINMENT
Robert Blye, Vice President, Normandeau Associates, Inc; Paul L Harmon & Brian Lees, Normandeau Associates, Inc.; Robert Matty, Exelon Power; Jason Kinnel, Veritas Economic Consulting

RECENT CHANGES IN STATES' SUSTAINABLE WATER USE POLICY
David Van Wie, Associate, AMEC Environment & Infrastructure

THE EVOLVING REGULATION OF THERMAL DISCHARGES
Erik Heinen, Senior Scientist, Environmental Consulting & Technology; Mark Gerath, Steve Cibik & Larry Danek

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I8. SUSTAINABLILITY GREEN

DODO-SAPIENS: WHY WE NEED REGENERATIVE, BIO-BASED BUILDINGS
(m)Eric Corey Freed, Founding Principal, organicARCHITECT

BIODEGRADABLE HYDRAULIC OILS & CLEANERS
Dr. Todd Tarrant, President, Hydro Safe, Inc.

SPILLS, SINS & STARBUCKS: HOW WE DESIGNED OUR CITIES AROUND OIL
(m)Eric Corey Freed, Founding Principal, organicARCHITECT

CLIMATE INDEPENDENT FOOD PRODUCTION WITH ALGAE
Mark Edwards, Professor, ASU

ACCELERATING SUSTAINABILITY SOLUTIONS FOR ORGANIZATIONS
Raj Buch, Practice Lead, Arizona State University

FRESHWATER FREE FOOD PRODUCTION WITH NO WASTE
(m)Mark Edwards, Professor, ASU

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I9.

J1. ENERGY EFFICIENCY

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ENERGY EFFICIENCY THROUGH POWER ELECTRONICS: NAVIGATING THE LANDSCAPE & ASSESSING OPPORTUNITIES FOR MATERIALS INNOVATION
Pallavi Madakasira, Analyst, Lux Research

COGENERATION UPGRADES FOR INCREASED ENERGY EFFICIENCY
Arvind Akela, Project Manager, CDM Smith

DOING WELL & GOING GOOD: PROFITING IN THE HOME PERFORMANCE BUSINESS
Mark Berman, Principal, Davis Energy Group

COLLABORATION FOR SMALL BUSINESS ENERGY EFFECIENCY SUCCESS
Judy Sunde, Project Manager Market Strategies, Omaha Public Power District; Kristi Wamstad-Evans, City of Omaha

MOVING THE HOUSING MARKET TO ENERGY EFFICIENCY
Steve Baden, Executive Director, RESNET

HIGH INTENSITY LIGHTING WITH NEXT GENERATION LIGHT SOURCES: A TECHNOLOGY SURVEY WITH KEY PRODUCT INSIGHTS
Ahmed Shuja, CTO, BritePointe Inc.

J2. ENERGY MGMT

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ISO 50001 - IMPLEMENTATION & ALTERNATIVES
Bryan Chen, Senior Engineer, ARCADIS US; William Allemon

ENERGY MANAGEMENT IMPLEMENTATIONS USING ISO 50001 & SEP - CRITICAL RISK & BUSINESS ECONOMIC BENCHMARK'S
Don MacDonald, Director - Sustainability & Energy Management, UL DQS

GREEN DESIGN / GREEN CONSTRUCTION- THE NEED TO REINVENT, RETHINK, RE-ENGINEER, & RESOLVE OUR GLOBAL ENVIRONMENTAL ISSUES
James Stawniczy, Director of Sustainability-Americas, Lend Lease

CUSTOMER ENGAGEMENT BEYOND CUSTOMER ENROLLMENT
Gail Allen, Sr. Manager - Customer Solutions, KCP&L

ON-BILL REPAYMENT PROGRAMS SPUR GREEN JOBS, CLEAN ENERGY & RATEPAYER SAVINGS
Brad Copithorne, Director of Financial Innovation, Environmental Defense Fund

J3. SMART GRID

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CYBER SECURITY IMPLEMENTATION APPROACH FOR UTILITY SMARTGRID INITIATIVES
(m)Jerome Farquharson, Practice Manager, Burns & McDonnell Engineering; Rahul Chhabra

250KW SMART MICROGRID
Jerry Datzman, Marketing & Contracts Manager, Caterpillar Inc.; Barry Payne

INTEGRATED SMART GRID POWER DISTRIBUTION & ENERGY CONSERVATION SYSTEM FOR REMOTE & EXTREME CONDITIONS
Frank Pendleton, Program Manager, MRIGlobal; Sayan Chakraborti & Scott Klamm

HURRICANE SANDY TURNS SMART GRID PLANS UPSIDE DOWN
John Finnigan, Senior Regulatory Attorney, Environmental Defense Fund

EXTRACTING VALUE OUT OF AMI DATA
(m)Peter Siggins, Partner, PA Consulting Group

ACHIEVING CONSUMER ENGAGEMENT REQUIRES MORE THAN SOCIAL MEDIA, A DIGITAL STRATEGY IS ESSENTIAL
(m)Peter Siggins, Partner, PA Consulting Group

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J4. ENERGY EFFICIENCY & MGMT I

Session Sponsor and Co-Chair

APPLICATION OF THE DRYFINING™ TECHNOLOGY AT EXISTING POWER UNITS FIRING LOW-RANK COAL
(m)Charles Bullinger, Senior Principle Engineer, Great River Energy; Vlad Vaysman & Yixin Lu, Worley Parsons

EDUCATION & COLLABORATION WILL HELP US BECOME MORE ENERGY EFFICIENT SOCIETIES
Chris Hartmann, Executive Vice President & CEO, Rexel Holdings USA

IMPACTS OF SEVERE WEATHER PHENOMENA ON THE ELECTRICITY INFRASTRUCTURE
Michael Kintner-Meyer, Staff Engineer, Pacific Northwest National Laboratory; Jim Dirks, Chunlian Jim, Will Gorrissen, Jennie Rice

NEW BIO-CONTROL APPROACH BOOSTS POWER PLANT PRODUCTION BY 10%
Tom Muilenberg, Commercial Operations Manager, MIOX Corporation

RESULTS & LESSONS LEARNED FROM A BEHAVIOUR-BASED CONSERVATION PILOT PROGRAM FOR SMALL BUSINESSES
Owen Rogers, Lead Developer, Pulse Energy

J5. DEMAND RESPONSE

Session Sponsor and Co-Chair

HOW DEMAND RESPONSE IS REVOLUTIONIZING WHOLESALE POWER MARKETS
Ryn Hamilton, Consultant, Ryn Hamilton Consulting

DEMAND RESPONSE ENVIRONMENTAL IMPACT STUDY
Rebecca Butler, Field Operations Project Manager, EnerNOC, Inc.

IMPORTANCE OF AVAILABILITY PAYMENTS TO DEMAND RESPONSE
Aaron Breidenbaugh, Director of Regulatory Affairs, EnerNOC, Inc.; Phil Martin & Dr. Paul Troughton

MARKET SOLUTIONS TO INCENTING ENERGY EFFICIENCY
Craig Glazer, Vice President Federal Govt. Policy, PJM Interconnection

DEMAND RESPONSE & THE VALUE IT OFFERS UTILITY, COMMERCIAL, & INDUSTRIAL USERS
Laurie Wiegand-Jackson, CEO & President, North America Power Partners

ROLE OF DEMAND RESPONSE BASELINES IN ESTIMATING PARTICIPANT IMPACTS
Mark S. Martinez, Manager, Demand Response, Southern California Edison

J6. ENERGY CONSERVATION & STORAGE

Session Sponsor and Co-Chair

GRID STORAGE UNDER THE MICROSCOPE: USING LOCAL KNOWLEDGE TO FORECAST GLOBAL DEMAND
Hilary Flynn, Senior Analyst, Lux Research; Brian Warshay, Steven Minnihan, Matthew Feinstein

MACRO LEVEL ENERGY HARVESTING
(m)Gare Henderson, Director of R&D, Gravitational Systems Engineering, Inc.

ENERGY CONSERVATION HYBRID STREET SWEEPER
Toshihiko Furukawa, Senior Manager, United Chemi-Con; Abas Goodarzi, Ph.D US Hybrid Corporation

REGULATION, DEVELOPMENT & FINANCING OF GRID-SCALE ENERGY STORAGE SYSTEMS
Donald Ousterhout, Partner, Reed Smith LLP; Amy Koch

J7. ENERGY EFFICIENCY & MGMT II

Session Sponsor and Co-Chair

OPPD INTERN BENCHMARKS HEALTHCARE CONSORTIUM FOR ENERGY EFFICIENCY SUCCESS
Andrew Smith, Energy Efficiency Intern, Kansas State University

HARNESSING WASTED ENERGY FROM GAS PIPES
Lee Palles, Vice President - Sales & Marketing, Langson Energy; Richard Langson

THE BENEFITS OF REAL TIME ENERGY PRICING FOR UTILITIES & THEIR CUSTOMERS
Pritesh Gandhi, CEO, Ambient Devices

INTERN PROGRAM HELPS INDUSTRIES ACHIEVE ENERGY & WATER SAVINGS
David Carter, Pollution Prevention Specialist, Kansas State University Pollution Prevention Specialist

WHAT BUSINESSES CHOOSE ENERGY RETROFITS? THE CHARACTERISTICS THAT PREDICT PARTICIPATION IN THE ENERGIZE PHOENIX PROJECT
Michael Kuby, Professor, Arizona State University; Anna Berlin, Samantha Neufeld, Scott Kelley, George Oliver, Michael Dalrymple, Alex Castelazo

OTHERS

Session Sponsor and Co-Chair

SOLAR OBSERVING DEMONSTRATION
Chris Reich, CEO, Solar Astronomer; TeachU

Session Sponsor and Co-Chair

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Sponsorship Opportunities

CYBER CAFÉ - $8,500 Exclusive

Your company name will be programmed into a screensaver on a rotating basis as well as being incorporated into graphics at the Cyber Café booth. There is usually a wait for a computer terminal, so why not get your name in front of one of the highest traffic areas at EUEC.

OFFICIAL SHOW GUIDE – $8,500

The Show Guide is the official, up-to-date information on the EUEC event. It is inserted into the attendee bags and is referenced multiple times a day by all attendees. As a Show Guide sponsor you will have your logo placed on the front cover, and two facing pages ad included.

HOTEL KEY CARDS – $7,500 Exclusive / 2 available

Effectively place your business card in every attendee's pocket. Four-color custom design imprinted on Hotel Key Cards distributed to all attendees staying at official show hotels (Sheraton or Hyatt).

PLATINUM NETWORK PACKAGE – $15,000 / 2 available

The Networking Reception featuring hosted bars, carver tables and heavy appetizers from 5:00 to 7:00 on Monday or Tuesday. Signage with Company logo placed exclusively at sponsor designated bars. As a Network Reception sponsor you will have your name and logo in front of conference attendees on each meal ticket, and signs during the reception on Monday or Tuesday. A full page ad in the official show guide distributed to 2,000 delegates. Get involved as a sponsor and position yourself as a major hospitality player at EUEC.

GOLD NETWORK PACKAGE – $8,000 each / 2 available

Help quench your target audience's appetite for new ideas, products and services that they are looking for. As a Network Lunch sponsor you will have your name and logo in front of conference attendees on each meal ticket, and signs during the luncheon on Monday or Tuesday, as well as a full page ad in the official show guide distributed to 2,000 delegates.

SILVER EVENT SPONSOR – $5,000 / 3 available

Fire up the conference by sponsoring the morning breakfast and coffee service offered to delegates on Monday, Tuesday or Wednesday. Your company will be recognized with signage and your name and logo in front of conference attendees on each breakfast & coffee ticket, redeemable at the conference hotels and convention center.

BRONZE EVENT SPONSOR – $3,000 / 4 available

Fire up the conference by sponsoring the morning or the afternoon break snack and coffee or beverage service offered to delegates on Monday, Tuesday or Wednesday AM and PM breaks. Your company will be recognized with signage and your name and logo in front of conference attendees on each break on the snack & coffee ticket, redeemable at the networking events in the conference exhibit hall.

CONFERENCE PROCEEDINGS in Flash Drive – $10,000 / 2 available - One Sold

What's more important to the conference delegates after the event than the complete conference proceedings? This package allows maximum take-home exposure with your logo on the top of every credit-card type flash drive. A full electronic brochure advertisement of your company is included in the flash drive.

ATTENDEE LANYARD AND BADGE HOLDERS – $8,500/ 2 available - BOTH SOLD

This package includes logo placement on lanyards of the attendee name badge holders.

SESSION SPONSORSHIPS AND LOGO AD - $1000

Moderate, co-chair and speak in session with your ompany logo advertised on session signage, on the website, and in the program. Session chairs are given the first right of refusal to sponsor the session.

AISLE SIGNS – $10,000

Directional signage for all aisles on the exhibit floor will carry the sponsor logo. Signage can be seen from both directions and are located in the exhibit hall of the convention center.

GOLF SPONSOR – $5,000

Exclusive sponsorship of the 2013 EUEC golf tournament including recognition in all material promoting the tournament. This includes the preliminary event guide, the show guide, and website, as well as the option of including promotional items in the check-in bags. Includes two foursomes in the tournament, welcome banner at the course, tee signs and sponsor logo on the pairings form. A custom golf gift with company logo will be given to each player.

REGISTRATION – $7,500

The sponsor of Registration gains great exposure throughout the registration area through logo placement on the registration counters. This sponsorship also includes your logo on the EUEC Event Website and newsletter distributed to 50,000 professionals for up to 6 months.

FAST TRACK - $6,000 – Exclusive

The Fast Track Priority Pass is emailed to all pre-registered attendees with an email address just days before the event. Your company may provide artwork for the Leaderboard banner and text for the bottom of the email.

CONFERENCE NOTEPADS/PENS – $8,500 – Exclusive

Your logo will be printed on notepads and writing pens distributed to all attendees at the Keynote Session.

FLOOR PLAN SPONSOR – $7,500 Exclusive

Your company logo will appear on the online exhibit hall floor plan onsite and on the map which is printed in the onsite Show Guide that all attendees reference.

WATER SPONSORSHIP – Exclusive $10,000

Sponsor water service for all attendees at EUEC. Sponsorship includes your company logo on Custom-Labeled Bottled Water distributed on the exhibit floor during the exhibition, and your logo placed on wraps on the water coolers in the conference area and exhibit hall.

ATTENDEE REGISTRATION BAGS – $10,000

Exclusive attendee bag sponsorship! Make your company name and logo float around the show floor on the side of the registration bags or a zippered folio with your company's logo.

Call the EUEC office (520-615-3535) or email info@euec.com

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Pre-Conference Workshops & Golf

Sunday, January 29th

1:00 pm to 5:00 pm

Workshop 1

Permitting & Compliance

Eric Hiser, Jorden, Bischoff & Hiser

This seminar will provide participants with critical information on new developments in clean air regulation, including recent developments in NAAQS, new source review, NESHAP regulation and GHG reporting. The seminar will also address current EPA enforcement priorities, planning and preparing for an inspection, and using the permit process to minimize your enforcement exposure.

Workshop 2

Challenges for Compliance With Short-term PM2.5, NO2, and SO2 Ambient Standards

Robert Iwanchuk, CCM (AECOM)
Robert Paine, CCM, QEP (AECOM)

This workshop will provide an overview of PM2.5, NO2, and SO2 NAAQS (and PSD increment, as appropriate) implementation and dispersion modeling procedures. It will also review the current status of litigation filed against USEPA to challenge the new 1-hour NAAQS for NO2 and SO2.

Workshop 3

Emerging Air Quality, Greenhouse Gas and Energy Requirements

Rich Pandullo, Trinity Consultants
Allan F. Bedwell, CantorCO2e

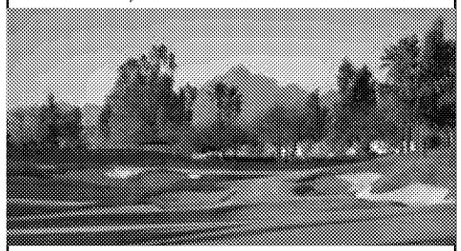
Power generators are facing a tsunami of emerging new regulations that will affect their ability to operate cost-effectively. These include Federal Clean Air Act regulations - such as the GHG Tailoring Rule, Boiler MACT, and Clean Air Transport Rule -- that will impose new emission limitations and operational restrictions on combustion sources.

EUEC

Golf Tournament

The Legacy Golf Resort
32nd St., Phoenix, AZ
Sunday January 27, 2013

7:30 am Breakfast
8:30 am shotgun start
1:00 pm Awards Luncheon



Cost:
$140 with clubs
$100 without clubs

Includes:
Green fees, cart, range balls, bag handling, gratuities & commissions Breakfast & Awards Lunch in Pavilion.

Check Option for Golf Tournament when you register online or

Contact:
info@euec.com
Ph: 520-615-3535
www.euec.com

1st Prize:

EUEC 2014 Registration for you and a guest with hotel included, entry into 2014 EUEC Golf tournament and the second annual EUEC Golf Trophy

All participants receive a free entry into a $10,000 hole in one contest

Place Your advertisement here

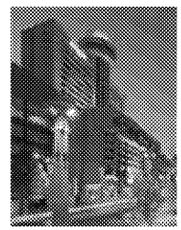
Your one page company advertisement in the EUEC Program Guide distributed to 2,000 delegates.

Full page — $2000
1/2 Page — $1000

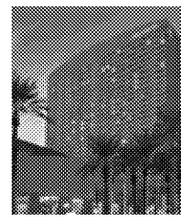
Submit advertisement in pdf (x-3 or higher) in CMYK color format

Hotels

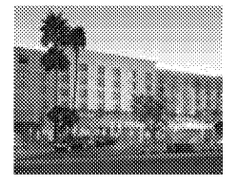
Conference Hotels | Hyatt and Sheraton located one block from Convention Center



HYATT REGENCY
122 N Second St.
Phoenix, AZ 85004
Ph: (602) 252-1234
EUEC RATE: $225



SHERATON PHOENIX
340 N Third St.
Phoenix, AZ 85004
Ph: (602) 262-2500
EUEC RATE: $235



RADISSON PHOENIX
3600 N Second Ave.
Phoenix, AZ 85013
Ph: (602) 604-4900
EUEC RATE: $99

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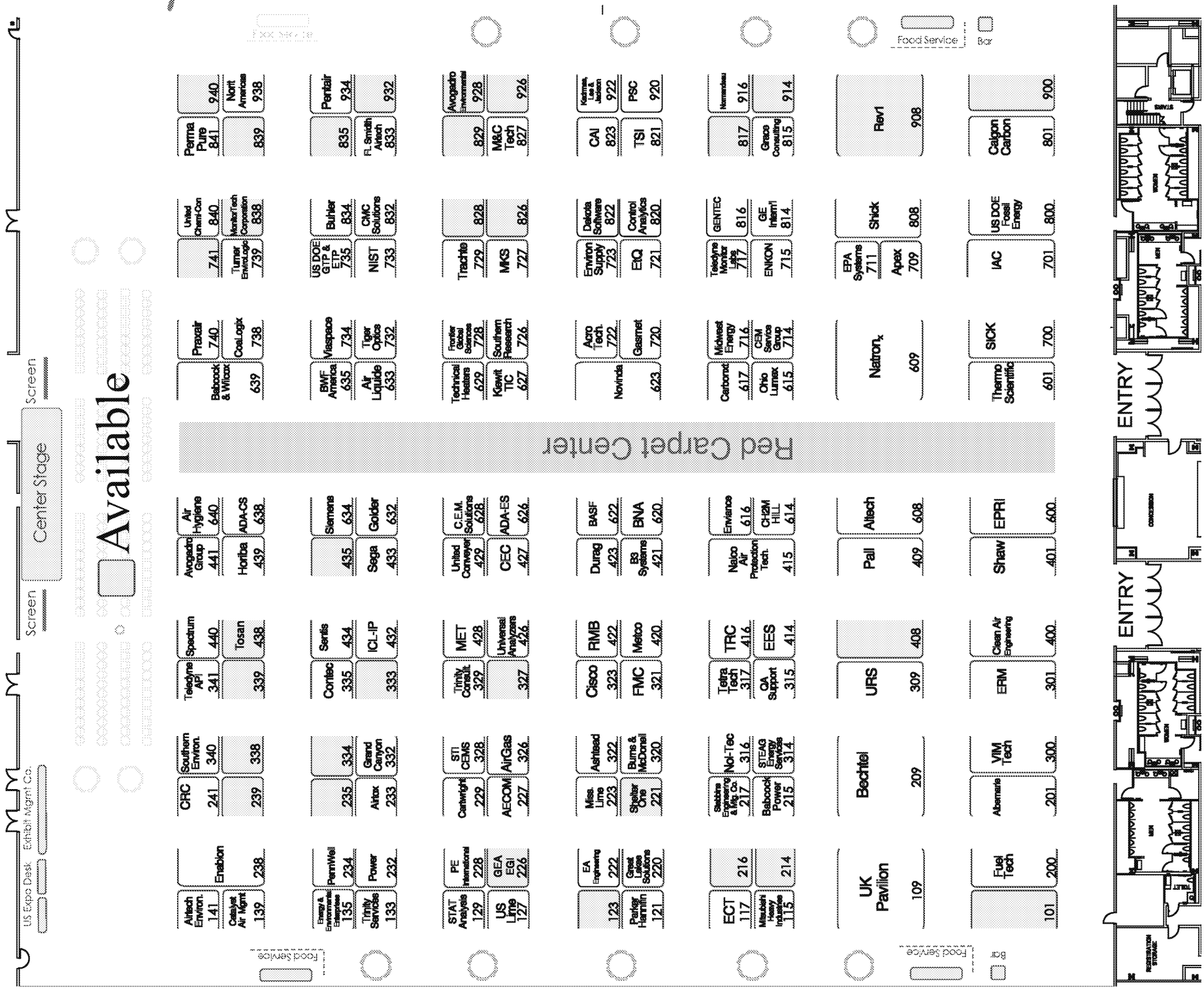
Exhibit Floorplan

Phoenix Convention Center
North Building, 3rd floor



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Exhibiting Companies

Sold | Hold/Second Choice Available

722 Acro Technologies, Inc.
638 ADA Carbon Solutions
626 ADA-ES , Inc.
227 AECOM, Inc.
640 Air Hygiene
633 Air Liquide America Spec. Gases
326 Airgas
141 Airtech Environmental Services
201 Albemarle Corporation
608 Altech Environment USA
709 APEX Instruments, Inc.
322 Ashtead Technology Inc.
441 Avogadro Group, LLC
421 B3 Systems, Inc.
639 Babcock & Wilcox
215 Babcock Power
622 BASF
209 Bechtel
620 Bloomberg BNA
834 Buhler Technologies LLC
320 Burns & McDonnell Engineering
635 BWF America
939 C Trade
801 Calgon Carbon Corporation
823 California Analytical Instruments
617 Carbonxt, Inc.
229 Cartwright & Associates
139 Catalyst Air Management, Inc.
714 CEM Service Group
628 C.E.M. Solutions
614 CH2M HILL
323 CiSCO - Custom Instr. Services
427 Civil & Environmental Consultants
400 Clean Air Eng. & Instrument
832 CMC Solutions
738 CoaLogix
335 Contec Systems
820 Control Analytics
241 CRC Industries
822 Dakota Software Corporation
741 Dekati
423 Durag
222 EA Engineering, Science & Tech.
238 Enablon
715 ENKON Information Systems Inc.
616 Enviance, Inc.
117 Environmental Consulting & Tech.
414 Environmental Energy Services
723 Environmental Supply Co., Inc.
711 EPA Systems
600 EPRI
301 ERM
721 EtQ, Inc.
833 FL Smidth Airtech
321 FMC Corp. PerNoxide
728 Frontier Global Sciences
200 Fuel Tech
720 Gasmet Technologies, Inc.
814 GE International, Inc.
816 GENTEC
632 Golder Associates. Inc.
815 Grace Consulting
332 Grand Canyon Univeristy
220 Great Lakes Solutions
439 Horiba Instruments, Inc.
432 ICL Industrial Products
701 Industrial Accessories Company
922 Kadrmas, Lee & Jackson
627 Kiewit
827 M&C Tech Group North
428 Marsulex Environmental Tech.
334 McIlvaine Company
420 Metco Environmental
716 Midwest Energy Emissions Corp.
223 Mississippi Lime Company
115 Mitsubishi Heavy Industries
727 MKS Instruments
838 MonitorTech Corporation
415 Nalco Air Protection Technologies
609 Natronx Technologies LLC
733 NIST
316 Nol-Tec Systems, Inc.
938 Norit Americas Inc.
916 Normandeau
623 Novinda
615 Ohio Lumex Company
409 Pall Corporation
121 Parker Hannifin Corporation
228 PE International
234 PennWell Corporation
934 Pentair, formerly TYCO
841 Perma Pure
232 POWER Magazine
740 Praxair
920 PSC
315 QA Support, LP
908 Rev1
422 RMB Consulting & Research Inc.
433 Sega, Inc.
434 Sentis
401 Shaw Group, Inc.
221 Shelter One, Inc.
808 Shick USA
700 SICK Maihak, Inc.
634 Siemens Industry
340 Southern Environmental, Inc.
726 Southern Research Institute
440 Spectrum Systems Inc.
129 STAT Analysis
314 STEAG Energy Services LLC
217 Stebbins Engineering & Mfg Co.
328 STI CEMS
629 Technical Heaters, Inc.
341 Teledyne API
717 Teledyne Monitor Labs
317 Tetra Tech
601 Thermo Scientific
732 Tiger Optics
438 Tosan
729 Trachte Inc.
416 TRC Companies, Inc.
329 Trinity Consultants
133 Trinity Services
821 TSI, Inc.
739 Turner EnviroLogic
109 UK Pavillion
840 United Chemi-Con
429 United Conveyor Corp.
127 United States Lime & Mineral
426 Universal Analyzers
309 URS Corporation
800 US DOE Fossil Energy/Clean Coal
735 US DOE GTP & ETP
933 Vensoft
734 Viaspace
300 VIM Technologies

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Exhibit Reservation

USA's Largest EUEC2013 Energy, Utility & Environment Conference
Jan 28th - 30th | Phoenix, AZ

EUEC 2013 Reservation Form

FAX TO: 1-602-296-0199
Registration Questions? View our website at www.euec.com or Contact EUEC at 1-520-615-3535 or info@euec.com,

Check Items of Interest:

- ☐ Gold (20'x20' Booth) $25,000
- ☐ Silver Front Row (20'x10' Booth) $10,000
- ☐ Bronze Front (10'x10' Corner) $5,000
- ☐ Premium Corner (10' x 10' Corner) $4,500
- ☐ 1 Page Ad in Conference Guide $1,000
- ☐ Session Sponsorship & Logo Ad $500
- ☐ Flash Drive with Audio $495

Exhibit Package:

- One exhibitor registration to attend conference and maintain booth
- One 10'x10' booth with one 6' draped table with two chairs
- 10 free exhibit passes for your clients
- Marketing of your company logo, website link and contact info
- 8 Networking functions in Exhibit area
- Resource book with attendee, mailing list & flash drive with 600 PowerPoints
- One speaking opportunity
- 50% discount at $695 for company employees ($1395 regular)

Exhibit Booth Selection:

☐ Same location as 2012

Please select your preferred choice of Booth # from the exhibit booth layout.

1st ☐ 2nd ☐ 3rd ☐

Exhibitors: Please list the names of company employees to attend EUEC 2013 at a 50% discount $695 ($1395 regular).

Name Email

1st Registrant (Free) _____

2nd Registrant ($695) _____

3rd Registrant ($695) _____

Speakers:

☐ Send me information to speak at EUEC 2013

☐ Send me information to chair and organize a session at EUEC 2013

Name of Session: _____

Contact Information:

Name: _____

Company Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Email: _____ Phone: _____ Fax: _____

Comment: _____

Authorized Signature (required): _____ Date: _____

Show Rules. Application implies that exhibitor will abide by Conference show rules. Please copy this contract for your files. Exhibitor hereby assumes entire responsibility and hereby agrees to protect, defend, indemnify and save the Phoenix Convention Center, its owners, its operator, EUEC, and each of their respective parents, subsidiaries, affiliates, employees, officers, directors, and agents harmless against all claims, losses or damages to persons or property, governmental charges or fines and attorney's fees arising out of or caused by its installation, removal, maintenance, occupancy or use of the exhibition premises or a part thereof, excluding any such liability caused by the sole gross negligence of the Convention Center and its employees and agents. Exhibitor shall obtain and keep in force during the term of the installation and use of the exhibit premises, policies of Comprehensive General Liability Insurance and Contractual Liability Insurance, insuring and specifically referring to the Contractual liability set forth in this Exhibit Agreement in an amount not less than $1,000,000 Combined Single Limit for personal injury and property damage. The group agrees to provide a Certificate of Insurance evidencing the coverage described above. Cancellation Policy: By submitting this form you agree to pay for your booth and all added items. 50% refund is available until October 1, 2012. After October 1, 2012 no refunds are avilable.

CONTACT EUEC: P. O. Box 66076, Tucson, AZ 85728 | info@euec.com | p.520-615-3535 | f.602-296-0199

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Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of Mike Grawe [nrdcinfo@nrdconline.org]
Sent: 7/10/2014 11:33:02 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Protect America's bees from toxic pesticides

Jul 10, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

I am calling on you to impose an immediate moratorium on neonicotinoids, or "neonics," a class of pesticides that many scientific studies have linked to the devastating decline in bee populations across the country.

Your agency has acknowledged that a number of these neonics are "highly toxic" to bees. Yet the EPA has failed to review the mounting scientific evidence that implicates these systemic pesticides as a key culprit behind the alarming collapse of bee colonies.

As vital pollinators, bees support a wealth of natural ecosystems, and we rely on them to pollinate more than 70 of our leading crops. We must not allow our food supply to be jeopardized simply because your agency refuses to properly assess the risks associated with bee-killing pesticides. I am alarmed that when it comes to bee survival, the EPA appears to be more concerned about companies like Dow, Bayer, Syngenta and Monsanto.

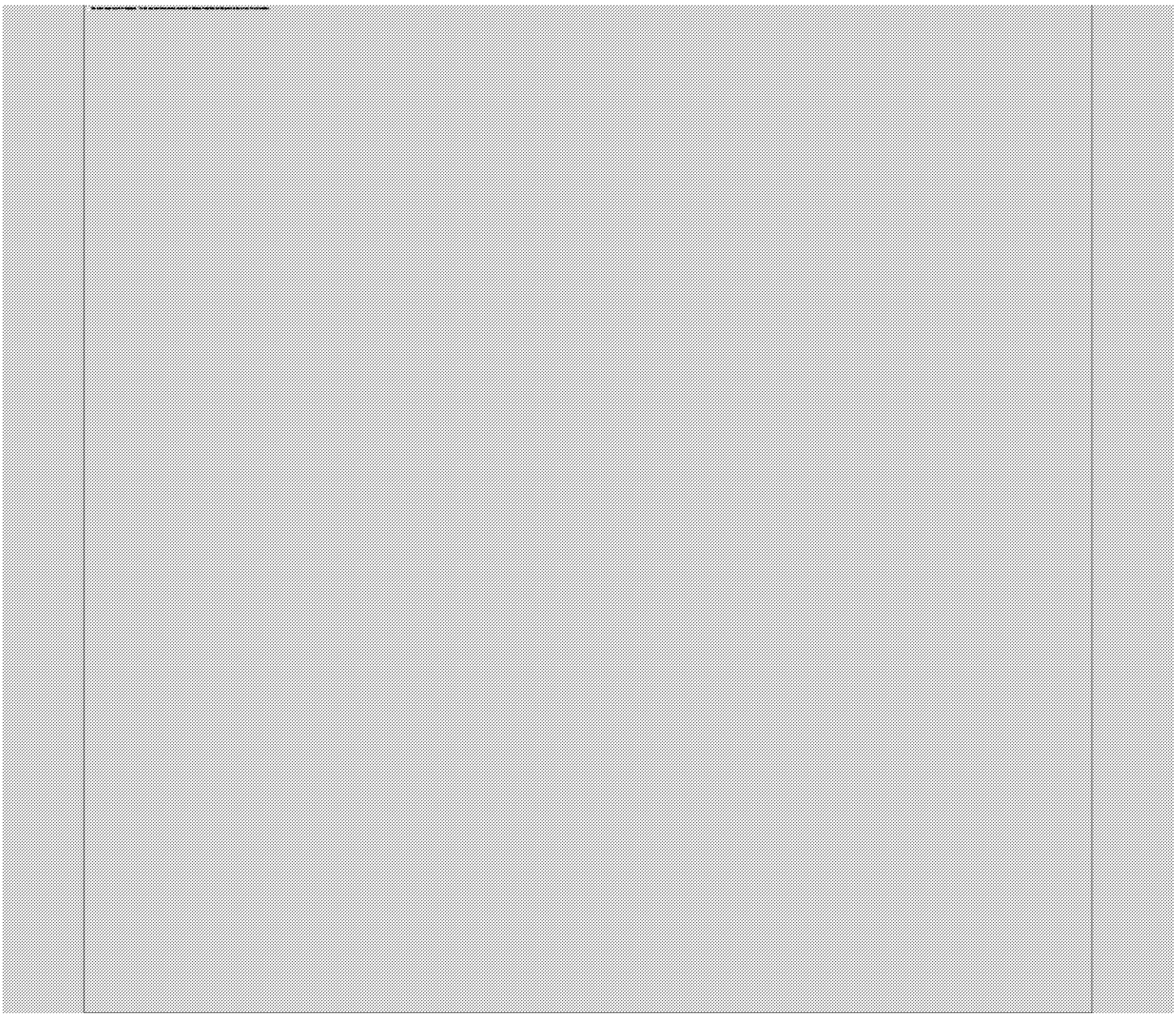
I strongly urge you to direct your agency to change course, to put the public interest ahead of corporate self-interest and to impose an immediate moratorium on neonicotinoids.

Sincerely,

Mr. Mike Grawe
Meramec
Ex. 6 Personal Privacy (PP)

Message

From: EUCI Events [events@eucievents.com]
Sent: 7/15/2016 12:40:41 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: 2016 316(b) Fish/Shellfish Impingement & Entrainment Conference - September in Baltimore



2016 EPA 316(b) Fish and Shellfish Impingement & Entrainment in Power & Industrial Facilities

Find Out More

September 29-30, 2016 :: Baltimore, MD

The purpose of EUCI's 2016 Fish Impingement conference is to address the challenges that have emerged as a result of the 2014 regulation. Along with plant-specific case studies, the conference will discuss development of compliance strategies, compliance timelines, proactive steps that can be taken to facilitate permitting, the peer review process, and the engineering, biological, and economic analyses that need to be conducted. Speakers from NOAA, the EPA and USFWS will detail the changes that have emerged as a result of the rule from a regulatory perspective.

➡ Read More

Reasons to Attend

Gain Key Insight on

- Impingement & entrainment compliance reports (r2 through r13)
- The regulator perspective of 316(b)
- The biology components of the ruling

➡ Read More

In-Depth Review of

- An entrainment characterization study
- Social costs and the role they play in site-specific, 316(b) compliance decisions
- The 7 options for compliance with the impingement mortality standards

➡ Read More

➡ Overview

➡ Agenda

➡ Speakers

➡ Location

➡ Pricing & Registration

Post-Conference Workshop

Engineering Considerations in Evaluating 316(b) Compliance Options :: September 30, 2016

This workshop will provide an in-depth look at engineering considerations for 316(b) compliance options. The instructors will begin with an overview of fish protection technologies, including structural and operational technologies, their advantages and disadvantages, and most common/preferred methods of fish protection.

➡ Read More

Testimonials from past attendees

"Engagement of the speakers on topics was obvious, as was their knowledge of their topic." *Assistant Project Manager, Southern Co.*

"The EUCI conference on 316b was very informative and featured subject matter experts who completely understood not only the beneficial issues but the markets

Continuing Education Credits

EUCI is authorized to offer IACET CEUs for its programs that qualify under the ANSI/IACET Standard.

➡ Read More

as well." *VP Business Development, CB&I*

"This conference provided me an overview of the 316b regulation and tools that I can use for implementation." *Senior Manager, Environ*

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Message

From: paul.zimbardo@ubs.com [paul.zimbardo@ubs.com]
on behalf of julien.dumoulin-smith@ubs.com [julien.dumoulin-smith@ubs.com]
Sent: 11/5/2015 1:42:20 PM
Subject: UBS: DYN: Muted Expectations (Buy; Reduce PT)
Attachments: Julien Dumoulin-Smith.vcf; disclaim.txt

Dynegy, Inc: Muted Expectations

Please click here for the full report.

2016 guidance falls short of Analyst Day given decline in power & gas
Dynegy launched 2016E adjusted EBITDA guidance of $1.1-$1.3Bn, in-line with our expectations but this could be a disappointment to those expecting a $1.3Bn midpoint (Analyst Day 2016-2018E guidance was $3.9Bn). FCF guidance of $300-$500Mn excludes $50Mn for non-recurring items and is similarly below the linear 2016-2018E Analyst Day guidance. IPH is expected to improve to $150Mn adjusted EBITDA in 2016 from $85Mn in 2015 (guidance trimmed $15Mn with 3Q15) but also below the ~$220Mn implied at the Analyst Day. Dynegy has outperformed NRG and TLN the past few months but the guidance miss vs Consensus could derail progress.

Still room for improvement at the fleet – improving dispatch is key
PRIDE will aim to reduce the uneconomic/unavailable hours on the Coal side as the acquired assets in particular generally continue to have below-average output. Stuart and Zimmer have been two of the more frequently cited assets and each was unavailable for ~1/3rd of the quarter. The PJM gas portfolio was in the money substantially around the clock w/ only Kendall sub-90% (3Q was 59% from 21% YoY).

Not bashful about PRIDE savings but how much is truly new to the market?
Dynegy has been vocal about a variety of the underlying elements of PRIDE Energized such as transport cost improvement and planned asset uprate expansions. The key question is how much is truly incremental. We currently only ascribe ~50% of the annual EBITDA uplift in our estimates discretely as we had previously incorporated some of the rail and dispatch benefits; as such we see some modest room to the upside on our estimates, particularly if successful in securing additional (rail) savings.

Valuation: Reduce Price Target $3 to $28; see upside even with lower multiple
Valuation is based on 2017E sum-of-the-parts. Although 2016 guidance should not be a surprise, we suspect investors could be caught off-guard based on the implicit $1.3Bn near-term annual guidance (Consensus expected ~$1.3Bn as well). While we believe materials provided by management at previous conferences alluded to the lower guidance, we suspect the higher coal ash spend for waste water as an incremental modest negative (NRG has yet to disclose any meaningful figures here despite its greater exposure). We see DYN as among the most depressed IPPs on valuation, mostly trading on coal and gas.

- **Questions for the call include:**

  (1) What specific factors drove Wood River to be uneconomic for such a larger percentage of hours than your other MISO coal assets? Is it feasible to have MISO reforms this late in the year as implied by EXC for reforms by next April's 16/17 auction?

  (2) How much of the PRIDE Energized EBITDA initiatives are incremental? i.e. you have discussed the plant uprates in the past, was that already in the plan?

(3) Can you provide an update on the MISO capacity market investigation?

(4) What type of reforms do you believe could come in MISO following the Issues Statement? How fast could these developments occur?

(5) When would anticipate bringing a request for further repurchase to the Board?

- **Near-term results unable to escape the weight of weak power:** The high-end of the 2015 range was cut to $825-$925Mn from $825-$1,025Mn while the free cash flow target was also reduced to $140-$240Mn from $100-$300Mn. This 2015 weakness is in contrast to NRG which was able to maintain its 2015 guidance midpoint yesterday thanks to the offsetting contribution from its large retail portfolio.

- **75% done with repurchase plan:** An additional 2.6Mn shares were repurchased in October at $22.82, incremental to the 7.6Mn bought back in August/October. Dynegy still has $63Mn level in current Board authorization. The question remains the cadence of buybacks, as mgmt has yet to delineate its 2016 capital allocation plans.

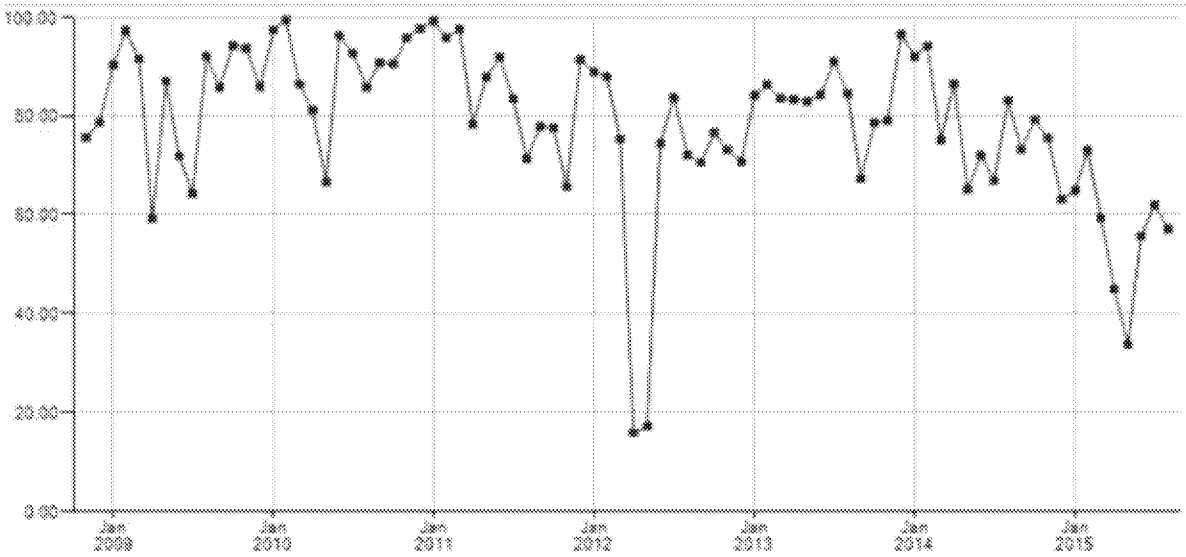
- **Closing a MISO baseload coal plant in June 2016 as economics deteriorate:** Dynegy announced it will be retiring the 465MW Wood River coal plant in Alton Illinois (near St. Louis in an industrial zone) for economic reasons. Per disclosures the plant was environmentally compliant with NPDES renewal in 2020 and only had <$2Mn of environmental spending required for nonchemical cleaning waste. Dynegy will file a notice of retirement with MISO by month-end after which MISO has until the end of May to determine if the asset is required for reliability. Units 4-5 burned 1.9Mn tons of PRB coal last year. Units 1-3 were retired in October 2011. Dynegy clarified that its PJM Coal fleet is profitable and no retirements are planned in that segment.

The Wood River plant was uneconomic 33% of the time in 3Q15, the highest level for any of Dynegy's MISO coal assets in either 3Q14 or 3Q15.

Addressing the need for a black-and-white MISO market. With the latest retirement, DYN has only grown louder about the need for 'true' market reform to effectively provide black/white barriers between restructured and regulated markets. While this appears necessary, we maintain our view that MISO does not have the adequate support from stakeholders to execute upon such a wide ranging series of reforms, particularly with pending petitions around market behavior pending.

We see this as necessary to resolve now, as future transmission upgrades could well drive the region to once more clear with the balance of the MISO market at near-zero prices. The latest retirement should preserve the higher prices for a modestly longer period of time, albeit reducing the total volume of eligible jobs at that.

Figure 1: Wood River 4-5 Capacity Factors (%)



Source: SNL Energy

- **Environmental compliance cost update a mixed bag:** Environmental cost updated expected with 4Q results but early indications are in-line with plans: After reviewing the finalized Effluent Limitation Guidelines (ELG) published in September Dynegy is facing increased compliance cost for assets sized between 51-400MW which erodes cost savings it was observing at the large assets (cost estimate provided for larger, >400MW units was $295 Mn). Coal Combustion Residuals (CCR) and 316(b) compliance costs are coming in below their original estimates which should offer some offsetting relief. *We suspect this will be closely watched as the more stringent ELGs could have a disproportionate impact on the smaller portfolio.*

ELG compliance costs for large assets are "slightly below" the $290Mn disclosed at the Analyst Day but increased costs at the smaller assets could push the total number higher.

- **MISO capacity revenue up from CP transition and IPA procurement:** Expected EBITDA from the Planning Year 16/17 and 2018/2019 auctions is notably higher than 2Q disclosures due to the Capacity Performance transition auction and results of the Illinois Power Agency (IPA) procurement. We include the weighted average of the winning bids in the latest IPA capacity procurement event, which cleared at $138.12 per MW-Day. The winning suppliers included DYN, DTE, EXC and AEE subsidiaries. Results were posted in mid-September. The key question heading into the next MISO Capacity Auction remains whether the market monitor will deem the eligible PJM reference price the new CP product or maintain its linkage to the base product. DYN and others appears to be assuming it is linked to CP ($134/MW-day) + 10% of CONE ($25/MW-day), totaling a new de-facto ceiling of $160/MW-day.

Expected MISO capacity EBITDA increased $95Mn QoQ due to PJM auction and IPA procurement.

Figure 2: Capacity Procurement Event for Ameren Illinois: Average Price ($/MW-Day) and Quantities (MW)

Zonal Resource Credits		
Planning Year	Average Price	Quantity
June 2016 – May 2017	$138.12 per MW-Day	1,033

Source: Illinois Power Agency

- **California gets more visibility:** Moss Landing 1 & 2 were awarded with Secured Resource Adequacy capacity with SCE as detailed below. Further updates in the strategic review should come early in 2016 following a CPUC final decision in the GT&S rate case (PD expected December 22nd).
  - 2017: 575MW
  - 2018: 400MW
  - 2019: 850MW
- **The PRIDE Energized targets** were reaffirmed with Dynegy still expected $135Mn of cost reductions in 2016 with $250Mn over the 2016-2018 period. 75% of the 2016 EBITDA synergies have been identified but not yet secured (Northeast gas optimization, congestion reduction, supply chain etc.). Although small, Dynegy's 70MW ISO-NE uprates (Milford and Lake Road) specifically should benefit from recent Pilgrim retirement. The retirement could add $80Mn EBITDA improvement, seemingly not in the PRIDE guidance. All of the 2016 balance sheet initiatives have been identified and following natural gas renegotiations the company was able to reduce its cash requirement to $400-$500Mn from $600Mn previously.

PRIDE Energized 2016-2018 Targets unchanged:

EBITDA: $250Mn
Balance Sheet: $400Mn

- **3Q15 adjusted EBITDA** of $350Mn came in between UBSe ($341Mn) and Consensus ($366Mn), up from $90Mn in 3Q14 due to $240Mn from acquired assets and indicating $20Mn of improved core operations with improved MISO capacity prices a key component.

Updated Estimates and Valuation

We have updated our power mark-to-market and share repurchase assumptions with our 2015/2016 estimates declining but 2017+ inching higher. While management had initially characterized the EBITDA profile from 2016-2018 as relatively flat through the period, we look for an update on the profile given the meaningful contango that appears to have emerged.

Figure 3: Updated Dynegy EBITDA Estimates

Dynegy EBITDA Breakdown (UBSe)	2014A	2015E	2016E	2017E	2018E	2019E
Midwest	114	52	131	146	157	203
West	52	75	63	38	45	44
Northeast	187	166	127	140	160	167
Illinois Power Holdings	79	105	42	82	107	117
Duke Midwest	0	234	311	283	322	340
Energy Capital Partners	0	274	354	413	484	514
PRIDE Reloaded & Other Synergies	0	118	233	305	330	330
Consolidated G&A and Other	(85)	(125)	(130)	(130)	(130)	(130)
Recurring Adjusted EBITDA	**347**	**889**	**1,131**	**1,278**	**1,475**	**1,585**
Previous	***347***	***934***	***1,175***	***1,247***	***1,468***	***1,506***
Consensus (11/4/2015)	$364	$998	$1,289	$1,272		
Mgmt Guidance: Adj EBITDA	$300-$350	$825-$925	$1.1-$1.3Bn	~$1,300	~$1,300	
Capital Spending	-$160	-$285				
Cash Interest	-$145	-$425				
Other Cash Impacts	$15	-$15				
Free Cash Flow	$10-$60	$140-$240	$300-$500	~$430	~$430	

Source: Company Filings, ThomsonReuters, and UBS Estimates

We are reducing our valuation to $28 from $31 using a sum-of-the-parts approach. Our valuation now reflects a 7x EV / EBITDA for all segments except EquiPower, consistent with our approach to Talen and representing the market environment were the intermediate-term outlook for power/gas continues to be challenged, particularly for PJM units where we believe we are approaching peak-cycle heat rates (this is despite the depressed gas environment). Even at the lower multiple we continue to see attractive risk/reward today.

Figure 4: Updated Dynegy Valuation

		EV / EBITDA Multiples					
Dynegy Inc - 2017E	EBITDA	Low	Base	High	Low	Base	High
Legacy Dynegy	325	5.0x	7.0x	8.0x	$1,625	$2,274	$2,599
Illinois Power Holdings (IPH)	82	6.0x	7.0x	8.0x	$490	$572	$653
Duke Midwest	283	6.0x	7.0x	8.0x	$1,699	$1,982	$2,265
EquiPower	413	7.0x	8.0x	9.0x	$2,890	$3,303	$3,716
Less: West Peaking & Brayton Point	(23)	6.0x	7.0x	8.0x	($138)	($159)	($182)
Synergies, Corp. Overhead, & Other	175	6.0x	7.0x	8.0x	$1,050	$1,225	$1,400
Total Unregulated EV	**1,255**	**6.1x**	**7.3x**	**8.5x**	**$7,617**	**$9,197**	**$10,668**
Net Debt							
Dynegy Inc.					$6,386	$6,386	$6,386
Illinois Power Holdings (IPH)					$825	$825	$825
Plus: NPV NOL Shield & West Peaking					($240)	($537)	($587)
Cash and 2015/2016 FCF					($941)	($1,175)	($1,690)
Total Net Debt					**$6,030**	**$5,499**	**$4,934**
Net Debt / Adjusted EBITDA					*5.1x*	*4.67x*	*4.2x*
Total Equity Value					**$1,587**	**$3,699**	**$5,753**
Implied FCF Yield					*29%*	*13%*	*8%*
Shares Outstanding					133	133	133
Dynegy Valuation					**$12.00**	**$28.00**	**$43.00**
Upside/(Downside)					**-40%**	**40%**	**116%**
Implied Gross EV/EBITDA Multiple					*6.x*	*7.2x*	*8.4x*
Current Price Implied Gross EV/EBITDA Multiple					*6.7x*	*6.3x*	*5.9x*

Source: Company Filings and UBS Estimates

Free Cash Flow profile remains solid

Our 2015 and 2016 estimates are below the respective guidance ranges as we do not make the same adjustments as management does. For example in 2015 DYN excludes one quarter of acquisition interest ($92Mn) and in 2016 the $50Mn of non-recurring environmental expenses. Beyond 2016 on a more normalized basis the cash flow profile improves and the FCF yield averages 16%.

Figure 5: Updated Dynegy FCF Profile

Dynegy Free Cash Flow Analysis	2015E	2016E	2017E	2018E	2019E	2020E
Adjusted EBITDA	889	1,131	1,278	1,475	1,585	1,605
Less: Interest Expense	(533)	(505)	(505)	(505)	(505)	(505)
Less: Taxes					(266)	(275)
FCF Pre-Capex (Proxy for FFO)	356	626	773	970	814	824
Less: Capital Expenditures (Pre-Growth)	(255)	(370)	(315)	(410)	(343)	(343)
Plus/Minus: Other	5*	35*	5*	5*	5*	5*
Free Cash Flow	86	291	463	565	477	487
Guidance	*$140-$240*	*$300-$500*	*~$430*	*~$430*		
Debt Profile (incl. ST Debt Balance)	$7,106	$7,106	$7,106	$7,106	$7,106	$7,106
Cash	$1,093	$1,454	$1,961	$2,387	$2,924	$3,481
Net Debt	$6,013	$5,652	$5,145	$4,719	$4,182	$3,625
Net Debt / EBITDA	6.8x	5.0x	4.0x	3.2x	2.6x	2.3x
FFO / Gross Debt	5%	9%	11%	14%	11%	12%
FCF Yield	2.8%	9.4%	14.9%	18.2%	15.4%	15.7%

Source: Company Filings and UBS Estimates * UBSe does not adjust for the same items as management in 2015/2016

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Dynegy, Inc.[4, 6, 16]	DYN.N	Buy	N/A	US$20.52	04 Nov 2015

Source: UBS. All prices as of local market close.
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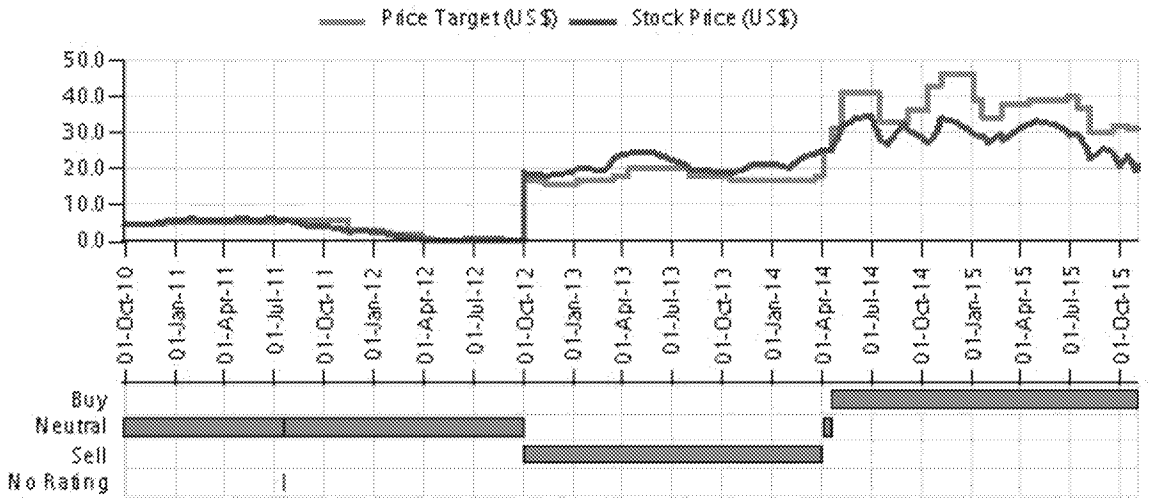

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To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: ***ACTION REQUIRED*** You must read and respond to this litigation hold notice

This is a reminder that EPA requires your assistance with respect to preserving and/or collecting information in the matter referred to below.

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As you have been notified, the United States Environmental Protection Agency ("EPA" or "Agency") is implementing a litigation hold because the Agency reasonably anticipates litigation against or between Ameren Missouri, St. Louis Missouri, pursuant to the Clean Air Act regarding violations of the Prevention of Significant Deterioration provisions of the Clean Air Act, the Missouri State Implementation Plan, and Title V of the CAA with respect to the Labadie, Meramec, Rush Island and Sioux Power Stations (the Facilities) owned and operated by Ameren Missouri throughout eastern Missouri. This litigation hold also applies to documents related to EPA's interpretation or implementation of the New Source Review regulations and any documents that discuss projects and pollution control technologies typically performed at coal-fired Electricity Generating Units. Accordingly, all Agency employees with potentially relevant information are directed to preserve the information until further notice.

Please click the link below to review the current custodian list and answer the questionnaire. NOTE: You must be logged into the EPA Network to access this link.

The legal team recognizes that your time is valuable and appreciates your cooperation and continued support.

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We're excited to kick-off EUEC 2016 in just six weeks.
Today's EnergyNews is pleased to feature the presentations in Track I: WASTEWATER, 316(b) and ELG.
For the full listing of all 10 tracks see **PROGRAM BROCHURE**

Program Brochure
EUEC 2016

SUBMIT ABSTRACT
By Dec 25

Opportunities are available to speak, and make a 20 minute PowerPoint presentation in several tracks. Open spots for this track are shown below - with a submit abstract link.

TRACK I

WASTEWATER, 316(b) and ELG

H1 WASTEWATER

liberty hydro

REACTOR VESSELS TO MANAGE & TREAT WASTEWATER AT ASH PONDS & LANDFILLS - Mark Kropilak, CEO, Liberty Hydro, Inc.

EUEC 2016

WASTEWATER, ZLD and FGD

I6 316(b) and ELG

APPROACHES TO ELG COMPLIANCE FOR FGD WASTE WATERS - Kristen Bell, Senior Associate, Sargent & Lundy

ENERGY NEUTRALITY IN WASTEWATER TREATMENT -
Tom Stanley, CTO, GE Water & Process Technologies, GE Power & Water

MINIMIZING WATER FOOTPRINT BY IMPLEMENTING SEMI-BATCH REVERSE OSMOSIS - Dr. Rick Stover, EVP, Desalitech

ELG COMPLIANCE AT COAL FIRED POWER STATIONS - Michael Preston, Chemical Engineering Section Leader, Black & Veatch

NATIONAL NUTRIENT REDUCTION STRATEGY UPDATE - Diane Martini, Senior Water/Wastewater Consultant, Burns & McDonnell; Sarah Gilstrap

AN UPDATE ON THE WATER RESEARCH CENTER - Tyler Cromey, Research Engineer, Southern Company Services,

I2 WATER - UTILITIES

MODELING ELECTRICITY SECTOR VULNERABILITIES RELATED TO WATER TEMPERATURES - Jordan Macknick, NREL; Macknick, Brinkman, Ibanez, Tomberlin, Hunsberger, Kandt & Miara

THE LATEST TECHNOLOGICAL UPDATES IN OIL SPILL CONTAINMENT SYSTEMS - Bill Gannon, President, Solidifi cation Products International, Inc.; John Panaro

ENERGY SAVINGS THROUGH PIPE SELECTION - Rosemary Smud, Sales Engineer, American Cast Iron Pipe; Maury Gaston

ENHANCE COORDINATION BETWEEN ELECTRIC AND WATER UTILITIES - Nushat Thomas, Team Leader, U.S. Environmental Protection Agency; Lauren Wisniewski

BR RISK MGMT; PREDICTIVE MODEL DEVELOPMENT FOR DISINFECTION BYPRODUCTS - Brian Mastin, Senior Consultant, Parsons

SCE STORM WATER MANAGEMENT & FLOOD PREPAREDNESS IMPROVEMENT INITIATIVE - Denise Yaffe, Mgr., Southern California Edison; J. Lakes, D. Barr, C. Akunyili & S. Johnson

I3 316(b) - UTILITIES

EPA'S 316B RULE: HOW TO ACHIEVE COMPLIANCE - Greg Seegert, Chief Ichthyologist, EA Engineering, Science & Technology

GREEN ALTERNATIVES FOR WATER SUPPLY DEVELOPMENT - Henry Hunt, Sr. Project Manager, Layne - Ranney Collector Wells

CONTROL OF DREISSENID MUSSELS WITH A MORE RATIONAL USE OF COPPER - David Hammond, Ph.D., Senior Scientist, Earth Science Labs, Inc.

COMPLIANCE WITH BOTH 316(B) AND THE ENDANGERED SPECIES ACT -
Harriet Nash, NOAA's National Marine Fisheries Service; Ashfi eld, U.S. Fish & Wildlife Svc.

EFFECT OF OPERATING CONDITIONS OF FGD UNIT ON THE FORM OF SELENIUM IN LIQUOR - Hiroyuki Akiho, Reseach Scientist, Central Research Institute of Electric Power Industry; Naoki Noda, Hiromi Shirai & Shigeo Ito

OPEN- SUBMIT ABSTRACT

I7 SUSTAINABILITY

THE ENERGY-WATER NEXUS: RESILIENT, SUSTAINABLE COMMUNITIES AND CHP
Scott Hutchins, Stakeholder Engagement, U. S. Department of Energy

WATER BALANCE ANALYSIS, MONITORING, & MANAGEMENT TOOL FOR POWER PLANTS
Charlie He, Assoc. VP, Carollo Engineers; E. McLeskey, G. Carpenter, J. Dresang & C. Chiu

SUPPORTING THE HEART OF THE WATER - ENERGY - FOOD NEXUS
Maury Gaston, Manager of Marketing Services, American Cast Iron pipe

MONETIZING WATER EFFICIENCY - THE RESNET WATER EFFICIENCY RATING INDEX - Steve Baden, Executive Director, RESNET

PREVENTIVE SAFETY MEASURE FROM POLLUTED SURFACE WATER LEAKAGE IN BUILDINGS - Nasser Alhemiddi, Professor, King Saud U.; A. Alhemiddi, M. Arch. & A. Alhemiddi, B. Arch

IMPACTS OF EPA 316(B) ON POWER PLANT COOLING WATER INTAKES - Roman Carter, National Account Manager, Intralox / Hydrolox; Tim Woodrow

CLEAN WATER ACT RULE: EXPANDING RISK & LIABILITY FOR PROJECT PROPONENTS - Deidre G. Duncan, Partner, Hunton & Williams

316(B) IMPINGEMENT COMPLIANCE: UNDERSTANDING DE MINIMIS - Radhika de Silva, Sr. Project Manager, HDR Engineering; Mark Bailey

316(B) - OVERVIEW OF TECHNICAL FEASIBILITY AND COST EVALUATION STUDY - Joy Rooney, Senior Associate, Sargent & Lundy LLC; Ken Snell & Mehrdad Salehi

316(B) OVERVIEW OF IMPINGEMENT TECHNOLOGY SELECTION PROCEDURE - Mehrdad Salehi, Senior Associate, Sargent & Lundy LLC

14 WASTEWATER ZLD

ZLD APPROACH BY APPLYING SPRAY DRYER EVAPORATOR (SDE™) TECHNOLOGY - Paulo Oliveira, Product Marketing Manager, Alstom Power, Inc.; Phil Rader

THERMAL ZLD SYSTEM USING A SDE IN A WASTE TO ENERGY PLANT - Robert Van Durme, P.E., Key Account Manager, Lechler Inc.; Ashwin Patni

FGD ZLD PROCESS IMPACT ON HEAT RATE & OTHER PLANT PERFORMANCE PARAMETERS
Benjamin Laurent, Senior Process Engineer, Heartland Technology Partners

PROCESSING POWER PLANT WASTE TO HIGH MARKETABLE COMMODITIES. AN UPDATE.
Robert Bobeck, Technical Sales, Dustex LLC; Patrick Paul

UPDATE ON B&W ZLD ACTIVITIES
Steven Feeney, Product Line Manager, Babcock & Wilcox; Steve Feeney & Mike Klidas

FORWARD OSMOSIS BASED HIGH WATER RECOVERY SOLUTIONS
Mary Theresa Pendergast, Director - Solutions R&D, Oasys Water, Inc.; John Tracy

15: WASTEWATER FGD

PRE-FABRICATED PROCESS EQUIPMENT SOLUTION TO MEET ELG & CCR STANDARDS
James Peterson, President, Frontier Water Systems

WATER REUSE FOLLOWING GROUNDWATER EXTRACTION & TREATMENT - Christina Rain, Project Engineer, Langan Treadwell Rollo; Graber, Glenn & Shipman

18 WATER SUPPLY

A SOLUTION TO OUR WATER SUPPLY PROBLEM - John Wilson, Territory Manager, American Cast Iron Pipe, Maury Gaston

DREDGING YOUR RESERVOIR: ENHANCING THE RESILIENCY OF YOUR WATER SUPPLY - Sarah Howard, Sr. Environmental Scientist, Black & Veatch; Elizabeth Quinlan

AN INNOVATIVE SOLUTION TO PREDICTIVE WATER MODELING FOR THE UTILITIES SECTOR - Kenn Cygan, Director, Nalco, an Ecolab Company; April YeYoung Yi

WEANING OURSELVES FROM OUR WASTEFUL WATER WAYS - Ned Daugherty, Principal Architect, H2O Futures

.ENGAGING A UNIVERSITY ON WATER CONSERVATION - Kyle Mann, Energy Effi ciency Program Specialist, California State University Fullerton

Damanhour Univ

GIS-FORECASTED SURFACE HYDROLOGY FOR REDUCING RISKS OF FOOD PRODUCTION - Abdrabelnabi Abdelhady, Professor, Damanhour Univ; Aggag, Abdelaty & Bahnassy

EFFECTS OF MERCURY CONTROL TECHNOLOGIES ON FGD WASTEWATER QUALITY
Gary Blythe, AECOM; Richardson, AECOM; Dene, EPRI; Acharya, Southern Company

ANALYTICAL METHODS FOR DETERMINATION OF METALS IN FGD & CCR MATERIALS
Richard Burrows, Corporate Technical Director, TestAmerica Inc.

ELG AND CCR COMPLIANCE - THE DOLLARS ARE IN THE DETAILS
Dennis Fink, Senior Project Manager, CH2M; Dr. Thomas E. Higgins

ELG COMPLIANCE SOLUTIONS - AN IN-DEPTH LOOK AT FGD FLOWRATE IMPACTS
Jeromy Jones, AQCS Manager, Burns & McDonnell

RECENT ADVANCES IN WASTEWATER MEASUREMENTS OF HG, AS AND SE USING AFS
Warren Corns, Research and Development Manager, P S Analytical; Cornelius Brombach

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GHG & CLIMATE MANAGEMENT

H1.1 STRATEGIES TO COMPLY WITH NEW FINANCIAL REGULATIONS IN THE GHG CONTRAINED MARKET - Nedia Miller, Founder, MILLER, CTA

H1.2 ALTERNATIVE SOLUTIONS FOR LOWERING CO2 EMISSIONS FROM FOSSIL FUEL EGUS - Tim Donnelly, POWER Engineers, Inc.; Gary Baranowski

H1.3 FIVE YEARS OF OPERATING EXPERIENCE WITH DRYFINING FUEL ENHANCEMENT PROCESS - Sandra Broekema, Charlie Bullinger, Great River Energy; Nenad Sarunac, Power System

H1.4 THE EFFECTS OF POLLUTION & CLIMATE CHANGE ON HUMAN HEALTH - Katie Baron, NYU Dentistry; Bapanaiah Penugonda

H1.5 SUGARCANE TO LOW CARBON ENERGY IN CALIFORNIA David Rubenstein, President / CEO, California Ethanol & Power, LLC

H1.6 KINETICS OF THE CO2 METHANATION REACTION OVER ALUMINA SUPPORTED NI & NI-FE CATALYST - Atul Kumar, IIT Kanpur; Deepak Kumar & Goutam Deo

H2.1 ANALYSIS OF POTENTIAL CO2 REDUCTION USING THE EPA'S GHG REGULATION BLOCK STRATEGIES FOR EXISTING EGUS - Emily Kunkel, Environmental Associate, Sargent & Lundy, LLC; Rajendra Gaikwad

H2.2 GHG PERMITTING: CURRENT STATUS & RECENT UPDATES - Maren Seibold, Managing Consultant, Trinity Consultants

H2.3 EGRID UPDATES -Travis Johnson, Environmental Protection Specialist, US Environmental Protection Agency; Jeremy Schreifels, US EPA; Cristina Quiroz, Radium Consulting

H2.4 PLASMA GASIFICATION OFFSETS OF GHG EMISSIONS FROM COAL-FIRED POWER PLANTS - Louis Circeo, Chief Scientist, Applied

TECHNICAL TRACKS

GHG & CLIMATE
SMART GRID
ESP, PM, CEMS
BIOFUELS
111 (D), NSR, NAAQS
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316 (B) WATER
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CCS & CCR
CEMS & HCL
PERMITS COMPLIANCE
OPERATIONS & MGMT
ALT FUEL EV FLEETS
BATTERY & STORAGE
FGD ZLD WASTEWATER
EHS EMIS RISK MGMT
SCR & CONTROL TECH
CLEAN POWER PLAN

Plasma Arc Technologies, LLC

H7.1 SIMPLE AB32 GHG POSITION MANAGEMENT SOLUTION - David Gloski, President, xOverTime Inc.; Todd Barth & Michael Lehane, xOvertime; Ken Nold, Turlock Irrigation District

H7.2 COMPARATIVE ANALYSIS OF GHG DATA COLLECTED UNDER EPA'S GREENHOUSE GAS REPORTING PROGRAM & CALIFORNIA'S MANDATORY GHG REPORTING REGULATION - Sean Hogan, US. EPA

H7.3 SAN DIEGO FORWARD: THE REGIONAL PLAN: CLIMATE CHANGE MITIGATION & ADAPTATION WHITE PAPER - Susan Freedman, SANDAG; Allison Wood

H7.4 REAL-TIME INTERACTIVE DASHBOARD OF ZERO EMISSION VEHICLE DEVELOPMENT IN CALIFORNIA - Ria Langheim, Center for Sustainable Energy; John Anderson

H7.5 UNDERSTANDING THE CALIFORNIA CARBON MARKET: THE TIMING EFFECT - Jonathan Ornelas, ICIS; Jan Frommeyer & Judith Schroeter

G5.1 A FRAMEWORK FOR ECOLOGICAL RE-USE OF DISTURBED ECOSYSTEMS - Mark S. Laska, Ph.D., Great Ecology,

G5.2 A GREENER SHADE OF BROWNFIELDS - A CORPORATE PERSPECTIVE - Jane Anderson, Strategy Advisor, Chevron Environmental Management Company

G5.3 A CASE STUDY OF WETLAND MITIGATION IN A HEAVILY INDUSTRIALIZED WATERFRONT - Brian Kellmann, Wetlands Project Manager, Kinder Morgan; Mark S. Laska, Ph.D., Great Ecology

G5.4 PRIVATE CAPITAL INVESTMENT IN LARGE SCALE RESTORATION - Adam Davis, Partner, Ecosystem Investment Partners

G5.5 RESTORATION OF IMPAIRED ECOSYSTEMS: AN OUNCE OF PREVENTION OR A POUND OF CURE? - Timothy Hoelzle, Great Ecology; Hooper, Larson & Farag, US Geological Survey; Hull, Intrinsik Env. Sciences; Clements, CO State Univ.; Stahl, Dupont;Stauber, CSIRO; Kapuska, LK Consultancy; Luoma, Univ. CA Davis; Univ. Ruhr, South FL;Wagner, Chevron Energy Tech. Co.; Glomb, USDOI

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- speak
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B. CEMS, AQ, EHS, EMIS

C. Mercury, SCR, FGD

D. T&D, Smart Grid, Coal

E. SO2, NOx, PM Control

F. RE- PV, Wind, Nuclear

G. O&M, DDD, Remediation

H. Climate, ELG, CCS & CCR

I. Water- 316(b), FGD, ZLD

J. Fleet, Battery & Storage

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Sent by pdayal@euec.com

Message

From: Care2 [petitionquestions@care2team.com]
on behalf of Linda Moss [info@care2.com]
Sent: 10/20/2014 4:33:05 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Save Monarch Butterflies From Monsanto!

Oct 20, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

The Monarch butterfly population in North America has been shrinking at an alarming rate because a significant portion of their breeding habitat is being destroyed by herbicides used on genetically engineered (GE) crops. Milkweeds are critical to the Monarch's survival because they are the only plants Monarch larvae will eat, but they are being decimated by the rampant use of Roundup (glyphosate) used in conjunction with Monsanto's Roundup Ready (TM) GE crops.

To protect Monarchs, we must protect their critical habitat. I urge President Obama to direct the Environmental Protection Agency and the Department of Agriculture to protect Monarch butterflies by stopping the approval of Monsanto's Roundup Ready (TM) and other glyphosate-resistant and pesticide-promoting genetically engineered crops.

Sincerely,

Ms. Linda Moss
Meramec

Ex. 6 Personal Privacy (PP)

Message

From: chen.alex@epa.gov [chen.alex@epa.gov]
Sent: 2/28/2014 2:02:37 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Reminder: You are under an obligation to preserve information (Litigation Hold)

You are a named custodian of potentially relevant information (PRI) subject to a litigation hold in the matter referred to below. Below is a copy of the original email that you previously received, and a link to the initial hold notice.

This a reminder that all EPA employees with possession, custody or control over any materials, whether paper, electronic, or otherwise, that are potentially relevant to this matter must continue to preserve those materials in accordance with the litigation hold instructions until further notice.

THIS IS A REMINDER -- YOU DO NOT NEED TO CLICK THE LINK BELOW OR RESPOND TO THIS MESSAGE. If you have questions regarding your obligation to preserve documents, please contact the case attorney below immediately.

Thank you for your assistance as we continue to implement this hold.

A litigation hold notice related to this matter was first sent by Alex Chen via EPA's Lotus Notes email system. This message, and the litigation hold accessible via the link contained in this message, serve to transition the original litigation holds (Ameren UE and Ameren Nationwide) to EPA's new EnCase system. The obligations imposed by the original litigation holds remain and are unchanged.

The United States Environmental Protection Agency ("EPA" or "Agency") is implementing a litigation hold because the Agency reasonably anticipates litigation against or between Ameren Missouri, St. Louis Missouri, pursuant to the Clean Air Act regarding violations of the Prevention of Significant Deterioration provisions of the Clean Air Act, the Missouri State Implementation Plan, and Title V of the CAA with respect to the Labadie, Meramec, Rush Island and Sioux Power Stations (the Facilities) owned and operated by Ameren Missouri throughout eastern Missouri. This litigation hold also applies to documents related to EPA's interpretation or implementation of the New Source Review regulations and any documents that discuss projects and pollution control technologies typically performed at coal-fired Electricity Generating Units. Accordingly, all Agency employees with possession, custody or control over any mater ials, whether paper, electronic, or tangible things, such as laboratory samples or other physical evidence, that are potentially relevant to this matter are directed to preserve those materials until further notice.

Please click the link below to view the entire litigation hold notice and questions pertaining to this matter. NOTE: You must be logged into the EPA Network to access this link.

We recognize that your time is valuable and appreciate your cooperation - the legal team is also expending considerable time and resources to support this matter and appreciates your continued support.

Failure to promptly respond to the questions found at the end of the litigation hold notice will result in automatic reminders to your email account until compliance is obtained.

DO NOT DELETE THIS EMAIL- YOU WILL NEED THIS LINK TO ACCESS THE LITIGATION HOLD NOTICE FOR FUTURE REFERENCE.

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Ex. 6 Personal Privacy (PP)

Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of Judith Medoff [nrdcinfo@nrdconline.org]
Sent: 9/15/2014 5:31:25 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Require full reporting of all chemicals used during fracking

Sep 15, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

I urge you and your agency to move swiftly to propose tough new rules that will require fracking chemical manufacturers and processors to report all the chemicals used during fracking as well as the risks they pose to EPA, and to require that EPA provide this critical information to the public.

Fracking is on the rise in communities across the country, producing a full-fledged chemical assault on our water and air. More than 15 million Americans now live within one mile of a fracking site. We deserve to know the full extent of the threat that fracking poses to our communities, our health and our environment. Please put people before polluters and require mandatory reporting and public disclosure of all chemicals used during fracking. Thank you.

Sincerely,

Ms. Judith Medoff
[redacted] Meramec Ave
Ex. 6 Personal Privacy (PP)

Message

From: Care2 [petitionquestions@care2team.com]
on behalf of Lisa Lewis [info@care2.com]
Sent: 3/12/2015 1:22:03 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Protect Our Pollinators

Mar 11, 2015

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

I'm writing on behalf of all who depend on our nation's pollinators, which are gravely threatened by the continued use of neonicotinoid pesticides. Once applied these indiscriminate toxics travel throughout plants' tissues -- making the entire plant poisonous, including its pollen and nectar.

Even if individual bees don't die from the nectar, they can pass the poison on in feeding their young. And sublethal effects to pollinators include decreased foraging activity as well as susceptibility to disease; impaired ability to learn, remember and navigate; and reduced survival and reproduction rates. When these chemicals interact with other toxics, the effects can be even more devastating.

As you may know, neonicotinoids have been strongly implicated in declines in insectivorous birds and earthworms and have been shown to persist in soils and streams, threatening fish and aquatic invertebrates. These products are so dangerous that many of them have been banned in Europe.

Please -- protect our pollinators and the multibillion-dollar economy that depends on them by:

1) Immediately revoking all registrations for neonicotinoid pesticides;

2) Increasing funding for pollinator habitat restoration on federal lands;

3) Mandating critical pollinator habitat designations on all existing and newly acquired federal lands; and

4) Formally appointing private-sector scientists specializing in pollination biology to the new Pollinator Health Task Force.

Sincerely,

M. Lisa Lewis
Meramec
Ex. 6 Personal Privacy (PP)

Message

From: EUEC 2016 [pdayal@euec.ccsend.com]
on behalf of EUEC 2016 [pdayal@euec.com]
Sent: 11/19/2015 1:07:39 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Program Announcement for EUEC 2016: Feb 3-5, San Diego, CA

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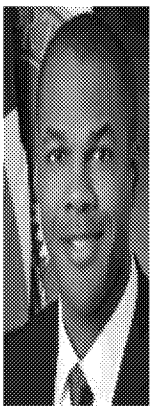
Janet McCabe Asst. Administrator, EPA



Chris Smith, Asst. Secretary, DOE

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Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of Michael Kueneke [nrdcinfo@nrdconline.org]
Sent: 8/5/2014 3:23:45 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Stop the Pebble Mine

Aug 5, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

I am writing in strong support of your proposed determination that would block the massive, ill-conceived Pebble Mine project. Your agency's thorough study concluded that the Pebble Mine poses significant -- even "catastrophic" -- risks to this irreplaceable natural treasure.

On the basis of that study, your agency has proposed specific restrictions at the Pebble site that would protect this ecologically sensitive area, its resources and the people of the region from the grave and unacceptable risks associated with this toxic mega-mine.

The Pebble Mine would generate billions of tons of contaminated waste, devastate up to 90 miles of streams, destroy thousands of acres of wetlands and threaten the world's greatest wild salmon runs -- the linchpin of the Bristol Bay ecosystem and the generator of 14,000 jobs and $1.5 billion in annual revenue.

Your agency's proposed determination will put a stop to this unacceptably massive and unavoidably destructive venture, and I urge you to adopt it. Please finish what your agency has started by finalizing the proposed restrictions that would effectively stop the Pebble Mine.

Sincerely,

Mr. Michael Kueneke
Ex. 6 Personal Privacy (PP) Meramec Ex. 6 Personal Privacy (PP)
Ex. 6 Personal Privacy (PP)

Message

From: Environment Missouri [action@environmentmissouri.org]
on behalf of salvatore cento Ex. 6 Personal Privacy (PP)
Sent: 3/27/2014 2:47:03 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Thank you for protecting Missouri's rivers!

Mar 27, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

All our waterways should be clean enough to drink from, fish from and swim in without risk of pollution -- from our local rivers and streams, to iconic waters like the Meramec and the Missouri River. Unfortunately, loopholes in the Clean Water Act have left many of our smaller waters unprotected, including those that feed and filter the drinking water for 2.4 million Missourians.

Thank you for taking a major step forward to restore Clean Water Act protections to Missouri's streams and wetlands and for your commitment to protecting our waterways.

Please move forward as quickly as possible to finalize a strong rule that will restore Clean Water Act protections to all Missouri's waterways and protect our environment and health.

Sincerely,

Mr. salvatore cento
Ex. 6 Personal Privacy (PP)

Message

From: Consumers Union Advocacy [actions@cu.consumer.org]
on behalf of Judith Medoff Ex. 6 Personal Privacy (PP)
Sent: 9/1/2013 9:03:09 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Finalize the clean-car plan!

Sep 1, 2013

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

As the new EPA director, you have an enormous responsibility to protect public health -- and right now you have a unique opportunity to dramatically improve our nation's air quality. I urge you to quickly finalize strong clean car and gasoline (Tier 3) standards, and update ozone standards and emission limits for power plants. These steps not only will improve the health of my family and millions of other Americans, they will protect generations to come.

More than one-third of Americans live near major roadways and are waiting on updated standards to protect their health. By lowering sulfur in the gasoline for vehicles already on the road, the program will have an immediate positive impact.

Also, finalizing these standards by the end of the year will make it easier to integrate them with new fuel economy standards for cars, lowering costs all around.

Cleaner air, improved public health, and a better environment are too important to be delayed. Please take advantage of this important opportunity and finalize strong Tier 3 standards by the end of this year.

Sincerely,

Dr. Judith Medoff
Ex. 6 Personal Privacy (PP) Meramec Ex. 6 Personal Privacy (PP)
Ex. 6 Personal Privacy (PP)

2015 Tennessee Environmental Conference AGENDA

Tuesday March 17, 2015				
Time	**1. Environment & Industry**	**2. Special Interest**	**3. Health**	**4. Innovation**
7:30	Registration & Exhibits Open			
7:30 - 8:45	Networking Continental Breakfast with Exhibitors & Setup			
9:00 - 9:15	Open/Welcome/Sponsor Recognition			
9:15 - 9:40	**Keynote - David Golden, Sr. Vice President and Chief Legal Officer, Eastman Chemical Company**			
9:45 - 9:55	Break			
10:00 - 10:45	Tennessee Division of Solid Waste Management Update **Pat Flood -Director**	Blaine Tennessee - A Success Story of Infrastructure Development **Jimmy Langley - LBC UD** **Eric Goodman - McGill Associates**	Experiences Fighting Ebola in Monrovia, Liberia **Rendi Murphree - CDC Epidemiologist**	Improving Public Health Through Reducing Fine Particulate Matter Pollution **Ying Li - ETSU, Asst. Professor, Dept. of Environmental Health**
10:50 - 11:35	Tennessee Division of Water Resources Update **Tisha Calabrese Benton - Director**	Peeking into the Oil Price Crystal Ball - Energy Independence, Emissions and Your Questions **Jonathan Overly - Director, E. Tennessee Clean Fuels** **David Greene - University of Tennessee** **Tim Ormond - HydroCycle Engineering**	EBOLA Preparedness for the Tennessee Department of Health Northeast Region **Chad Bruckman - TDH Emergency Response Coordinator**	Removal of Trace Organic Compounds in Domestic Wastewater by Recirculating Packed-Bed Media Filters **Brittani N. Perez - UTK, Master's Candidate in Biosystems Engineering and Minor in Watershed Management**
11:40 - 12:55	**Luncheon Keynote - Toks Omishakin, TDOT Deputy Commissioner**			
1:00 - 1:45	USEPA Region IV Air Quality Update **Beverly Banister - Director: Air, Pesticides and Toxics Management Division**	**TNSA Stormwater Workshop** **Dan Wankel, Moderator - City of Kingsport** **1.** Overview: Regulations, Policies and Procedures (Robert Karesh,TDEC)	TDH Commissioner's Primary Prevention Initiative **Rebekah English - Northeast Regional Director, TDH**	Tennessee's New State Parks **Robin Wooten - East Tennesee Park Area Manager**
1:50 - 2:35	Tennessee Division of Air Pollution Control Update **Quincy Styke - Deputy Director**	**2.** One-inch Capture Overview and Options (Karina Bynum & Foster Wheeler, TDEC and Mary Halley, AMEC) **3.** Runoff Reduction Assessment Tool (Dr. Andrea Ludwig, UT)	Epi-Ready **Katie Garman - MPH, TDH**	The Tweetsie Trail Project **Daniel Reese - Alpha Trace Consulting** **Bob Richards - TN Greenways & Trails Coordinator**
2:40 - 2:55	Break			
3:00 - 3:55	PANEL: Summary Discussion	**Stormwater Workshop (cont'd)**	PANEL: Splash Pad **Joshua Clayton and Susan Miller (TDH)** **Jim Howlett, Howlett Equipment Company**	Tires4Ward Recycling Program **Debra Hamlin - Bridgestone Retail Operations, LLC**
4:00 - 6:00	Reception with Exhbitors Sponsored by CEC, Inc. (Academic poster session to run concurrently from ~4:00-4:45) **Ivy Road** sponsored by DENSO			

2015 Tennessee Environmental Conference AGENDA

Wednesday March 18, 2015

Time	2. Environment	1. Industry	3. Energy	4. Sustainability
7:30	Registration & Exhibits Open			
7:30 - 8:15	Networking Continental Breakfast with Exhibitors			
8:15 - 8:25	Open/Welcome/Sponsor Recognition			
8:25 - 8:45	**Keynote - Heather McTeer Toney EPA Region IV Administrator**			
9:00 - 9:35	Innovative Stormwater Research for Mountain Regions and Beyond **Tim Ormond - HydroCycle Engineering**	How EPA's New Proposed Ozone NAAQS May Affect Tennesseans **Rick Bolton and John Shipp - EnSafe, Inc.**	PANEL: Opportunities for Small Business **Donovan Grimwood, Moderator - TDEC** **Crystal Applewhite - TDEC, Chuck Morris - USDA & Walter Perry - US SBA**	EarthSmart FedEx Solutions for a More Sustainable World **Kathryn Crighton-Smith - FedEx, Senior Project Management Specialist**
9:40 - 10:15	Academic Partnerships, Engaged Scholarship, and Community Outreach for Alternative Transportation Projects **Matt Farr - The Nature Conservancy**	Compliance Strategies to Meet the New 316(b) Regulations **Fred Heitman - ENERCON Services**	Designing a Green Chevy Camaro: The University of Tennessee EcoCAR 3 Hybrid Vehicle Design Team **Scott Curran - UTK Outreach Advisor**	PANEL: TDEC - TN Green Star Partnership **Vaughn Cassidy - Office of Sustainable Practices, John Zeanah - Memphis & Shelby County Office of Sustainability & Cody Buell - La-Z-Boy**
10:20 - 10:40	**Break with Exhbitors**			
10:45 - 11:20	Helping Communities Make Smart Choices through Energy Education and Technical Assistance **Luke Gebhard and Reid Conway** **TDEC Office of Energy Programs**	PANEL: Liability, Enforcement and Ethics **Karen Stevenson, Moderator - TDEC** **Chris Moran and Bill Miller -TDEC** **Scott Gordon - USEPA R4**	TVA Watts Bar Unit 2 Construction and Environmental Benefits **Gary Mauldin - TVA**	Sustainable Transportation Alternatives for Small and Medium Cities Case Study: Kingsport **Troy Ebbert - City of Kingsport**
11:25 - 12:00	GHG Regulatory Update **Margaret Campbell - Troutman Sanders**		PANEL: Watts Bar Unit 2 **John Myers, Moderator - TVA** **Jeanne Dion - NRC, Gary Mauldin - TVA** **Anthony Hogan - TDEC**	Promoting Sustainable Choices at Home, Work, and Public Realm **John Zeanah - Memphis and Shelby County Office of Sustainability**
12:05 - 1:15	**Lunch**			
1:20 - 2:45	On-Site Tour of Eastman **Fred Mullner - Eastman**		Panel/Workshop: Prescribing a Healthier Tennessee **Washington County Mayor Dan Eldridge, Moderator** **Commissioner John Dreyzehner - TDH, Lori Munkeboe - TDEC** **Angela Hagaman - ETSU & Tommy Farmer - TBI**	
2:45	**Adjourn/Door Prizes (Must Be Present to Win)** ***Special Door Prize for Afternoon Sessions attendees - 39 inch Vizio Smart TV (Must Be Present to Win)**			

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | www.eei.org
202.508.5555 | Fax: 202.508.5786 | tkuhn@eei.org

Power by Association℠

Edison Electric Institute

Thomas R. Kuhn
President

December 1, 2014

The Honorable Gina McCarthy
Administrator
U.S. Environmental Protection Agency
Washington, D.C. 20460

Dear Administrator McCarthy:

The Edison Electric Institute (EEI) appreciates the opportunity to submit comments on the proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* issued by the Environmental Protection Agency (Agency) in Docket No. EPA-HQ-OAR-2013-0602. 79 *Fed. Reg.* 34,830 (June 18, 2014). These comments also address the subsequently issued *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Data Availability*, 79 *Fed. Reg.* 64,534 (Oct. 30, 2014).

EEI is the association that represents all U.S. investor-owned electric utilities, international affiliates and industry associates worldwide. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. As generators of electricity and the operators of the nation's electric transmission and distribution system, EEI's member companies have a critical interest in the proposed guidelines for states to regulate greenhouse gas emissions from existing fossil-based electric generating units.

EEI's member companies are committed to providing safe, reliable, affordable and increasingly clean electricity to all customers. The power sector continues to transition to cleaner forms of generation. The proposed guidelines would require dramatic changes to the ways in which electricity is produced, transmitted and consumed, accelerating this transition and giving rise to concerns about the continued provision of affordable, reliable electricity to consumers. EEI's comments identify issues and concerns with the proposed guidelines and, where possible, provide suggestions to help ensure that the final emission rate goals can be achieved without compromising the reliability and affordability of electricity. EEI looks forward to continuing our dialog with the Agency on this complex and significant rulemaking.

Sincerely,

Thomas R. Kuhn

cc: Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation
Joseph Goffman, Senior Counsel

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COMMENTS OF THE EDISON ELECTRIC INSTITUTE ON CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS

Docket No. EPA-HQ-OAR-2013-0602

December 1, 2014

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COMMENTS OF THE EDISON ELECTRIC INSTITUTE ON CARBON POLLUTION EMISSION GUIDELINES FOR EXISTING STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS

Docket No. EPA-HQ-OAR-2013-0602

December 1, 2014

The Edison Electric Institute (EEI) submits these comments on the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units issued by the Environmental Protection Agency (EPA or Agency) in Docket No. EPA-HQ-OAR-2013-0602. 79 *Fed. Reg.* 34,830 (June 18, 2014).[1] EPA subsequently issued a Notice of Data Availability that provided additional information and solicited comments on several topics raised by the proposed guidelines. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Notice of Data Availability*, 79 *Fed. Reg.* 64,534 (Oct. 30, 2014) (NODA).[2]

In these proposed emission guidelines, issued under Clean Air Act (CAA or Act) section 111(d), EPA proposes state-specific emission rate goals aimed at reducing the average carbon dioxide (CO_2) emission rate of each state's fleet of existing affected fossil-based electric generating units (EGUs). After the guidelines are final, states will be required to submit compliance plans for EPA approval that demonstrate how they will achieve these goals.

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[1] EPA subsequently extended the comment deadline to December 1, 2014. *See Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 *Fed. Reg.* 57,492 (Sept. 25, 2014).

[2] In the same docket as the proposed guidelines, EPA also issued *Carbon Pollution Emission Guidelines for Existing Stationary Sources; EGUs in Indian Country and U.S. Territories; Multi-Jurisdictional Partnerships*, 79 *Fed. Reg.* 65,482 (Nov. 4, 2014) (Supplemental Proposal). Where appropriate, issues raised in this Supplemental Proposal are addressed in these comments.

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EEI is the association that represents all U.S. investor-owned electric companies, international affiliates and industry associates worldwide. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than $90 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable and sustainable electricity powers the economy and enhances the lives of all Americans. As generators of electricity and the operators of the nation's electric transmission and distribution (T&D) system, EEI member companies have a critical interest in the proposed state guidelines for existing EGUs. As discussed in these comments, the proposed guidelines envision dramatic changes to the ways in which electricity is produced, transmitted and consumed.

I. Introduction And Executive Summary.

EPA's proposed section 111(d) guidelines for existing steam EGUs and combustion turbines (CTs) set state-specific CO_2 emission rate goals that must be achieved by 2030, with an interim rate goal that must be achieved over the period 2020-2029. *See* 79 *Fed. Reg.* at 34,836-37. As required by the CAA, any proposed goals must reflect the emission rates that are achievable through the use of the "best system of emission reduction" (BSER) that has been "adequately demonstrated." *See* CAA section 111(a)(1).

EPA's proposed BSER is the combination of four "Building Blocks." These Building Blocks, which form the basis of the proposed state-specific interim and final emission rate goals, quantify reductions from affected fossil-based units, as well as emission reductions that EPA believes could be achieved through heat rate improvements at existing coal-based units; increased dispatch of existing natural gas combined cycle (NGCC) units; use of existing and

increased deployment of new renewable energy (RE) generating technologies; currently under construction nuclear units and the preservation of some existing nuclear units; and decreases in overall electricity usage and demand as a result of expanded end-use efficiency (EE) programs. *See* 79 *Fed. Reg.* at 34,836. EPA asserts that it is reasonable to base state goals on reductions beyond those that could be achieved at affected units because of the interconnected nature of the power system. *See id.* at 34,880.

EPA's novel "systems" approach to BSER in the proposed guidelines raises legal questions about EPA's authority to base standards for existing units on reductions that can be achieved only by units not regulated under the CAA or through changes in the end-use of a product. Because EGUs cannot, on their own, achieve the level of reductions necessary to comply, the proposed guidelines effectively require states, utilities owning EGUs and, in many cases, consumers and organizations that are totally unrelated to an existing EGU to undertake new programs and measures to meet the emission rate goals. Never before have the BSER provisions of the CAA been applied to authorize EPA to regulate states and markets in this way. These legal issues, which are discussed in more detail in section IV, below, eventually will be addressed by the inevitable litigation of the proposed 111(d) guidelines.

EEI member companies are committed to providing safe, affordable, reliable and increasingly clean electricity to customers. Should EPA's final guidelines survive judicial review, they *must* establish achievable state emission performance goals, provide realistic timeframes to make the system changes necessary to achieve such goals and create a workable framework for state and utility compliance while ensuring the continued provision of reliable electric service to all

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customers during all weather conditions. Importantly, the final guidelines also must provide states the flexibility to choose the most cost-effective reductions and to minimize costs for electricity consumers. States and electric utilities must be able to mitigate the potential impact on costs to customers and ensure the overall reliability of the power system. For these reasons, EEI submits these comments addressing EPA's proposed guidelines *as they have been proposed*. The purpose of these comments is to identify issues and concerns with the proposed guidelines and, where possible, to provide proposed solutions to ensure that the emission rate goals can be achieved without compromising the reliability and affordability of electricity. EEI's comments should not be construed as an endorsement of the proposed guidelines and, specifically, EPA's approach to BSER. By design, the proposed guidelines are state-specific, and as a result, individual entities will each address their own specific concerns and approaches to the proposed guidelines.

A. Executive Summary

The member companies of the Edison Electric Institute (EEI) are committed to providing reliable, affordable and increasingly clean electricity that powers the U.S. economy and benefits the lives of customers. As of the end of 2013, the power sector has reduced carbon dioxide (CO_2) emissions 15 percent below 2005 levels. While the power sector continues this transition to cleaner forms of generation, the guidelines that the Environmental Protection Agency (EPA or Agency) has proposed under Clean Air Act (CAA or Act) section 111(d) for states to regulate CO_2 emissions from existing steam electric generators and combustion turbines (collectively, EGUs) would require dramatic and accelerated changes to the ways in which electricity is produced, transmitted and consumed. Accelerating these changes will be excessively costly to customers and threaten the reliability of electric service.

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If finalized as proposed, the emission guidelines, particularly the interim goals for 2020, would have a significant impact on customers and the nation in terms of cost and the overall reliability of our electric system. EPA's novel approach to regulation of CO_2 emissions from existing units under section 111(d) raises legal questions. Therefore, should EPA's final guidelines survive judicial review, they must establish achievable state emission rate goals and provide realistic timeframes in which to make the changes to the interconnected power system necessary to achieve these goals, consistent with the power sector's obligation and commitment to providing reliable and affordable electricity. To this end, EEI's comments offer suggestions to alleviate the many issues and concerns many EEI member companies have identified with the proposed guidelines. If adopted, these suggestions would help to mitigate concerns about the impact of the guidelines on member companies' ability to provide reliable and affordable electricity while reducing CO_2 emissions. However, EEI's comments should not be construed as an endorsement of the proposed guidelines, and, specifically, EPA's approach to BSER.

EPA's proposed guidelines for existing EGUs include state-specific emission rate goals. Upon finalization of the guidelines, states will be required to develop plans for EPA approval that demonstrate how emissions from affected EGUs will be reduced to meet these goals. EPA asserts that these goals are achievable because they are based on the "best system of emission reduction" (BSER) that the Agency claims has been "adequately demonstrated," consistent with the requirements of CAA section 111(a)(1). EPA's proposed BSER is comprised of four Building Blocks that seek to reduce emissions not only directly from the regulated existing EGUs, but also indirectly from actions at other sources throughout the interconnected power system that have effects on affected sources.

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Because EPA's proposed BSER goes beyond the scope and control of regulated EGUs to require reductions throughout the "electric system" and even beyond the outlet to consumers, a significant portion of EEI's comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system. Maintaining reliability requires more than ensuring adequate reserve margins. In fact, it requires that myriad system needs be met on a second-to-second basis, which requires significant planning and lead time. EPA incorrectly assumes that the accelerated transition envisioned in the proposed guidelines for the existing generating fleet either does not have reliability implications or can be achieved within the time frames EPA has established for interim goals. This is not the case.

According to the North American Electric Reliability Corporation (NERC), the entity charged with maintaining reliability of the power grid, implementing the proposed BSER Building Blocks will require significant changes in the way that the interconnected power system currently is planned and operated. Retiring base load fossil generating units, expanding the use of natural gas-based generating units, increasing the deployment of variable renewable resources, and incorporating increased end-use efficiency and demand response all will have an impact on the grid and the pipeline and other infrastructures the grid depends on. Managing these impacts requires significant time and planning that EPA has not allowed for in the proposed guidelines' compliance schedule.

For each state, EPA proposes both an interim and final emission rate goal. The interim goal is measured via a 10-year averaging period that starts in 2020, which EPA specifically says

"increases state flexibility to choose among alternative potential plan measures." In order to satisfy the 10-year average goal, many states must achieve more than 50 percent of their 2030 emission reduction goals by 2020; and 11 states—including Arizona, Arkansas, Florida and Minnesota—must achieve more than 75 percent of their 2030 goals by 2020. **This effectively turns the 2030 goal into a 2020 goal for these states**. Thus, contrary to EPA's stated intent of providing states flexibility to achieve the 2030 emission goals, the interim compliance average goal creates more compliance challenges than it solves.

Eliminating the interim compliance goal and allowing states to determine their own reduction glide paths and milestones to achieve the 2030, or the early action alternative 2025 goals, as part of their compliance plans would provide states with real flexibility to preserve reliability and minimize costs to electricity customers. States and utilities lack sufficient time between now and 2020 to develop plans, design and complete the infrastructure required to accomplish changes in dispatch between coal-based and natural gas-based units and increase deployment of renewable generation or other zero-emitting resources. Eliminating the proposed interim compliance goal would allow states to determine the most cost-effective actions and measures to pursue to achieve the 2030 goals, and to choose a reasonable schedule for implementing those measures consistent with providing safe, reliable, affordable and environmentally responsible power to customers. Similarly, states should have the option to achieve emission reductions earlier by developing plans to implement EPA's proposed early action 2025 alternative goals.

Numerous arguments support the elimination of the interim compliance period. **EPA's proposed compliance timeline does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020**, by which time many states would need to have accomplished significant emission reductions. EPA has not demonstrated that every state can increase utilization of existing natural gas combined cycle (NGCC) units to 70 percent by 2020, as EPA incorrectly assumes that current natural gas infrastructure is sufficient to support this dramatic increase and EPA does not account for the fact that many natural gas units must back up renewable generation. Further, increasing generation from existing NGCC units also may require electric transmission upgrades and expansions. As NERC recently has noted, these projects can take 10-15 years to plan, design, permit and construct.

The interim compliance goals also are inconsistent with state planning processes, market schedules and utility investment decision-making, which generally have much longer planning cycles and asset lives. Further, the proposed interim compliance period does not allow sufficient time for regional transmission organizations (RTOs) and independent system operators (ISOs) to evaluate and potentially alter market rules to accommodate changes in dispatch.

As envisioned in the proposed guidelines, the changes in how demand is met—through increased dispatch of existing NGCC units, increased deployment of renewable generation, the use of existing renewable generation, and increased end-use efficiency—could have implications for the wholesale electricity markets operated by RTOs and ISOs. Because each market has its own set of rules, it is not immediately clear how the RTOs and ISOs will respond to such state plans. RTOs and ISOs will have very little, if any, time to make market changes before 2020.

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Eliminating the interim compliance goals would not eliminate the need for states to submit and implement plans to reduce emissions on a reasonable glide path to the 2030 or 2025 goals. EPA's proposed guidelines already would require that states submit—and that EPA approve—plans that clearly set forth how states would achieve the final goal. Thus, it would be incorrect to assume that the elimination of the interim goals would not result in emission reductions in the 2020-2029 timeframe. States would demonstrate progress toward the final goal consistent with their projected emission reduction glide path, which would include significant milestones through the annual reporting of emission performance to EPA, taking corrective measures if needed. Ultimately, if states could not show reasonable progress toward the final goal, EPA would have the authority to call for a state to correct its plan or issue a federal plan of its own. Taken as a whole, the state plan process set forth in the proposed guidelines, and the requirements of the CAA itself, would ensure that significant, verifiable emission reductions would occur before 2030.

There are a range of options for states to consider when defining approvable emission reduction glide paths. Some of these options include: existing trading programs such as the Regional Greenhouse Gas Initiative (RGGI) and California's A.B. 32 program; a "safe harbor" from compliance with the interim targets for states that choose to require in-state resources to include a carbon adder pre-determined by EPA when bidding resources into the market; and planned, enforceable coal plant retirements.

To promote maximum state flexibility in the design of approvable compliance plans and to enable states to take into account changed circumstances, **the final guidelines should clarify**

that states can modify plans, subject to EPA approval, to address changing circumstances, thereby giving states the flexibility to incorporate changing and improved technologies that benefit all customers.

In addition to pace and timing, another significant compliance challenge is that **the proposed guidelines fail to recognize the critical role of nuclear and hydropower in reducing CO_2 emissions, and do not incent their continued operation and development**. All zero-emissions generation sources (e.g., nuclear, wind, solar, and hydropower) have climate benefits.
The nation cannot achieve its carbon-reduction goals without the existing nuclear fleet—without the nuclear fleet, carbon emissions will be higher, as will the cost of electricity, natural gas and carbon allowances under a carbon-control regime. Nuclear plants also are critical to the reliability of the electric grid. Yet, the proposed guidelines create no real incentive to maintain existing nuclear power plants. Although EPA notes that some existing nuclear facilities are at risk of premature retirement, the proposed guidelines greatly underestimate the quantity of nuclear generation that is actually at risk in some states, while overstating the amount at risk in other states. If EPA is going to continue with its broad interpretation of BSER, **the Agency should remove the six percent "at risk" factor from the goal calculation**. Instead, EPA should consider alternative approaches for incenting the continued operation of existing nuclear generation capacity.

For nuclear units that are under construction, EPA should include in an expanded definition of "new" nuclear in the final guidelines:

- New nuclear power plants (those currently under construction or others that might be built between now and 2030 and beyond);

- Power uprates at existing nuclear plants, including those undertaken during or after 2012 or a modified baseline period; and

- Nuclear plants relicensed to operate past their initial license terms (i.e., beyond 40 years) that have not received their license renewal from the Nuclear Regulatory Commission (NRC) before the baseline year or period, and nuclear plants relicensed to operate beyond 60 years (subsequent license renewal).

The proposed guidelines also fail to recognize the value of new and imported hydropower—particularly hydropower imported from Canada—in providing affordable, zero-emissions power in certain regions of the country. The final guidelines also should allow states to include generation from "new" hydropower generating capacity in a state's compliance plans, and should define "new" hydropower broadly to include:

- New hydropower plants that become operational after 2012;

- Power uprates at existing hydropower plants, including those undertaken during or after 2012 or a modified baseline period; and

- Any hydropower facilities relicensed during or after the baseline year or period.

In addition, EPA also should not penalize states that are lowering their carbon emissions by building new nuclear and NGCC units. The output from under-construction nuclear and NGCC units should not be included in the calculation of state emissions rate goals. At minimum, if EPA determines to consider under construction NGCC units when finalizing the state goals, EPA should not assume the same re-dispatch potential of 55 percent for all under construction units.

As a general matter, the design of the proposed guidelines penalizes states and companies that took action before 2012 to reduce emissions by giving these states more stringent goals. **The**

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proposed guidelines would penalize leadership in emission reductions, renewable energy and other clean energy programs. In particular, the proposed guidelines would: (1) impose more stringent goals on states that, prior to 2012, retired coal units and replaced them with NGCC units; (2) require greater reductions from states that use NGCCs to balance high levels of renewable generation; and (3) ignore the significant contribution of existing state renewable and energy efficiency programs toward the nation's progress in reducing greenhouse gas emissions. Ironically, the proposed guidelines would impose greater burdens on states that have already implemented the very programs that EPA would like to encourage.

As a policy matter, EPA should allow states to recognize all reductions that occur after 2012, the baseline year selected by the Agency for calculating the state emission rate goals and use these reductions to meet the final goals. Specifically, **the final guidelines should allow states to bank, and then use for compliance, emission reductions that result from new state requirements, measures and programs instituted after 2012 and prior to 2020**.

The final guidelines also should **affirm that states can include in compliance plans emission reductions without reference to whether these reductions were achieved by measures that were "on the books" at the time the guidelines were proposed**. For purposes of the CAA, the relevant question in assessing any reductions that are achieved after 2012 is not *why* reductions were achieved, but *whether* they were achieved.

EEI members companies have identified a range of technical concerns with each of the four Building Blocks that comprise EPA's proposed BSER. **EPA overestimated the potential CO_2**

emission reductions that could result from each of these Building Blocks. In addition to specific issues with EPA's analysis of potential reductions from each Building Block, any assertion of the achievability of the proposed state goals is undermined by the fact that **EPA ignored the interactions between and among the Building Blocks and state-specific constraints when assessing the reduction potential of each Building Block, and, consequently, proposed state emission rate goals may not be achievable**.

For example, the addition of large amounts of variable wind and solar resources under Building Block 3 likely will require increased use of natural gas-based units to provide back-up and ramping services. Units cannot run continuously at high utilization rates and also simultaneously be available to support renewable generation, which requires frequent increases and decreases in generation in response to variable renewable output. If natural gas-based units cannot run at consistently high utilization rates, they may not be able to be used to displace as much coal generation as EPA estimates is possible under Building Block 2.

Similarly, increased utilization of existing NGCC units is intended to reduce the utilization of existing coal-based units, many of which will cycle more often as a result. Because coal-based units have lower emission rates when they run consistently at high capacity factors, increased cycling undermines efforts to improve their heat rates under Building Block 1. EPA's Building Block analysis considered none of these impacts. As a result, the proposed state goals do not realistically reflect electric system operations, as EPA asserted.

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Further, EPA's analysis ignored state-specific constraints when calculating the emission rate goals. These state-specific constraints range from challenges related to hot summers in some states, use of inaccurate data, failure to consider existing state programs and insufficient recognition of infrastructure and reliability concerns. To the extent that these issues are identified by states and companies in their comments, **EPA should work with the states to set achievable state goals that reflect in-state conditions, using accurate data. EPA should address these state-specific concerns about the proposed emission rate goals before finalizing these goals.**

Specific concerns with EPA's approach to calculating the reductions potential of each Building Block are discussed in detail in EEI's comments. Some key concerns include:

- EPA's assumption that fleet-wide, existing coal-based units can improve heat rates by four percent through O&M "best practices" is not supported by the Agency's assessment of recent heat rate data and, therefore, is not reasonable.
- EPA has not provided a reasonable basis for concluding that "equipment upgrades" can improve heat rates by two percent.
- EPA overestimated the value of fuel costs savings to an affected EGU.
- EPA's analysis does not support the achievability of increasing NGCC utilization to 70 percent in all states for a sustained period of time.
- EPA drew unsupported conclusions about the achievability of re-dispatch based on limited data regarding historical NGCC operations; relied on inaccurate or inappropriate data; and did not take into account the difference between nameplate capacity factor and demonstrated capacity factor.
- EPA ignored physical, technical and financial constraints in both the natural gas and electric systems in determining the possible levels of re-dispatch to NGCCs by 2020.
- EPA has not considered constraints related to the gas and electric systems' interdependency (especially the fact that many gas pipelines can supply electric generation only for peak summer periods because they must serve heating needs in

winter), and has not demonstrated that the current natural gas pipeline infrastructure can support increased NGCC utilization.

- EPA's reliance on state renewable energy standards (RES) in setting state goals overestimated achievable RE deployment in some states.

- EPA's RES assessment failed to account for the fact that state RES requirements allow the use of existing hydropower, biomass and other sources of renewable generation that EPA does not permit states to use for 111(d) compliance; include multipliers for some types of generation; and allow for alternative compliance payments.

- EPA's use of RE growth rates based on the historic performance of a limited group of states is not reasonable.

- EPA has not provided a reasonable basis for assumptions underlying future estimates of the costs of renewable energy technologies.

- EPA has not assessed the technical challenges associated with increased penetration of renewable generation sufficiently.

- EPA has not demonstrated that the projected EE savings rate or related expenditures are achievable by all states; the experience of three states in 2012 does not demonstrate that this savings rate can be achieved and sustained by all states over the compliance period.

- EPA ignored the role of supportive state regulatory frameworks in increasing state EE savings rates.

In addition to the issues related to how EPA assessed the reductions achievable through the Building Blocks and subsequently calculated the proposed state goals, EEI's comments address a range of compliance issues and concerns.

States need clarity on a range of other issues before beginning work on compliance plans. As a preliminary matter, **states need guidance as to how to account for the interstate impacts of renewable energy and end-use efficiency, so that they can develop plans that do not risk disapproval because they rely on reductions that have been double counted**. EPA proposes to allow states to use renewable energy generated in other states for compliance. While this

approach appropriately recognizes existing interstate markets for renewable energy credits, it places significant compliance burdens on states that are the source of renewable generation but were not, in the past, large consumers of this generation.

Multi-state planning would mitigate some double counting concerns. It also would mitigate some concerns about inefficient dispatch and siting that would arise from a patchwork of state plans, particularly when similar units in different states participate in the same power market, but face substantially different CO_2 costs. However, states may not be able to design multi-state plans in the limited amount of time between when the guidelines are finalized and compliance plans are due. **EPA should facilitate, incentivize and provide sufficient time for states to develop multi-state plans to mitigate possible double counting concerns.**

EPA proposes that a state only be allowed to include in its plan those CO_2 emission reductions that occur in the state as a result of demand-side energy efficiency programs and measures implemented in that state. Not only is this physically impossible, but it is conceptually at odds with EPA's general approach to EE measures. **EPA should allow states to include the full estimated benefits of in-state EE programs in state plans, regardless of whether a state imports or exports electricity.** Further, forcing states to discount EE reductions because of electricity imports may discourage states from using EE as a compliance tool, and EPA should not create disincentives that might prevent states from incorporating these measures in compliance plans.

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EPA appropriately recognizes that states have the authority to include non-BSER measures in compliance plans. **The final guidelines should affirm the ability of states to include a wide range of non-BSER measures—both those identified by EPA in the guidelines and those not specifically included—in an approvable state compliance plan**. In particular, the final guidelines should affirm that states can include transmission and distribution efficiency improvements in compliance plans. These technologies can help increase reliability, resiliency and efficiency, all of which ultimately contribute to reducing CO_2 emissions.

To help states and electric utilities design compliance plans, EPA should provide greater clarity on a range of compliance issues. For example, EPA should take steps to ensure that New Source Review (NSR) concerns do not create disincentives or impede efforts to improve heat rates at existing coal-based units by clarifying that these actions do not trigger NSR. EPA should also provide clarity regarding accounting for emissions from biomass before states are required to submit compliance plans. Furthermore, states should be able to use new NGCCs to reduce total emissions, support integration of new renewable generation and meet future increases in demand. A state plan that relies on new NGCC units to achieve its emission rate goal should recognize the emissions from these units to avoid unintended environmental outcomes. Additionally, states with goals of less than 1,000 lb/MWh should be allowed to build new NGCCs to support integration of variable renewable resources or to serve load while preserving state discretion as to whether to include these new units in a state's compliance plan.

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Other compliance issues that **EPA should provide clarity on in the final guidelines include broadly defining the types of "corrective measures" that states could include in compliance plans** to include methane reductions from natural gas distribution systems**.**

EPA also should affirm the importance of electrification in reducing CO_2 emissions from other sectors, and make clear that states will not be penalized under section 111(d) as a result of these efforts.

The final guidelines should facilitate the use of end-use efficiency measures for compliance by recognizing existing state evaluation, measurement and verification (EM&V) protocols for EE measures, allowing the use of gross energy savings, and allowing states to include new EE measures (such as codes and standards) in their compliance plans. Guidance on how states can incorporate distributed generation in compliance plans also needs to be provided. In addition, the guidelines should offer greater clarity regarding how obligations placed on EGU owners, electric utilities and others contained in state plans will be enforced.

The majority of EEI's comments address the guidelines as they have been proposed by EPA, with the goal of creating a compliance framework that allows states and electric utilities to achieve emission reductions while also providing affordable and reliable electricity. The proposed guidelines, however, are predicated on an unprecedented and expansive approach to BSER that encompasses the potential to reduce emissions as a result of action at both affected EGUs and throughout the entire interconnected power system. The implications of this approach

for the power sector, the states and all other source categories regulated under section 111(d) are significant, and EPA's approach raises many legal issues and concerns.

B. The Final State Emission Rate Goals and Compliance Periods Must Consider and Accommodate the Operational Reliability Requirements of the Interconnected Power System.

As EPA notes, states and electric utilities are in the process of transitioning the generating fleet and the transmission system so that it is cleaner and more resilient. Achieving the interim and 2030 goals would accelerate this transition dramatically and require significant changes to the interconnected power system and the way that it operates. However, the proposed state goals and compliance period do not account for the complexity of power grid operations adequately, nor sufficiently address how the need to maintain reliability affects the pace and timing of implementing such changes.

The need to maintain operational reliability while undertaking significant changes to the way in which power is generated, transmitted and consumed has important implications for EPA's BSER determination, the computation of the state-specific emission rate goals and the achievement of the proposed interim average goals. It is essential that these changes be implemented in a way that maintains reliability for electricity customers.

While EPA does not have the expertise to assess fully the implications of the proposed guidelines on the interconnected power system, that does not mean that the Agency can ignore the complexity of the electric system when developing state-specific emission rate goals and compliance timelines. Rather, EPA should take into account information from experts in reliable system operations to develop achievable final goals and a workable compliance period that does

not jeopardize reliable electric service. However, all of the reliability studies and information needed to assess the significant changes that will be required to achieve the interim and 2030 goals will not be available before EPA finalizes the proposed guidelines or even before states are required to submit compliance plans for EPA approval. States, electric utilities, system operators and other regulators will need sufficient time to assess the changes that will be required to implement the state plans and will need the time required to make the system changes and develop the infrastructure needed to implement the state plans and maintain reliability. Going forward, EPA must be willing to allow states to address these changes by proposing revised compliance plans as necessary to meet the 2030 goals.

1. There are many elements to ensuring the reliable operation of the interconnected power system; resource adequacy is only one of them.

In the preamble, EPA undertakes an analysis of the electric system that fails to accurately and completely depict the complexity of operating the interconnected electric system. This is exemplified by EPA's repeated inaccurate assertion in the preamble and supporting Legal Memorandum, that electricity is "fungible." *See, e.g.*, 79 *Fed. Reg.* at 34,880; Legal Memorandum at 44-45. In meeting customer demand, electrons and generation units are *not* fungible. While an end-use customer may be indifferent as to the source of the electrons consumed, the bulk power system is not.

When the North American Electric Reliability Corporation (NERC)—the entity charged by the Federal Energy Regulatory Commission (FERC) with ensuring, evaluating and improving the reliability of the bulk power system under the Federal Power Act (FPA)—prepares its required annual long-term reliability analysis, it looks at a range of "key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development and changes in the

overall system characteristics and operating behavior." *See* NERC, *2013 Long-Term Reliability Assessment*, at 1 (Dec. 2013) (2013 LTRA).[3] EPA's limited analysis focused primarily upon resource adequacy as measured by generation reserve margins and assumed that the state plan development process provides adequate opportunity to address other reliability issues. *See* Resource Adequacy and Reliability Analysis Technical Support Document (Resource Adequacy TSD). This clearly is not the case.

In order to understand how the proposed guidelines will change power system operations, it is important to first understand how the electric system operates. Specifically, it is critical to understand how reliable operation of the bulk power system is achieved and maintained both under normal and abnormal conditions. Because of the complexity of the interconnected power system, reliability is something that must be planned for, coordinated and constantly assessed and monitored.

a. Resource adequacy is just one of many dimensions that must be managed to ensure the reliability of the electric system.

At its most basic level, reliability is maintained when the demand for, and supply of, electricity are precisely matched (often referred to as "balancing"). As FERC staff explains:

> [O]perators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

[3] The 2013 LTRA is available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

See FERC, Office of Enforcement, *Energy Primer: An Overview of Energy Market Basics*, at 37 (July 2012) (FERC Primer).[4]

Providing reliable power is the electric industry's top priority mission, and getting electricity from generators to customers requires more than ensuring there is an adequate supply of power to meet demand. Because electricity, by its nature, moves only via the flow of current, the interconnected power system, which has been described as the largest and most complex machine in the world,[5] is in a constant state of flux. The industry maintains the grid's physical and cyber security, reliability and robustness on a continual, minute-by-minute basis. For many years, the electric sector developed and operated under voluntary programs to assure reliability.[6] Since the enactment of FPA section 205, the electric industry has transitioned successfully to a comprehensive set of mandatory, enforceable reliability standards for the bulk power system. Companies now may be assessed penalties of up to $1 million per day per violation under this system.

Consistent with the mandatory, enforceable reliability standards which ensure that power can be delivered to customers reliably, other system requirements—beyond ensuring that there is sufficient electricity to meet demand—must be respected and addressed. These system

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[4] The FERC Primer is available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

[5] *See* Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World (Joseph Henry Press 2006).

[6] Federal Power Commission, *Report to the President by the Federal Power Commission on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965* (Dec. 6, 1965), http://blackout.gmu.edu/archive/pdf/fpc_65.pdf.

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requirements cannot be afterthoughts. The interconnected system must be designed to accommodate these requirements.

First, load and generation resources—which can include both generation and demand-side resources—must be balanced continuously. This constant balancing includes not only having the megaWatts (MW) of energy that are needed to meet peak demand, but also the mix of generation types needed to maintain system reliability as not all resources provide the same services to the electric grid. Having an adequate amount of total resources (resource adequacy) "does not necessarily equate to having the right type of resources with the right functional capabilities to maintain reliability." NERC, *Essential Reliability Services Task Force, A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability*, at 13 (Oct. 2014) (ERS Report).[7]

In addition to those resources needed to serve actual customer demand, adequate **operating reserves** must be available throughout the system to connect instantaneously or on very short notice in the event a generator goes down or other system disruptions occur. There also must be adequate **ramping capability**—the ability to increase or decrease generation over a period of time in response to major changes in demand—to follow variable generation resources or in emergencies. Ramping capabilities and reserve requirements are heavily intertwined with the dispatch control of the power system. These requirements ensure that sudden changes in load and the variability of power supply can be met.

[7] The ERS Report is available at: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

In addition to maintaining grid stability, resources must be able to **maintain frequency control** within tight tolerances to maintain the target 60 Hz frequency. Frequency is an indication of the real-time balancing between supply and demand. Large nuclear and fossil synchronous generating units with rotating mass traditionally have provided **inertia** (stored rotating energy), which is an important reliability characteristic supporting frequency control by arresting frequency decline if there is an unexpected loss of a generating unit, giving system operators time to restore frequency to the target operating level. *See* ERS Report at 8-9.

Voltage control is needed to maintain voltages in a secure, stable range throughout the system and to maintain this support in the event of voltage disturbance. Voltage is the force needed to move electrons in the transmission system, and its constant changes over time must be managed. Voltage support is a very local service and cannot be transmitted far from the source that provides it. This requires complex considerations to assure **reactive power/power factor control and stability**. Reactive power requirements can change rapidly. *See* ERS Report at 9-10.

Balancing demand and supply not only must ensure consistency with all of these system constraints, but also must ensure that the amounts of electricity placed on the transmission and distribution system do not overload those systems. There are **thermal (heating) limits** that must be respected; otherwise transmission and distribution lines may be overloaded and damaged. Heat conduction (how heat is dispersed through equipment) also is affected by temperature, wind and other factors. In extreme circumstances, an imbalance could require generation resources to disconnect from the system.

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"[T]ransmission flows must be monitored to ensure that they stay within voltage and reliability limits." *See* FERC Primer at 58. This means that the location of particular generators, relative to other generators and available transmission capacity, is an important factor in determining which units can be dispatched because location affects transmission flows and voltage limits. To support the moment-by-moment balancing of electricity demand and supply, FERC regulations require the provision of adequate transmission service.[8] Public utilities have tariffs on file pursuant to these regulations. FERC audits these transmission service tariffs and has imposed penalties for deviations from tariff requirements.

Adequate transmission and generation infrastructure, as well as other essential services, are critical for the reliable operation of the integrated grid. System operators do not have complete flexibility in the procurement of these services, many of which are often referred to as "**ancillary services**," as they often need to be provided by units in specific locations due to the physics of electricity. Reactive power, for example, does not "travel" over distances and is,

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[8] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities: Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 *Fed. Reg.* 21,540 (May 10, 1996), FERC Stats. & Regs. & 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 *Fed. Reg.* 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (Order No. 888); *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 *Fed. Reg.* 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890-A, 73 *Fed. Reg.* 2,984 (Jan. 16, 2008), FERC Stats. & Regs, ¶ 31,261 (2007), *order on reh'g,* Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009) (Order No. 890); *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd*, *So. Carolina Pub. Serv. Auth. v. FERC*, No. 12-1232 (D.C. Cir. Aug. 15, 2014) (Order No. 1000).

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therefore, a "local" requirement that can be provided only by a few resources when needed. *See* ERS Report at 11. FERC recognizes the following as ancillary services: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; generation and energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service. *See* Order Nos. 888, 890. Under FPA sections 205 and 206, all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce are required to take transmission service, including these ancillary services, for wholesale sales and purchases of electric energy under open access tariffs.[9] Ancillary services, in addition to capacity and energy, are necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services are so essential that FERC also requires that transmission service providers—absent third-party service—provide them to ensure the reliable delivery of electricity.

It is important to note that all generating resources do not provide the same services to the electric grid and that all electrons may not be able to serve all customers due to electric transmission or other constraints. Different sources are needed to ensure that electrons actually reach end-users. While all generating units produce electricity, some types of units only supply energy, others supply critical grid services (balancing, back-up and ancillary services like voltage

[9] Black start service, an additional ancillary service, is a voluntary service that can be provided by some, but not all, generation resources. These generating units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore power flows in the grid. *See* FERC Primer at 37.

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and frequency control) that are needed to ensure the stability of the transmission system and other types provide capacity to ensure resource adequacy and reliability. Renewable generation units can provide electrons, but are limited in their ability to provide grid or peak period capacity services. Retirement of base load coal-based units diminishes the pool of resources that are able to provide these other services to the grid and places increased responsibility on natural gas-based resources to serve as base load units, back up renewable resources, provide ramping capability and provide ancillary services to the grid.

Given the system requirements that must be met in order to maintain reliability, even the seemingly simple decision to close a single fossil base load unit and replace it with a renewable generator requires consideration of, at least, the availability of sufficient generation to meet demand, the need for ramping and back-up power, the availability of natural gas supplies and the infrastructure to deliver it, the impact on the transmission system and the need to maintain inertia, frequency and voltage control. Choosing to increase the generation at an existing unit that already is interconnected to the transmission system requires consideration of similar issues. Managing these considerations requires a significant amount of rigorous and time-intensive study and coordination.[10]

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[10] Any addition or change to the transmission system has to go through the interconnection study and analysis process. This is true whether the change is to the capacity of an existing generator or a new generator is proposed. The purpose of these studies is to assess the impact of a new generating unit (or increase in generation from an existing unit) on the existing transmission system. The required studies consist of thermal analyses, stability studies and assessments of possible faults in the system that could result in cascading failure of the transmission system. No generator can be attached to the transmission network unless and until these studies show that the system can withstand the injection of energy at that particular point.

However, these studies only determine whether the system will be harmed by adding the generator or increasing capacity. An additional study, generally referred to as a "simultaneous

b. There are many entities charged with managing the various elements critical to maintaining the reliability of the electric system.

There are many entities charged with ensuring that all system requirements are met, such that reliable electricity is provided to customers. FERC is the federal authority ultimately responsible for maintaining the reliability of the interstate electric transmission grid under the FPA. NERC is the entity charged by FERC with developing reliability standards, overseeing and evaluating system reliability. But, in general and at the practical level, it is the system operator's responsibility to ensure that the system operates reliably. The system operator in bilateral markets is the electric utility. In areas in which electric utilities have joined regional transmission organizations (RTOs) or independent system operators (ISOs), the RTO or ISO has functional responsibilities for system operations.

The electric grid in the continental U.S. is electrically synchronized in three interconnections—Eastern, Western and the Electric Reliability Council of Texas (ERCOT). The Eastern Interconnection is comprised of numerous actors, including: federal power marketing agencies (PMAs); the Tennessee Valley Authority (TVA); public power utilities; transmission-only utilities; and vertically-integrated investor-owned utilities. Many of these entities are members of one or more of five separate RTOs/ISOs.[11] The Western Interconnection is comprised of: federal PMAs; public power entities; and vertically-integrated utilities, including utilities that are members of the California ISO. ERCOT is comprised of investor-owned and public power

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feasibility study," must be done to determine whether the electricity actually can be moved from the point of production to other points on the transmission system. The results of this study determine whether transmission upgrades or expansions are needed to accommodate the increased generation. MISO's Generator Interconnection Procedures, for example, describe these required studies in more detail. *See* MISO Tariff, Attachment X, section 2.1 (a).

[11] These are: ISO NE, PJM, MISO, SPP and NYISO.

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utilities that either own transmission and distribution facilities or provide deregulated generation and retail services.

Some of the principal functions of the system operator include provision of transmission service and transmission planning to ensure the continual reliability of the grid. *See* Order No. 2000. They also make dispatch decisions by taking into consideration least-cost generation, numerous reliability requirements and any existing transmission constraints to determine which EGUs run to meet demand or provide other grid reliability services (this process is known as "security-constrained economic dispatch"). Another key function of system operators is to manage congestion. In RTOs and ISOs this is addressed through competitive markets, including day ahead and real-time energy markets, capacity markets and other markets to address energy imbalances and provide other ancillary services. The market rules and structures are subject to FERC jurisdiction to ensure that they produce "just and reasonable rates," as required by FPA section 205(a).

In competitive markets, each RTO and ISO has created markets to replicate the revenue streams for energy, capacity and ancillary services provided in vertically integrated markets that have regulated rates of return. Generators in RTO/ISO markets rely on price signals from these markets to make investment decisions regarding which generating resources are needed and should be added to the system. Significant market changes impact these price signals—which could have reliability and resource adequacy implications if the price signals do not incent construction of needed new generation and infrastructure.

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2. The proposed state emission rate goals and compliance periods do not reflect the reliability implications of changing the interconnected power system by implementing the BSER Building Blocks.

In proposing the state emission rate goals and compliance periods, EPA did not assess the interconnected power system's reliability requirements. EPA also did not assess the effects each Building Block will have on the other Building Blocks or on the bulk power system when simultaneously undertaken at the levels EPA believes are achievable. Because the goals and compliance periods proposed do not reflect the reliability implications of the changes to the interconnected power system that will be required to implement the BSER Building Blocks, they do not fully depict the changes the system may have to implement, the costs that will be incurred or the time that these changes will take.

a. In setting the state-specific emission rate standards, EPA did not consider the impacts of the BSER Building Blocks on each other in the context of the integrated power system.

As a preliminary matter, EPA cannot assess the reduction potential of each Building Block individually and then add their total generation and emission reductions together to establish the state-specific emission rate goals. This ignores the fact that the actions and measures under each Building Block will impact each other when implemented simultaneously because they are not independent, but part of the integrated power system.[12]

For example, the addition of variable wind and solar resources likely will require increased use of natural gas units for back-up and ramping, which could be incompatible with EPA's proposed 70-percent utilization rate for existing NGCC units. These units cannot both run at high utilization rates and simultaneously be available to support variable renewable generation.

[12] These issues are discussed fully *infra*, section II, which addresses the assumptions and analysis that underpin EPA's proposed state-specific emission rate goals.

Further, increased utilization of existing NGCC units is intended to reduce the utilization and increase the cycling (turning on and off) of existing coal-based units, which will undermine efforts to improve the heat rates of existing coal-based units. These units are most efficient when they run consistently at high capacity factors. Therefore, reduced load and operations of coal-based units will erode any efficiency gains that might be made through heat rate improvements. The final goals should reflect such interactions and any limitations they place on achieving the levels of reductions the Agency projects could be achieved by any single Building Block.

b. Reliably implementing state compliance plans that incorporate the BSER Building Blocks will require changes in the way that the interconnected power system currently is designed and operated; these changes cannot be accomplished by 2020.

EPA assumes that the proposed guidelines provide sufficient time and flexibility for states to manage the accelerated transition of the existing generating fleet that the rules envision. *See, e.g.,* 79 *Fed. Reg.* at 34,904*; see also* Resource Adequacy TSD at 1. This assumption is predicated on the idea that implementing the proposed Building Blocks[13] will not require changes to the existing interconnected power system. As noted above, this is simply not true. A change to any part of the interconnected power system—even one that appears relatively minor, such as increasing the generation produced by an existing unit—requires an analysis of the potential impacts on the rest of the system. The multiple, larger changes proposed by EPA

[13] EPA notes that states are not limited to the four Building Blocks when designing compliance plans aimed at achieving the emission rate goals. As a practical matter, and as discussed in greater detail *infra*, section III, state plans largely will rely on the four Building Blocks because there are few other options to achieve the same magnitude of reductions in states' average emission rates. States may be able to vary the level of reductions from any particular Building Block to some degree, relative to the assumptions EPA made in setting the state goal rates, but few states will be able to forego completely any one of the Building Blocks and still demonstrate compliance with the 2030 emission rate goal.

certainly require such analysis under NERC's reliability standards.[14] In addition to new resources, changes in how the generation fleet is dispatched may cause significant changes in how power flows across the grid. To meet NERC standards, new transmission infrastructure may be required, which is not possible by 2020 because of the numerous transmission studies, planning and construction required to reliably integrate the changed system conditions.

NERC addressed the need for such studies and the potential for major system modifications in its 2013 Long-Term Reliability Assessment.[15] NERC assessed the system implications for the key reductions and measures that comprise EPA's BSER determination and likely compliance tools. The following discussion highlights some of the key NERC findings on the required system changes and analysis necessary to achieve CO_2 emission reductions, all of which will require changes to the interconnected power system that must be planned and managed closely to ensure continued reliability:

Fossil-Based Retirements and Coordination of Outages for Environmental Control Retrofits. The potential reliability implications of closing a coal-based unit are varied. Retiring a coal-based steam electric turbine reduces the ability to arrest and stabilize system frequency following a grid disturbance or the loss of a large generator. *See* 2013 LTRA at 31-32. Replacing the lost generation with renewable resources is possible, but these may not be able to offer inertia or frequency response. Wind could be used to replace some of these requirements, but must be specifically designed to do so. *See id.* Replacing the coal-based units with increased generation from an existing NGCC unit may be feasible, but this requires other assessments to

[14] The Southwest Power Pool (SPP) released a reliability assessment of the proposed guidelines, which concluded, among other things, that new generation and transmission expansion would be necessary to maintain reliability while achieving the proposed emission rate goals. *See* SPP, Reliability Assessment of the EPA's Proposed Clean Power Plan at 7 (Oct. 8, 2014), http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf. MISO also is analyzing the impact of the proposed guidelines will file comments in Docket No. EPA-HQ-OAR-2013-0602.

[15] NERC engaged in similar analyses and reached similar conclusions in the 2014 LTRA, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf.

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determine if the transmission system can accept this increased generation or if transmission or interconnection modifications first will need to be made. *See id.* at 36.

Increased Dependence on Natural Gas for Electric Power. NERC has noted that "[a] growing dependence on natural gas-based generation can increase [bulk power system] exposure to disruptions in fuel supply, transportation, and delivery." *Id.* at 35. Substantial investments in bulk power system and gas infrastructure may be needed to ensure that the requisite volume of gas can reach new and existing gas-based units. *See* NERC, *Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development*, at 53 (July 2010) (Technology Assessment).[16] NERC also found that "interconnecting these new resources will require new transmission" and the transmission system may need enhancements to provide reactive and voltage support, address thermal constraints, and provide for system stability. Long lead times for new rights-of-way for additions and transmission enhancement create timing issues beyond those required for generation." *See* 2013 LTRA at 36.

Continued and Accelerated Integration of Renewable Generation. Quickly integrating an increasing amount of variable renewable generation requires electric utilities, states and system planners to consider a variety of factors. "Accommodating higher levels of variable resources requires cooperation and coordination…especially between [bulk power system and non-bulk power system] entities. Frequency stability, frequency response, energy imbalance, and increased and dynamic transfers must be addressed at all levels." *Id.* at 22. NERC particularly noted the importance of ensuring that increased amounts of solar photovoltaic generation do not lead to decreased system inertia and frequency response capabilities that are critical for maintaining reliability. *See id.* Voltage support concerns also must be addressed, given the long distances between some renewable generators and the point of interconnection with the transmission system. *See id.* at 24. Transmission expansion will be a key consideration. As NERC has noted, "[t]ransmission system expansion is vital for unlocking the capacity available from variable generation, and it can be used as a tool to reduce overall variability across a broader area." *Id.* at 25. "The addition of a significant amount of variable generation to the [bulk power system] changes the way that transmission and resource planners develop their future systems to maintain reliability." *Id.* at 24.

Increased Use of Demand-Side Management. NERC concludes that increased use of demand-side management (DSM), including energy efficiency (EE), can help to offset future resource needs, but creates additional uncertainty for system planners. *See generally* 2013 LTRA at 39-41. In order for electric utilities, states and other regulators to fully realize the potential benefits of increased DSM and EE measures, there must be close coordination between entities responsible for DSM and EE to ensure appropriate capacity values are estimated. Further, not all demand resources have the same reliability benefits. Assuring adequate measurement and verification of the load response, which will require advanced metering, load curtailment technologies and two-way customer communications, will be key. *See* Technology Assessment at 44-45.

[16] This report can be found at http://www.nerc.com/files/RICCI_2010.pdf.

Nuclear Generation Retirements and/or Long-Term Outages. NERC concludes that nuclear generation not only provides a significant amount of generation, but provides important reliability services (inertia and voltage support) that contribute to the stability and integrity of the system and that widespread retirements or long-term outages could have significant impacts on the bulk power system. *See generally* 2013 LTRA at 42-44.

NERC affirmed that the proposed guidelines will require major changes to the way the interconnected power system is planned and operated in order to ensure reliability while achieving emission reductions in its recent Initial Reliability Review of the proposed guidelines.[17] NERC stated that the proposed guidelines "introduce[] potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation." Initial Reliability Review at 17. In particular, NERC noted that the proposed guidelines do not recognize the need to expand and enhance the transmission grid and that the guidelines do not address grid reliability issues associated with increased variable resources and retirement of fossil-based generation:

> Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERS, needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

Initial Reliability Review at 13.

Accordingly, "specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of [state plans] that are

[17] *See* NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review* (Nov. 2014). The Initial Reliability Review is attached as Appendix A.

aligned with system reliability needs." *Id.* at 4. Given the interconnected nature of the system, specific reliability impacts and necessary system changes cannot be assessed and coordinated until after all state compliance plans are finalized and approved, which will not be until 2017 at the earliest. As a practical matter, this schedule does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020. *See* Initial Reliability Review at 10, 27. The studies themselves can take several years to complete.

Further, once the required studies are completed, actually building new generation, new natural gas delivery infrastructure and new transmission lines can also take years to complete, especially when involving rights-of-way crossing federal or tribal lands. As the Department of Energy (DOE) has recognized,

> Infrastructure projects—such as high voltage, long distance, electric transmission facilities—often involve multiple Federal, State, local and Tribal authorizations and are subject to a wide array of processes and procedural requirements in order to obtain all necessary permits and other authorizations. Delays in securing required statutory reviews, permits, and consultations can threaten the completion projects of national and regional significance.

DOE, Rapid Response Team for Transmission (RRTT),[18] *Request for Information*, Docket No. RRTT-IR-01, 77 *Fed. Reg.* 11,517 (Feb. 27, 2012).

[18] The RRTT was created in response to a Presidential Memorandum recognizing the critical need to expedite the review and permitting of major electric transmission infrastructure projects. *See* Presidential Memorandum, Speeding Infrastructure Development through More Efficiency and Effective Permitting and Environmental Review (Aug. 31, 2011). The RRTT recognized that "[a]t least three problems may arise when trying to develop this type of infrastructure: (1) Non-synchronous evaluations by all governmental entities with jurisdiction; (2) uncertainty about whether all necessary permits and approvals will be received; and (3) significantly different development times for generation and transmission."

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However, EPA does not propose to wait until these studies are complete or until needed system changes are effectuated to finalize the proposed guidelines or require states to submit compliance plans. Therefore, the final proposed section 111(d) guidelines can and should recognize the complexity of what the Agency is asking states, electric utilities, system operators and other regulators to do in order to achieve the 2030 goals. To the extent possible, EPA's final state goals should reflect the operational reliability needs of the interconnected power system as they currently are understood. In addition, the final guidelines should include a compliance timeline that provides states with sufficient time to analyze the impacts of their proposed plans on the interconnected power system and ensure that the power sector has sufficient time to implement the required changes to the entire interconnected power system.

Further, although EPA has not yet considered how the proposed Building Blocks will cumulatively affect the interconnected power system, the Agency should be open to modifying the 2030 state-specific emission rate goals in the final guidelines to recognize that the Building Blocks affect each other in the context of the interconnected power system, which is discussed in more detailed in sections II.B-E., below.

II. EPA's Analysis Of The Emission Reductions That Could Be Achieved By Each Proposed BSER Building Block Is Flawed And Overestimates The State-Specific Emission Rate Goals.

EPA proposes that BSER for existing affected fossil EGUs is the combination of four "Building Blocks." EPA's four Building Blocks are: (1) reduced carbon intensity of individual affected coal-based units through heat rate improvements (HRI); (2) increased dispatch of existing NGCC units and corresponding decreased dispatch of affected coal-based units; (3) increased deployment of new renewable generating technologies, coupled with the preservation of some

existing nuclear units and all currently under construction nuclear units; and (4) decreased overall electricity usage and demand as a result of expanded end-use efficiency programs. *See* 79 *Fed. Reg.* at 34,836. EPA estimated the potential reductions that the Agency believes could be achieved by each of these Building Blocks for each state to develop state-specific emission rate goals. EPA asserts that it is reasonable to base state goals on reductions beyond those that could be achieved at affected units because of the interconnected nature of the power system. *See id.* at 34,880.

Assuming arguendo that EPA can use all four Building Blocks as the basis for the state-specific emission rate goals, EEI reviewed and analyzed EPA's assumptions about the magnitude of reductions that each Building Block could achieve. As discussed in more detail below, EPA's analysis is flawed and generally overestimates the possible reductions available from the Building Blocks, resulting in state goals that may not reflect the reductions that are achievable. These comments provide a general assessment of the Building Blocks. Given the state-specific nature of the goal calculations, states and electric utilities will have specific concerns regarding the application of EPA's analysis and assumptions to each state.

As an initial matter, the largest overarching flaw in EPA's methodological approach to BSER and the proposed state goals is that EPA simply adds the estimated potential reductions from each Building Block, rather than considering whether and how the Building Blocks affect one another. Because the Building Blocks are part of the interconnected power system, they need to be evaluated jointly, taking into consideration their interactions in the context of that system. EPA did not consider these interactions, which tend to limit the reduction potential of each

Building Block when compared to EPA's assessment of the Building Blocks in isolation. If EPA relies on the interconnected power system as the basis for the BSER determination, the Agency cannot ignore these interactions when projecting the reductions achievable through each of the Building Blocks. These interactions are discussed in more detail below, and the Agency should consider them before finalizing the state-specific emission rate goals. Similarly, to the extent possible, EPA's final state goals also should reflect the operational reliability needs of the interconnected power system as they currently are understood.

EPA also should consider the specific concerns raised by states and by the electric utilities that operate in those states and adjust its assumptions and final goals accordingly. One way to recognize state-specific concerns about the goals and the assumptions that underpin them would be to allow states to opt to pursue individual compliance plans that achieve either the final 2030 or 2025 rate or mass emission levels proposed by EPA in the section 111(d) guidelines.

Importantly, the Agency also should allow for a continuing dialog on these issues with states as they submit compliance plans. The interconnected power system is a complicated interstate machine and the proposed guidelines are similarly complex. Even with an extended comment period, states may not be able to provide EPA a complete analysis of concerns related to the four Building Blocks as they apply to the particular facts and circumstances of each state. Accordingly, EPA should consider any state-specific issues identified in state compliance plans, permit modifications to state plans as appropriate and, where necessary, adjust final state goals.

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A. The Proposed 111(d) Guidelines Do Not Recognize Appropriately Early Action to Reduce Power Sector Greenhouse Gas Emissions.

As a preliminary matter, EPA's approach to setting the state-specific emission rate goals does not recognize appropriately emission reductions achieved by states and electric utilities before 2012. In the preamble, EPA spends considerable time cataloging the efforts that states and electric utilities have taken to date to reduce CO_2 emissions. *See, e.g.*, 79 *Fed. Reg.* at 34,833-34. States and companies that have been leaders in reducing emissions have achieved meaningful reductions in power sector emissions. For example, the RGGI states estimate that they have reduced CO_2 emissions from the electricity sector by 20 percent through the use of market-based programs, renewable portfolio standards, energy efficiency resource standards and funding commitments, utility planning, and other efforts from 2005 to 2011. These efforts also improved their net carbon emission rate by 19 percent over the same time period, from 941 to 759 lb CO_2/MWh.[19] Similarly, Xcel Energy worked with the state of Colorado to develop a multi-pollutant plan that involved the retirement of existing coal-based units, increased natural gas-based generation and new deployments of renewable generation that is projected to reduce power sector emissions by 35 percent by 2020. *See* 79 *Fed. Reg.* at 34,849. There are many other examples of states and electric utilities taking the initiative to reduce power sector emissions well before 2012. However, EPA does not recognize these efforts.

In the preamble, EPA notes that it "agrees" with the "policy principle" that the section 111(d) guidelines should be structured so as not to "disadvantage states that already have adopted

[19] *See States' §111(d) Implementation Group Input to EPA on Carbon Pollution Standards for Existing Power Plants*, at 8 (Dec. 16, 2013), http://www.georgetownclimate.org/sites/www.georgetownclimate.org/files/EPA_Submission_from_States-FinalCompl.pdf.

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programs that reduce CO_2 emissions from EGUs." 79 *Fed. Reg.* at 34,918. Agreement with this policy principle notwithstanding, the structure of the proposed guidelines and, in particular, the approach to calculating the state-specific emission rate goals disadvantages states and electric utilities that already have undertaken substantial investments to reduce emissions from affected EGUs by assigning them more stringent targets. The proposed 111(d) guidelines, therefore, do not appropriately recognize early action and may serve as a disincentive to others to take early action to reduce emissions.

1. The proposed emission rate goals are more stringent for states and electric utilities that took action before 2012 to reduce emissions.

EPA's proposed approach to calculating the state-specific emission rate goals is discussed in more detail in sections II.B-E., below. Two particular elements of EPA's proposed approach to the goal calculation are relevant to the discussion of states that have already taken action to reduce power sector emissions. First, EPA created a 2012 baseline emission rate for each state that reflects the level of generation from all in-state affected fossil-based units. *See* Goal Computation TSD at 8-9. As a result, the 2012 baseline emission rate for states that had retired coal-based units and built new NGCC units already reflects these reductions, resulting in a more stringent goal.[20] Similarly, the goal calculation approach also relies on the amount of electricity produced by renewable sources in 2012, *see id.* at 15-16, meaning that the more renewable energy produced in 2012, the more stringent a state's goal emission rate. Moreover, states that already had, as of 2012, increased use of wind, solar and other variable renewable resources often had built new NGCC units to balance their systems. As a result, NGCCs in states with

[20] Under a Minnesota statute, for example, Xcel Energy retired two coal plants in the Twin Cities and replaced them with NGCC units. As a result, Minnesota's proposed goal is approximately 80 lb/MWh more stringent than it would have been had the state not undertaken the emission reduction program.

significant amounts of renewable generation had a lower capacity factor and, thus, the re-dispatch goals envisioned under Building Block 2 have a more significant effect on their emission reduction goals.

In other words, states that by 2012 had deployed renewables—one of the very things the proposed guidelines are designed to encourage—have more stringent goals than states that did not. Further, as discussed in more detail in Section III.B., states and electric utilities that have invested in nuclear generation that is now under construction also face more stringent emission rate goals than if they had not taken steps to reduce power sector emissions.

EPA asserts that "states that have already shifted toward lower carbon-intensity generation or ramped up demand-side EE programs are better positioned to meet the state-specific goals." *See* 79 *Fed. Reg.* at 34,918. This would be the case if the state emission rate goals were uniform, such that states that already had taken action and made investments to reduce emissions were closer to compliance than states that had not yet taken such actions. However, given the state-specific nature of EPA's proposed state targets that were built upon pre-2012 actions taken by the states, these states are not in a "better position" to meet their goals, but instead must achieve greater levels of reductions at greater cost than if they had taken no action to reduce emissions.

2. The proposed guidelines penalize clean energy leadership and will discourage others from taking early action to reduce emissions.

EPA asserts that states that have reduced emissions will be better positioned to meet their emission rate goal, implying that this will ease the burden of achieving additional reductions. *See* 79 *Fed. Reg.* at 34,918. As a preliminary matter, this does not address the fact that states that have reduced emissions likely already have undertaken those reductions that were most cost-

effective and, in order to meet EPA's proposed goals, now must pursue more expensive reduction options. Pre-2012 action by states and electric utilities to deploy renewable generation, replace aging coal plants with NGCC units or invest in EE programs does not reduce the costs of expanding these efforts going forward. It is just the opposite: Those states have already "picked the low-hanging fruit" and now must invest more to further reduce their emissions than their neighbors who have not already undertaken significant actions to reduce their emissions.

Moreover, requiring greater reductions from states that have already reduced emissions is not consistent with the structure of the CAA. Nowhere in the Act is EPA authorized to require additional reductions from a source simply because it had already achieved the desired level of emission performance. In a more traditional approach to section 111 standards, EPA would base standards on the emission rate achievable through the use of a particular control technology. If a unit already had installed that control technology, it would be deemed compliant. This would not be a free pass—to the contrary, it would recognize that the source had invested in achieving the required emission performance goal early and, therefore, was achieving that goal. In the proposed section 111(d) guidelines, however, reductions already achieved through state and utility investments in clean energy are not deemed compliant, but are, instead, met with standards that require additional, more stringent reductions.

Further, creating more stringent standards for clean energy leaders will create disincentives for others to take early actions to reduce emissions. The CAA does not require states and electric utilities to be punished for reducing emissions before EPA required them to do so. The design of

the proposed guidelines for existing EGUs should make clear to states, electric utilities and other source categories that will be the subject of future 111(d) guidelines to reduce CO_2 emissions that early action is needed and will be recognized appropriately. EPA's proposed approach to setting the state-specific emission rate goals in these proposed guidelines sends a clear message to the contrary. As a policy matter, EPA should recognize and incent investments that result in early emissions reductions.

B. EPA Overestimated the Potential to Improve Average Heat Rates Across the Existing Coal-Based Fleet.

EPA proposes that a state's affected coal-based EGU[21] fleet could achieve, on average, a six percent improvement in heat rate leading to a six percent reduction in CO_2 emissions (Building Block 1). *See* 79 *Fed. Reg.* at 34,861. EPA's proposed six percent HRI value is comprised of two elements: (1) a four percent reduction attributable to operations and maintenance (O&M) "best practices"; and (2) a two percent reduction due to higher cost hardware "equipment upgrades" that were identified in a 2009 Sargent and Lundy (S&L) report[22] on potential

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[21] EPA's regulations set forth applicability requirements to determine which existing coal-based steam EGUs are affected. EEI's concerns about EPA's proposed changes to these applicability requirements are discussed in comments addressing EPA's proposed standards for modified and reconstructed units, which were filed October 16, 2014, in Docket No. EPA-HQ-OAR-2013-0603. The relevant portions of these comments are attached as Appendix B and incorporated herein.

[22] *See* Davis Hasler, *Coal-fired Power Plant Heat Rate Reductions,* Sargent & Lundy (Jan. 22, 2009), http://www.epa.gov/airmarkt/resource/docs/coalfired.pdf. Although EPA funded and reviewed the report, the report has not been approved by the EPA for publication as an EPA report. All estimated capital and installation costs contained in the report were obtained from work-in-progress and vendor quotes as of the year 2008, and the costs represent values of new equipment purchased in the year 2008. The authors note that the costs contained in the report "are not indicative of those that may be expected for a specific facility due to variables such as equipment, material, and labor market conditions and site specifications." *Id.* at 1-3.

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efficiency improvements at coal-based EGUs.[23] *See id.* at 34,860. EPA also asserts that fuel cost savings largely will offset the costs related to any efforts to improve heat rates through O&M best practices or equipment upgrades. *See id.* at 34,861.

EPA determined the fleet-wide potential for the two types of HRI using fundamentally different analyses. Both of these approaches are flawed, resulting in overly optimistic projections for fleet-wide HRI that may result in state emission rate targets that are unachievable. EPA also overestimated the value of fuel costs savings to an affected EGU. EPA should revise the analyses used to determine the potential fleet-wide HRI that could result from both O&M "best practices" and equipment upgrades. In addition, EPA should revise the HRI goals for any state that can show that EPA's assumptions about HRI potential are flawed with respect to the existing fossil-based units in that state. At a minimum, EPA should address state-specific concerns about the proposed emission rate goals before finalizing these goals. EPA should work with the states to set achievable state goals that reflect in-state conditions.

1. The record does not support EPA's assumption that "best practices" operations and maintenance can improve fleet heat rates by four percent.

EPA's assumption that fleet-wide, existing coal-based units can improve heat rates by four percent through O&M "best practices" is not supported by the Agency's assessment of recent heat rate data and, therefore, is not reasonable. EPA's "best practices" analysis begins with the premise that any variability in a unit's heat rate represents an opportunity to improve heat rate and reduce emissions. *See id.* at 34,860. EPA further assumes that most heat rate variability can be attributed to deficient O&M practices and, therefore, can be eliminated through improved

[23] EPA also proposed an "Alternative State Goal," cited as "Option 2," which derived state goals using only the four percent "best practices" component of EPA's analysis.

O&M practices. While EPA is correct that improved heat rates result in reduced emissions from coal-based EGUs on a rate basis, *see id.* at 34,905, EPA has failed to produce a reasoned analysis to quantify how much average heat rates can be improved by implementing additional O&M measures. Many factors contribute to heat rate variability; some of these are outside the control of the unit operator and can never be eliminated. More importantly, EPA's assumption that improved O&M can ameliorate most variation in heat rate ignores the existence of these other factors and is not supported by any analysis. This undermines EPA's determination that a four percent HRI is both reasonable and economic.

For the "best practices" analysis, EPA examined affected EGU hourly heat rate data for 884 coal-based EGUs for the years 2002-2012 to determine the amount of variability in heat rates across the existing fleet. *See id.* at 34,860. Recognizing that ambient temperature and hourly load levels (capacity factors) have a direct impact on a unit's heat rate and are outside a unit's control, EPA grouped the hourly data into "bins" to attempt to control for these variables. *See* GHG Abatement Measures Technical Support Document at 2-15 (Abatement Measures TSD). The Agency assumed that any remaining variability in heat rate data in the various bins would be "an indication of the degree of technical potential to improve the consistency with which optimal heat rate performance is achieved by adopting operating and maintenance best practices." 79 *Fed. Reg.* at 34,860.

For each bin, EPA then calculated a "top decile" heat rate performance—presumably the heat rate of the 10th percentile lowest value in each bin. *See id.* at 34,860. EPA further calculated a range of 1.3 to 6.7 percent "technical potential for improvement of the average heat rate of the

entire fleet of coal-fired EGUs" by "assuming that between 10 percent and 50 percent of the deviation from top decile performance in each subset of hourly heat rate observations within defined ranges of temperature and load could be eliminated through adoption of best practices." *Id.* at 34,860. Based on this analysis, EPA concluded that:

> A reasonable estimate for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a *four percent improvement in heat rate through adoption of best practices* to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation.

Id. at 34,860 (emphasis added).

In short, the proposed four percent "best practices" reduction in average coal-based unit heat rate rests most heavily on the assumed 30 percent factor applied by EPA in the Agency's bin analysis. In the absence of a clearly articulated basis for this 30 percent value, it can only be described as arbitrary, rendering the resulting four percent HRI mandate arbitrary as well.

a. EPA's bin analysis does not demonstrate that most heat rate variability can be attributed to O&M practices.

EPA's bin analysis is flawed and does not demonstrate that most heat rate variability is caused by O&M practices. As a preliminary matter, EPA's assumption that reduced variability in heat rate implies improvement in a unit's heat rate fails to understand what "variability" is. Variability is change relative to an average value, not relative to an optimal (in the case of heat rate, minimal) value.

Nevertheless, EPA conducted a regression analysis of 884 generating units and concluded that units with more variable heat rates tend to have higher heat rates. *See* Abatement Measures TSD at 2-22. Even if this is true, the regression analysis only identified the relationship between variability and higher heat rates; it did not identify the cause of the variability. In other words, correlation is not causation. EPA assumes that the cause must be deficient O&M, but there are other factors that could cause this variability that EPA did not address.

EPA cited nine different categories of factors influencing heat rate. *See* Abatement Measures TSD at 2-4 to 2-5. EPA's analysis attempted to partially account for some of these, including load factor (capacity factor) and ambient temperature. As NERC has noted, EPA's regression analysis did not adjust for factors that have a "profound" effect on the process efficiency of a coal-based EGU, including boiler design; unit size and age; and coal quality variations. *See* Initial Reliability Review at 8. EPA's only attempt to recognize and control for the range of factors that might affect heat rate variability is to assume that 30 percent (instead of 50 percent) of the variability observed in bin data is caused by O&M practices. No analysis supports this assumption and assigning the cause of 30 percent of the variability to O&M practices, therefore, is arbitrary. Accordingly, EPA's analysis did not identify the cause of the observed variability in heat rates. Further, if heat rate variability cannot be attributed to O&M practices, EPA has no basis for asserting that O&M "best practices" will result in HRI of four percent.

b. EPA's bin analysis indicates that load factor, not O&M practices, likely plays a significant role in explaining heat rate variability.

In fact, what EPA's analysis demonstrates is that, even after attempts to control for load factor via the bin analysis, load factor is a very important determinant of heat rate for units with varying load. *See* Abatement Measures TSD at 2-25. The bin analysis reduced the effect of load factor

changes, but each bin *itself* includes a 10 percent range of load factors. *See* Abatement Measures TSD at 2-24 to 2-25. An International Energy Agency (IEA) report found that a 10 percent change in load factor can result in a four percent change in heat rate.[24] Thus, the bin approach reduced, *but did not eliminate*, the very significant impact of variable load factor on heat rate.

As explained in detail in EEI's comments on the proposed CO_2 standards for new units, load factor (capacity factor) has an inverse relationship to heat rate for fossil-based EGUs. *See* Appendix C at 4-5. The higher the load factor, the lower the heat rate. Lower capacity factors or increased cycling increase heat rates and increase heat rate variability. In the integrated electric system, units are dispatched to respond to load, following economic merit order principles and consistent with reliability requirements, thus reducing generator control over specific dispatch levels. Unit owners and operators, therefore, cannot control load factor to address concerns about heat rate. If the variation within bins is significantly influenced by load factor, less variability would be amenable to improvement via O&M practices, and, such variability may not be able to be addressed by O&M practices at all.[25]

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[24] *See* IEA, Coal Industry Advisory Board, *Power Generation from Coal: Measuring and Reporting Efficiency Performance and CO_2 Emissions*, at 20 (2010)(finding that a 10 percent reduction in capacity factor (from 50 to 40 percent) can increase heat rate by four percent), http://www.iea.org/ciab/papers/power_generation_from_coal.pdf.

[25] EPA's analysis is historical. Any future decrease in load factors as a result of the implementation of the other proposed Building Blocks, all of which are designed to reduce utilization of existing coal-based units, could offset the four percent "best practices" HRI potential estimated by EPA.

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c. EPA did not adjust projected HRI potential to reflect likely heat rate increases related to the installation of pollution control technologies.

Additionally, other factors unaddressed by EPA's bin analysis also could have a significant impact on heat rates and heat rate variability. EPA acknowledges that "[t]he electric power consumed by air pollution control equipment reduces the overall efficiency of the EGU." Abatement Measures TSD at 2-4. However the addition of such systems after 2012, for compliance with recent EPA regulations, has not been incorporated in EPA's analysis. A May 2014 report for the Secretary of Energy by the National Coal Council cited an increase in heat rate of two to three percent for the addition of a flue gas desulfurization (FGD) system, and cited other operational factors that would also lead to higher heat rates (operation at reduced load, variable load operation, changing to a coal with a higher moisture content).[26] The addition of FGD systems presents a special case with respect to increased CO_2 emissions because, in addition to the increase in heat rate, the chemicals used by most FGD systems release CO_2 as part of the reaction that captures sulfur dioxide. *See* 79 *Fed. Reg.* at 34,859, n.113.[27] EPA's own analysis indicates that 20 gigaWatts (GW) of coal-based units will install dry scrubbers and 63 GW will upgrade currently installed scrubbers in 2015-2016 to comply with the Mercury and Air Toxics Standards (MATS).[28] The potential for other new EPA regulations to negate the benefit of any potential HRI is also significant. For example, state implementation of the Clean Water

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[26] The National Coal Council, *Reliable and Resilient – The Value of Our Existing Coal Fleet*, at 70 (May 2014).

[27] EPA recognizes that some controls themselves increase CO_2 emissions because of the use of certain reagents. EPA asserts that these increased CO_2 emissions will be offset by decreased fuel usage due to increased unit efficiency. *See* 79 *Fed. Reg.* at 34,859 n.113. EPA does not address the parasitic load associated with these controls and the detrimental effect this will have on unit heat rates.

[28] *See* Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, Docket No. EPA-HQ-OAR-2009-0234, at 3-15 (Dec. 2011).

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Act 316(b) rulemaking may require certain locations to install cooling towers or air cooling in some circumstances. The parasitic load impacts of cooling tower operation may outweigh the benefit of installed HRI projects.

EPA did not account for the impact of measures that would degrade heat rates when projecting the potential for future HRI. Improved O&M practices would be at least partially offset by such heat rate degrading measures.

d. EPA should not have considered units that are expected to close when assessing fleet-wide HRI potential.

There also is no evidence that EPA considered the impact of retiring coal units on the results of the analyses. If a unit closes, there can be no HRI potential at that unit. EPA ran a sensitivity analysis that excluded units that have announced retirement dates before 2016. *See* Abatement Measures TSD at 2-35. However, this did not include the additional 46-49 GW of coal-based units that EPA projects will retire as a result of compliance with the proposed guidelines. *See* Resource Adequacy and Reliability Analysis (Resource Adequacy TSD) at 1. Presumably, these units have higher design heat rates because they are older. Accordingly, they might appear (statistically) to have significant HRI potential, but this potential will not be realized if these units retire. Therefore, EPA should exclude these 46-49 GWs when assessing the future HRI potential of the existing coal-based fleet. Inclusion of these units likely inflated EPA's assessments of HRI through O&M "best practices."

e. EPA made no effort to determine which O&M "best practices" already may have been implemented.

Finally, EPA made no effort to establish whether the identified "best practices" already have been deployed on any unit included in its analysis. As EPA notes, there is an apparent trend of

improving (decreasing) heat rates over time. *See* Abatement Measures TSD at 2-18. One cause of such a decrease could be implementation of the very "best practices" measures that EPA recommends to improve heat rates. In other words, it is plausible that EPA is correct that a four percent improvement in historic heat rates *was* possible, and in fact already has been achieved or largely achieved. EPA notes that the fleet heat rate in 2008 was three percent less (improved) than in 2002. *See id.* at 2-29.[29] This improvement may be related to improved O&M and other efforts to decrease heat rates.[30] Moreover, electric utilities have strong financial incentives to deploy measures that improve heat rate because of fuel savings. These measures often provide greater reliability and fuel supply certainty as well, thus providing additional economic incentives. These factors argue that the improvements sought by EPA and suggested by the S&L report may already be "baked into" the existing fleet and cannot be "counted twice." EPA has made no effort to determine if these measures have already been implemented and to adjust the analysis accordingly. At a minimum, if a state can demonstrate that HRI projects already have

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[29] EPA's analysis also shows that heat rates had increased (deteriorated) by one percent by 2012. This deterioration could be due to the addition of environmental compliance systems or a decline in load factors.

[30] In the early 1980s, many utilities developed an interest in monitoring and improving the efficiency of their generating units, implementing many performance improvement programs and investing significant capital to achieve and maintain this improved performance. A 1983 utility survey covering 129 fossil generation units concluded that a mean HRI of more than four percent could be achieved at existing power plants by implementing an effective HRI program. Then, in the early 1990s, as utilities began planning for a more competitive market, the emphasis shifted towards maintaining peak performance by using station instrumentation and computerized calculation systems in order to track performance on a more frequent basis. *See* Electric Power Research Institute (EPRI), *Range and Applicability of Heat Rate Improvements* (Apr. 2014), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx? Product Id=000000003002003457; *see also* EPRI, *Maintenance Optimization Project at Merom: Volume 2: Heat Rate Improvement* (Feb. 1999), http://www.epri.com/abstracts/Pages/ ProductAbstract.aspx?ProductId=TR-111897-V2.

been implemented at in-state affected coal-based EGUs, EPA should recalculate that state's emission rate goals accordingly.

2. EPA has not provided a reasonable basis for concluding that "equipment upgrades" can improve heat rates by two percent.

As noted, EPA also concludes that unit-specific "equipment upgrades" result in HRI of two percent. *See* Abatement Measures TSD at 2-34. EPA's conclusion is unsupported by any analysis. Accordingly, EPA lacks a sufficient and reasonable basis for concluding that equipment upgrades can achieve HRI of two percent, on average, across the existing coal-based fleet.

EPA conducted an analysis of heat rate data and examined anecdotal data from seven plants reporting HRI, but ultimately relied exclusively on the 2009 S&L report in its determination that equipment upgrades could result in HRI of two percent. *See* Abatement Measures TSD at 2-33.

The S&L report outlined 13 different HRI measures. The Agency separated these measures into two categories, based largely on cost. *See id.* at 2-33. The less costly measures were characterized as "best practices" and the higher cost items were characterized as "upgrades." *See id.* The four "upgrade" measures:

1. Economizer replacement
2. Acid dew point control
3. Combined variable frequency drive and fan replacement
4. Turbine overhaul (which appears to include rotor replacement)

EPA concluded that if all four "upgrade" measures were deployed on an existing unit (that had not already deployed them) the overall HRI would be four percent. *See id.* at 2-34. EPA then

reduced the expected outcome of such upgrades to two percent, to account for possible prior deployment of some of the "upgrade'" measures on existing units. *See id.* at 2-35.

While equipment upgrades can improve heat rates and reduce emissions, a single S&L report is not a sufficient basis for concluding that the existing coal-based fleet can, on average, achieve a two percent HRI through equipment upgrades. EPA examined reported heat rate data in the context of the "best practices" analysis, but ultimately rejected, without explanation, this approach for the purpose of assessing the HRI potential of equipment upgrades.

Further, EPA's determination that half of the possible equipment upgrades may have already been deployed is unsupported by any data, and the Agency has failed to explain how it ensured that any of the improvements that were attributed to O&M "best practices" should not more properly be attributed to equipment upgrades.

3. EPA overestimated the cost savings associated with heat rate improvements.

In determining BSER, EPA is required to consider, among other things, cost. *See* CAA section 111. EPA asserts that the costs of the projected HRI are reasonable based on cost data from the S&L report and because fuel savings will offset the costs of HRI measures. *See* Abatement Measures TSD at 2-33 to 2-34. Neither of EPA's assertions about HRI costs is reasonable. First, EPA's cost assessment is based on costs as reported in the 2009 S&L report. *See* 79 *Fed. Reg.* at 34,861. This cost data is nearly five years old. EPA must explain why it is appropriate to rely on old data before asserting that any assessment of this cost data is reasonable.

Second, EPA's core argument in support of the reasonable cost of the HRI is that "any heat rate improvement made for the purpose of reducing CO_2 emissions will also reduce the amount of fuel the EGU consumes to produce its electricity output." *Id.* at 34,861. Using cost estimates from the S&L report, EPA calculates an annualized cost per kiloWatt hour (kWh) of HRI measures. *See id.* EPA then calculates an annualized fuel cost to estimate the average fuels savings related to a six percent HRI. *See id.*

HRI reduces fuel costs, on a per kW basis, but EPA's analysis, which focuses on annualized costs, ignores the lag between capital expenditures and fuel cost savings. HRI capital costs may be financed, which spreads the costs over time. This financing is dependent on continued operation of the unit to create a revenue stream that allows the capital costs to be repaid over time. EPA's own analysis indicates that many existing coal-based units will be retired by 2020 and that the utilization of the remaining units will decrease as part of states' compliance efforts. *See* Regulatory Impact Analysis (RIA) at 3-32. This dramatically shortens the payback period, and therefore, reduces the electricity sales that are necessary to support capital costs investments in HRI measures.

To some extent, EPA recognizes this, noting that "reductions in the utilization rates of coal-fired EGUs anticipated from other components proposed for inclusion in … [BSER] would tend to reduce the fuel savings associated with [HRI], thereby raising the effective cost of achieving the CO_2 emission reductions." 79 *Fed. Reg.* at 34,861. But, EPA quickly dismisses—without any analysis—the impact that reduced utilization would have on the reasonableness of HRI costs, stating "[n]evertheless, we still expect that the majority of the investment required…would be

offset by fuel savings." *Id.* at 34,861. EPA does not address at all the potential impact of early retirement on its cost estimates.

Further, in its cost estimate for HRI, it does not appear that EPA considered the potential costs related to New Source Review (NSR). Units engaging in HRI projects could trigger NSR's pre-construction permitting requirements, which likely would require installation of additional pollution controls. Projects that improve thermal efficiency will incur additional costs related to permitting delays and control installations.[31] The costs of additional controls, in particular, may completely undermine EPA's assertions that the costs of HRI are reasonable.

Finally, nowhere in the cost analysis does EPA recognize the non-permanent nature of HRI. Such improvements may begin to deteriorate almost immediately, requiring ongoing O&M to maintain the improved heat rate. Other HRI measures require multiple equipment replacements or upgrades over the life of the unit, which increases the initial improvement (i.e., not a one-time capital expenditure).

Accordingly, EPA has not adequately supported its claims that reductions associated with HRI measures can be achieved at reasonable cost.

C. EPA Has Not Demonstrated that All States Can Increase the Utilization of Existing Natural Gas Combined Cycled Units to 70 Percent.

EPA's BSER Building Block 2 involves increased dispatch of existing NGCC units. *See* 79 *Fed. Reg.* at 34,905. EPA assumes that a reduction in mass emissions from higher-emitting coal-based and oil/gas-based steam EGUs can be achieved by shifting generation from these units to

[31] *See* Sarah K. Adair, *et al.*, *New Source Review and Coal Plant Efficiency Gains: How New and Forthcoming Air Regulations Affect Outcomes*, 70 ENERGY POLICY 183 (July 2014).

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lower-emitting existing NGCC units. *See* 79 *Fed. Reg.* at 34,857. In order to estimate the magnitude of emission reductions that could be generated through increased re-dispatch of NGCC units, EPA assumes that, on average, each state's existing NGCC fleet, including NGCC units under construction as of January 8, 2014, could achieve a utilization rate of 70 percent. *See id.* EPA's analysis does not provide a reasonable basis for rate-based goals predicated on 70 percent NGCC utilization rates.

Changes in dispatch are a main driver of the stringency of the interim and final goals in many states,[32] particularly in the early years of the interim compliance period.[33] Given the significant role that this Building Block plays in the calculation of state goals, it is all the more important that the analysis underpinning that calculation is sound. However, EPA's conclusion that NGCC utilization rates can reach 70 percent in every state is faulty. For example, EPA's analyses do not take into account required changes in system dispatch control, system balancing and reliability responsibilities, existing energy and fuel supply contracts, transmission rights or transmission service reservations. Also, EPA has not demonstrated that all state NGCC fleets will be able to sustain that rate over the long-term. In many cases, achieving such dramatic increases in NGCC utilization effectively would require a fundamental redesign of the entire electric grid. This also would require substantial changes in how the natural gas industry and

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[32] *See* Goal Computation TSD; *see also* ICF International, *EPA's Clean Power Plan: Challenges Ahead for Sources and States* (June 25, 2014), http://www.icfi.com/insights/white-papers/2014/epa-clean-power-plan.

[33] As noted by UBS, EPA expects reductions from the proposed guidelines from 2012 to 2020 "to be 39% from CCGT re-dispatch, 10% from heat improvements at coal plants, 23% from renewables, 3% from nuclear build, 25% from efficiency." UBS, Global Research, *US Electric Utilities & IPPs: Making Cents of EPA's Clean Power Proposal (Incl. Conf. Call Transcript)*, https://neo.ubs.com/shared/d1o5yP8AIt78Wb.

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organized wholesale electricity markets operate, both of which are outside the scope of the proposed guidelines and EPA's general authority under the CAA. Finally, EPA has not addressed the effect that increased existing NGCC utilization rates will have on the other proposed Building Blocks. Existing fossil-based units do not exist in a vacuum and are part of the complex, integrated electric grid. Shifting the way these units are operated will impact other forms of generation and the grid.

For the reasons discussed above, EPA should not expand the definition of the NGCC fleet to include co-firing or new NGCC units in states' baselines. *See, generally*, 79 *Fed. Reg*. at 64,549-50. Further, EPA should not modify the way it calculates state goals by imposing a minimum level of re-dispatch or redefine Building Block 2 by calculating it on a regional basis. To do so ignores the fact that every state and region has unique generation portfolios that reflect specific energy demand requirements and resource availability.

For example, for the power sector to reduce the amount of generation from coal and increase generation from natural gas, more natural gas geologic storage is needed to maintain adequate reliability assurances. According to a 2013 report, "[g]eology limits opportunities to build storage where the market would prefer it. Because of that, the current 400 or so storage facilities are not distributed evenly across the country and many of those facilities are single season reservoirs—rather than higher deliverability salt cavern-based facilities."[34] Thus, while generators may want to take advantage of lower-priced natural gas, supply and storage issues

[34] Roger S. Turley, *Coal to Natural Gas Electric Utilities Repowering: Consequences for valve usage and replacement 2013,* http://www.cranecpe.com/chem-energy/news/crane-the-key-sponsor-of-valve-world-expo-americas-highlights-its-products-in-houston.

hinder this development. Finally, while the NODA points to discrepancies and limitations of the proposed guidelines, none of the new proposals provide credible solutions. On the contrary, the NODA's proposals would add subjective elements and would exacerbate some problems by grossly overestimating fuel switching potential in the states.

Instead, at minimum, EPA should address state-specific concerns about the proposed emission rate goals. EPA should work with the states and RTOs to set achievable state goals that reflect future in-state conditions.

1. EPA's flawed analysis does not support the achievability of increasing NGCC utilization to 70 percent in all states.

EPA's analysis of the potential for re-dispatch between existing coal-based units and existing NGCC units is faulty. In its analysis, EPA draws unsupported conclusions based on limited data regarding historical NGCC operations, relies on inaccurate data, and does not take into account the difference between nameplate capacity factor and demonstrated capacity factor. These deficiencies cause EPA to overestimate the potential for re-dispatch and the related possible emission reductions.

As a preliminary matter, EPA fails to recognize that NGCCs are built to fulfill specific needs within the electric system. In some cases, NGCCs operate as base load resources; in others, they operate as non-base load resources—such as load following, mid-merit or even peaking resources, playing a critical role in providing essential ancillary services to balancing areas. Despite EPA's assumption that all NGCC units currently in operation were designed to achieve utilization rates between 85 and 95 percent, *see* 79 *Fed. Reg.* at 34,863, NGCCs that have been

designed to operate as intermediate or peaking units may not be technically able to increase their utilization to 70 percent for sustained periods of time.

a. Past, localized volume achievements cannot constitute the baseline for assessing the feasibility of sustained, system-wide performance improvements.

EPA states that it is reasonable for the existing NGCC fleet to achieve average utilization rates of 70 percent because a significant number of NGCC units achieved capacity factors between 50 and 80 percent during the winter and summer seasons of 2012. *See* 79 *Fed. Reg*. at 34,857. This conclusion is not based on sound data analysis and is predicated on a misunderstanding of the electric system.

EPA's own analysis indicates that the average utilization rate of NGCC capacity in 2012 was only 44-46 percent. *See* GHG Abatement Measures TSD at 3-6. As EPA notes, only 10 percent of these units operated at *annual* utilization rates of 70 percent or greater. Further, only 19 percent of these units operated at utilization rates of at least 70 percent—and only over the summer season. *See id.* Given the wide range of electric system configurations and NGCC characteristics throughout the country, 10 percent of the fleet is an insufficient sample on which to base guidelines that will be applied to every state.

More importantly, the appropriate measure for determining whether existing units can operate at higher utilization rates for a sustained period of time is not whether some plants, which may have historically run at relatively high capacity factors, ran at high utilization rates in 2012. Rather, it is whether the increase in the utilization rate from one year to another was sufficiently large to demonstrate that the existing natural gas and electric transmission systems have the necessary

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capacity and flexibility to accommodate large and sustained increases in natural gas-based generation.

EEI's analysis shows that only a fraction of those plants cited by EPA as operating at high capacity factors in fact had experienced a significant increase in their utilization rates.[35] Most units saw only small changes vis-à-vis 2011. *See* Appendix D, Table 3. These particular units, therefore, already operated in a system that was designed to accommodate their high capacity factors, so EPA's analysis does not provide sufficient justification to find that the entire natural gas pipeline and electric transmission systems can accommodate large increases in natural gas usage. No changes to the system were needed to accommodate the higher-than-average utilization of the particular cited units because the infrastructure to support high levels of utilization was already in place at these units. Accordingly, the existence and performance of these units in 2012 is not a valid justification for EPA's determination that all NGCCs could operate in the same way and at the same level. EPA's observations about the operation of these individual units cannot be extrapolated to the whole system.

EEI's analysis also suggests that neither the existing natural gas nor the existing electric systems are as flexible as EPA implied. In fact, in 2012, not a single state ran its NGCC fleet at an average capacity factor of more than 61 percent. This demonstrates the importance of analyzing the performance of individual plants in the context of the whole system. It also reinforces the idea that, even though one plant may achieve a certain utilization rate at one point in time, other plants within the same system may not be able to do so, and system-wide constraints may

[35] EEI's summary analysis, based on the same data used by EPA, is attached as Appendix D.

become particularly acute when, on average, all units are expected to achieve that utilization rate. *See* Appendix D, Table 4. It is also important to note that the manner in which units are dispatched in the markets also affects capacity factors. Resources are dispatched based on the least cost resource needed to meet the load in a particular area, which depends on the unit dispatch price, the load and any existing transmission constraints. As such, specific resources may not be needed to run at maximum capacity factor at all times. In most cases, the natural gas and electric systems will have to be redesigned in order to realize EPA's assumed increase in NGCCs' utilization rate.

b. EPA used inaccurate data in assessing the potential for re-dispatch.

In addition, states and electric utilities have identified data errors in EPA's goal calculation, raising more general questions about EPA's basis for finding that the proposed state-specific goals are achievable. At minimum, EPA must address these data errors in the calculation of final state emission rate goals.

For example, American Electric Power (AEP) has identified "several data errors…relating to EPA's calculation of the portion of the state goal attributable to Building Block 2 in two states in which AEP operates. These errors result in a significant overstatement of the potential for re-dispatch to natural gas combined-cycle (NGCC) units by EPA."[36] In one case, EPA used generation data for only two months when the plant actually had operated for 11 months. In another case, EPA attributed emissions from a co-located steam unit to an NGCC. EPA also included non-NGCC units and other non-affected sources in its analysis. *See id.*

[36] *Data Concerns Drive New Calls To Extend ESPS Deadline*, Inside EPA (Sept. 5, 2014).

States also have identified significant data errors.[37] Arizona's Department of Environmental Quality (DEQ) already has informed EPA that the state will not be able to rely on fuel switching to meet its 2020 interim goal because there is no available NGCC capacity in the summer months, which will hamper its ability to meet the 2030 target. *See id.* Similarly, Louisiana's environmental regulator has noted concern about EPA's data regarding NGCCs in the state, such as the inclusion of a plant that has not even been permitted. *See id.* Alabama's environmental regulator also has expressed concern about the EPA's general approach to reducing emissions from existing sources. *See id.* EPA must address the data errors and erroneous assumptions identified in state and industry comments when finalizing the state-specific goals and pay particular attention to the concerns raised in such comments.

c. EPA cannot use nameplate capacity when determining achievable utilization rates for existing NGCCs.

EPA inappropriately uses *nameplate capacity* to calculate NGCC achievable utilization rates. *See, e.g.*, Goal Computation TSD at 5 and 10. Nameplate capacity is the nominal maximum output of a generator, assuming a particular set of ideal, often location-specific, operating conditions, including altitude, temperature, humidity and other factors that cannot be controlled by unit operators. Because of a variety of technical and ambient factors, power plants never achieve their technical maximum capacity.[38] Nameplate capacity is not demonstrated capacity, which represents the net maximum dependable capacity (MDC) rating and available dispatchable energy that can be delivered to the grid as measured by a unit's historic performance.

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[37] Lea Radick, *States Warn EPA Climate ESPS' Fuel-Switching Plan Flawed, Unachievable*, Inside EPA (Sept. 8, 2014).

[38] Stan Kaplan, *Power Plants: Characteristics and Costs*, at 5 n.7 (Nov. 13, 2008), http://fas.org/sgp/crs/misc/RL34746.pdf.

Furthermore, most combined cycle resources are relatively new and their net ratings are based on new and clean conditions. Net capabilities will decline over time as a consequence of combustion and steam turbine degradation. EPA's analysis should focus on the net MDC rating and available dispatchable energy that has been demonstrated to be achievable, instead of nameplate capacity, to avoid overestimating the potential for re-dispatch.

d. EPA's analysis inappropriately included new and retiring NGCC units and combined heat and power units in its calculation of potential for re-dispatch.

EPA inappropriately includes non-dispatchable combined heat and power (CHP) units in its calculation of the potential for re-dispatch. These resources should not be included, as the grid operator cannot direct their operations to meet demand. Further, EPA inappropriately includes under construction and retiring NGCC units in its re-dispatch assessment.

i. EPA cannot include non-dispatchable combined heat and power plants in any analysis addressing the potential for re-dispatch.

In its analysis of the NGCC fleet, EPA inappropriately includes industrial non-dispatchable CHP plants. In 2012, almost a third of the NGCCs over 25 MW were CHP plants, and they accounted for approximately 15 percent of the total electric generation analyzed by EPA. *See* Appendix D, Table 1.[39] Although these CHP plants contribute to the overall electric production of the nation, their operation is completely different from that of a power plant exclusively dedicated to serving load and the needs of the grid. CHP plants tend to have much higher capacity factors than EGUs. Their electric output is directly related to their on-site industrial activity and heat (or steam) production. They do not respond to the demands of the grid. Also, many CHP plants use

[39] Further, unless these units sell more than one-third of their potential output to the grid, they are not affected units, making their inclusion in EPA's analysis particularly inappropriate. *See* proposed 40.C.F.R. § 60.5759(b)(2), 79 *Fed. Reg.* at 34,954.

much of the electricity they produce for their own needs and cannot be dispatched like power sector plants. More than half (34 out of 64) of the plants that EPA identifies as having utilization rates of 70 percent or more were, in fact, CHP plants. *See id.*, Table 2. These CHP plants cannot be taken into account when assessing the potential for increased utilization of the existing NGCC fleet. Their inclusion in EPA's goal computation methodology results in an overestimate of the potential for re-dispatch. The re-dispatch portions of the state targets must be recalculated accordingly.

ii. EPA has not appropriately accounted for under construction NGCC units when calculating the state goals.

EPA suggests that all states' NGCC fleets, including units under construction as of January 1, 2014, are able to achieve a 70 percent utilization rate. EPA assumes that the additional generation from under construction NGCC units also will displace coal generation, thereby reducing CO_2 emissions. The potential for re-dispatching these under construction units is one of the inputs used in calculating state-specific goals. *See* 79 *Fed. Reg.* at 34,896.[40]

EPA should not include the units that were under construction, and therefore unavailable to produce power, during the 2012 baseline year when calculating state goals. Only units that were *operational and producing power* in the 2012 baseline year should be included in the baseline. Given that all the data used by EPA is based on the electric generation system as of 2012, removing the units that were not operational in 2012 will result in calculations that better reflect the real potential for re-dispatch in 2012.

[40] EPA was not consistent in its approach to under-construction NGCC units, excluding some from the state goal calculations. For example, in calculating New Jersey's emission rate goals, EPA failed to include several under construction NGCC units. If these units are excluded, EPA should make clear that New Jersey's compliance demonstration does not include these units. If EPA chooses to consider under construction units when setting the final goals, EPA should ensure that all under construction NGCC units in all states are included.

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If EPA determines to consider under construction NGCC units when finalizing the state goals, EPA should not assume the same re-dispatch potential for all under construction units. EPA assumes that under construction NGCCs would operate at a 55 percent capacity factor, which would result in a fuel-switching potential of an additional 15 percent (resulting in a total 70 percent capacity factor). *See* 79 *Fed. Reg.* at 34,896. This assumption is arbitrary, and EPA has not provided a basis in the record for applying this assumed capacity factor to all under construction units.

The decision to build a new NGCC plant generally is motivated by another change within the system (e.g., an increase in electric demand, the retirement of another resource, or the addition of variable resources). Therefore, these under construction units were built to serve a specific purpose. Assuming a 55 percent capacity factor for all under construction units ignores the purpose for which they were built. If they were built to serve base load demand, they could be intended to operate at capacity factors above 55 percent, reducing the capacity that would be available for dispatch under EPA's methodology. To the extent EPA retains its proposed approach to include under construction NGCC units in the calculation of state goals, EPA should take into account the specific circumstances of under construction NGCC units to determine the extent to which those units can increase their utilization in order to displace higher-emitting steam generating units.

Further, EPA must ensure that the data used to calculate the standards is correct. For example, EPA incorrectly lists PacifiCorp's Utah-based Lake Side 2 NGCC as operational in 2012. The plant was under construction in 2012 and did not achieve commercial operation until June of

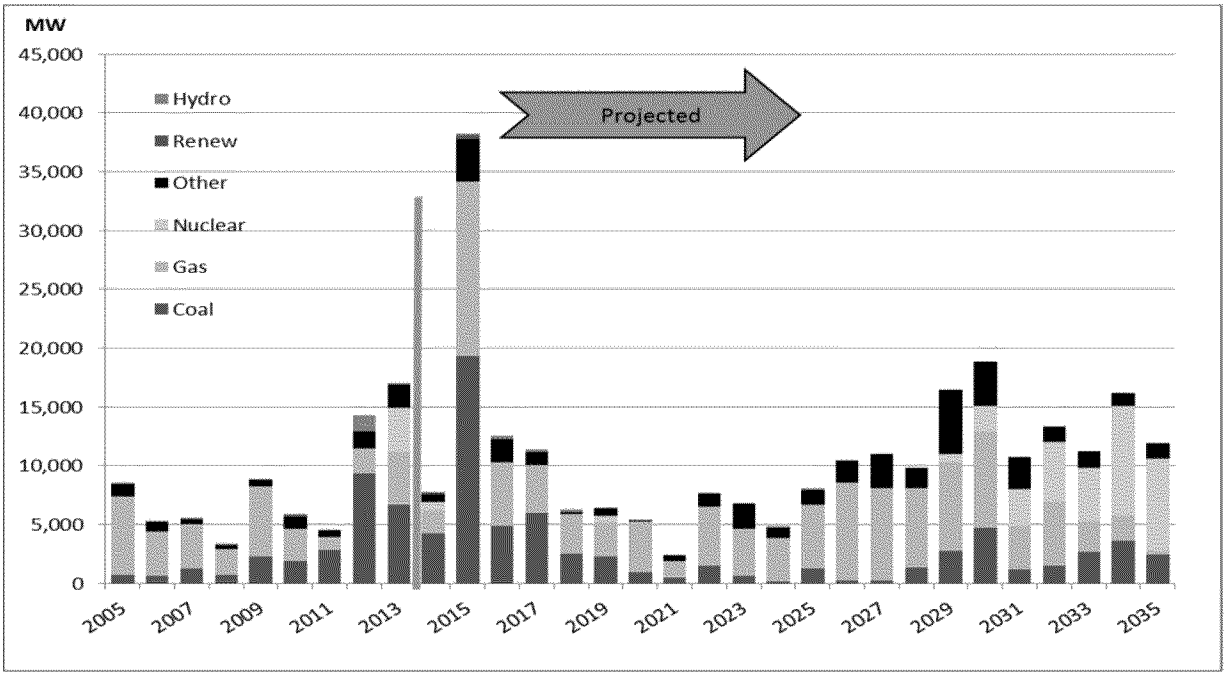
2014.[41] This unit should be treated as an under construction unit, not an existing unit, for purposes of calculating Utah's state goal. Accordingly, the re-dispatch portion of the Utah state target should be recalculated, consistent with the intended use of the unit. At minimum, EPA should not use the 70 percent capacity factor assumption for this unit when calculating the state goal.

iii. EPA has not accounted appropriately for retiring NGCC units.

If plants under construction are included in the goal-setting calculations (which, as argued above, is incorrect), then it is also appropriate in some instances to exclude plants that were scheduled to be retired between 2012 and 2014. EPA does not exclude from the calculations the NGCCs at risk of being retired. Given the large number of possible NGCC retirements suggested by the age of the natural gas-based fleet, see Figure 1 below, EPA's failure to account for future unit closures while simultaneously including under construction units, potentially overestimates the size of the NGCC fleet, as new NGCCs could be replacing older units scheduled to be retired. This "double counting" could result in inflated projections of the magnitude of emissions avoided and, consequently, unachievable state-specific goals.

[41] *See* Rocky Mountain Power, http://viewer.zmags.com/publication/e97992bd#/e97992bd/2.

Fig. 1. Retirements (announced and projected based on the age of plants)[42]



Source: EEI

2. EPA ignored physical, technical and financial constraints of both the gas and electric systems in determining the possible levels of re-dispatch to NGCCs.

The interaction between and among electric generation, wholesale electricity markets and the natural gas and pipeline industries is much more complex than described in the proposed section 111(d) guidelines. The potential for re-dispatch between existing coal-based and NGCC units is, in part, a factor of whether certain system constraints have been addressed. Making the appropriate infrastructure and system changes that will be necessary to achieve increased utilization of existing NGCC units in certain areas will take longer than EPA's proposed guidelines currently allow.

[42] The natural gas-based unit retirements projected in 2015 and after include units that are generating past their expected operating life and may, or may not, be retired.

a. EGU and electric system constraints may make increased NGCC utilization unachievable in the timeframe stipulated by EPA.

As mentioned above, despite having the physical potential to run at higher utilization rates, some plants are unable to achieve higher utilization rates when in actual operation because of dispatch decisions based on market signals, constraints in other elements of the bulk power system or in the natural gas pipeline delivery system.

A 2010 Congressional Research Service (CRS) report concluded that the ability of existing natural gas plants to displace coal generation depends on many factors, including:

- The amount of excess capacity in the natural gas fleet;
- The operating patterns of coal and gas plants and the system's degree of flexibility to change them;
- The ability of the transmission system to deliver power from existing gas plants to loads served by coal plants; and
- The ability of the natural gas supply industry to deliver larger amounts of natural gas where it is needed.[43]

The CRS report demonstrates the importance of evaluating the electric power system as an integrated whole that comes with various locational constraints. An assessment of the "excess" natural gas generating capacity is not enough. Physical (infrastructure) and operational limitations, as well as the location of each plant in relation to other generation facilities and load must be considered. These locational limitations matter as much as unit size or technical capabilities. For example, some NGCC units that theoretically could run at higher capacity

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[43] Stan Mark Kaplan, *Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants*, CRS (Jan. 2010) (CRS Report), http://fpc.state.gov/documents/organization/135929.pdf.

factors will necessarily be hindered by transmission constraints. Additionally, for coal-based generation to be able to be replaced by increased production from existing NGCCs, the natural gas units would have to be located in proximity to the coal plant. CRS conducted a proximity analysis and concluded, based on locational constraints alone, that "[e]xisting NGCC plants near coal plants may be able to account for something on the order of 30% or less of the displaceable coal-fired generation and CO_2 emissions." CRS Report at 17. The report goes on to note that this limitation should be factored into any plans to replace coal with natural gas. *See id.* Proximity matters, but equally important is whether the two units are dispatched by the same transmission operator. This concern was raised by Montana Public Service Commissioner Kavulla when he noted that two plants in the same state can be dispatched by different entities. This means that the two plants would "not share a dispatch signal that would allow one plant's increased operations to result in the lower dispatch of a plant operating in a different market."[44]

There are a myriad of other system constraints that can make it difficult to displace coal with existing natural gas-based generation. For example, it is possible that increasing the capacity factor of existing NGCC units would involve the closure of coal-based "must run" resources that could put reliability at risk. Also, there may not be enough actual NGCC spare capacity to achieve the necessary levels of fuel switching that are included in the proposed guidelines. As is the case in Arizona, for example, states with units that do not run much in the winter, but run at maximum capacity during the hot summer months, will find it very difficult to comply with the

[44] *State Perspectives: Questions Concerning EPA's Proposed Clean Power Plan: Hearing Before H. Comm. On Energy and Commerce*, 113th Cong. (2014) (statement of Travis Kavulla, Cmm'r, Montana PSC), http://docs.house.gov/meetings/IF/IF03/20140909/102623/HHRG-113-IF03-Wstate-KavullaT-20140909.pdf.

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interim targets.[45] In explaining this situation, the Director of the Arizona DEQ pointed out that "electricity generated at a facility in the winter cannot offset the need for electricity during the peak demands experienced in the middle of the summer."[46] In other words, due to the extreme temperature fluctuations in Arizona, EPA cannot assume that all capacity from natural gas units is available to be dispatched to replace coal generation. While such capacity may be available to displace some coal generation during winter months, this "excess" capacity will be needed to meet summer peak demand. Further, increasing existing NGCC generating capacity may also not be possible due to conflict with ozone attainment plans and unit-specific run-time limitations in NGCC permits in areas such as Southern California that are non-attainment for some criteria air pollutants.

As discussed in detail in section II.A., below, meeting EPA's state goals through increased re-dispatch of existing NGCCs in lieu of coal would, in many cases, require a system redesign, including the building of new transmission lines and new EGUs, which would take a much longer time frame to be completed than EPA allows, particularly given that the interim compliance period begins in 2020, only three years, at the most, after a state could have a final, approved compliance plan.

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[45] *See* Lea Radick, *States Warn EPA Climate ESPS' Fuel-Switching Plan Flawed, Unachievable*, Inside EPA (Sept. 8, 2014)(noting that the Arizona DEQ has already informed EPA that it has no excess NGCC capacity during the summer peak months).

[46] *State Perspectives: Questions Concerning EPA's Proposed Clean Power Plan: Hearing Before the H. Comm. on Energy and Commerce,* 113th Cong. (2014)(statement of Henry R. Darwin, Dir, Ariz. DEQ), http://democrats.energycommerce.house.gov/sites/default/files/documents/Testimony-Darwin-EP-EPA-Clean-Power-Plan-2014-9-8.pdf.

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b. EPA has not considered constraints related to the gas and electric systems' interdependency.

EPA has not identified or addressed constraints within the natural gas industry in its analysis in support of the feasibility of achieving 70 percent utilization rates at existing NGCC units. It is essential that the Agency assess whether the natural gas industry can support the level of increased NGCC utilization contemplated by the proposed guidelines both prior to and during the interim compliance period.

EPA assumes, based on observed past results (pipeline capacity additions from 2001 to 2003 and delivery of unconventional natural gas production since 2008), that natural gas pipeline capacity will be expanded to meet all electric sector needs in time for the sector to be able to comply with the proposed interim and final goals. *See* 79 *Fed. Reg.* at 34,864. However, as discussed below, there are a number of considerations involved in natural gas–electric coordination issues, of which the adequacy of pipeline infrastructure is only one. The two industries have different regulatory schemes, different operational requirements and different processes for building infrastructure. These differences are more acutely seen in areas with RTO/ISO markets. These issues are being discussed at both FERC and at the regional level. It is also important to note that, once financing for new natural gas infrastructure is obtained, it takes time to acquire the required regulatory approvals and to construct the pipelines. In general, it can take three to five years to permit and construct new natural gas transmission, and even longer if the project crosses federal or tribal lands or faces environmental obstacles or public opposition.[47]

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[47] *See* GAO, *Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Processes Include Multiple Steps, and Time Frames Vary* (Feb. 15, 2013), http://www.gao.gov/products/GAO-13-221.

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The regional nature and complexity of these issues have been discussed by FERC Commissioners. Chairman LaFleur noted in 2013 Congressional testimony that "[i]n certain regions, there may be inadequate local pipeline capacity to support generation during the winter heating season, due to geography, fuel mix, and market structure. This is already an issue in New England, and may be an emerging issue in other regions as more gas is utilized for generation."[48] Similarly, Commissioner Moeller has voiced his concern about "whether there will be sufficient pipeline capacity to support this increase in natural gas generation."[49] During a September 18, 2014 public meeting convened by Commissioner Moeller, electric generation owners voiced a number of concerns about the ability of the natural gas system to meet the needs of the electric system as well as "concerns regarding unknown or unreasonable commercial terms in pipeline service agreements, a lack of transparency surrounding available services and illiquidity in the natural gas market."[50]

The need for, the accessibility to, and the impacts of the increased use of natural gas in electricity generation are not uniform in all parts of the country. There are regional differences in fuel

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[48] *American Energy Security and Innovation: The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges: Hearing Before the H. Comm. on Energy and Commerce*, 113th Cong. (2013) (statement of Cheryl A. LaFleur, Comm'r, FERC), http://www.ferc.gov/EventCalendar/Files/20130319105841-LaFleurC-testimony.pdf.

[49] *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges: Hearing Before the H. Comm. on Energy and Commerce*, 113th Cong. (2013) (statement of Philip D. Moeller, Comm'r, FERC), http://democrats.energycommerce.house.gov/sites/default/files/documents/ Testimony_Moeller-EP-FERC-Clean-Power-Grid-Challenges-2014-7-29.pdf.

[50] William Friedman, *FERC Commissioner Moeller Convenes Public Meeting Focusing on Resolving Natural Gas Supply Challenges for Electric Generators*, ENERGY BUSINESS LAW (Sept. 23, 2014), http://www.jdsupra.com/legalnews/ferc-commissioner-moeller-convenes-publi-74430/.

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diversity, the use of firm or interruptible natural gas pipeline capacity by electric generators, natural gas pipeline capacity availability and flexibility, natural gas storage availability, integration of variable renewable resources, communication protocols as well as potential reliability impacts or system vulnerabilities that may occur as the generation fuel mix changes in the various regions. For example, while New England has concerns related to the lack of pipeline infrastructure and the ability of generators to contract firm natural gas delivery services, the desert Southwest has firm pipeline contracts but lacks natural gas storage and has concerns related to the flexibility needed on the gas side to address challenges associated with the increased deployment of variable resources.

FERC began examining this issue in August of 2012, and, since that time, electric utilities, system operators and state commissions also have examined the reliability issues associated with the increased use of natural gas for electric generation in their respective regions.[51] For example, FERC has recently turned its attention to natural gas and electric scheduling in an effort to determine whether and how natural gas and electric industry schedules and practices could be harmonized to achieve the most efficient scheduling systems for both industries.[52]

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[51] Some of these groups are the Eastern Interconnection Planning Collaborative; Eastern Interconnection States Planning Council; Western Governors Task Force; Desert Southwest Pipeline Stakeholders; Northwest Mutual Assistance Agreement; Pacific Northwest Utilities Conference Committee; and Columbia Grid.

[52] *See Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (2014), http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf.

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In addition to FERC, the RTO/ISOs also are discussing these issues through their stakeholder processes[53] and are conducting regional studies to determine what must be done to maintain reliability going forward. Similarly, NERC has noted that "higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built." Initial Reliability Review at 10. If the organizations charged with maintaining reliability and ensuring the functioning of electricity systems and markets are concerned about natural gas infrastructure and gas-electric coordination, EPA cannot ignore these issues in its BSER analysis. Chief among these issues are the sufficiency of the current natural gas pipeline infrastructure, as well as the financing mechanisms for future pipeline construction and the competition for existing pipeline capacity.

i. EPA has not demonstrated that the current natural gas pipeline infrastructure can support increased NGCC utilization.

EPA has not demonstrated that the current pipeline infrastructure can support the level of increase in natural gas utilization that would be required by the proposed guidelines. As previously discussed, the fact that a portion of a system may have been able to manage increased natural gas-based electric production in 2012 does not justify its use as a national benchmark for the future. The cold weather events in January and February of 2014 raised a number of issues related to gas operational flow orders and gas availability. EPA incorrectly concludes that because, in 2012, the natural gas pipeline system supported NGCC utilization rates of 60 percent or higher during peak hours in certain portions of the country, and, because natural gas generation grew considerably in 2012 and the gas industry was able to supply the necessary gas

[53] These groups include the New England States Committee on Electricity Gas-Electric Focus Group; ISO NE Electric Gas Operations Committee; NY ISO Electric Gas Coordination Working Group; MISO Electric Natural Gas Coordination Task Force; PJM Gas-Electric Senior Task Force; and SPP Electric Coordination Task Force.

to generators, then the existing pipeline infrastructure can support sustained increased NGCC production nationwide. *See* 79 *Fed. Reg.* at 34,863. Again, this assumption ignores regional disparities, seasonal variations, the anomalies of 2012 and the realities of the natural gas pipeline markets.

The ability of the nation's natural gas infrastructure (pipeline, storage, markets) to deliver dramatically increased amounts of natural gas where and when it is needed by electric generators is an issue of serious concern. FERC has been working on gas-electric interdependency issues for some time now and NERC, as well as the RTOs and ISOs, continue to study the adequacy of the natural gas infrastructure system to ensure that electric reliability is maintained as natural gas use for power generation increases.[54]

In the Eastern part of the country, this concern has been voiced recently by NERC, when it recognized the potential benefits of prospective pipeline capacity, but noted that the New England region would continue to face challenges, even after expected expansions were completed. Specifically, the report stated that, "[f]or New England, this includes the potential for natural gas interruption to gas-fired generators and a reliance on back-up fuel (generally oil) to meet peak demand."[55]

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[54] *See, e.g.,* NERC, *2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States* (Dec. 2011), http://www.nerc.com/files/gas_electric_interdependencies_phase_i.pdf.

[55] NERC, *2013-14 Winter Reliability Assessment,* at 7 (Nov. 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013WRA_Final.pdf.

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Other experts have addressed concerns about the sufficiency of natural gas infrastructure in the West, emphasizing in a recent report that "existing infrastructure…will be increasingly strained if new investments in natural gas generation increase any region's reliance on that fuel."[56] The report pointed out the interconnected and interdependent nature of natural gas infrastructure and stated that "regional planning efforts must not only consider infrastructure within the region but the conditions and market forces in neighboring regions as well." *Id.* at 13.

EPA cannot ignore the conclusions of these experts about the realities of the nation's natural gas system and cannot assert that infrastructure will be sufficient to support an increase in natural gas utilization at the pace and level contemplated by the proposed guidelines.

ii. EPA's assumptions about increased natural gas use ignore the firm capacity contracts used in the industry.

Natural gas pipelines have traditionally been financed through long term, firm capacity contracts signed by natural gas consumers (local distribution companies (LDCs), utilities and industrial consumers). Unlike electric transmission lines, which are planned based on *projected* electricity demand, natural gas pipelines are built when there is a *real* demand for natural gas that can be translated directly into long-term, firm contracts. Power generators do not always sign firm capacity contracts because they do not always know how much natural gas they will need or when. This is especially true in RTO/ISO markets as generators do not know if they will be required to run until they clear the day-ahead market. Because these generators only recover costs when they run (or may only run at peak), they may not want to enter into long-term firm

[56] Energy + Environmental Economics, *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective*, at 14 (Mar. 2014), https://www.ethree.com/documents/E3_WIEB_Report_3-17-2014_ExecSum.pdf.

contracts for "24-7" natural gas. They rely, instead, on more flexible and affordable non-firm or interruptible contracts. As noted, RTO/ISOs are examining these issues in their stakeholder processes. Changing this practice may require institutional and regulatory changes that take time, particularly in areas with organized markets where generators cannot pay the premium required to purchase firm pipeline service and remain competitive in wholesale electric markets.

As an example, a February 2014 Energy Information Agency (EIA) report on natural gas issues and trends in New England found that low natural gas prices and decreased LNG imports had led to increased utilization of natural gas for electricity generation and that "[i]increased pipeline utilization rates on peak days create physical stress on the natural gas transport system, which leads to reliability concerns for electric power sector deliveries."[57] Further, the EIA report observed that regulated pipeline companies require financial assurance to support the capital required for such projects obtained primarily "by signing long-term firm transport capacity contracts with shippers" but that "firms signing these contracts also assume the financial liability." *Id.* As an example, the report noted that Spectra Energy announced in 2011 a capacity expansion of its Algonquin pipeline of 1 Bcf/day but that, in 2013, the proposed expansion was reduced to 0.33 Bcf/day, with the target completion in November 2016. *See id.* This 65 percent reduction was due to lack of interest in long-term firm transport capacity contracts because of concerns about absorbing the financial costs inherent in such contracts—despite identified reliability concerns related to insufficient capacity. Additionally, the report found that public utility commissions (PUCs) require utilities to seek approval for signing long-term contracts and

[57] EIA, *Issues and Trends – Natural Gas* (Feb. 7, 2014), http://www.eia.gov/naturalgas/issuesandtrends/deliverysystem/2013/.

the rate changes required to pay for them, which increases the uncertainty of when, and if, pipeline expansions occur.

EPA needs to take into account the complexities of the electricity and natural gas industries as well as recognize that the links between power markets and pipeline construction make it difficult to develop the pipeline system in a way that allows states to comply with EPA's proposed rule.

iii. EPA must consider the competing demands on natural gas infrastructure when calculating achievable NGCC utilization rates.

In addition to the challenges associated with building new pipeline capacity discussed above, EPA also does not consider the competition for existing pipeline capacity. The electric power sector competes for pipeline services with two other major natural gas consumers: gas LDCs serving both residential and commercial sectors, and industrial consumers. Consumption by electric generators does not necessarily coincide with consumption in the natural gas transmission system. As such, noting that the pipeline network can support high levels of natural gas-based generation during electric peak hours tells only part of the story. In fact, on an annual basis, natural gas and electricity consumers traditionally demonstrate counter-cyclical consumption patterns, which help facilitate greater sharing and efficiency in the use of pipeline capacity. The natural gas peak tends to coincide with the winter heating season, whereas the electric peak usually occurs in the summer. By requiring the increased use of natural gas for electricity throughout the year, the proposed rule likely would strain the supply of natural gas in the winter months. In addition, and as NERC notes, "though fuel supply concerns for natural

gas-fired generation are more significant during the winter season, difficulties can arise during the summer season."[58]

As previously noted, traditionally, natural gas pipelines have been built through long-term firm contracts for the pipeline capacity. Because firm contract holders purchase for peak periods, they may have excess capacity that they will release or contract to others (using interruptible or secondary firm contracts). Because the electric and natural gas systems historically have peaked at different times, this "released" capacity has been available for use by EGUs without firm contracts. The increased use of natural gas by EGUs, industrial customers and distribution companies creates additional competition for this finite existing capacity.

Figure 2 below, illustrates the typical consumption patterns of the three competing groups of natural gas users. As the figure demonstrates, consumption from the three groups generally creates an "infrastructure use equilibrium." If that equilibrium is broken because natural gas generation increases dramatically during the whole year, it is likely that the electric power and natural gas distribution industries will have to compete for limited pipeline capacity. This can result in natural gas shortages for either power generation or residential heating.[59] A major expansion of the pipeline network and/or a modification of the rules governing that market would be required to avoid such results.

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[58] NERC, *2014 Summer Reliability Assessment*, at 19 (May 2014). http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf

[59] For health and safety reasons, gas for home heating traditionally has had priority over natural gas for power generation.

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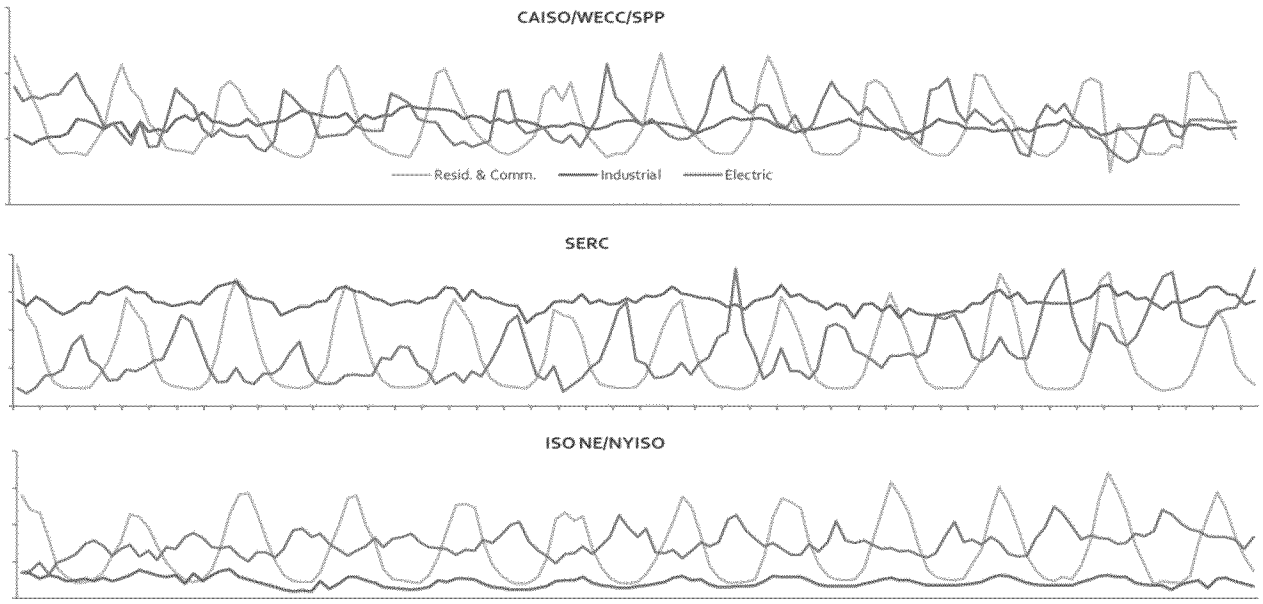
Fig. 2. Competition for Pipeline Capacity – Selected Regions (2001-2012)



Source: EEI

In the proposed guidelines, EPA recognizes some of the challenges to increasing NGCC utilization, primarily infrastructure and system considerations. EPA does not, however, analyze the impact of those challenges or take them into account when determining an achievable level for the nation's NGCC fleet utilization rate. Moreover, EPA fails to recognize the importance of these constraints. Solutions to some of these challenges depend on actions taken by other sectors, injecting a level of uncertainty into any discussion about fuel availability and deliverability.

EPA should take into account the work being done by both the electric and gas industries and recognize that the challenges presented by gas-electric coordination are greater than the Agency

assumed when calculating potential natural gas utilization rates. Natural gas consumption patterns of other industries should also be factored into any determination of "reasonable" or achievable levels of NGCC utilization.

3. EPA has not demonstrated that a 65 percent utilization rate for NGCCs is achievable.

In the proposal, EPA requests comments on an alternate utilization rate of 65 percent. *See* 79 *Fed. Reg.* at 34,899. In support of the 65 percent utilization rate, EPA notes that 16 percent of the NGCC plants had utilization rates of 65 percent or higher during 2012. *See id.* at 34,866. None of the problems with EPA's analysis in support of a 70 percent utilization rate, discussed above, are ameliorated by a 65 percent goal. Accordingly, EPA has not provided a reasonable basis for its determination that a 65 percent utilization rate is achievable.

While EPA recognizes that there are constraints on increasing NGCC utilization rates, EPA does not appear to have adequately considered these constraints or the potential enormity of their cumulative impacts. Instead, EPA concludes that the challenges can be overcome and claims that it has provided sufficient time within which to address any necessary expansion of infrastructure. *See* 79 *Fed. Reg.* at 34,837 and 34,862-64. Moreover, according to EPA, the level of potential coal-to-gas switching associated with assuming that existing NGCC units could run at a utilization rate up to 70 percent will not impact natural gas or electric system reliability. *See id.* at 34,864. Accordingly, EPA deems that this level of re-dispatch is potentially achievable by all states. EPA's assumptions, and resulting conclusions, should be amended to account for a broader set of potential system constraints and their cumulative impacts.

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4. EPA should not adopt the proposals advanced in the NODA regarding natural gas use and changes to the calculation of Building Block 2.

In the NODA, EPA addresses several issues that have been raised by stakeholders since publication of the proposed guidelines. With respect to natural gas units, the NODA invites comments on including new NGCC units and natural gas co-firing in existing coal-fired boilers in Building Block 2, imposing a minimum level of re-dispatch and recalculating Building Block 2 goals based on a regional approach. *See* 79 *Fed. Reg.* 64,549-50. The concerns regarding the treatment of natural gas in the proposed guidelines are valid, and EPA should work with the states to identify solutions to these potential problems. However, EPA should not adopt the new proposals advanced in the NODA.

a. New NGCC units and co-firing at coal-based units should be available as compliance options for states, but not included in Building Block 2 calculations.

As with under construction units, new NGCC units should not be included in Building Block 2 calculations. EPA based the proposed guidelines on a state-by-state analysis of the state generation fleets and used 2012 as the baseline year. As EPA noted, 2012 was used because it was the last year for which data was available and it was important to base the proposal on existing data in order to have the most complete and accurate calculations possible. Accordingly, an increased departure from 2012 actual fleet characteristics will result in increased uncertainty and potential for errors in calculation and modeling associated with potential fuel switching and re-dispatch. New NGCC units are, by definition, uncertain and ambiguous resources. While states should have the option of including these units in compliance plans, they should not constitute a component of BSER.

Although co-firing can be a cost effective way to reduce emissions from coal-based generation, assessing the potential for co-firing is almost impossible due to the complexities and uncertainties that surround the future of coal power plants. This is particularly true given the uncertain new landscape for coal-based power plants that will result from the proposed rule and other environmental regulations. For example, in order to co-fire, coal-based units must have enough natural gas delivery infrastructure to support the level of natural gas expected to be burned.

As noted previously in these comments, sufficient infrastructure may not be available in the timeframe defined by the proposed rule. Moreover, co-firing can only be considered in units that will remain operational during all or part of the compliance period and that will have an output that will remain relatively unchanged by the re-dispatch goal. Without knowing which coal-based units will remain operational and what the individual output of each unit will be, it is essentially impossible to determine the potential level of co-firing. The future of these coal-based units, however, will not be known until states have submitted compliance plans. Accordingly, co-firing should remain a tool available to states to help them achieve emission reduction goals, but should not be part of BSER. Simultaneous inclusion of co-firing with re-dispatch could lead to double counting of potential emission reductions.

b. EPA should not redefine the Building Block 2 calculations as proposed in the NODA.

In the NODA, EPA notes that stakeholders have expressed concern regarding the impact of the Building Block 2 calculations on states that have little or no NGCC capacity. Specifically, these states have less stringent goals than states with larger natural gas fleets. In an effort to address

these concerns, EPA proposes two new approaches: imposing a minimum level of natural gas dispatch and calculating Building Block 2 on a regional basis. *See* 79 *Fed. Reg.* at 64,549-50.

As proposed in the NODA, EPA's new approach amounts to a mandate to burn a minimum amount of natural gas. EPA has not made any determination that justifies the imposition of a mandate for natural gas use as a component of BSER. Moreover, although the mandate would ostensibly be used only to determine the target for Building Block 2, for all practical purposes, the actual implementation of state goals would have to mirror the targets in the other Building Blocks to a very large degree. Any predefined amount of natural gas usage would be arbitrary and would lock states into a specific technology and fuel—potentially to the detriment of cleaner fuels—which would further reduce state flexibility and go against principles of fuel neutrality and cost effectiveness.

Additionally, EPA invites comment on redefining Building Block 2 targets based on regional availability of NGCC generation. EPA suggests that this approach would make it easier to overcome natural gas infrastructure constraints and may help address the disparity in stringency of goals across states. *See id.* at 64,550-51. This approach is also problematic as it would add another subjective element to the goal computation. A regional approach for Building Block 2 is an arbitrary and artificial way to increase the stringency of some states' goals and smooth out differences in state targets by normalizing states' generation mixes. This result is at odds with the proposed rule's stated goal of accommodating the differences in state generation mixes. Further, calculating Building Block 2 values on a regional basis would be complex and EPA has not provided any details on how regions would be determined or how shares would be allocated among the states within a region. In the BSER formulation, EPA treats natural gas and coal

generation as two sides of the same coin. Therefore, if a regional approach was used to determine NGCC capacity availability, a regional approach should also be used to determine how much coal-based generation is available to be displaced. As stated throughout these comments, the electric system is planned and built as an organized and coordinated structure, largely independent of state boundaries.

5. EPA did not acknowledge or consider the complex interrelationships between the four BSER Building Blocks when setting state goals.

In its BSER analysis, EPA determines "achievable" levels of implementation for each individual Building Block in isolation. EPA has not considered the impact of each of the four Building Blocks on the electric system as a whole nor has it examined how the Building Blocks will interact with, or affect the achievability of, each other. Instead, EPA concludes that reaching the prescribed levels of each of the Building Blocks is possible separately and, hence, also simultaneously. This is not likely.

For example, there is a direct interdependency between variable renewable generation and natural gas units. As will be further explained in section II.D. below, because the output of renewable resources is variable, use of these resources requires balancing and back-up services from the grid. Natural gas-based units are more flexible than other fossil fuel-based dispatchable resources and usually provide these services. Units needed to back up variable resources operate at lower capacity factors so that they can respond to a relatively sudden or unplanned decrease in electric generation at any time by increasing output. Increasing the utilization rate of the existing NGCC fleet to 70 percent reduces their availability to back-up renewables. Moreover, increasing renewable generation could mean that existing NGCC units may need to *reduce* their capacity factor to increase their responsiveness to the variability of renewable output. Alternatively,

increased utilization of NGCC unit generation could limit the ability to integrate additional renewables into the grid unless other resources are added. These interrelationships undermine EPA's assertion that the desired level of re-dispatch will occur within the existing NGCC fleet and that no new power plants would be needed. *See* 79 *Fed. Reg.* 34,876.

Assessing each Building Block in isolation also hides another important interrelationship between resources. Power plants are designed and built with specific characteristics and are able to achieve maximum efficiencies under particular circumstances. If increased renewable generation results in more cycling of NGCC units, their generation efficiency likely will be degraded, increasing the emission rate of the unit and that of the entire system.[60] As discussed in EEI's May 9 comments, increased cycling, more startups and lower capacity factors increase the emissions rate of power plants. See Appendix C at 4-5. NERC also has noted that "[l]ower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire fleet are unlikely." Initial Reliability Review at 8.

[60] *See* NERC & California ISO, *2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach*, at 15 (Nov. 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

D. EPA's Methodology for Calculating State Renewable Energy Goals Contains Inconsistencies and Flaws that Must Be Addressed.

EPA's Building Block 3 encompasses both the increase of renewable generating capacity and the preservation of "at risk" and under construction nuclear capacity.[61] EEI members are already actively increasing the development of renewable generation nation-wide, but EPA's approach to quantifying the potential emission reductions that could be achieved through increased deployment of renewable generating capacity raises a number of methodological concerns and may result in individual state emission goals that are not achievable. EPA should revise the generic approach to quantifying potential reductions from increased deployment of renewables and adjust state-specific goals to reflect state-specific concerns about the proposed emission rate goals before finalizing these goals. EPA should work with the states to set achievable state goals that reflect in-state conditions.

Renewable energy (RE) resources provide valuable zero-emissions electricity generation. As a preliminary matter, EEI supports the use of electricity from existing and new RE resources as a means of demonstrating compliance in any final rule. Electric utilities, including EEI's members, are actively building and investing in renewable generating technologies and are expanding renewable options for customers via utility-scale resources, green power programs, community solar program, grants, rebates and performance-based incentives. The last few years have seen record development of wind and solar resources, and the pace of development is expected to continue. According to the EIA, there are more than 158,000 MW of installed

[61] Concerns about EPA's approach to new and preserved nuclear capacity are discussed *infra* section III.B.

renewable capacity in the U.S.[62] In addition, there are more than 20,400 MW of renewable generation under construction or in advanced stages of development and another 20,600 MW that have received permits to begin construction.[63] While EEI members continue to pursue the development of renewable resources, it is essential that utilities and developers retain the flexibility to site and build these generation resources where they make the most practical, economic, technical and environmental sense. This may or may not fall within a given state's borders as envisioned by EPA.

To calculate the state-specific RE goals, EPA proposed a primary and an alternate approach. Under the primary approach, EPA averaged the individual state 2020 renewable energy standard (RES) requirements within each of six EPA-determined regions and then set a regional RE target for 2029 equal to this average. Next, EPA calculated a regional annual growth rate—an annual percentage increase in RE generation—required to reach the regional target. Finally, EPA applied that growth rate to each state's level of 2012 RE generation. EPA's state-specific RE goals assume states start increasing RE generation in 2017 and continue increasing RE generation every year through 2029. *See* 79 *Fed. Reg*. at 34,867.

EPA's alternate proposed approach addresses some of the key flaws in the primary proposed approach by trying to take into account each individual state's RE potential. However, this

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[62] *See* EIA, *Annual Energy Outlook 2014,* at A-21 (Apr. 2014), http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

[63] *See* EEI, *Generation Status Update* (2014), http://www.eei.org/issuesandpolicy/generation/Pages/default.aspx.

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approach relies on unsubstantiated assumptions about the rate at which states can develop renewables and the future costs of RE generation technologies.

While utilities are actively building and financing RE development and support including RE as an option for state compliance with the proposed 111(d) guidelines, EPA's proposed primary and alternate methods for setting RE generation goals raise significant concerns about whether the proposed goals can be achieved by the states. Specifically, the primary proposed approach relies on individual state RES targets to set regional goals. *See id.* at 34,836. This regional approach inappropriately assumes that individual state RES mandates are proxies for region-wide RE potential and that all neighboring states have similar RE potential. Further, EPA's use of RES requirements fails to consider key design features of state RES programs. For example, hydropower resources often are included in setting the state standards, but they are excluded from the available compliance options. *See id.* at 34,867. As for biomass, while EPA has provided some guidance as to whether states will be able to consider biomass for compliance purposes, significant uncertainties still exist. *See id.* at 34,927.

Finally, EPA fails to consider the technological challenges of integrating additional renewable generation into the interconnected power system. EPA also did not assess how the other proposed Building Blocks and the interconnected nature of the power system could affect a state's ability to achieve the proposed levels of RE generation.

EPA asserts that the proposed state RE goals are reasonable and, in fact, that states have the potential to increase renewable generation well beyond the goals EPA proposes. *See* 79 *Fed.*

Reg. at 34,859. The myriad flaws in EPA's proposed approaches to establishing state RE goals undermine EPA's analysis in support of these assertions. EPA should revise its approach to setting state RE goals.

1. EPA's reliance on state renewable energy standards is flawed and overestimates the achievability of states' RE goals.

Under the proposed guidelines' primary approach to determining RE baseline and target goals, EPA relies on state RES requirements to create regional RE targets that are then applied to individual states. *See id.* at 34,836. This approach may overestimate what is achievable in some states, particularly those that do not have existing RES mandates, and ignores policy decisions that have already been made in those states. In addition, EPA misuses state RES programs by failing to recognize that certain RES design elements can have the effect of reducing the amount of in-state generation necessary for compliance. Further, EPA fails to adjust state RES goals to reflect the fact that generation from existing hydropower generation and other resources cannot be used for compliance under the proposed 111(d) guidelines, despite the fact that many state RES goals rely on these resources. EPA also has indicated that some, but not all, biomass that is eligible under state RES programs could be used for compliance, adding further uncertainty to the RE assumptions in the proposed guidelines.

a. The use of EPA-determined regions in calculating baseline and target RE generation levels overestimates RE goals for some states.

EPA acknowledges that there are regional differences throughout the country that may result in differing capabilities and resources for increasing RE generation. *See id.* at 34,917. However, EPA fails to recognize that significant differences often remain among states within a given region, and what may have been demonstrated to be achievable in one state may not be achievable in another, neighboring state. Energy market prices, geography, topology,

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transmission, load, seasonality, endangered species-related siting rules, state or local permitting and siting rules, congestion and existing energy mix are just a sample of the many factors that play a role in where renewable resources are developed.

EPA grouped states together into six regions for determining state RE goals. *See* 79 *Fed. Reg.* at 34,866-67. However, states within the same region can and do have very different solar or wind potential. For example, Louisiana and Kansas have dramatically different wind resource potential, but are included in the same region.[64] It is not reasonable to assign Louisiana the same RE goal as Kansas, given the known differences in their wind resource potential. NERC further highlighted this problem with the Building Block 3 methodology in a recent report, which found that "[g]iven the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two States in the same region sets unattainable targets for Louisiana." Initial Reliability Review at 12.

If EPA chooses to retain a regional approach to developing state RE goals, the Agency should allow a state to change regions if it can demonstrate that another region is more representative of its RE potential, or alternately allow a state-specific analysis of what is achievable within a state.

[64] *See* National Renewable Energy Laboratory (NREL), *United States Wind Resource Map* (May 2009), http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf.

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b. EPA cannot assume regional compliance when calculating state-specific RE goals.

In setting a regional RE target as the first step in setting a state goal, EPA appears to assume that there will be regional or multi-state compliance efforts. As discussed in section III.D., below, multi-state compliance planning may be valuable in resolving certain compliance challenges identified by some states and utilities. However, EPA cannot set targets assuming that multi-state plans will be developed and implemented. This approach could result in inflated RE goals for states that are not able to engage in multi-state compliance plans. EPA cannot argue that targets predicated on regional efficiencies—or on the trading of RE credits from regional partners for compliance—are achievable by individual states.

Moreover, generation planning is typically done at the state level (or service territory level or organized market level in areas where RTOs or ISOs exist). It can take many years, along with many changes to existing rules and regulations, to adapt and evolve toward a regional approach in electric generation planning. As proposed, the state goals are based on states increasing their RE generation starting in 2017—the earliest that a state would have a final, approved compliance plan and before regional plans would be submitted to EPA for approval. *See* 79 *Fed. Reg.* at 34,873. Accordingly, the guidelines do not provide sufficient time for states to design and implement the regional compliance approaches needed to achieve the proposed RE goals.

c. EPA inappropriately ignored states that do not currently have RES requirements when calculating regional and state RE goals.

EPA's calculation of regional RE goals does not recognize that some states do not have existing RES requirements. For each region, EPA averaged the existing state RES requirements for 2020. If a state in the region did not have an RES, EPA ignored that state by excluding it from

the denominator of the averaging calculation. *See* 79 *Fed. Reg.* at 34,866-67; Abatement Measures TSD at 4-16 ("the EPA compiled the state-level effective RE levels derived above, organized them by region, and determined an average percent generation target for that region. This average did not include any values for states in which there is no binding RPS requirement."). EPA then applied this skewed "average" RES requirement to *all* states in the region. *See id.* This has the effect of making the renewable goal in some regions more stringent than it would be if it were an average of all states in the region. EPA provided no reasoned explanation for the exclusion of states without 2020 RES requirements when calculating regional and state RE goals. In fact, EPA states that "[t]he proposed approach is derived from state experience with policies that drive investment in RE and the generation that results from those efforts." *See* Abatement Measures TSD at 4-2. Yet EPA simultaneously ignores the fact that some states have made a determination that their RE resources are not sufficient for mandating a required level of RE generation in a particular state.

EPA's approach to averaging state RES mandates to develop a regional RE goal is particularly problematic in the Southeast and South Central regions, where many states do not currently have RES requirements.[65] *See* Abatement Measures TSD at 4-15. In the Southeast region, only one of the eight states has an RES.[66] In the South Central region, only one of the six states has an

[65] For state-specific information about RES requirements, *see generally* C2ES, *Renewable and Alternative Energy Portfolio Standards* (2014), http://www.c2es.org/us-states-regions/policy-maps/renewable-energy-standards.

[66] *See id.*

RES.[67] As a result, in these two regions, a single state's RES requirement becomes the standard for an entire region. This approach ignores the question of whether the other states in these regions have the same potential to deploy an increased amount of renewable generation. EPA's proposed state emission rate goals in the East Central Region must also be re-calculated due to the passage of S.B. 310 in Ohio just prior to the publication of EPA's proposed 111(d) rule. Ohio S.B. 310 amended EE and alternative energy resource mandates (including renewable mandates) by imposing a two-year pause on energy efficiency, peak demand reduction and renewable energy resource requirements. It also eliminated both the RE resource in-state requirements and advanced energy resource requirements, thereby reducing the former alternative energy resource mandate by half. Due to the timing of Ohio SB 310, EPA did not reflect the impact of this new state law in the Building Block 3 calculations for the East Central Region. EPA must recalculate state RE goals within the region based on the passage of Ohio's S.B. 310.

In addition, EPA's BSER goal calculation approach does not appear to recognize that the Kansas RES goal is based on peak demand capacity (in MW), whereas state BSER targets are based on net electricity generation (in MWh). Because there is no direct or predictable correlation between the extent of RE deployment (measured in MW) and RE utilization (measured in MWh), it is impossible to accurately translate capacity directly into generation. Yet, this is precisely the approach that EPA took when calculating the Building Block 3 RE goals for each

[67] The Texas RES is capacity-based. In addition, EPA's averaging approach did not recognize that the Kansas RES goal is based on peak demand capacity, whereas most RES targets are based on retail electric sales. *See* C2ES, *supra*, n.65.

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state in the South Central region. This further illustrates the problems associated with the regional averaging approach in the South Central region.

A slightly different, but similarly problematic, result occurs in the West region. In the West region, multiple states (Idaho, Wyoming, Utah) have no RES requirements and one state—California—has the most aggressive RES requirements in the country.[68] Because California is not the only state in the region with RES requirements, California's RES does not set the RE goal for the region, but California's RES does serve to dramatically increase the regional RE goal. EPA made no effort to control for California's aggressive RES requirement as an obvious outlier among state RES mandates in the West region. California was able to set such an aggressive RES, in part, because other states in the region have not. Much of the renewable generation built in the West is relied upon for compliance with California's RES, and may therefore be unavailable to count toward compliance with the RE goals in the state in which the facility resides—further increasing the stringency of many of these western states' goals as currently proposed. Alternatively, California may have trouble finding RE to import if the other western states now need the generation to meet their own stringent in-state RE goals, making it more difficult for California to achieve its RE goal.

Applying one state's RES mandate to an entire region, or allowing one state's mandate to dramatically increase the regional goal, is inappropriate. First, as discussed above, states in the same region do not necessarily have the same RE potential. It is unreasonable to assume that one state can achieve the same level of RE deployment as a neighboring state. Second, RES targets

[68] *See* C2ES, *supra,* n.65.

are forward-looking goals. In many cases, therefore, the state with the existing RES target has not yet achieved the goal, yet it is assumed that neighboring states will be able to achieve a similar goal. As discussed in more detail below, a state's RES requirements not only reflect that state's assessment of the potential to deploy RE generation and RE-related policy decisions, but also reflect a range of policy choices that have nothing to do with technical RE potential.

Accordingly, if EPA continues to average state RES mandates in order to derive regional RE generation goals, the Agency should include *all* states in calculating the average,[69] even those states with no RES requirements. This would provide an actual average of the state requirements in the region and would ensure that one state's RES is not arbitrarily and inappropriately imposed on all other states in the region. Similarly, EPA should control for states with significantly more aggressive RES requirements when determining regional RE goals.

d. EPA did not consider RES design elements that reduce the required levels of in-state RE generation when setting regional RE goals.

EPA's regional RE goal calculations do not recognize important elements of individual state RES programs, such as the use of out-of-state renewable energy credits (RECs) for compliance, alternative compliance payments and credit multipliers for certain resources. These mechanisms serve to reduce the actual levels of in-state RE generation needed to satisfy RES mandates. EPA's failure to consider these factors results in inflated state RE goals that may not be achievable by certain states.

[69] Given that states in the same region may have very different loads, the average should be weighted accordingly.

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State RES mandates are not proxies for a state's potential to deploy more RE generation, but rather, they reflect policy choices made in each state with regard to how much and what type of renewable resources it wants to encourage, at what cost and in what timeframe. This is underscored by the fact that at least 23 of the 29 states with an RES allow compliance deviations due to cost impacts, supply constraints or reliability concerns. Eleven states allow compliance deviations based on a force majeure finding or if utilities have made good faith efforts to comply but cannot because of factors beyond their control.[70]

Further, 24 of the 29 states with an RES allow the use of out-of-state power and RECs for compliance.[71] The use of these important compliance mechanisms enables critical flexibility in achieving the mandates and serves to recognize that, in some cases, sufficient RE resources are more widely available or can be more economically developed in other states (and Canada and Mexico), which helps keep RES costs lower for customers. Some state RES programs also allow compliance through alternative compliance payments.[72] If EPA uses state RES mandates as the basis for setting regional or state RE goals, EPA must adjust RES goals to reflect these design elements in recognition of the fact that RES mandates typically require a lesser amount of in-state generation.

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[70] *See* Department of Energy (DOE), Database of Energy Efficiency Renewable Energy (DSIRE), http://www.dsireusa.org.

[71] DSIRE, *Rules, Regulation & Policies for Renewable Energy*, http://www.dsireusa.org/summarytables/rrpre.cfm.

[72] *See* C2ES, *supra*, n.65.

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EPA also fails to recognize the credit multipliers that some states apply to certain resources to further encourage development of these renewable resources. EPA states that "these credit multipliers and bonuses are not an accurate representation of the amount of renewable energy generation that is attributable to an RPS." *See* State Plan Considerations TSD at 63-64. Twelve states have some type of resource-specific credit multiplier.[73] Failure to adjust state RES requirements to reflect these credit multipliers results in overestimated RE goals. For example, if a state RES requirement is 20 percent by 2020, and that state provides an extra multiplier for solar generation, the actual requirement is less than 20 percent because solar resources are given greater compliance credit. Therefore, any state RES mandates used by EPA in setting regional or state RE goals should be discounted to reflect these credit multipliers.

EPA must take into account the fact that states have not established RES percentage targets in isolation, but have thoughtfully and intentionally determined the targeted levels of renewable generation for each state in the context of, and in conjunction with, determining the resources that are available to meet the target level, the cost of meeting the target level and other policy objectives. If EPA uses state RES mandates as the basis for setting regional or state RE goals, EPA also must adjust RES goals to reflect these design elements or enable additional compliance mechanisms consistent with existing state RES programs.[74]

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[73] *See* DSIRE, *Renewable Portfolio Standard Policies*, http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[74] In the alternative, if EPA does not adjust its approach, EPA could allow states to use all RES-eligible resources in 111(d) compliance plans.

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e. EPA must adjust regional RE goals to reflect the fact that generation from domestic and international existing hydropower resources may not be used for compliance.

Hydropower generation is an essential zero-carbon emitting resource and reduces the overall mass emissions of the U.S. energy sector. In 2012, 6.8 percent of electricity generation came from hydropower, making it the largest RE resource.[75] Nearly every state allows generation from certain existing hydropower facilities—including in-state, out-of-state and international facilities—to be used for RES compliance, and hydropower generation is used to satisfy a large portion of many state RES requirements.[76] EPA states that the Agency "adopted a broad interpretation of RE generation to include any non-fossil renewable fuel type, with the exception of generation from existing hydroelectric power facilities" when calculating baseline levels of state RE generation. *See* Abatement Measures TSD at 4-5. When determining the regional RE targets, however, EPA does not appear to have adjusted state RES targets to exclude existing hydropower. This approach is inconsistent with EPA's stated approach to hydropower in setting state goals.[77]

Moreover, the proposed guidelines do not allow the use of these resources for compliance with the proposed state-specific goals. *See* 79 *Fed. Reg*. at 34,867. Should EPA restrict the resources available for compliance, despite their role in states' existing RES programs, the Agency must

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[75] EIA, *Electric Power Monthly*, *With Data for September 2014*, Table 1.1, Net Generation By Energy Source: Total - All Sectors, 2004-August 2014 (Nov. 2014), http://www.eia.gov/electricity/monthly/.

[76] *See* DSIRE, *Hydroelectric Incentives*, http://www.dsireusa.org/incentives/index.cfm?EE=1&RE=1&SPV=0&ST=0&technology=Hydro&sh=1.

[77] EPA's treatment of biomass resources presents similar concerns. These issues are discussed *infra*, section III.D.2.b.

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also reduce the state RE goals to account for this limitation. It is arbitrary for EPA to use state RES mandates that explicitly contemplate the use of certain hydropower resources to set regional or state RE goals for 111(d) purposes, but not allow these resources to be used for compliance as it increases state goal stringency while simultaneously depriving states of an important compliance tool.

The same issue arises when considering pumped hydro storage facilities. EPA's proposed formula penalizes states that have prudently constructed pumped hydro facilities because the emissions and MWh from plants used to charge the storage system are included in the RE goal setting equation, yet the megawatt hours discharged from the storage resources to provide emissions-free electricity are not. Thus states with large pumped hydro facilities, such as Michigan, have more stringent emissions reduction goals than is warranted.

EPA's assumptions and methodology for calculating RE goals should be consistent with state RES rules and include all RES-eligible generation in states' compliance calculation, including RES-eligible hydropower and pumped storage.

2. EPA's alternate proposed approach to setting RE goals relies on unsubstantiated assumptions about the growth and future costs of renewable technologies.

EPA's alternate proposed approach for calculating RE goals attempts to address the discrepancy between resource potential and other state-specific RE deployment constraints. However, the development of state RE targets under this alternate methodology still raises concerns that should be addressed if EPA opts to finalize the alternate state RE goals. Specifically, because EPA must show that a BSER is "adequately demonstrated," CAA section 111(a)(1), EPA must provide a

reasonable basis for any RE growth rate and for any assumptions about future decreases in the costs of RE technologies.

Under the proposed alternate approach, each state's existing renewable generation is determined by technology—EPA focuses on solar, wind, geothermal and hydro—along with the technical potential for deployment of each technology in that state. *See* Abatement Measures TSD at 4-5. To determine technical potential, EPA relied on NREL technical potential data and paired it with IPM modeling. *See id.* at 3-20 and 4-13. EPA then compared the adjusted technical potential with the level of RE generation in each state in 2012 to yield a RE development rate for each technology in each state. *See id.* at 4-12.

By averaging the development rates in the top 16 states, EPA arrived at a single national benchmark RE development rate for each technology. *See id.* at 4-2. EPA then applied this development rate to each state's development potential to determine a set of technology-specific renewable generation goals for each state. *See id.* at 4-2 to 4-3. EPA summed the individual technology generation targets to set a target RE generation level for each state. *See id.* at 4-3. EPA's methodology raises several concerns, which are discussed in turn below.

a. EPA's use of an RE growth rate based on the historic performance of a limited number of states is not reasonable.

EPA's reliance on historic RE development in only the top 16 states skews the resulting benchmark RE development rate. Those states have typically been the most successful in developing renewable resources because they have the greatest renewable generation potential,

often at lower development costs for a given renewable resource.[78] They are also likely to have socioeconomic characteristics and electric rates that make RE comparatively less costly. Other states may not have sufficient resource potential and/or ability to deliver the energy at a given penetration level to achieve the benchmark development rate set by the top 16 states. EPA has not explained why it is appropriate to assume that the development achieved to date in a select group of states is replicable and represents what is achievable in all states going forward, particularly given the technical challenges associated with increased penetration of renewables on the electricity system. These technical challenges include loss of inertia, increased cycling requirements and increased need for regulation capabilities, among others. Past development of these RE resources has little to no bearing on the future development of RE generation sources and ignores the technical challenges associated with increased RE deployment. These challenges can be managed, but only with sufficient time.

In order to realistically account for differences in renewable resource potential among states, at a minimum, EPA should use all states to develop an average RE benchmark development rate, not just the top 16 states. This approach would provide a better estimate of what may be achievable across the country, grounded in what has been adequately demonstrated as achievable in the past.

b. EPA has not provided a reasonable basis for assumptions underlying its estimates of the future costs of RE generation technologies.

EPA's assumed cost reduction for future RE deployment under the alternate proposed approach is even more problematic. EPA provided no analysis or justification its use of the assumed cost

[78] For example, a 2013 DOE report highlighted the fact that the interior of the U.S., "as a result of its low average project costs and high average capacity factors…also tends to be the lowest-priced region over time." *See* DOE, *2013 Wind Technologies Market Report,* at 58 (Aug. 2014), http://www.energy.gov/sites/prod/files/2014/08/f18/2013%20Wind%20Technologies%20Market%20Report_1.pdf.

reduction of $30/MWh that is factored into the IPM modeling. EPA asserts that a $30/MWh reduction is a reasonable estimate of the projected decline in the cost of renewable deployment in the future, across the entire suite of renewable technologies.[79] *See* Alternative RE Approach TSD at 2-5. However, EPA has not provided a rationale for this assertion.

As a preliminary matter, EPA must explain why it is appropriate to use a single reduction estimate when estimating the future costs of a diverse range of renewable technologies. Each renewable technology declines (or increases) in cost at its own unique rate, based on its own cost basis, permitting and development costs, regional considerations, energy production curve and market factors. The cost trends for one renewable technology are typically independent of the cost trends of other renewable technologies, and vary by region of the country and prevalence of the resource. For example, the greatest onshore wind resource is in the interior of the country, where wind power purchase agreements (PPAs) are approximately $35/MWh cheaper than they are in the west.[80]

Accordingly, EPA should use regional, technology-specific costs in its modeling as opposed to a broad average derived from all renewable technologies. Averaging the cost of all technologies across all regions is misleading for the purpose of setting individual state goals. Indeed, the only reports that EPA points to in its cost estimate discussion explicitly recognize these regional

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[79] EPA repeatedly refers to "the modeling that reduced the cost of new RE technologies by up to $30/MWh" *See, e.g.*, Alternative RE Approach TSD at 4.

[80] *See* DOE, *supra*, n.78.

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concerns.[81] Making broad, national assumptions based on limited, region-specific data is not appropriate when setting standards that must be achievable by all states.

However, EPA provides no evidence or substantiation for its assumption that renewable technologies, as a whole, will continue to decline in cost at the magnitude of $30/MWh, nor does EPA provide a baseline number from which $30/MWh is deducted. Applying a $30/MWh cost reduction to the current prices for wind could result in a value below zero in some regions of the country. This result is neither credible nor reasonable. In addition, DOE's latest Utility-Scale Solar 2013 report notes that "with PPA prices [for solar] now hovering around $50/MWh on average (based on the combined 2013/2014 sample), future price declines are likely to be much smaller than in the past."[82]

Moreover, the cost of RE technologies remains heavily influenced by public policies. As NREL noted, tax credits greatly influence the development of RE.[83] Lazard, an independent financial advisory and asset management firm, notes the impact of federal subsidies on the levelized cost

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[81] EPA cites two reports: Mark Bolinger and Samantha Weaver, *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Lawrence Berkeley National Laboratory (LBNL), LBNL-6408E (Sept. 2013) and David Hurlbut, *et al.*, *Beyond Renewable Portfolio Standards: An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West*, NREL, NREL/Tp-6A20-57830 (Aug. 2013). In both of these reports, the authors note that they relied upon small sample sizes due to limited availability of data and that the data used tends to be concentrated in one region of the country.

[82] Mark Bolinger and Susan Weaver, *Utility-Scale Solar 2013: An Empirical Analysis of Project Costs, Performance, and Pricing Trends in the U.S.*, LBNL, at 31 (Sept. 2014), http://emp.lbl.gov/sites/all/files/LBNL_Utility-Scale_Solar_2013_report.pdf.

[83] *See* Owen Zinaman, *et al.*, *ReEDS Modeling of the President's 2020 U.S. Renewable Electricity Generation Goal*, NREL/PR-6A20-62077, at 12 (May 2014), http://www.nrel.gov/docs/fy14osti/62077.pdf.

of energy (LCOE) for renewable technologies in their annual LCOE analysis. The cost reduction due to subsidies varies by technology, but can be as much as $42/MWh on a levelized basis.[84]

The cost of any technology depends on many factors, and EPA provided no information about how these factors were considered in determining that $30/MWh is a reasonable cost reduction estimate. Accordingly, it is not clear that EPA accounted for technology- and region-specific factors and trends. If EPA finalizes its alternate proposed approach, it must provide sufficient data and analysis to justify this number. If no such analysis is available, then EPA must remove the estimate altogether from any calculation of state RE targets and should not adjust IPM results by any estimated cost decline.

c. EPA's alternative approach focuses on technical potential despite acknowledging the limits of this approach.

As EPA recognizes in the Alternative RE Approach TSD, "technical potential data is typically unconstrained by grid limitations, costs associated with development, quality of resource, and may overstate electricity production potential because a given site cannot produce RE simultaneously from multiple technology types." Alternative RE Approach TSD at 2. Stated another way: Technical potential is divorced from reasonably achievable RE goals because it does not consider a variety of critical factors that influence the actual deployment of RE generation.

Despite acknowledging the concerns related to using a technical potential metric, EPA makes no effort to address these concerns in its IPM modeling. EPA's modeling should address the many

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[84] *See* Lazard, *Levelized Cost of Energy Analysis* (Sept. 2014), http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

other factors, aside from costs, that may limit renewable development: permitting delays (federal or tribal lands), lack of transmission,[85] lack of firming generation, endangered species and other environmental concerns, competing land uses, local opposition to projects, etc. EPA should conduct a more robust modeling analysis that factors in technology- and region-specific trends, policies and development constraints before finalizing state RE goals based on the alternate proposed approach.

3. The regionalized approach proposed in the NODA does not resolve many of the challenges identified in EPA's proposed and alternate approaches.

In the NODA, EPA recognizes the challenges associated with developing state RE goals, given the interstate exchanges of RE. *See* 79 *Fed. Reg.* at 64,551-52. In response to these challenges, the NODA outlines an additional approach to calculating these goals. This new proposed approach would establish regional RE targets based on the renewable potential within a given region and apportion the responsibility for meeting that target to individual states in the region based on a criterion, such as 2012 retail sales of electricity. This approach would provide some additional flexibility within a region by allowing the apportionment of the RE goals in a manner that accounts for the fact that renewables may be built in one state, but serve load in another state. Challenges remain to implementing such an approach, however.

First, concerns regarding the regional nature of electricity, discussed previously in these comments, would remain an issue under the NODA approach. EPA assumes that there will be regional compliance efforts and that states will be willing to engage in multi-state planning.

[85] NERC has noted that RE generation often is a located substantial distance from the point of interconnection to the transmission system, which both requires the construction of new transmission and creates additional reliability implications, particularly with respect to voltage support. See 2013 LTRA at 24.

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However, the amount of time required to develop a regional approach is likely longer than what is afforded under the proposed guidelines. Additionally, some states will have more of an incentive to participate in a regional approach than others. A state that is a net importer of RE will benefit from a regional approach that allows it to take credit for RE built in another state, but serves load within the importer state. In contrast, a net RE exporting state has little to no incentive to allow renewables produced in the exporting state to be counted elsewhere. While the regionalized approach attempts to recognize the interstate nature of electricity, individual state goals create complications. Individual states may find themselves winners or losers depending on if they are net importers or net exporters of renewable generation.

Second, basing RE goals on technical potential evokes the same concerns whether the technical potential being calculated and used is state- or region-specific. Technical potential is not a suitable basis for establishing a goal, as it has not been demonstrated that any state or region can actually achieve its assigned technical potential. Using technical potential in goal calculation fails to consider a number of critical factors including cost, permitting delays, lack of transmission, lack of firming generation, endangered species and other environmental concerns, competing land uses and local opposition to projects, among others.

Finally, it is difficult to assess how this approach would work without knowing what each state's RE target would be. The viability of a regionalized approach will depend on how the requirements for each state are apportioned, and the impacts of potential reapportioning methodologies have not been quantified or vetted. The NODA suggests that 2012 retail electricity sales could be one such criterion for apportioning state targets. *See* 79 *Fed. Reg.* at 64,551, n.12. While using this metric attempts to account for renewables built in one state to

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serve load in another, the problems described above remain. A net importer of RE will benefit from the apportionment, while a net exporter may not be able to take credit for generation that it has permitted, sited and built within its borders. This challenge must be addressed for any regional approach to be viable.

4. EPA's general approach to biomass is arbitrary and results in inflated, unachievable state RE goals.

As discussed above, EPA has proposed two potential approaches for determining the appropriate RE goal for each state. Both approaches consider biomass-based generation to be carbon neutral for the purpose of establishing the state RE goals, but recent EPA guidance indicates that only a limited subset of the biomass currently used to satisfy state RES requirements will be considered carbon neutral for purposes of state 111(d) compliance plans. *See* Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, to Air Division Directors, Regions 1-10, at 3 (Nov. 19, 2014) (Biomass Memorandum). As with hydropower, EPA should treat biomass in a manner consistent with state RES rules and enable all RES-eligible generation to count towards a state's compliance determination.[86]

As discussed, the primary approach relies on existing state RES programs to develop regional and state RE goals. All states with an RES include biomass as part of tier 1 eligible renewable resources.[87] For many states, biomass constitutes a significant portion of renewable generation.[88]

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[86] The role of biomass in compliance is discussed *infra*, section III.G.3.

[87] *See* DSIRE, *RPS Data Spreadsheet*, http://www.dsireusa.org/rpsdata/RPSspread042213.xlsx.

[88] *See* EIA, *Electricity Data Browser, Net Generation for All Sources* (2013), http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=0208&geo=vvvvvvvvvvvvo&sec=g&freq=A&start=2001&end=2013&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin.

EPA averaged state RES requirements to create regional RE goals without regard to the proportion of compliance that states expect to come from biomass generation.[89]

The alternate approach also incorporates biomass as a zero-carbon emitting resource. *See, generally,* Alterative Renewables Approach TSD. While evaluated slightly differently than other resources,[90] biomass-based generation is one of the RE resources evaluated and constitutes a significant portion of the RE MWh that would be incorporated in state goals through Building Block 3. *See* Alternative Renewables Spreadsheet. Both the proposed and alternate approaches, therefore, include biomass when determining the stringency of state RE goals. In both cases, biomass is treated as a zero-carbon emitting resource. However, the proposed guidelines and EPA's recent memorandum are not clear on the extent to which states and affected EGUs will be able to utilize the emission reduction benefits of biomass combustion for compliance.

EPA should modify any final rule to ensure that any biomass included as part of Building Block 3 impacts the calculation of state goals in a manner that is consistent with how the Agency ultimately requires states to account for that generation as part of compliance. To the extent that

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[89] Confusingly, instead of focusing on the types of biomass units burned, EPA focused on the type of unit when calculating the state 2012 fossil generation baselines from which the state goals were built. EPA considered biomass generation to be carbon neutral if the unit burned 100 percent biomass, but imputed emissions to units that co-fired with biomass. *See* Goal Computation TSD at 8.

[90] The proposed guidelines provide little explanation for the treatment of biomass under the Alternative Renewables Approach. However, it appears that biomass potential is determined only based on IPM-based cost criteria and not technical feasibility. Moreover, EPA appears to only be evaluating *existing* biomass-based generation. *See* Alternative Renewables Approach TSD at 3 n.6.

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biomass is treated as zero-emitting generation for purposes of calculating state RE goals in the final guidelines, EPA must provide consistent treatment of biomass for compliance purposes.

5. EPA has not sufficiently assessed the technical challenges associated with the increased penetration of renewable resources.

In both of the Agency's proposed approaches, the RE goals are based, in part, on prior renewable development trends, yet the prior growth of renewable resources is not necessarily an indication of future growth. In some cases, the most rapid and cost-effective gains are achieved in the early years of development and in those areas with the greatest resource potential and the greatest potential to deliver and integrate these RE resources (i.e., available transmission). In addition, many of the prime areas for renewable development are located far from load centers and will require new transmission to be built to deliver the power to load centers.[91] NERC notes that EPA's "analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region," but that "[g]iven the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary…and required to transport the amount of renewable generation coming online, particularly in remote areas." Initial Reliability Review at 20. A typical transmission line requires at least five years or more to site, permit and construct, particularly if it crosses federal or tribal lands.[92] Large-scale transmission projects, such as high-voltage overlays and those needed for renewable integration can involve even longer lead

[91] *See* California PUC, *Transmission for Renewables* (June 28, 2011), http://www.cpuc.ca.gov/PUC/energy/Renewables/transmission.htm.

[92] National Association of Regulatory Utility Commissioners, *Transmission 101,* at 51 (Apr. 20, 2011), http://www.naruc.org/grants/Documents/Silverstein%20NCEP%20T-101%200420111.pdf.

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times.[93] This does not include time required for ESA permitting and mitigation. In addition, given the likely changes in the operational status of many existing fossil-based units, many studies may need to be conducted to identify where new and upgraded transmission will be needed. NERC noted that "[l]ong lead times for transmission development and construction require long-term system planning—typically a 10-15 year outlook." Initial Reliability Review at 20. The addition of incremental renewables to the grid (especially if geographically far from load) potentially will come at an increasingly higher cost.[94]

In addition, both of EPA's approaches are predicated on the assumption that large quantities of new renewable generation can be integrated into the grid. EPA has not accounted for the technical challenges related to integrating and managing large quantities of renewables into the existing transmission and distribution systems. These challenges grow as the level of RE penetration increases. This effect has already been observed in Hawai'i and Germany, where these technical challenges recently have slowed the pace of growth of renewables and have

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[93] *See* EEI, *Comment on Rapid Response Team for Transmission ROI* at 8 (2012), http://energy.gov/sites/prod/files/Edison%20Electric%20Institute%20-%20Comments%20to%20the%20RRTT%20RFI.pdf; *see also Second Set of Comments of the Edison Electric Institute, Department of Energy, Quadrennial Energy Review*, http://www.eei.org/issuesandpolicy/testimony-filings-briefs/Documents/141010OwensDoeQuadrennialEnergyReview.pdf.

[94] In a 2013 market report, DOE highlighted wind cost trends over the past 18 years. Prices have not declined consistently. Rather, PPA prices were the lowest in the early 2000s and rose in the following years because new projects increasingly were sited in lower quality wind resource areas, raising costs. Technology improvements and efficiencies have resulted in prices now falling to levels close to those seen in the early 2000s. *See* DOE, *supra,* n.78, at 58.

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limited their cost-effectiveness as additional grid upgrades are needed to accommodate increasing amounts of RE.[95] As the Hawai'i PUC has articulated:

> The Commission believes it is unreasonable to expect that the high growth in distributed solar PV capacity additions experienced in the 2010-2013 time period can be sustained, in the same technical, economic, and policy manner in which it occurred, particularly when electricity usage is declining, distribution circuit penetration levels are increasing, system level challenges are emerging and grid fixed costs are increasingly being shifted to non-solar PV customers.

Hawai'i DG Interconnection Plan at I-9. In order to set realistic RE generation goals, EPA must take into account the challenges associated with increased penetration of renewables when setting RE generation targets under section 111(d). This may entail moderating the growth of state RE goals in the later years of the proposed interim compliance period.

6. EPA did not consider the interaction among the Building Blocks and system reliability when setting state RE goals.

In determining the level of RE deployment that may be achievable by states, EPA did not consider the system and reliability implications of adding a substantial amount of RE generation. Initial Reliability Review at 13. Similarly, EPA did not consider how the integrated power system would affect the achievability of the proposed RE goals. EPA's failure to fully consider the electric system as a whole when setting state RE targets undermines the reasonableness and achievability of these goals. More importantly, this failure could result in overall emission increases, even if states satisfy their compliance obligations.

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[95] Hawai'i PUC, *Hawai'i DG Interconnection Plan* (Aug. 26, 2014), http://files.hawaii.gov/puc/4_Book%201%20(transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5).pdf; *see also* Hans Poser, *et al.*, *Development and Integration of Renewable Energy: Lessons Learned from Germany*, FinAdvice (July 2014), http://www.finadvice.ch/files/germany_lessonslearned_final_071014.pdf.

As discussed in detail in section II.C., above, there is a symbiotic but complex relationship between natural gas-based generation and renewable generation. Because the output of renewable resources is variable, use of these resources requires ramping, balancing, reliability and back-up services from the grid. Initial Reliability Review at 13. Natural gas-based units are more flexible than other dispatchable resources and usually provide these services. Units needed to back up variable resources must operate at lower capacity factors so they can respond to a decrease in electric generation at any time. Therefore, increasing renewable generation could mean that certain existing NGCC units may need to reduce their capacity factor or maintain a capacity factor lower than 70 percent to increase their responsiveness to the variability of renewable output. Alternatively, increased utilization of NGCC unit generation (i.e., base load NGCC) could limit the ability to integrate additional renewables into the grid cost-effectively.

Variable renewable resources could also be supported by existing simple-cycle CTs, which would need to operate at higher utilization rates. Because CTs are less efficient than NGCCs, this would tend to increase the overall CO_2 emissions rate and hamper states in their efforts to meet their overall emission reduction goals. Finally, as NERC notes, greater reliance on variable renewable resources may require transmission and related infrastructure expansion whose lead times may not align with the plan's goals. *See* Initial Reliability Review at 13. EPA does not appear to have considered these potential impacts and outcomes when calculating RE potential. Thus EPA's proposed RE goals are not adequately demonstrated.

E. EPA Should Revise its Analysis of Estimated Savings from Electric Efficiency Activities to Use More Realistic Estimates.

Electric efficiency (EE) activities are the fourth Building Block that comprise EPA's proposed BSER. EPA has determined that states can achieve a 1.5 percent incremental EE savings rate[96] annually over the course of the 10-year interim compliance period and beyond. EPA asserts that this level of EE savings is achievable and it forms part of the basis for each state's emission performance goal. *See* 79 *Fed. Reg.* at 34,871. The cumulative 2030 savings rates for the states range from nearly 10 percent to almost 13 percent.

EPA's assumptions on the projected EE savings and growth rates used in calculating the interim and final state goals go well beyond current experience with EE programs and the best practices of leading states. NERC notes that "EPA appears to overestimate most states' energy efficiency savings potential…resulting in setting performance targets too high for individual states." Initial Reliability Review at 14. For the majority of states, achieving such dramatic increases in EE savings rates will require correspondingly dramatic increases in utility EE program budgets and customer expenditures, which EPA does not address.

Furthermore, the Agency's assumption of an annual 1.5 percent EE savings rate does not take into account how such an assumption would impact load forecasting. As the NERC report notes, not only do electricity demand forecasts directly influence the required level of generation from existing and affected generating units under the proposed guidelines, they also affect the required amount of new construction of generating units that is needed to meet expected electricity

[96] Incremental savings represent the reduction in electricity use in a given year associated with EE activities in that same year from new participation in established or newly-formed demand-side management EE programs.

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demand and provide reliable power. Initial Reliability Review at 16. EPA has not accounted for these effects in its BSER calculations. EPA also fails to address the existence of a range of constraints that will make attaining the state goals both more difficult and more expensive than EPA presumes. At minimum, EPA should address state-specific concerns about the proposed emission rate goals before finalizing these EE goals. EPA should work with the states to set achievable state goals that reflect in-state conditions.

1. EPA ignored the critical role of supportive state regulatory frameworks in increasing state EE savings rates.

EE programs can be cost-effective ways to transform how electricity is managed and used by households, businesses and industries across the U.S. EE programs are designed to educate and encourage customers to make technical improvements, voluntary behavioral changes and purchasing decisions that will provide long-term benefits in managing their energy usage. But, utilities cannot directly control consumers' behavior. The primary goals of utility EE programs are to produce capacity and energy savings that benefit the customer, as well as the utility. For decades, utilities have encouraged and supported customer interest in being efficient by administering EE programs that provide incentives to lower the cost of purchasing efficient devices, controls and new buildings, along with information that encourages sound energy management practices. The focus of these programs is to reduce electricity consumption (measured in kW hours (kWh) and/or peak electric demand (measured in kW or MW). Utilities cannot force customers to be more efficient or use less electricity, but they can offer customers the opportunity to participate in demand response (DR) programs to reduce peak electricity

demand (kW or MW) during times when the wholesale price of electricity is relatively high or when an event creates a situation that affects the reliability of the interconnected power system.[97] EPA's discussion of the potential for increased EE savings focuses only on technical potential and ignores the reality of how EE savings are actually achieved. Electric utilities (including investor-owned utilities, municipal utilities and cooperatives) are by far the largest providers of EE in the country—they are responsible for 89 percent of the total customer-funded EE nationwide.[98] *See* IEI Summary at 7. Electric utility customer-funded[99] EE programs—both EE and DR programs, such as load control and price-responsive demand—saved 126 TeraWatt-hours (TWh) of electricity in 2012. This is enough electricity to power 122 million homes for one year; it also avoided generation of 89 million metric tons of CO_2. *See id.* at 4. Many states, working with their electric utilities, likely will include EE programs in 111(d) compliance plans.

Regardless of the EE savings levels proposed by EPA, no EE savings will be achieved unless current state- and administrator-run EE programs are both continued and expanded. The regulatory environment in each state determines the size of the budget for customer-funded EE programs; the budget determines the scope and breadth of EE programs. Regulatory frameworks

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[97] The Edison Foundation Institute for Electric Innovation (IEI), *Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures, and Budgets*, Issue Brief, at 4-5 (Mar. 2014) (IEI Summary), http://www.edisonfoundation.net/iei/Documents/InstElectricInnovation_USEESummary_2014.pdf; *see also* FERC, *2012 Assessment of Demand Response and Net Metering,* at ch. 3, Demand Response (Dec. 2012), http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf.

[98] EPA states that ratepayer funding accounts for more than 90 percent of total EE expenditures nationally. *See* Abatement Measures TSD at 5-14.

[99] Electric utility ratepayer- (or customer-) funded EE programs have been in place for over two decades in some states. The costs of administering the programs are paid for by a utility's ratepayers, usually through a fixed charge added to electric bills, and are routinely reviewed by PUCs to ensure that such programs pass a cost-benefit test.

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that support utility investments in EE programs (through cost recovery mechanisms or performance incentives), therefore, are the key to achieving actual EE savings.[100] Despite this clear relationship between supportive regulatory policies and EE savings, EPA's analysis does not make any mention of this. As a practical matter, annual incremental state EE savings rates cannot be increased without supportive regulatory frameworks and the EE program budgets they create.

At present, 33 states allow for some type of fixed cost recovery (either decoupling or a lost revenue adjustment mechanism), and 28 states have EE performance incentives. In order for states to achieve and maintain the target savings rates, regulatory environments in all states must allow for some type of fixed cost recovery. *See* IEI Summary at 15, Appendix A. EPA has not addressed how a failure to align regulatory policy and EE goals in some states will inhibit states' abilities to achieve the target annual EE savings rate.

2. EPA arbitrarily assumes that EE spending will be triple what has been projected by experts.

EPA's analysis indicates that achievement of the target incremental savings rate will result in first-year EE costs in 2025 of $21.8 billion. *See* Abatement Measures at 5-59, Table 5-29.[101] EPA's projected first-year EE costs represent an increase in costs of $16.2 billion over 2010

[100] Innovation Electricity Efficiency (IEE), *State Electric Efficiency Regulatory Frameworks* (July 2013) (IEE Regulatory Frameworks), http://www.edisonfoundation.net/iee/documents/iee_stateregulatoryframe_0713.pdf.

[101] EPA assumes a 1:1 cost sharing between EE programs and participants. Therefore, EPA also projects participant costs of another $21.8 billion. *See* Table 5-29.

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budgets, which were only $5.6 billion.[102] More importantly, LBNL—which has been assessing EE budgets and spending for dozens of years—has projected customer-funded budgets for 2025 and found that, even under their high projection case, budgets are expected to be only $12.2 billion. *See* LBNL Study at 17. EPA's projected first-year costs in 2025 exceed LBNL's high case budget projections by $9.6 billion. When compared to LBNL's medium case budget projections, which forecast budgets of $8.1 billion, there is a shortfall of $13.7 billion. *See* LBNL Study at 19, Table 5.

EPA does not discuss, however, how these costs would be covered or why it is reasonable to expect that future budgets and spending will be sufficient to achieve the proposed 1.5 percent annual incremental savings rate. Indeed, EPA arbitrarily assumes that the necessary resources will be available. EPA cannot ignore these costs or assume that the necessary budgets will materialize (on the utility side or the customer side) to support the proposed savings rate. These program budgets directly affect electricity rates for end-use customers and depend on regulatory approval. As LBNL notes, "[c]oncerns about impacts from energy efficiency programs have been institutionalized in a number of states, either through explicit caps on spending or rate impacts…meeting aggressive [ ] targets in some states will likely require exceeding these caps or otherwise justifying rate increases." LBNL Study at 28. EPA has not considered the interplay of state policies addressing cost concerns and a state's ability to increase its EE savings rate.

[102] *See* Galen L. Barbose, *et al.*, *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL, at 10 (Jan. 2013) (LBNL Study), http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf.

3. EPA has not demonstrated that the projected EE savings rate is achievable by all states.

EPA determined that every state can achieve an aggressive EE savings rate of 1.5 percent annually over the course of the 10-year interim compliance period and then "maintain" the resulting level of savings indefinitely starting in 2030. *See* 79 *Fed. Reg.* at 34,872-73.[103] EPA concedes that the 1.5 percent annual incremental EE savings rate has not been achieved and sustained nationwide previously. *See* Abatement Measures TSD at 5-37. However, the Agency asserts that a review of reported 2012 incremental EE savings data, the expected performance of a limited number of existing state EE programs in 2020 and a review of a select number of EE potential studies show that this level of savings is achievable by all states. *See generally id.*, ch.5. When examined in closer detail, none of these assertions provide adequate support for EPA's assertions that all states can achieve and maintain annual incremental EE savings rates of 1.5 percent. In fact, in 2012, the average incremental EE savings as a percentage of U.S. electricity consumption was only about 0.6 percent. As EPA's own analysis shows, annual incremental savings as a percentage of sales varies tremendously by state. *See* Abatement Measure TSD at 5-17.

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[103] EPA acknowledges it will take time for some states to reach the 1.5 percent incremental EE savings rate. EPA projects that states expected to be below this level in 2020 will start ramping up EE programs by 0.2 percent annually, starting in 2017, until they reach the target rate of 1.5 percent. *See* 79 *Fed. Reg.* at 34,872-73. EPA notes that, once a state achieves 1.5 percent annual incremental EE savings, savings are "maintained at that level through 2029." *Id.* at 34,873. EPA's own analysis indicates that this level of EE savings is, in fact, maintained through 2030. *See* GHG Abatement Measures, Appendix 5-4, Sheet 1, Incremental Savings as a Percent of Prior Year Sales. As discussed in more detail *infra*, section II.E.7., the use of the word "maintained" is misleading in that states will have to continuously develop new programs or attract new participants to existing programs in order to "maintain" incremental savings.

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4. Snapshot data from 2012 does not demonstrate that states can achieve incremental EE savings of 1.5 percent.

Looking at reported 2012 incremental EE savings snapshot data, EPA found that three states—Arizona, Maine and Vermont—had achieved an annual incremental retail sales savings rate of 1.5 percent. *See* Abatement Measures TSD at 5-33, Table 5-8. EPA then concludes that this level of reductions is the "best practices" level and an annual incremental savings that *all* states can achieve. *See id.* at 5-33.[104] EPA's reliance on this 2012 snapshot data is misplaced for two reasons: first, EPA takes the 2012 reported data out of context by not discussing how or how long it took the three "best practices" states to achieve this savings rate; second, if this data demonstrate anything, it is that the savings rate that arguably could be achieved by all states is closer to 0.5 percent, not 1.5 percent, as this is the median savings level achieved in 2012.

a. EPA's use of 2012 snapshot data ignores key contextual information about what is required in order for states to achieve an incremental annual savings rate of 1.5 percent.

EPA notes that three states—Arizona, Maine and Vermont—reported annual incremental savings rates of 1.5 percent in 2012. *See id.* While it is true that these states reported this level of savings, this 2012 snapshot data does not provide any historic context. In particular, it does not address how long it took these states to achieve these rates or whether the state regulatory environment supports EE. This information would provide important context about whether the achievements of these states actually could be replicated by other states. Without information

[104] EPA refers to this as "Option 1." *See* Abatement Measures TSD at 5-33. In "Option 2," EPA uses an annual incremental retail sales savings rate of 1.0 percent with an interim compliance period that would cover 2020-2024. The concerns identified herein with EPA's approach to setting an appropriate annual incremental EE savings rate apply equally to Options 1 and 2.

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about how long these EE programs have been in place, 2012 reported savings rates are meaningless with respect to what reasonably could be achieved by all states.[105]

The key inquiry, therefore, is not whether some states have achieved the target savings rate, but whether this achievement can be replicated by other states and over what timeframe. A single year's snapshot data does not allow EPA to answer this question. Moreover, it is not clear that the 2012 savings rate of three states is indicative of the rate that is sustainable for these states, going forward, or feasible for the rest of the states.

As noted, EE savings are dependent on EE budgets approved by state regulators. EE savings and budgets are highly dependent on whether a particular state's regulatory framework supports utility investment in EE programs. *See* IEE Regulatory Frameworks. For example, many states in the Northeast, like Maine and Vermont, have had aggressive EE programs in place for more than two decades. This is not the case in many other states. *See id.* at 1 and 3.

In this context, it is important to note that the three states with the largest EE expenditures in 2012 had not yet reached the target 1.5 percent incremental savings level by 2012. California leads the states with close to $1.3 billion in EE expenditures in 2012 (and has been investing at the highest levels for decades),[106] but only achieved an incremental savings rate of 1.24 percent

[105] EPA's use of a growth factor tacitly acknowledges that EE programs take time to ramp up. Given this, it is particularly important that EPA not ignore contextual details about when and how states have achieved certain incremental savings rates when assessing the 2012 reported data. *See also* Initial Reliability Review at 14.

[106] *See, e.g.,* California PUC, *Energy Efficiency Primer*, at 23 (June 19, 2014), http://www.cpuc.ca.gov/NR/rdonlyres/1E2FFBF2-E93D-4FEA-BD38-

in 2012. Similarly, New York and Florida spent more than $600 million and more than $370 million, respectively, in 2012, but only achieved annual incremental savings rates of 0.93 percent and 0.27 percent, respectively, despite aggressively having pursued EE and DR programs for decades. *See* IEI Summary at 8 and Abatement Measures TSD at Table 5-4. Accordingly, EPA cannot rely on three states' reported EE savings rates in one year as adequate support for the achievability of a 1.5 percent annual incremental savings rate for all states.[107]

b. If anything, 2012 reported data shows that the demonstrated annual incremental EE savings rate is closer to 0.5 percent.

Consistent with the CAA's requirement that BSER be "adequately demonstrated" and that the resulting standards be "achievable," the use of the median savings rate would be a better measure of what the states actually achieved in 2012. EEI analysis shows that the median savings rate in 2012 was 0.48 percent. EPA notes that the national average was 0.58 percent.[108] *See* Abatement Measures TSD at 5-17. When data is skewed, however, a median is a better measure of central tendency than a mean. In this case, the 2012 data is skewed, with 14 states reporting incremental savings rates of between 0.5 and .99 percent and 25 states reporting rates of less than 0.5 percent. *See id.* at Table 5-8. Regardless of whether the mean or median is used, however, both figures

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00D83576BB2E/0/CPUCEEPrimer_.pdf; *see also* Lee Schipper and James E. McMahon, *Energy Efficiency in California: A Historical Analysis*, ACEEE Research Report E951 (July 1995)(prepared for the California Energy Commission), https://www.ase.org/sites/ase.org/files/resources/Media%20browser/33_commission_history_report_2-1-13.pdf.

[107] EPA recognizes that states that have already achieved the 1.5 percent annual EE savings rate at or before 2020 will be required to sustain this savings rate through 2029. *See* Abatement Measures TSD at 5-37. EPA asserts, but provides no evidence, that achievement of a 1.5 savings rate in one year demonstrates that a state can sustain this target level of savings for 13-17 years.

[108] A recent LBNL report found that the national average was 0.49 percent in 2010. *See* LBNL Study, *supra*, n.102.

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are considerably less than EPA's proposed 1.5 percent annual incremental savings rate,[109] and thus, the 2012 reported savings rates do not support EPA's assertion that all states can achieve 1.5 percent annual incremental savings. If the reported data demonstrate anything meaningful about the feasibility of different levels, it would be that the median savings rate achieved in 2012 is a better measure of an achievable annual incremental savings rate.

5. EPA cannot rely on the expected future performance of state EE programs to demonstrate that the target savings rate is achievable.

EPA notes that nine states are anticipated to achieve incremental EE savings rates of 1.5 by 2020 by virtue of existing state policies. *See id.* at 5-33. Accordingly, EPA notes that 12 states have achieved or will have achieved the target savings rate by 2020. *See id.* EPA cannot rely on expected future performance when setting state goals under section 111.[110] In fact, one of the states EPA expects to achieve 1.5 percent incremental EE savings by 2020 is Indiana, which repealed its energy efficiency standards in March 2014.[111] In addition, Florida, while not projected to reach a 1.5 savings rate by 2020, was one of the top three states in terms of EE spending in 2012. Florida's Public Service Commission (PSC) currently is reviewing the state's energy efficiency goals. As part of this proceeding, the four main investor-owned utilities have asked the PSC to consider scaling back the current EE program goals because the EE gains made in recent years make further efficiency improvements harder and more costly to achieve. The

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[109] Further, the projected annual incremental savings rate in the LBNL's medium case is 0.5 percent. *See* LBNL Study, *supra*, n.102 at 5.

[110] This is not a comment on whether these states will meet their 2020 goal EE savings rates, but rather, a comment on whether EPA can assume this for purposes of setting state-specific emission rate goals under section 111(d).

[111] *See* Scott Smith, *Pence allows energy-efficiency repeal to become law*, KOKOMO TRIBUNE (Mar. 28, 2014), http://www.kokomotribune.com/news/local_news/article_3498d2fc-1b46-5771-9581-a9788c04416c.html.

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utilities argue that slow economic growth, lower electricity consumption and the relatively low cost of natural gas-based power mean that the goals of Florida's EE program are being met through industry trends.[112]

Accordingly, at this time, these nine states have not achieved the target rate, and, in fact, the 2012 reported savings rates for all except three of the states were below 1.0 percent. *See id.* at Table 5-4.

6. EPA's meta-analysis of achievable potential EE studies does not support the target EE savings.

EPA conducted a meta-analysis of 12 EE potential studies undertaken between 2010 and 2014. According to EPA, these studies demonstrate that the average annual achievable EE potential is 1.5 percent per year. *See* Abatement Measures TSD at 5-22; Appendix 5-1 at Table 1. EPA's meta-analysis is not adequate support for the achievability of a 1.5 percent incremental savings rate.

While technical potential studies—all of which are products of imprecise assumptions related to the pace of future technological change, participation levels and the size of the incentives, among other assumptions[113]—may project determine that there is additional EE potential in the states, the level of EE savings that states can actually or reasonably achieve may be quite different. In this regard, EPA's meta-analysis provides interesting information about the amount of EE

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[112] Dan Testa, *Fla. Utilities Propose Scaling Back Conservation Goals, Ending Solar Rebate Programs*, SNL (Jun. 26, 2014), https://www.snl.com/InteractiveX/Article.aspx?cdid=A-28454504-13610.

[113] *See* Max Neubauer, *Cracking the TEAPOT: Technical, Economic and Achievable Energy Efficiency Potential Studies*, ACEEE, at 28 (Aug. 14, 2014).

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potential that might exist, but does not speak to the levels that have been adequately demonstrated to be achievable. A better, more reliable metric of what can be achieved is what states have done to date. As discussed above, such an analysis would focus on the existence of supportive regulatory policies and the sufficiency of expected budgets for utility managed, customer-funded EE programs.

NERC echoed these concerns regarding EPA's analysis, pointing out that EPA applied one national energy efficiency growth factor to all state situations without considering program performance or cost. As NERC stated

> [t]he discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated…Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

Initial Reliability Review at 14. NERC concluded that, "this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential." *Id* at 15.

7. EPA does not take into consideration the challenges in achieving and sustaining the proposed EE savings rate over time.

EPA assumes that, once a state achieves 1.5 percent annual incremental EE savings rate, savings are "maintained at that level through 2029." 79 *Fed. Reg.* at 34,873. (EPA's own analysis indicates that this level of EE savings is, in fact, maintained through 2030 and beyond. *See* GHG Abatement Measures, Appendix 5-4, Sheet 1, Incremental Savings as a Percent of Prior Year

Sales.) This produces very large savings goals by the end of the interim compliance period.[114] The cumulative 2030 savings rates range from nearly 10 percent to almost 13 percent. *See id.*, Sheet 2, Cumulative Savings as a Percent of Sales.

Because the savings rates are first-year rates, states must continually deploy new EE programs or attract additional customer participation in existing programs in order to achieve the incremental savings rate throughout the interim compliance period and the cumulative rate in 2030 and beyond. States must also replace expiring EE measures, as they are assumed to produce reductions only for 10 years. The result is that states, utilities and customers are not required simply to "maintain" a certain EE savings rate, but must continually make additional, expansive investments just to keep up.

The magnitude of this challenge should not be underestimated. As LBNL noted, savings rates of 1.5 or 2 percent of retail sales go "well beyond current experience and practice in most leading states." *See* LBNL Study at 28. Accordingly, "[t]he challenge for [ ] program administrators will be to design and implement programs that can achieve both deeper savings, on average, at customer facilities and have a broader reach in terms of market penetration over a sustained period of time." *Id.* LBNL went on to note that "service providers will have to achieve savings levels of 25-40% of existing usage at customer facilities compared to current practice in utility customer-funded programs, which is typically in the 5-20% range." *Id.* This means that the sustained achievement of greater levels of savings would require increasing EE program

[114] The calculation: Base Year kWh * $\{(1 - 0.015)^n\}$ where "n" = the year being considered.

performance by a factor of two to five times. This is unprecedented. EPA cannot point to any data showing that this is possible or even probable.

EPA's focus on incremental EE savings rates does not address concerns about the achievability of the cumulative goals through 2030 and beyond. EPA notes that California and Minnesota achieved cumulative savings rates in excess of 13 percent, respectively, in 2012. *See* Abatement Measures TSD at Table 5-4. Achieving this level of cumulative savings in one year is, however, no indication that this level can be achieved indefinitely. In fact, it may become more difficult for these states to maintain such savings rates going forward. EPA has not proffered any evidence to support its belief that individual states have the EE potential to support and maintain high levels of cumulative EE savings. Further, EPA has not considered the "combined effect of economic torpor, moderate gas prices, and tightening energy codes and minimum standards." LBNL Study at 30. According to LBNL, these will "pose challenges for continued growth in electric efficiency programs." *Id.*

8. EPA did not properly account for the "pinching" effect of building codes and appliance and equipment standards on achievable EE savings rates.

While not part of EPA's assessment about the achievable annual incremental EE savings rate, which focused on utility-sponsored EE, EPA notes that appliance and equipment standards and building codes have the potential to reduce electricity consumption in the states. EPA asserts that "[i]f we were to capture the potential for…state or local building codes…to contribute additional reductions beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5 percent." 79 *Fed. Reg*. at 34,872. EPA believes that the savings from building codes and appliance and equipment standards can be added to the savings from EE programs. EPA does not understand the

relationship between codes and standards and customer EE programs—these reductions are not additive, but can limit future customer EE growth potential as they will decrease EE savings opportunities in the future. Accordingly, EPA cannot assert that the target rate is "less stringent than a level would be that accounted for" codes and standards. *See* Abatement Measures TSD at 5-38.

Building codes and appliance and equipment standards historically have, and will continue to, save electricity for consumers. According to a 2012 study by ACEEE and the Appliance Standard Awareness Project (ASAP), codes and standards in effect in 2010 reduced electricity consumption by about 280 TWh in 2010.[115] The study also projects that new codes and standards adopted between 2012 and 2016 would save about 212 TWh in 2025 and 306 TWh in 2035. A recent IEE study found that new appliance and equipment standards would save about 202 TWh in 2025 and 297 TWh in 2035, and that new building codes have the potential to save an additional 75 TWh in 2025 and 123 TWh in 2035.[116]

While these savings are meaningful and important, a "side effect" of increasing minimum codes and standards, which set the minimum efficiency levels for newly constructed buildings and a large range of residential, commercial and industrial energy consuming appliances, is that this significantly decreases the energy savings opportunities that would be available to EE program

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[115] Amanda Lowenberger, *et al.*, *The Efficiency Boom: Cashing In on the Savings from Appliance Standards,* ACEEE & ASAP, at 1 (Mar. 2012), http://www.appliance-standards.org/sites/default/files/The%20Efficiency%20Boom_ExecSumm_0.pdf.

[116] IEE, *Factors Affecting Electricity Consumption in the U.S.*, 2010-2035 (Mar. 2013) (IEE March 2013 Report), http://www.edisonfoundation.net/iei/Documents/IEE_FactorsAffectingUSElecConsumption_Final.pdf.

administrators, while driving up the costs to acquire additional energy savings above the new minimum efficiency levels. For example, EPRI has noted that

> Appliance codes and standards coming into effect over the next five years increase baseline equipment efficiency, impacting the forecast for energy consumption out to 2035. In addition, *with more efficiency baseline requirements there is less room for cost-effective energy efficiency*...Refrigerators and freezers *had shown the highest level of savings,* with achievable potential in all five major appliance categories. *Now there are no savings found for refrigerators and clothes washers as a result of codes and standards.*

EPRI, *U.S. Energy Efficiency Potential Through 2035*, at 4-17 (Apr. 2014)(emphasis added). [117]

Accordingly, standards for refrigerators and freezers have had a "pinching effect" that reduces opportunities for customer EE. As IEE noted, new codes and standards "shift the starting point and this changes the potential for savings from rate-payer funded programs." *See* IEE March 2013 Report at 10. It is reasonable to assume that the effect of future codes and standards for other appliances and equipment types will produce similar "pinching effects" on customer EE potential. Therefore, instead of increasing the target EE annual incremental savings rate, as EPA argues, future codes and standards should result in EPA lessening this target to reflect diminution of achievable EE.[118] This does not mean, however, that states should not be able to include codes and standards in compliance plans.

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[117] This report is available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477.

[118] While some states are beginning to allow utilities to get credit for funding efforts to improve codes and standards as part of their suite of EE programs, *see* IEI, *Integrating Codes and Standards into Electric Utility Energy Efficiency Portfolios* (Aug. 2010), http://www.edisonfoundation.net /iei/Documents/IEE_IntegratingCSintoEEPortfolios_final.pdf, codes and standards should not be considered when setting state-specific emission rate goals under section 111(d).

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9. EPA ignores sectoral composition and its impacts on states' abilities to achieve the EE savings rate.

EPA states that studies analyzing the potential achievable EE reductions achievable nationwide show "significant potential in every region of the country including…across regions with varied sectoral composition." *See* Abatement Measures TSD at 5-24. Citing a recent EPRI study, EPA states that there is "significant opportunity in the residential, commercial and industrial sectors in every region." *See id.* EPA implies, therefore, that the sectoral composition of a state is not a factor in whether that state can achieve an annual 1.5 percent incremental EE savings rate. EPA cannot use generalized regional data to demonstrate that any particular state can achieve the target EE savings rate.

Many studies find that the potential for EE savings varies across different customer sectors. For example, IEE has detailed the varying potential for codes and standards to improve the efficiency of residential, commercial and industrial projects. *See* IEE March 2013 Report at 15. Given that different sectors have different opportunities for EE, it would be unreasonable to assume that an individual state's sectoral composition had no bearing its ability to achieve and sustain 1.5 percent annual incremental increases in EE. States with little or no manufacturing will not be able to achieve the portion of EE potential estimates attributable to that sector. At minimum, EPA should allow states to demonstrate that sectoral composition will impede attainment of the target incremental savings rate.

F. EPA's Proposed Numeric Approach to Calculating State Goals Should Not Assume that Incremental RE and EE Replace Fossil Generation Below 2012 Levels Because this Approach Ignores the Role of Base Load Generation in Ensuring the Reliable Operation of the Power System.

The proposed numeric formula EPA used to calculate the state goals included in the proposed guidelines issued in June 2014 assumes that incremental generation from existing NGCC units, under Building Block 2, will replace historical fossil steam generation as measured relative to 2012 baseline generation levels. *See* 79 *Fed. Reg*. at 34,896; *see also* Goal Computation TSD at 10-12. In contrast, the proposed numeric formula assumes that incremental RE and EE, under Building Blocks 3 and 4, replace (or, more appropriately, displace) fossil generation in excess of the 2012 baseline generation levels and does not assume that any incremental MWh generated or saved using RE and EE measures replace historical fossil generation below 2012 levels. *See* 79 *Fed. Reg*. at 34,896; *see also* Goal Computation TSD at 15-18.

In the NODA, EPA notes that some stakeholders believe that EPA should use a consistent numerical approach to all Building Blocks. Specifically, some stakeholders want EPA to assume that incremental RE generation or EE savings replace historical fossil generation, relative to the 2012 baseline. *See* 79 *Fed. Reg*. at 64,552-53. EPA suggests two ways that the numeric goal calculating formula could be revised to address these concerns: (1) assume that RE and EE measures replace all historical fossil generation on a pro rata basis; or (2) assume that RE and EE first replace higher-emitting fossil steam generation below 2012 levels and then replace gas turbine generation. In the NODA, EPA requests comment on whether a formula change of this nature—either the pro rata replacement approach or the prioritization replacement approach—"would better reflect the emission reduction potential from incremental RE and EE." *See id*. at 64,553.

Despite the fact that EPA used these approaches in translating the state rate-based emission goals into mass-based equivalents,[119] EPA should not adopt either approach to change the proposed numeric formula when calculating final state goals. Both approaches would overestimate the potential emission reductions from RE and EE because they incorrectly assume that RE and EE can replace base load fossil generation. At this time, neither EPA nor other stakeholders can demonstrated that this would be technically feasible or adequately demonstrated, as RE nor EE cannot provide the full range of essential grid services that are fundamental to ensuring the reliable delivery of electricity to consumers.

1. EPA cannot assume that renewable generation and energy efficiency can replace all fossil generation because this will prevent the reliable operation of the interconnected power system.

At base, the two revised approaches for calculating the state goals forwarded in the NODA are predicated on the incorrect assumption that all historic fossil generation could be replaced by renewable generation and decreased consumption. While not discussed explicitly in the NODA, replacing all 2012 fossil generation in the numeric formula used to calculate the state goals likely would result in some state goals that are 0 lb CO_2/MWh—or even lower—meaning that these states would have to cease all operation of existing base load fossil generation.[120] Neither EPA nor any stakeholder can demonstrate that, at present, the interconnected power system can be operated reliably without these critical base load resources. Moreover, renewable wind and solar

[119] In the Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents TSD, EPA notes that "BSER is applied to generation from the historical affected fossil fuel-fired fleet, rather than to a projection of the affected fleet's future performance." Mass-Based Equivalents TSD at 4.

[120] Under the proposed formula, EPA's estimate of the number of renewable MWh that can be generated between 2020 and 2029 already exceeds the amount of in-state fossil MWh generated in Washington and Idaho in 2012. *See* 79 *Fed. Reg.* at 34,868 n.155. Further, as EPA itself admits, "a strict application of this equation for those states would yield a *negative number* for adjusted affected fossil generation." Mass-Based Equivalents TSD at 5 n.16 (emphasis added).

resources are variable in nature and need to be backed-up by dispatchable resources when they are not operating. EPA does not address how such back-up can be accomplished without reliance on at least some fossil generation.

As discussed extensively above in Section I.B. and NERC's Initial Reliability Review, all electrons are not fungible when it comes to operating the grid. Fossil-based base load units play a critical role in ensuring the reliable operation of the bulk power system and cannot be replaced on a MW for MW basis by either renewable generation or EE measures. RE and EE cannot provide key services provided by base load resources that are essential for maintaining reliability, including frequency response, voltage support, load and resource balancing and inertia. *See generally* ERS Report; *see also* Initial Reliability Review at 13.

The proposed state goals—which would be less stringent than goals calculated using either approach discussed in the NODA—will result in a dramatically changed electricity generation mix that has significant implications for reliability. As NERC notes, the proposed guidelines "introduce[] potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation…the ongoing transformation to the resource mix and corresponding impacts on [essential reliability services [ERS]] required to maintain a reliable [bulk power system]. Initial Reliability Review at 17.

NERC identified two categories of reliability implications for the proposed state-specific emission rate goals: (1) direct impacts to resource adequacy and electric infrastructure; and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring

generation, accommodating operating characteristics of new generation, integrating new technologies and imposing greater uncertainty in demand forecasts. *See id.* If the proposed goals, which would allow for some continued operation of existing fossil-based generation, create potential reliability concerns, goals that are predicated on the replacement of all existing fossil generation with RE and EE sources must raise more significant concerns. EPA has not addressed how the alternative approaches to calculating the state goals are consistent with the reliable operation of the interconnected power system. The potential reductions achievable by Building Blocks 3 and 4 cannot be measured in a vacuum. EPA's approach to calculating the state goals must consider the potential impact the resulting goals would have on the interconnected power system.

For example, while EE provides benefits to the grid, the services EE provides are different and have very different performance parameters. As discussed in section I.B., above, generation resources provide services to the grid—in addition to energy—which support the reliable operation of the integrated system. EE cannot provided these services and, therefore, are not a perfect substitute for "steel in the ground" generation resources. PJM has attempted to address performance limitations inherent in demand response (DR) products by setting limits on the amount of DR procured in its forward capacity market. *See PJM Interconnection, L.L.C.*, Order Accepting Tariff Revisions, 146 FERC ¶ 61,052 (Jan. 30, 2014). PJM's action is a direct response to the reality that the deployment of large amounts of EE—including DR—can create operational discontinuities that may challenge ongoing reliable system operations. Integrated system planners need assurance that EE and DR products continue to materialize in a way that does not cause a resource shortage given long lead times for generation and transmission assets.

The impacts of DR and EE modeling practices and assumptions on reliability planning studies are still evolving, but it is widely recognized that they cannot be treated as direct replacement for generation resources.

The NODA does not address how the alternate approaches to the numeric goal setting calculation would take into consideration these reliability considerations or how the interconnected power system could operate without fossil-based base load resources. EPA cannot use a numeric formula that creates state goals that are inherently at odds with the reliable operation of the interconnected power system.

2. Assuming that RE and EE replace all existing fossil generation will limit the reliable integration of new RE generation into the grid.

RE and EE not only cannot replace base load fossil generation in providing essential reliability services, but also place additional reliability demands on the interconnected power system and system planners. As NERC notes, the proposed guidelines seek to more than double the energy capacity that currently is provided by variable energy resources, like wind and solar. "[W]ind projects will significantly increase the demand for reactive power and ramping flexibility." Initial Reliability Review at 25. Further, "as the penetration of variable generation increases, maintaining voltage stability can be more challenging." *Id.* These demands, which must be met to ensure the reliable integration of variable renewable resources into the grid, are met only by fossil-based resources.

As noted in section III.G.4., below, the proposed guidelines actually could prohibit the building of new natural gas-based units because, in some states, the emission rate goals are less (and, in some states, dramatically less than) than the emission rate allowed these units under

CAA section 111(b). Under the alternate approaches to calculating state goals, many state goals would become increasingly more stringent, further limiting the future construction of new NGCC units to support renewables integration.[121]

3. It is appropriate to treat Building Block 2 reductions differently than reductions achieved by Building Blocks 3 and 4.

While these comments raise significant concerns about the level of re-dispatch that is possible under Building Block 2, see section II.B., above, to the extent that NGCC units are able to provide the same essential reliability services that are provided by existing coal-based units, it is appropriate to assume that generation from existing NGCCs could replace generation from coal-based steam EGUs in the proposed goal computation equation. Because RE and EE cannot provide the same services, EPA should not use a goal-setting calculation that assumes that these measures can replace fossil MWh on a one-for-one basis. Accordingly, it is appropriate to have different approaches to the different Building Blocks when calculating the state goals, as this recognizes that different generation sources can and do play different roles in the reliable operation of the interconnected power system.

Moreover, the proposed approach to the numeric goal calculation is consistent with how utilities forecast load. As in the proposed numeric calculation, incremental RE and EE serve to meet (or avoid) load growth, avoiding new generation and the related emissions. In the Mass-Based Equivalents TSD, in which EPA implemented the alternate approaches to the numeric

[121] The proposed applicability requirements would exempt existing and new simple-cycle CTs that sell less than one-third of their potential output to the grid. *See* proposed 40 C.F.R. § 60.5795(b)(2), 79 *Fed. Reg.* at 34,954. If simple-cycle CTs alone were required to support the reliable integration of renewable generation into the grid, many of these units likely would exceed this one-third sales limit, subjecting them to standards, at least for new units, with which they cannot comply. *See* EEI's 111(b) comments, Appendix C at 14-16. It is not clear how renewable generation could be integrated into the grid under such regulatory conditions.

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calculations discussed in the NODA, EPA assumes the opposite—that "incremental resources under building blocks three and four replace historical generation from affected fossil fuel-fired sources and those incremental resources are therefore unavailable to meet new demand for electricity." Mass-Based Equivalents TSD at 6 n.20. This approach is not consistent with utility operations, in which incremental RE and EE are used to reduce future demand and emissions, not reduce historic demand and emissions.

III. EPA Must Address A Range of Compliance Issues So That States Are Able To Craft and Submit for EPA Approval Plans That Demonstrate How They Will Achieve The Proposed Goals.

The final guidelines will set the emission rate goals for the states, but how these goals will be achieved depends on the reductions, actions and measures that states include in the compliance plans that will be submitted to EPA for review and approval. As EPA has recognized, states need the flexibility to design plans that reflect a range of state-specific circumstances. *See* 79 *Fed. Reg.* at 34,837. Importantly, states need real flexibility in order to be able to choose the most cost-effective reductions, as determined by the states, to ensure that electricity remains affordable for consumers. Allowing each state to choose its individual glide path will allow them to use the actions that work best for them to reliably and cost-effectively reduce carbon emissions in their state. States also need clarity on a range of topics so that they can craft compliance plans that will be approvable.

Specifically, states need the flexibility to design emission rate reduction glide paths that reflect the states' determination of the best way to achieve the 2030 goals while maintaining reliability and protecting the affordability of electricity. However, the current design of the interim average compliance period forces many states to achieve the majority of the required reductions by 2020,

if not before. Not only is this not practically achievable, it deprives states of the flexibility to design their own compliance plans or choose the pace of reductions to respect state-specific conditions and circumstances. Further, as discussed at length in the beginning of these comments, implementing actions and measures that comprise the four BSER Building Blocks—which also will comprise the centerpiece of most states' compliance plans[122]—will require states, electric utilities and other regulators to assess the impacts of the Building Blocks on the interconnected power system. The complex analysis required will take time, as will making the changes necessary to accommodate the dramatic shift in how electricity is generated and delivered as envisioned by the proposed guidelines. The final guidelines should ensure that adequate time is available, both to design compliance plans and to implement them. The final guidelines should clearly authorize this range of options, so that states have the confidence to pursue them, pending final EPA approval of compliance plans.

States need clarity on a range of other issues before beginning work on compliance plans. States also need guidance as to how to account for the interstate impacts of RE and EE measures, so that they can avoid plan disapproval related to the possible double counting of reductions. States also need clarity on how state plans will be enforced; enforcement concerns could limit states flexibility when choosing among the options for state plan design. Related to enforcement

[122] As discussed elsewhere in these comments, states are not required to implement the Building Blocks exactly as they were used by EPA to set the state-specific emission rate standards. However, as a practical matter, there are limited alternative measures that would achieve the same magnitude of reductions such that it is unlikely that a state could completely forego the use of a particular Building Block. Non-BSER measures will be important flexibility tools that allow states to choose to deviate, where necessary, from EPA's assumed level of reductions that can be accomplished by the Building Blocks, but they will not be substitutes for any of the Building Blocks.

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concerns, EPA should recognize the powers reserved to the states in regulating the interconnected power system.

Further, EPA should affirm states' ability to include non-BSER measures in compliance plans, a key flexibility mechanism that allows states to design workable compliance plans. EPA also should provide needed clarity on a range of issues related to non-BSER compliance options. The final guidelines also should provide a mechanism to ensure that states are not penalized by efforts to reduce emissions from other sectors, particularly the transportation sector.

EPA should ensure that guidance addressing the role of biomass-based units is clear before states are required to submit compliance plans for approval so they can judge whether these units can be used for compliance. To facilitate state plan development, EPA should provide guidance on evaluation, monitoring and verification (EMV) protocols for EE measures. Finally, to the extent that states may opt to build new NGCC units to reduce emission rates, the final guidelines must be clear on the role of these units when making compliance demonstrations.

A. EPA Should Eliminate the Interim Compliance Goal and Approve State Plans that Achieve the 2030 Goals through Reasonable Emission Reduction Glide Paths and Milestones that Assure Reliability and Protect Customers.

For each state, EPA proposes both an interim and final emission rate goal. *See id.* at 34,895 & Table 8. The interim goal is measured via a ten-year averaging period that starts in 2020. *See id.* at 34,851. EPA asserts that the proposed guidelines generally provide states with sufficient time and flexibility to design "practical" plans that achieve reductions in a "reasonable cost way." *See id.* at 34,387. EPA specifically notes that the interim plan period "increases state flexibility to choose among alternative potential plan measures." *Id.* at 34,897. The interim compliance

period may be well intended, but its design—particularly the interim 10-year average goal—actually serves to limit state flexibility. In order to satisfy the 10-year average goal, a significant number of states need to achieve reductions before the start of the interim compliance period in 2020.[123] Moreover, many states must achieve over 50 percent or more of their 2030 emission goals by 2020; and eleven states—including Arizona, Arkansas, Florida and Minnesota—must achieve over 75 percent of their 2030 goals by 2020. This effectively turns the 2030 goal into a 2020 goal for these states. Thus, contrary to EPA's stated intent of providing states flexibility in setting 2030 emission goals, the interim compliance average goal creates more compliance challenges than it solves. Further, as NERC notes, this "proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020" and that attempting to implement the proposed guidelines without addressing reliability considerations "would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages." Initial Reliability Review at 22.

Eliminating the interim compliance goal and allowing states to determine their own reduction glide paths and milestones to achieve the 2030 goals—subject to EPA approval and annual compliance reporting—would provide states with real flexibility in designing state plans while providing real, verifiable emissions reductions. Eliminating the interim targets does not mean that no actions will be taken by each state to reduce carbon emissions before 2030. On the contrary, each state would have the flexibility to determine the most cost effective and reliable way to achieve the 2030 emission goals while outlining the meaningful reductions expected in

[123] The state goals, in part, are predicated on states taking action before 2020. For example, EPA identifies individual states that need to begin implementing programs in 2017 for expanded renewable generation and additional energy efficiency measures if the emissions reductions EPA identifies in Building Blocks 3 and 4 are to be realized.

each individual state plan's glide path. This approach would allow states sufficient flexibility to determine not only which actions and measures to pursue to reduce emission rates, but also to choose a reasonable schedule for implementing those measures consistent with providing safe, reliable, affordable and environmentally responsible power to customers. Importantly, this would provide states and utilities additional time to complete needed infrastructure development (including expansions and upgrades of both electric and natural gas transmission systems) to manage changes in dispatch between coal-based and natural gas-based units and increase deployment of renewable generation and energy efficiency programs. It also would provide states, electric utilities and other regulators time to assess the significant changes to the interconnected power system that will be required to achieve the 2030 goals, discussed in more detail in section I.B., above, while respecting system requirements necessary to maintain reliability. States would also be able to better manage the impact of the program on customer rates. Real flexibility helps states achieve reductions while ensuring the continued provision of affordable and reliable electric power.

EPA should allow states to adopt an approach in their state plans, based on objective criteria that deliver the desired reductions in a manner consistent with consideration of the remaining useful life of existing generating resources, grid reliability and customer cost minimization. Unless EPA finds that the states are not properly demonstrating reasonable progress toward attainment of the goal, no need for strict interim deadlines exists.

This approach is also consistent with EPA's stated goals for the proposed guidelines. In the NODA, EPA notes that the Agency is "interested in considering additional stakeholder ideas,

such as those regarding the 2020-2029 glide path, to ensure that the overall framework includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from affected units so that states can develop cost-effective strategies, and states, utilities, grid operators and others can readily respond to unexpected challenges or demand on the energy system, such as severe weather." 79 *Fed. Reg.* at 64,545.

Consistent with the state plan requirements that EPA has proposed, states would be required to demonstrate reasonable and verifiable progress toward the 2030 goal and could not delay taking action to reduce emissions. EPA's proposed guidelines already would require that states submit—and that EPA approve—plans that clearly set forth how states would achieve the 2030 goal. Once approved by EPA, a state's plan, including the emission reduction glide path, would become enforceable. States would demonstrate progress towards the 2030 goal consistent with their projected emission reduction glide path through the annual reporting of emission performance to EPA, taking corrective measures if needed to achieve the 2030 emission levels. Ultimately, if states are unable to show reasonable progress toward the 2030 goal, EPA, as set forth in the CAA section 111(d), still would have the authority to call for a state to correct its plan or to prescribe a federal plan. Using the proposed approach to state plans, EPA can ensure that the 2030 goals are achieved while allowing states sufficient flexibility to design their own compliance glide path.

To promote maximum state flexibility in the design of approvable compliance plans and to enable states to take into account changed circumstances, such as improvements in clean energy and other technologies, the final guidelines should clarify that states can modify plans, subject to

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EPA approval, to address changing circumstances. The final guidelines also should affirm that EPA will approve compliance plans that satisfy the requirements for such plans. Finally, the guidelines should recognize a range of potentially approvable options for defining state emission glide paths that would be unique to the specific circumstances within a state or multi-state program and, in particular, should support the use of existing programs and market mechanisms.

1. The proposed guidelines, including the proposed interim average emission rate goal, create significant near-term compliance challenges and limit state flexibility.

The proposed interim average compliance period and goal would create unnecessary compliance challenges, limit state flexibility in designing compliance plans and impose unnecessary additional costs on electric customers.

a. The operational realities of the interconnected power system are inconsistent with a proposed interim compliance period beginning in 2020.

For states to comply with EPA's proposed 10-year average goal, a majority of states must achieve the majority of emission reductions by 2020. As noted in section I of these comments, achieving the 2030 goals while ensuring the continued reliable operation of the interconnected power system would require significant changes to the system and the way that it operates. These changes in the manner in which power is generated, transmitted and consumed must be done in a way that maintains operational reliability and provides consumers with least-cost power. This cannot even potentially be accomplished without eliminating the interim goals and allowing states to establish an individualized glide path to 2030 compliance.

For states and utilities to achieve the proposed 2030 goals, new generation and upgraded and expanded transmission and distribution facilities will be needed. Some of these will be required

to meet the goals; others will be required to ensure that system reliability requirements are met. Any new or upgraded infrastructure elements will require significant time, capital and planning by states, utilities, system operators, permitting agencies and other state and federal regulators in order to integrate them into the interconnected system. In order to make these changes, system operators and their stakeholders must conduct specific reliability impact assessments and necessary system changes. As noted earlier, given EPA's rulemaking timeline, this schedule does not allow adequate time for the needed reliability assessments and system changes to be accomplished before 2020. Building new generation, new gas delivery infrastructure and new transmission lines—which take years to plan and execute—will also necessarily occur after 2020. *See* Initial Reliability Review at 10, 20.

b. States cannot increase utilization of existing NGCCs units to 70 percent by 2020.

The proposed interim average goal assumes that the full 70 percent utilization of existing NGCC units has occurred by 2020 and is held constant through the 10-year interim compliance period. *See* Goal Computation TSD at 10-11. Unlike RE and EE measures, increased NGCC utilization is not phased in over the interim average compliance period; therefore, in order to meet the proposed goals, states *must* achieve the full magnitude of the reductions associated with this significant dispatch change starting in 2020. *See id.* at 18. For states in which increased utilization of existing NGCC units drives the stringency of the emission rate goals, this means that the majority of compliance must be achieved *before* 2020. EPA asserts that the interim period is a "10-year ramp-up period," 79 *Fed. Reg.* at 34,906, but instead of allowing states to phase-in reductions, the 2020 interim average goals create an emission reduction 'cliff' for many states.

Requiring that all changes in dispatch be achieved before the interim compliance period begins eliminates any flexibility states have to determine how quickly to make these changes or to assess and address the implications for the interconnected power system. It also reflects the fact that the proposed guidelines do not acknowledge or consider how the interconnected power system works. For example, the Director of the Arizona DEQ has noted that, "the proposed goals for Arizona were set based upon an EPA assumption that all of our existing coal-fired power generation could be immediately transferred to existing natural gas-fired power plants by 2020."[124] Arizona, therefore, is required to achieve at least 75 percent of its final 2030 goal by 2020. According to the DEQ, Arizona's only option to achieve this level of reductions by 2020 is through switching from coal to natural gas. *See id.* Even if Arizona has an approved state plan by 2017, this is an unprecedented reductions requirement that must be achieved in, at most, a few short years.

Moreover, it is not clear that the dramatic increase in utilization of existing NGCC units by 2020 envisioned by EPA can be achieved. As discussed in section II.B., above, EPA incorrectly assumes that current natural gas infrastructure is sufficient to support this dramatic increase in the utilization of existing NGCC units.[125] Under EPA's proposed guidelines, existing pipeline

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[124] *State Perspectives, supra*, n.46.

[125] There is a seasonal divide in the use of existing natural gas pipeline capacity that may exacerbate pipeline infrastructure issues in some regions. For instance, in certain regions, many pipelines originally were developed in coordination with local gas distribution companies for the purpose of delivering gas to residential and commercial customers, generally for heating or industrial purposes. A significant portion of natural gas pipeline capacity in those regions is therefore utilized during winter months to transport gas for home heating purposes, rather than for power generation purposes. Many natural gas units provide peaking services primarily in summer months due to the abundance of available capacity; however, they typically provide

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infrastructure would need to be expanded in a short time frame. However, it can take three to six years to permit and build new pipelines. *See* Initial Reliability Review at 10. Although the FERC is the lead federal agency for approving interstate natural gas pipelines, under the FPA these new pipelines often require approvals under other statutes from other federal, state and local agencies.[126] In order to take advantage of the abundance of shale gas resources, new pipelines will be needed to transport these natural gas supplies to regions of the country that propose to build new, lower-emitting NGCC units. If the pipelines will cross federally-owned lands, approval of permanent rights-of-way from federal land managers must be obtained. Because there is no streamlined process for obtaining such federal approvals, their approval can take years, which could impede the ability to expand the network of natural gas pipelines to deliver gas for power generation.

Further, increasing generation from existing NGCC units also may require electric transmission upgrades and expansions. However, as NERC has noted, a transmission project can take 10 or more years to complete, from project identification to final certification and energization. *See* Initial Reliability Review at 20. It may take even longer if a project crosses federal or tribal lands. These infrastructure constraints will challenge states' ability to achieve significant changes in dispatch before—and even after—2020. Recognizing infrastructure challenges and

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fewer services in winter months, in part, because the pipelines they rely upon for natural gas supply are capacity constrained through the delivery of natural gas for home heating purposes.

[126] *See* GAO, *supra*, n.47. The GAO report lists other applicable statutes to include the National Environmental Policy Act, the Clean Water Act, the Endangered Species Act, the National Historic Preservation Act, the Rivers and Harbors Act of 1899, the Clean Air Act, the Migratory Bird Treaty Act, the Safe Drinking Water Act and the Wilderness Act. Permitting agencies include FERC, EPA, U.S. Corps of Engineers, Bureau of Indian Affairs, Bureau of Land Management, Department of Wildlife and Fisheries, Forest Service, DEQ and a host of other federal, state and local agencies as well as tribal and local governments.

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the need to make investments, EPA provides some time for other reductions measures, namely RE and EE to ramp up,[127] but provides no such flexibility for equally important changes in dispatch.

c. The interim compliance average period deprives states of choosing which reduction actions and measures to pursue and how quickly to implement them, with negative consequences for costs to customers.

EPA notes that "while states must begin to make reductions by 2020, full compliance with the CO_2 performance level in the state plan must be achieved by no later than 2030." 79 *Fed. Reg.* at 34,838. Many states will have few options to start making reductions by 2020, which limits their ability to choose the reductions actions and measures that best reflect their specific circumstances and to implement them in a way that minimizes costs to customers.

For example, Ameren, which serves Missouri, among other states, has a plan that can achieve the President's goal, of carbon emission reductions as outlined in the 2030 targets, by 2035. This plan has been submitted to the Missouri PSC as part of an integrated resource planning process calls for meaningful carbon emissions starting in 2022. The plan includes retirement of coal plants at the end of their useful lives, including a large coal plant in 2022, expansion of renewable generation and/or nuclear, adding an additional NGCC unit and a significant EE program. Under the defined rate based interim targets included in the proposed rule, the only reliable but costly way to demonstrate progress toward achieving the interim average goal—which, for Missouri, is 62 percent of its 2030 goals—is to accelerate the NGCC capacity by 15 years to 2020 and double that capacity to 1200 MW. This new gas-based generation is not needed to serve Ameren's customers; it will only displace coal generation in order to meet the

[127] But, EPA assumes that these measures will start ramping up in 2017, before state plans may have been approved. *See* 79 *Fed. Reg.* at 34,867.

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interim rate based goals. Ameren will also be required to accelerate the closure of a coal plant and accelerate the building of additional renewable generation. This will cost Ameren's ratepayers an incremental $4 billion. This compliance plan assumes that Ameren actually could have its new NGCC gas plant in commercial operation by 2020, which is highly unlikely, given the planning, permitting, construction and other infrastructure requirements involved, as described above. Thus, the interim goal limits the state's and Ameren's flexibility in determining how best to achieve EPA's ultimate goals, and in doing so, significantly increases costs to customers.

d. The interim compliance average period is inconsistent with state planning processes, market schedules and utility investment decision-making.

The proposed interim compliance average period is inconsistent with state planning processes, market schedules and utility investment decision-making. Although state plans are due in mid-2016, EPA has offered states the option of seeking an additional year (for an individual state plan) or two (for multistate plans). *See* 79 *Fed. Reg.* at 34,916. Additional time to create workable state plans is a welcome flexibility. However, this extension conflicts with legislative schedules in many states. Several states already have noted that their legislatures do not meet every year and that the relevant future sessions are out of sync with the proposed timing for submission and approval of state plans. For example, both the Arkansas and Texas legislatures will not have sessions in 2016 and will meet again for the first time after the guidelines are finalized in 2017. To the extent that states need to pass new legislation to ensure that all elements of compliance plans are enforceable, the legislative calendar in some states will be an impediment to both ensuring that compliance plans are completed on time and allowing key compliance measures to reduce emission rates to move forward before 2020.

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Similarly, for states that participate in competitive wholesale markets, the timing of state compliance plans does not account for already scheduled capacity auctions. For example, the PJM capacity auction addressing the 2017/2018 planning year took place in May 2014, the auction addressing the 2018/2019 planning year will occur before EPA finalizes the proposed guidelines in 2015 and the auction addressing the 2019/2020 planning year will occur in early 2016. Because units that are selected in these auctions are expected to be available to provide power in the relevant timeframes, decisions about which resources will be required to be available in 2020 will be made in early 2016, *before* the first set of state plans have been submitted to EPA. This will complicate state planning as it may limit reduction options available before 2020.

Furthermore, the 2020 compliance goals limit the ability of states, electric utilities and system operators to manage what could be a large number of simultaneously retiring coal-based units. EPA's own analysis indicates that 46-49 GWs of coal-based units will close before 2020. *See* Resource Adequacy TSD at 8. This is in addition to the approximately 70 GWs of announced coal-based unit closures that will occur between 2010 and 2022. In total, almost a third of the U.S. existing coal-based fleet could be closed around the end of the decade. This will have significant implications for system reliability that must be managed, as discussed in section I, above. The ability to schedule these closures in a reasonable way is critical to maintaining reliability and minimizing costs—the interim compliance average deprives states of this tool.

Finally, it takes years for electric utilities to plan, gain approval for and build infrastructure and other supporting projects.[128] This includes new efficient fossil-fuel plants; unit-level efficiency retrofits; new transmission lines to mitigate plant closures and to bring new energy sources to the grid; and a host of other compliance activities. Companies generally will not commit to make large financial investments—nor will state PUCs approve such investments—prior to final, EPA-approved state plans which could be well into 2018 or 2019. This uncertainty will challenge states' ability to meet and demonstrate compliance with the interim average emission rates starting in 2020. EPA's assumption that states can take significant steps to reduce emissions in advance of the start of the interim compliance period is thus inconsistent with its own regulatory timeline. The interim compliance goal does not take into account this lead time necessary to achieving reductions.

e. The proposed interim compliance average period excludes emission reductions achieved before 2020 and perversely limits state incentives for initiating earlier emission reductions.

EPA calculated a 2012 emission rate for each state as part of the process to set the state-specific emission rate goals, but the interim average compliance period does not start until 2020. EPA proposes to limit the reductions that can be included in state plans to those achieved during the interim period. *See* 79 *Fed. Reg.* at 34,918. This means that states would not be able to include reductions that occur before 2020.[129] For example, states that undertake EE measures in 2015 will only be able to include the reductions from five years of those measures' estimated 10-year

[128] In many cases, site- and project-specific permit requirements and challenges can cause substantial construction delays for these projects. Utilities attempt to account for these potential hurdles in planning. However, any number of site-specific issues can cause lengthy delays in integrating new generation, transmission and distribution assets into the grid.

[129] As discussed *supra*, section II.A., the proposed guidelines do not recognize appropriately the value of state and electric utility efforts to reduce emissions prior to 2012.

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reduction life. Similarly, depending on whether a state chooses a rate- or mass-based approach, retiring coal-based units may have a limited impact on state emission rates, especially if EPA prohibits states from including reductions that were already on the books as of 2013 in state compliance plans.[130]

In creating an interim compliance average measured over the period 2020-2029, EPA has created an arbitrary dividing line: planned emissions reductions that were "on the books" as of 2012 may not be counted, but the same reductions that were put "on the books" in 2013 or later would be counted. Section III.C., below, discusses the role of reductions achieved after 2012, but before 2020, in more detail.

f. The proposed interim compliance period does not allow sufficient time for RTOs and ISOs to evaluate and potentially alter market rules to accommodate changes in dispatch.

The changes in how demand is met envisioned by the proposed guidelines—increased dispatch of existing NGCC units, increased deployment of RE generation and use of existing RE generation and the preservation of some existing nuclear units—will have significant implications for the wholesale electricity markets operated by RTOs and ISOs. Current market structures are built around the concept of security-constrained economic dispatch. But, state plans could require different approaches to dispatch. Because each market has its own set of rules, it is not immediately clear how the RTOs and ISOs will respond to such state plans. As a general matter (and at minimum), adequate time is required to ensure appropriate consideration and rule changes are made in each market. Replacing rate based interim targets with a state

[130] *See, infra*, section III.C., for a discussion of EPA's approach to including existing state programs and measures in approvable compliance plans. EPA should not limit states' ability to use reductions from existing state programs and measures in demonstrating compliance.

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determined glide path with defined and verifiable milestones to achieve the final 2030 emission target levels help provide adequate time for a reliable transition to new market rules.

Wholesale electricity markets are under the jurisdiction of FERC, and any market changes will require FERC approval. Under the FPA, FERC is required to ensure that rates are "just and reasonable" and "not unduly discriminatory or preferential." FPA sections 205(a) and 206(a). After state plans are submitted and approved, the RTOs and ISOs must evaluate and implement any market changes that will be needed to effectuate state compliance plans. The RTOs and ISOs will need time to determine any necessary market rule and system changes; vet these proposed changes through their stakeholder processes; obtain state and federal approvals, including FERC approval; and reliably implement the required changes. In RTO/ISO markets, the stakeholder process can take six to eight months, even on an expedited basis. FERC approval can take as long as a year or more, and implementation cannot start before final approval. Accordingly, even on the most expedited basis, RTOs and ISOs would have very little, if any time, to make market changes before 2020.

2. EPA's proposed approach to state compliance plans can be used to promote state flexibility while ensuring that the 2030 goals are achieved.

States should be able to choose a reasonable emission reduction glide path that achieves the 2030 goal. Requiring that states demonstrate compliance with the 2030 goal through implementation of the EPA-approved plan, without reference to the proposed interim 2020-2029 average goal, would give states sufficient flexibility to design workable compliance plans which establish reasonable compliance glide paths consistent with ensuring reliability and protecting consumer interests. This would allow states to ensure that there is sufficient time to complete needed infrastructure development (including electric and/or gas transmission) in order to provide

reliable power, and would reduce concerns regarding the system impacts of abrupt shifts in dispatch between existing coal- and gas-based units. It would eliminate conflicts between the timing of the interim period and legislative calendars, market rules and utility investment schedules. Finally, it also would recognize and value reductions achieved since 2012, encouraging early action where possible.

Eliminating the interim compliance average goal does not require a fundamental altering of the proposed guidelines. Instead, the proposed guidelines already are designed to allow states to develop their own compliance plans, and a description of the reduction trajectory to 2030 is a required element of state plans. EPA can and should use the proposed approach to state plans to ensure that state plans and emission reduction glide paths are designed to meet—and do actually achieve—the 2030 goals, with the ability to make corrective actions or allow for alternative compliance paths if new technologies or market conditions change requirements.

Importantly, even without the interim average compliance goal, EPA still will review and approve proposed state plans and emission reduction glide paths. Even under the proposed guidelines, EPA would be able to disapprove proposed plans and glide paths that do not meet the minimum requirements and that do not demonstrate satisfactorily how the 2030 goals will be achieved. *See* 79 *Fed. Reg.* at 34,916. Allowing states to design emission reduction glide paths as part of their state plans would not undermine the overarching goals of the proposed guidelines. Further, as discussed below, other elements of EPA's proposed approach to state plans ensure that states make reasonable and verifiable progress toward the 2030 goal, report that progress to EPA and take corrective measures if needed. Ultimately, if states do not show progress toward

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the 2030 goal, EPA could call for a state to revise its compliance plan or implement its own federal plan. *See* 79 *Fed. Reg.* at 34,908.

The requirements for state plans are detailed and rigorous. *See id.* at 34,911-14. Particular elements of the state plans process require discussion as they demonstrate that EPA can allow states to design their own reasonable reduction glide paths and ensure that reductions are being achieved. First, the proposed guidelines require that states demonstrate continuous progress towards the 2030 goal and verify their performance through annual reporting of emission performance to EPA. Starting in 2022, states would be required to submit annual reports detailing plan implementation and progress, including a comparison of actual plan performance against projected plan performance. *See id.* at 34,914. In this way, EPA can monitor if states are making progress toward the 2030 goals and whether states are achieving reductions consistent with the proposed glide paths.

Second, the guidelines require that state plans must include periodic programmatic milestones to show progress toward implementation. These milestones are required to have specific dates for achievement. This requirement prevents states from delaying reductions. *See id.* at 34,912.

States plans also must identify additional measures that they will adopt and enforce in the event that an annual emissions progress report shows that the state's emission performance is not within 10 percent of the emissions performance path projected in the state plan. *See id.* These corrective measures would have to be implemented soon after a state report indicated that

reductions were not being achieved consistent with the glide path, further ensuring that states could not delay reductions and that progress continues to be made toward the 2030 goals. *See id.*

Importantly, the proposed guidelines allow for states to propose modifications to approved plans to update or alter existing enforceable measures or add new enforceable measures. *See id.* at 34,917. This is an important state flexibility as it allows states to address changing circumstances over the long life of compliance. It is not likely that plans developed in 2016 would reflect the emission reduction options available in 2025, nor could they. Plans developed in 2016 also may not be able to appropriately address the requirements of the interconnected power system in the future. As discussed, implementation of the Building Blocks simultaneously will require fundamental changes in how the power system is operated and planned—many of these changes cannot be anticipated at the time state plans are submitted and before implementation has begun.[131] Allowing states to revisit plans to adjust glide paths or enforceable reductions actions and measures is both reasonable and necessary to ensure the continued reliable provision of electricity to customers and to reflect unanticipated circumstances.

However, the proposed regulations potentially limit states' flexibility to propose amendments to their compliance plans and are inconsistent with the preamble's clear statement that states can seek EPA approval for modified plans. Specifically, the proposed regulations could be read to limit states' ability to propose modifications only where a modification is necessary in order to ensure that the emission performance goals will be met. *See* proposed 40 C.F.R. § 60.5785, 79

[131] As noted, *supra*, section II, EPA should consider state-specific factors when finalizing the 2030 goals to ensure that they are achievable.

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Fed. Reg. at 34,954 ("If one (or more) of the elements of the state plan set in § 60.5740 *require revision with respect to reaching the emission performance goal set in § 60.5765* a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.")(emphasis added). This seemingly would prevent a state from amending its plan in a circumstance where it was projected to meet its performance goals, but nonetheless determined that it could better provide reliable power to its citizens using a different mix of emission reduction measures.

States should not be limited to modifying plans only to address the failure of a plan element to perform as projected. As discussed, states need the flexibility to modify compliance plans and emission glide paths to address changing technology and the needs of the interconnected power sector. Each state should be allowed to modify its state compliance plan as long as it can demonstrate compliance with the 2030 emission goals. New generation or energy storage technologies that provide a cleaner, more reliable or cost effective path to achieve the 2030 goals should be allowed to replace existing elements of the state compliance plan. As EPA notes, as long as states can continue to demonstrate that plans are designed to achieve the 2030 goals, states should be able to propose modifications. *See* 79 *Fed. Reg.* at 34,917 ("During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing measures with new measures. The EPA proposes that the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan."). EPA should clarify the proposed regulation accordingly.

3. The final guidelines should recognize a range of options for defining approvable emission reduction glide paths and state plans.

As discussed, EPA has clear authority to approve or disapprove state compliance plans and emission reduction glide paths. As set forth in the proposed guidelines, EPA will assess whether state plans are approvable using four general criteria. *See id.* at 34,909. First, the state plan must contain enforceable measures that reduce EGU CO_2 emissions; second, these measures must be projected to achieve emission performance equivalent to or better than the proposed 2030 goal; third, reductions must be quantifiable and verifiable; and fourth, the plan must include a process for reporting on implementation and emission performance and implementation of corrective measures, if necessary. *See id.* As a preliminary matter, EPA should make clear that it will not disapprove any plan that satisfies these four criteria.

There are a range of mechanisms for states to consider to determine potentially approvable, reasonable emission glide paths. As discussed in section III.E., below, EPA already has recognized that states can include non-BSER measures in compliance plans. *See id.* at 34,923-34. Similarly, approvable emission reduction glide paths do not have to be based exclusively on the actions and measures that EPA proposes constitute BSER. The following is a discussion of some of the options states could consider. It is not intended to be exclusive or to limit state flexibility or choice in designing workable compliance plans.

a. Existing trading programs could be used to define state compliance glide paths.

An approvable plan or emission reduction glide path could take advantage of existing state programs. Further, any final guidelines should recognize, as noted in the proposed guidelines, that existing cap-and-trade programs under RGGI and California's A.B. 32 programs could be

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part of state plans and define an emission reduction trajectory for affected existing EGUs in those states. *See id.* at 34,838.

b. Federally enforceable coal plant retirements could also be used to define state compliance glide paths.

Under section 111(d) of the CAA, EPA is required, when promulgating a standard of performance under section 111(d), to take into consideration the remaining useful lives of the sources in the category of sources to which such standard applies. However, in proposing interim goals that effectively obligate the early retirement of coal resources in some states, EPA does not address the remaining useful lives of these resources, as well as other provisions of the CAA which may require the installation of major environmental controls or have resulted in established retirement dates.

Another option states should be able to pursue to define compliance glide paths would be the use of coal plant retirements, which is consistent with EPA's approach to compliance in other CAA programs.[132] CAA programs with a similar federal-state policymaking process as is required under section 111(d) include the regional haze program and related BART emission standards.

[132] EPA also has allowed regulated units to use retirement as a compliance tool in regulatory regimes outside of the CAA. For example, in the recently finalized cooling water intake structures rule, EPA allows facilities to use plant retirement as a means of compliance with both impingement and entrainment standards. *See* EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, 79 *Fed. Reg.* 48,300, 48,332 (Aug. 15, 2014). Additionally, state clean water agencies are provided the flexibility to take into account a plant's remaining useful life in determining the appropriate entrainment standard. *See id.* at 48,376.

In the regional haze context, EPA has allowed and approved state implementation plans that rely on a variety of different types of early coal plant retirement commitments to define a state's regional haze BART and reasonable progress compliance glide paths, so long as the retirements occur before a benchmark date and are legally enforceable.

- In considering Washington State's regional haze SIP, EPA accepted a Revised BART compliance option using a staggered decommissioning schedule that was required under unrelated State laws limiting GHG emissions.[133]

- EPA approved an Oregon regional haze SIP that set a Revised BART emissions limit based on a voluntary, operator-set, enforceable retirement date.[134]

- Finally, EPA approved a Revised BART emission limit in a Wyoming regional haze SIP based on an early retirement date that corresponded with the end of the facility's depreciable life as determined by and made enforceable by the owner's economic regulator, the Wyoming Public Service Commission.[135]

Consistent with these precedents, states should be allowed to use different types of retirement commitments to define, in part, their reduction glide paths and milestones to achieve the proposed section 111(d) 2030 goals—subject to EPA approval and annual compliance reporting.

In addition, several existing coal-fueled coal plants have recently undergone major retrofits to install pollution control equipment or will be required to install significant control equipment in the near future under EPA programs such as the regional haze program and related BART emission standards. In most cases, EPA justified the costs of installing these controls based on

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[133] *See Approval and Promulgation of Washington Regional Haze State Implementation Plan*, 77 *Fed. Reg.* 30,470 (May 23, 2012).

[134] *See Approval and Promulgation of Oregon Regional Haze State Implementation Plan*, 76 *Fed. Reg.* 38,997, 38,999 (July 5, 2011).

[135] *See Approval and Promulgation of Wyoming Regional Haze State Implementation Plan*, 79 *Fed. Reg.* 5,032, 5,165 (Jan. 30, 2014).

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operating the coal units at high capacity factors over a twenty-year life. The proposed interim goals do not allow a state to ensure the useful life of these recent investments. If these coal units are retired earlier than expected, significant stranded assets could result.

c. RTO dispatch could be used to define state compliance glide paths.

States also could rely on other existing market mechanisms to define emission reduction glide paths. For example, the competitive wholesale markets administered by RTOs could be used to define a reduction trajectory for states. Under such an approach, states could choose to require in-state resources to include a carbon adder pre-determined by EPA when bidding resources into the market. This would alter the dispatch of units to better reflect their CO_2 emissions and provide a mechanism for continued emission reductions from existing units in a way that both respected system requirements and ensured reliable operation of the portions of the grid administered by the RTOs.

EPA could provide that while the carbon adder is used to affect dispatch, states would not be required to file annual compliance reports or otherwise demonstrate compliance with the proposed guidelines in recognition of the fact that the maximum amount of re-dispatch that could be supported by the system operated by the RTO would be accomplished. This "safe harbor" would give states and electric utilities time to undertake actions and measures that result in emission reductions later, in recognition of, as discussed above, the infrastructure challenges related to implementing Building Blocks 1 and 2 and the timing issues related to implementing legislation necessary to implement Building Blocks 3 and 4. It would also provide an appropriate incentive to maintain zero carbon resources and avoid (at least in the short term) the

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concerns expressed above about the treatment of nuclear resources in the emission rate formula proposal.

Importantly, because the carbon adder relies on existing market structures, it could be implemented soon after state compliance plans are approved (and before 2020) to start reducing emissions. As noted, EPA should strive to create state flexibility that promotes early achievement of emission reductions. Further, to address concerns about costs for electricity customers, the carbon adder could be collected by the market operators and then used to offset increased costs to customers, ensuring that electricity remains affordable for end-users.

To support the potential use of this option to define state glide paths, the final guidelines should recognize the value of using existing market dispatch structures to achieve emission reductions and specifically note that states could pursue this option as part of an approvable plan. Further, the final guidelines could include a carbon adder value for states to require affected units to use when bidding into competitive markets.[136]

4. The NODA includes discussion of mechanisms that could address near-term compliance concerns for some states.

As discussed, the recently-released NODA recognizes that many stakeholders have concerns about the near-term compliance challenges created by the proposed guidelines. In particular, EPA notes that some commenters have suggested, consistent with the concerns raised in these comments, that

> calculating the interim goals on the basis of achieving the shift in generation assumed under building block 2 by 2020…requires states to

[136] EEI member comments will provide more detail on this possible approach for states to define compliance glide paths using existing market structures.

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> achieve such a significant portion of the required CO_2 emission reductions early in the interim period that it defeats the intended purpose of providing states flexibility in how they may achieve the required emission reductions. In addition, we have heard that there may be technical challenges associated with achieving all of the reductions that state would be required to make as early as 2020, when the interim period commences.

79 *Fed. Reg.* at 64,545.

Because of these concerns, EPA suggests it will consider additional stakeholder ideas, such as those regarding the 2020-2029 glide path, to ensure that the final guidelines provide states with flexibility to timely make reductions, develop cost-effective compliance plans and respond to unexpected demands on the power system. *See id.* As discussed above, eliminating the interim compliance goal and allowing states to choose a reasonable glide path to achieve their individual 2030 goals based on objective criteria outlined by EPA in the final guidelines would be the most appropriate way to help ensure that states can design cost-effective strategies to reduce emissions and would eliminate the significant technical challenges associated with requiring the majority of the reductions to be achieved on or before 2020. It also would allow states, electric companies and system operators to plan for and implement changes to the interconnected power system in a way that would help support reliability in the case of unexpected demands on the power system, such as extreme weather events. Therefore, while the phase-in approaches discussed in the NODA are an improvement over the proposed guidelines, they are insufficient to address all of the concerns raised in these comments.

In the NODA, EPA discusses two ways of addressing concerns raised by stakeholders to address concerns about the glide path: (1) allowing states to credit early CO_2 emission reductions; and (2) phasing in the increased utilization of existing NGCC units under Building Block 2 over

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time, similar to the phase in of reductions under Building Blocks 3 and 4. *See* 79 *Fed. Reg*. at 64,545. Each of these options, which are discussed in turn, below, could address some of the concerns about the 2020-2029 glide path that have been raised by commenters. However, neither provides states the same ability to design cost-effective compliance plans that are consistent with the technical realities of shifting generation between existing coal- and gas-based units that would be provided by eliminating the interim goals.

a. States should have the option to recognize early reductions as a way to address concerns about the 2020-2029 glide path.

In the NODA, EPA notes that some stakeholders have suggested that "early reductions could be used as a way to ease the 2020-2029 glide path." *Id.* EPA also notes that the proposed guidelines seek comment on whether credit for certain pre-2020 reductions could be used to reduce the overall amount of reductions that need to be achieved during the interim period. *See id.* at 64,545-46. The NODA also seeks comment on whether states could choose early implementation of state compliance plans, which would allow states to achieve the interim goals by making some reductions earlier. *See id.* at 54,546. EPA asserts that either of these approaches would allow states to phase in reductions. *See id.*

Allowing states to recognize early action that reduces emissions between 2012 and the start of the interim compliance period is an important tool that could be useful to some states when designing compliance plans. As EPA notes, it is important to recognize early reductions so as not to create disincentives for pre-2020 reductions. *See id.* The final guidelines should permit early recognition of reductions as states develop their individual glide paths to the 2030 goal.

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However, early recognition does not address fully the concerns raised in these comments about the interim compliance goal and the magnitude of reductions that are required before 2020. EPA notes that allowing states to credit some early reductions or state compliance periods earlier than 2020 could make it possible for "at least some states to take advantage…of RE and demand-side [EE] projects already under development and scheduled to be implemented prior to 2020 or by expediting other projects." *Id.*[137] While states may be able to use some reductions from RE and EE measures, it is unlikely that these reductions would be significant enough to offset the need to increase significantly utilization of existing NGCC units to meet the interim goals. Credit for early RE and EE reductions also does not address infrastructure concerns or other technical challenges associated with increasing the utilization of existing NGCC units discussed extensively in sections II.C and III.A, above.

In addition, given the timing challenges states face in submitting timely compliance plans for EPA approval, which are outlined above in section III.A.1., above, it is unlikely that states would be able to begin compliance plans early in order to take advantage of pre-2020 reductions. If states would like to do so, the final guidelines should make it clear that this is an option. Early recognition, however, is not sufficient to alleviate these concerns and does not obviate the need to eliminate the interim compliance goals.

[137] As discussed *infra*, section III.D, the final guidelines should clarify that states can include reductions in compliance plans regardless of whether they are the result of measures or programs that were already "on the books" as of June 2014. The "on the books" limitation would reduce the amount of post-2012, pre-2020 reductions that states could use to address concerns about near-term compliance challenges.

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b. Phasing in the increased utilization of existing NGCC units could help some states create a more gradual glide path, but would not address all concerns about state plan flexibility.

As discussed above, despite the fact that the interim goals can be met on an average basis for the 2020-2029 period, the structure of the numeric calculation for establishing the state goals assumes that all changes in dispatch between existing coal- and gas-based units has occurred by 2020. As discussed above, this front-loads reductions related to Building Block 2, creating significant technical challenges and limiting state flexibility in designing compliance plans. To address these concerns, EPA suggests that Building Block 2 reductions could be phased in. *See* 79 *Fed. Reg.* at 64,548. In the NODA, EPA seeks comment on two approaches for creating a phase-in schedule for Building Block 2. The first would examine whether, and to what extent, any additional natural gas pipeline infrastructure is needed to support increased use of existing natural-gas based generation. The second would consider the book life of existing generation assets, including any major upgrades to the assets, like pollution control retrofits. *See id.* at 64,548-49.

As a preliminary matter, phasing in reductions under Building Block 2, similar to the phase-in of reductions under Building Blocks 3 and 4, could address some of the near-term compliance challenges discussed in these comments for some states. In general, phasing in these reductions is more reasonable than assuming that all changes in dispatch between coal- and gas-based generation occurs before 2020. As EPA recognizes in establishing the Building Block 3 and 4 goals, it is appropriate to give states and electric utilities sufficient time to make system changes or create new programs. A phase-in of Building Block 2 reductions could allow for the necessary expansion of natural gas infrastructure to support increased utilization of existing

NGCC units and could provide competitive markets time to review and adjust market rules, if needed.

It is not clear from the NODA, however, exactly how EPA would structure a phase-in schedule for Building Block 2. Under the first option, EPA would account for the needed expansion in natural gas pipeline infrastructure, but the Agency has not provided any details as to how the Agency would determine which states need new capacity and how quickly it could be built. At minimum, EPA should recognize that it takes three to five years to plan, permit, contract for capacity, finance and build additional pipeline capacity. *See* Initial Reliability Review at 10. However, in general, it is difficult to see how the Agency could determine a phase-in rate for new pipeline capacity that would make sense for each state or accurately reflect state-specific infrastructure circumstances. Eliminating the interim goal so that states can determine the most appropriate phase-in schedule for Building Block 2 reductions would be simpler and better address state-specific concerns.

EPA's second approach would focus on the remaining book life of existing coal-based units, which EPA notes, would avoid stranding investments recently made in pollution control retrofits for coal-based units. *See* 79 Fed. *Reg*. at 64,549. While not clearly stated in the NODA, it appears that EPA would consider the remaining book life of certain coal-based units when calculating the re-dispatch potential available in a state. If EPA were to take this approach to phase in re-dispatch under Building Block 2, EPA should recognize both the remaining book life

of units and any recent upgrades and major pollution control installations when setting state goals.[138]

However, while this approach may be very important in some states as a way of providing a smoother glide path that does not strand investments, it would not address the 2020-2029 concerns of many other states with respect to the assumed changes in dispatch between coal- and gas-based units. In particular, it would not address any of the natural gas infrastructure concerns identified by electric utilities and states. If EPA determines to recognize remaining book life when calculating state goals under Building Block 2, it should be coupled with other approaches to address the full range of near-term compliance concerns.

B. The Proposed Guidelines Fail to Recognize the Critical Role of Nuclear and Hydropower in Reducing GHG Emissions and Do Not Incent Their Continued Operation and Development.

The proposed guidelines do not recognize the value of all zero-emitting resources, particularly existing nuclear facilities and hydropower resources, in achieving and maintaining the proposed state emissions rate goals.

1. The proposed guidelines create no real incentive to maintain existing nuclear power plants and penalize states building new nuclear generation; EPA should broaden the definition of "new" nuclear generation.

a. Existing merchant nuclear facilities are at risk of premature retirement.

Our nation's nuclear power plants produce about 20 percent of our electricity, yet emit no carbon dioxide.[139] Analyses of climate change by independent organizations, in the United States and

[138] The NODA focuses solely on the book life of units, but it may be more appropriate to consider the depreciation schedule of the unit and any capital improvements. This would provide greater protection to consumers that ultimately bear the costs of these expenditures. Considering book life or depreciation schedules as a way to phase in Building Block 2 reductions does not satisfy EPA's obligation to consider the remaining useful life of units, as required by section 111(d). Book life is an accounting concept and does not measure the remaining useful life of an EGU.

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globally, demonstrate that nuclear energy must be part of the portfolio of resources that helps drive carbon reductions. Without nuclear energy, carbon emissions will be higher, as will the cost of electricity and natural gas and the cost of carbon allowances under a carbon control regime. Simply put, the nation cannot achieve its carbon reduction goals without the existing nuclear fleet.

For perspective, just 1 GW of nuclear generating capacity (typical of a single nuclear unit) avoided more carbon in 2013 than all U.S. solar energy capacity (4.5 GW at a 17 percent capacity factor). Moreover, the U.S. currently has more than 100 GW of nuclear generating capacity. The amount of CO_2 emissions avoided by nuclear energy facilities is equal to the CO_2 emissions from 113 million passenger cars—more than all the passenger cars in the U.S.[140] Without the nuclear power plants that operate in 31 states, carbon emissions from the U.S. electric sector would be approximately 25 percent higher.

Nuclear plants also are critical to the reliability of the electric grid because they operate continuously and generally independent of weather conditions. For example, during the "Polar Vortex," which occurred during the week of January 6, 2014, the nation's nuclear power plants operated at an average capacity factor of 95 percent, and on several days, at an average capacity factor of 97 percent.[141] No other source of electricity approached that level of reliability. In fact,

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[139] EPA, *Nuclear Energy*, http://www.epa.gov/cleanenergy/energy-and-you/affect/nuclear.html.

[140] *See* Nuclear Energy Institute (NEI), *Environment: Emissions Prevented*, http://www.nei.org/Knowledge-Center/Nuclear-Statistics/Environment-Emissions-Prevented.

[141] *See* NEI, *Nuclear Fleet Shrugs Off Polar Vortex Like a Comfy Old Coat* (Jan.8, 2014), http://neinuclearnotes.blogspot.com/search?q=polar+vortex.

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approximately 20 percent of the generating capacity in PJM and 22 percent of the capacity dispatched by the MISO[142] was forced out of service by the severe weather (either because power plants could not obtain fuel or because fuel-handling equipment froze). The ability to rely on nuclear power in all circumstances will become increasingly important as the nation's electricity system becomes less reliant on coal, and more reliant on gas-fired generating capacity and on renewable technologies that are intermittent and weather-dependent. For example, MISO's experience with wind generation during the Polar Vortex is instructive: On Sunday, January 5, as the weather front known as the Polar Vortex approached, approximately 9,700 MW of wind generation in MISO was in service; on Monday, January 6, that had dropped to approximately 7,500 MW; by Tuesday, January 7, when the extreme cold settled over the region, only slightly more than 1,000 MW of wind capacity was operating.[143]

EPA has correctly acknowledged in the proposed guidelines that, despite generating large amounts of clean energy and playing a vital role in grid reliability, certain nuclear facilities across the country are at risk of premature retirement. Roughly half of the nation's existing nuclear units are merchant generators in states with competitive electricity markets – meaning that they only recover what the market will pay for electricity. Moreover, markets in many regions currently do not value the reliability and carbon attributes of base load zero-emitting

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[142] *See* Platts, *MISO forced outages peaked at 22% of generation during polar vortex: RTO* (Jan. 15, 2014), http://www.platts.com/latest-news/electric-power/houston/miso-forced-outages-peaked-at-22-of-generation-21084199.

[143] MISO, *January 2014 Extreme Weather Event, MISO Preliminary Review*, at 3-4 (Jan. 10, 2014), https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/January2014ExtremeWeatherEvent_PreliminaryReview_MISO.pdf.

nuclear capacity. At the same time, market revenues have been affected by seven years of low growth in electricity demand, lower natural gas prices, increasing generation of renewable power, and the absence of a carbon policy that would value the carbon-free electricity that nuclear plants produce, thereby avoiding emissions from fossil-fired plants.

Relying on a national projection from the EIA, the Agency has estimated that six percent of the nation's nuclear capacity is at risk of premature retirement. However, public data shows that a much larger percentage of the merchant nuclear generating capacity in competitive markets is at risk, and that the "at risk" plants are not evenly distributed among all of the states. In some states, such as Illinois, significantly more than six percent of the merchant nuclear capacity is at risk. There, for example, Exelon Corp. has indicated publicly that five of its 11 nuclear reactors in the state are at risk of premature shutdown. The eleven nuclear reactors in Illinois produce approximately 48 percent of the state's electricity.

Moreover, EPA's own analysis demonstrates that the proposed guidelines have the potential, paradoxically, to *increase* the financial pressure on existing nuclear plants. This will occur if states in competitive markets choose to comply with EPA's emission rate target by incentivizing new natural gas or renewable generation in a manner that allows such generation to sell electricity for less than its true marginal cost, which would have the effect of artificially lowering the market price of electricity for all generators and further challenging the economic viability of existing merchant nuclear plants. *See* RIA at 3-43 (estimating bill decreases of up to 8.7 percent in 2030).

b. EPA's differing treatment of existing zero-emission sources is not justified.

In developing BSER, EPA's view was that including a small percentage of nuclear energy to make a state's emissions rate more stringent would provide an incentive to avoid premature nuclear shutdowns. The approach, however, will not achieve the intended effect and is legally vulnerable. All zero-emissions generation (e.g., nuclear, geothermal, wind, solar and hydropower) have climate benefits and the dissimilar treatment of existing zero-emission generation is not warranted.

Non-hydro renewable energy, nuclear energy, and hydropower receive vastly different treatment under the proposed rule, which EPA does not explain—let alone justify—even though the purpose of the proposed rule is "to address greenhouse gas emissions from existing fossil fuel fired electric generating units." 79 *Fed. Reg.* at 34,851. EPA's failure to provide such an explanation violates basic administrative law principles. An agency rule is arbitrary and capricious where the agency "failed to consider an important aspect of the problem," or "offered an explanation for its decision that runs counter to the evidence before the agency." *Motor Vehicle Mfrs.' Ass'n v. State Farm Mut. Auto. Ins. Co.*, 436 U.S. 29, 43 (1983). A court "may not supply a reasoned basis for the agency's action that the agency itself has not given." *Id.* (quoting *SEC v. Chenery Corp.*, 332 U.S. 194, 196 (1947)). Indeed, EPA must "explain [its] decisions with precision," and the Administrator must "cogently explain why [she] has exercised [her] discretion in a given manner." *Am. Lung Ass'n v. EPA,* 134 F.3d 388, 392 (D.C. Cir. 1998) (second and third alteration in original).

In addition, the carbon abatement value of each MWh generated by such sources is generally the same, regardless of whether it is generated by nuclear, hydropower, geothermal, solar, wind or other zero-emission sources. Take California as an example. In determining initial and targeted emissions rates for California—an "early mover" state with respect to emissions abatement—EPA would include *all* of the electricity generated from California's Shiloh Wind Power Plant, which came online in 1989; *six percent* of the electricity generated from its Diablo Canyon Nuclear Power Plant, which came online in 1985-1986; and *none* of the electricity generated from its Stenner Canyon Hydropower Plant, which came online in 1985. Yet all three plants are approximately the same age, and when operating, all three plants provide carbon-free generation. If anything, preserving existing zero-emissions sources, particularly nuclear generation, is *more* relevant to carbon abatement, not less. EPA acknowledges as much through the cost-effectiveness evaluation of "at risk" nuclear units in the proposed rule. There, EPA notes that the cost of keeping "at risk" nuclear plants operating is approximately $12-$17 per metric ton of CO_2 avoided, *see* 79 *Fed. Reg.* at 34,871, which is more cost-effective than virtually any other carbon abatement strategy. For example, preventing the early retirement of nuclear plants (and other existing zero-emissions sources) is more cost-effective than:

- Adding new renewable capacity ($10-$40 per metric ton of CO_2 abated). *Id.* at 34,858.
- Increasing natural gas combined cycle power plant utilization rates to 70 percent ($30 per metric ton of CO_2 abated). *Id.* at 34,865.
- Implementing demand-side management programs ($16-$24 per metric ton of CO_2 abated). *Id.* at 34,875.

These data demonstrate that ignoring the vast majority of nuclear generation in the Clean Power Plan is not justified by the carbon abatement benefit it provides.

c. EPA's proposed "six percent solution" for "at risk" nuclear units is not appropriate.

EPA calculates the generation (in MWh) of electricity from "at risk" nuclear plants and then adds this generation to the denominator of the goal, resulting in a more stringent 2030 emission rate for states with nuclear capacity. EPA explains that the proposed rule counts only six percent of existing nuclear facilities because (according to EPA) six percent of nuclear capacity nationwide is "at risk" for premature retirement.

However, if states are to achieve meaningful emission reductions, it is important that *all* existing nuclear generation (as well as all existing zero-emission sources) remain in operation—yet the proposed treatment of "at risk" nuclear generation inadequately promotes this goal. For instance, if a state has a single 1000 MW nuclear plant that is retired, six percent of that capacity will be only 60 MW—capacity that a state could easily replace with, e.g., a new wind farm. A state should not be indifferent to the loss of the remaining 940 MW of nuclear capacity—supply that will almost certainly be replaced in large part by new NGCCs that will increase the state's total carbon footprint. Yet such indifference is precisely what the proposed rule fosters by charging the state with the loss of only six percent of prematurely retired nuclear capacity and providing no incentive to keep the remaining nuclear capacity in operation.

Moreover, the proposed rule's rationale for counting only six percent of nuclear generation—namely, that only six percent of nuclear capacity is "at risk"—is too broadly applied. First, the reality is that "at risk" nuclear facilities are concentrated in a small number of states with competitive markets, generally located in three regions of the country: the Northeast, the

Midwest and the Great Lakes.[144] In those areas, the fraction of the merchant nuclear fleet that is at risk of early retirement is much greater than six percent. In other regions, where nuclear plants are owned by regulated utilities, the fraction of the at-risk fleet is much less than six percent and, in many of those states, effectively zero. Second, if *any* nuclear facility is prematurely retired, it is nearly certain to represent more than six percent of a state's nuclear capacity—indeed, likely far more. For example, a number of states have only one nuclear facility—which means that any retirement will necessarily be a retirement of 100 percent of the state's nuclear fleet. Yet six percent is the *most* that is relevant under the proposed guidelines. EPA's decision to count the six percent of nuclear generation "at risk" when setting state-specific goal rates unreasonably increases the stringency of state goals where nuclear already exists while not providing an adequate incentive to maintain the economic viability of any "at risk" nuclear plants.

Finally, there are practical reasons not to use a snapshot-in-time figure of nuclear capacity at risk as the basis for a rule that will govern for decades. Market conditions are dynamic, and a plant that is not at risk today may be at risk tomorrow.

d. Proposed treatment of existing nuclear units.

If EPA is going to continue with its proposed interpretation of BSER, the Agency should remove the six percent "at risk" nuclear capacity from the goal calculation. A number of alternative approaches to the treatment of existing nuclear generation will be offered by stakeholders in individual comments. One approach that EPA should consider, however, is for a state to demonstrate in its plan reasonable assurance that it will preserve its existing carbon-free

[144] In fact, the analysis referenced by EPA shows all at-risk generation in the Northeast/Midwest/Great Lakes region, and not evenly distributed nationwide. EIA, *Annual Energy Outlook 2014*, Tables 76, 80, 83, http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

generating capacity, particularly nuclear generating capacity. For operating nuclear generating units in regulated states, such assurance already exists because integrated utilities have a reasonable opportunity to recover costs, plus a reasonable return. In competitive states with nuclear generating units potentially at risk, this could involve a commitment to policy changes through legislation or regulation, or other market-based mechanisms, or a combination that would create incentives for continued operation of these zero-emitting generators.

In the event of premature economic shutdown of a nuclear unit (most likely to occur in a competitive market if the unit is not recovering its costs), the lost nuclear kilowatt-hours should be subtracted from the denominator of the state's compliance calculation. This would provide states an unequivocal signal that existing nuclear generating capacity has irreplaceable carbon-abatement value and must be preserved. This compliance penalty would not apply in any situation or in any state where a nuclear unit shuts down for reasons beyond a state's control. This compliance penalty would only be applied for the period between premature shutdown and the end of the unit's remaining useful life.[145]

In addition, EPA should consider ways to provide at least some limited compliance value for existing nuclear generating capacity, as an additional incentive to the states to preserve that capacity. For example, in its calculations, EPA assumes a uniform 90 percent capacity factor for all nuclear power plants, existing and new. While the U.S. nuclear fleet, on average, has

[145] The intent would be to provide an incentive for states in competitive markets to maintain their nuclear fleet, but not to impose restrictions in non-market jurisdictions. This concept would need to be further developed before it could be included in final guidelines. In particular, critical details, such as the definition of "premature economic shutdown" and "reasons beyond the state's control" need to be addressed.

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consistently achieved capacity factors in the 90 percent range for the last 15 years, the average lifetime capacity factor of the 100 nuclear plants now operating is 81.6 percent through 2013. Given this, EPA should consider as an option allowing states to determine an appropriate baseline level of existing nuclear generation against which they could provide limited compliance value, such as:

- Counting toward compliance MWh produced by any nuclear plant above an 81.6 percent capacity factor; or
- Allowing nuclear MWh above the lifetime capacity factor of a state's nuclear generating units to be counted toward compliance; or
- Allowing a state to count toward compliance any nuclear MWh produced above the industry's three-year rolling average. A single-year baseline may not be appropriate for nuclear power plants, which typically shut down only every 18-24 months for refueling and maintenance outages. If the baseline year happens to be a refueling outage year, it may understate a nuclear generating unit's long-term performance. For this reason, the industry typically uses three-year rolling averages when evaluating nuclear plant performance.

In sum, creating ways for states to capture limited compliance value for existing nuclear generating units would directly serve and support EPA's principal objective—ensuring continued operation of the nation's largest source of carbon-free generating capacity.

e. Output from under-construction nuclear units should not be used to calculate state emissions rate goals.

In calculating the proposed state-specific emission rate goals, EPA included hypothetical generation from new nuclear units that were under construction in 2012. *See* 79 *Fed. Reg.* at 34,870. As EPA notes, "reflecting the completion of these units in the goals has a significant impact on the calculated goals for the states in which these units are located." *Id.* EPA's decision to include these units in setting the state-specific goal rates unreasonably increases the stringency of the goals for the states and electric utilities that have made substantial investments

in new zero-emitting generation resources. Accordingly, under construction units should not be considered when calculating the final state-specific emission rate goals.

First, as a practical matter, these plants are not complete and not operating, and there is no basis for EPA to assume that they will begin operation on or before 2020. Second, EPA unrealistically has assumed that these under construction units will immediately operate at a 90 percent capacity factor, although that is unlikely to be the case during the first few years of operation. Finally, adding the potential output from these plants to the denominator in the rate-setting algorithm dramatically increases the stringency of the emission rate goals for the three states where they are being built, thus penalizing those states for supporting new nuclear plant construction. These states *must* use all of the generation from these new units in order to meet the proposed reduction emission rate goals. If these units are not available for any reason in the future, these states would face significant compliance challenges.

i. Units that are not complete and not operating should not be considered when setting state emission rate goals.

The proposed guidelines state that "Building Block 3 is based on shifting generation from affected fossil units to new renewable energy generating capacity, which is added over time, and *new or preserved nuclear capacity, all of which is expected to be in place by 2020*." 79 *Fed. Reg*. at 34,906 (emphasis added). The five under-construction nuclear units should not be considered when calculating the final emission rate goals because they are not complete and not operating. Development of a new nuclear plant is a long and complicated process that takes a

minimum of nine years to complete, even if everything goes according to schedule,[146] but new units are often subject to construction and permitting delays.

Further, assuming a 2020 start date for these units is inconsistent with EPA's general approach to setting the state-specific emission rate goals for the states. For all other actions and measures, EPA used 2012 as the base year. EPA "chose the historic data approach as it represented the most recent year for which complete data were available at the time of the analysis." Goal Computation TSD at 4. If the state goals are based on historic 2012 data, it is arbitrary to use projected 2020 data for the nuclear portion of the goals for Georgia, South Carolina and Tennessee.

ii. EPA unrealistically assumed that these under construction units will immediately operate at a 90 percent capacity factor.

EPA also factored in the expected generation from the under construction nuclear units at an assumed 90 percent capacity factor in developing the interim and final state goals for these three states. *See* 79 *Fed. Reg.* at 34,871. However, it is not realistic to assume that these units will operate at such a high capacity factor from the date of first commercial operation. Although a capacity factor of 90 percent is a realistic long-term equilibrium value, these under construction units can be expected to experience a "shake down" period once they commence operation when

[146] A number of steps are involved in licensing a new nuclear unit. Fist, a company must develop a combined construction and operating license application, which typically takes about two years. The Nuclear Regulatory Commission (NRC) must then review the application, which takes approximately three years. After licensing, construction of new nuclear units typically takes about four years. This is in addition to the initial lead time it would take to choose a site and reactor design, and for design certification. NEI, *Licensing New Nuclear Power Plants,* Fact Sheet (Oct. 2014), http://www.nei.org/CorporateSite/media/filefolder/Backgrounders/Fact-Sheets/Licensing-New-Nuclear-Power-Plants-October-2014.pdf?ext=.pdf.

capacity factors could be significantly lower. Moreover, as of late October, 2014, on average the total U.S. nuclear plant capacity factor was slightly less that 85 percent.[147]

iii. Inclusion of nuclear units under construction in the rate setting penalizes states that support new nuclear plant construction.

As discussed, EPA proposes to include the "projected amounts of generation available by completing all nuclear units currently under construction…" (Watts Bar 2 in Tennessee, Vogtle 3-4 in Georgia, Summer 2-3 in South Carolina) by 2020 in the rate setting for three states, even though those units are still under construction and not yet operating. *See* 79 *Fed. Reg.* at 34,851. EPA has chosen an arbitrary projected start date of 2020, and an unrealistic capacity factor of 90 percent. By taking this approach, the Agency has created unreasonable compliance risks, and significantly increased the stringency of the emission rate goals for Georgia, South Carolina and Tennessee by creating "phantom" zero-emissions generation used to determine the state goals. As EPA itself notes, "reflecting completion of these units in the goals has a significant impact on the calculated goals for the states in which these units are located. If one or more of the units were not completed as projected, that could have a significant impact on the state's ability to meet the goal." 79 *Fed. Reg.* at 34,870. As a result, EPA's approach penalizes states that are building new nuclear capacity, and potentially consigns three states to a deficit in zero-emissions generation needed to demonstrate compliance before the interim compliance period even begins.

As EPA notes, including these under construction units in the rate setting for Georgia, South Carolina and Tennessee could have a significant impact on the ability of those states to meet their goals, since they would have to replace any lost zero-emissions MWh with other zero-

[147] SNL, *Nuclear Update: Total U.S. production steady at 84.65% capacity* (Oct. 29, 2014), https://www.snl.com/interactivex/article.aspx?id=29630410&KPLT=6 (figure based on data from SNL Energy's Nuclear Operating Status Page).

emissions MWh (by increasing reductions from both BSER and approvable non-BSER measures). *See* 79 *Fed. Reg.* at 34,870. Given the magnitude of the generation expected from these units, it will be impossible to make up deficits in zero-emissions MWh with other BSER or non-BSER reductions. Therefore, the output from under-construction nuclear units should not be used to calculate a state's emission rate goal.

iv. EPA should revise its assumptions regarding the incremental cost of the under construction units.

EPA includes the five units under construction as part of BSER because it contends that there is no "incremental cost" associated with CO_2 emission reductions from completion of these multi-billion dollar nuclear units based on the belief that "since the decisions to construct these units were made prior to this proposal, it is reasonable to view the incremental cost associated with the CO_2 emissions reductions available from completion of these units as zero for purposes of setting states' CO_2 reduction goals." 79 *Fed. Reg.* at 34,870. In reality, approximately $10 billion remains to be spent on these five reactors. EPA's assertion that there is "no incremental cost" associated with completing these plants is incorrect.[148] These are real costs that are being incurred. EPA needs to revise this assumption regarding the incremental cost of the under construction units.

[148] Contrary to EPA's assessment, the total projected cost of the V.C. Summer two-unit nuclear project is currently estimated at approximately $10.5 billion. Of this, approximately $5.4 billion had been spent as of the end of the third quarter 2014, leaving approximately $5.1 billion in remaining capital investment. EPA should not treat this remaining investment as if it were "zero." These figures are extrapolated from the South Carolina Gas & Electric Company's Quarterly Report to the South Carolina Regulatory Staff, based on their 55 percent ownership share in the project. *See South Carolina Gas & Electric Company Quarterly Report to the South Carolina Regulatory Staff*, at 21 (Sept. 30, 2014), http://www.scana.com/NR/rdonlyres/CC6965BC-FFE3-4080-914C-1BFFE858EFE7/0/BLRA3Q2014.pdf.

f. The definition of new nuclear units should be expanded.

As EPA proposes, the final guidelines should allow states to include generation from "new" nuclear generating capacity in state compliance plans. *See* 79 *Fed. Reg*. at 34,870. However, the final guidelines should include an expanded definition of "new" nuclear that would encompass:

- New nuclear power plants (those currently under construction or others that might be built between now and 2030 and beyond); and
- Power uprates at existing nuclear plants, including those undertaken during or after 2012 or a modified baseline period; and
- Nuclear plants relicensed to operate past their initial license terms (i.e., beyond 40 years) that have not received their renewed licenses from NRC before the baseline year or period, and nuclear plants relicensed to operate beyond 60 years (subsequent license renewal).

i. Under construction units should be classified as "new" and allowed to be included in state compliance plans.

While under construction units should not be used in the rate-setting process, states should be able to include these units in their compliance plans once they are operational, as they would be the functional equivalent of any other new nuclear capacity achieved (e.g., new plants or power uprates). These units should be classified as new nuclear units, the generation from which could be used by a state to help meet its goal. Allowing these and other as yet unplanned units to be utilized for compliance will not only aid states in meeting their goals, but also serve as an incentive for states to build new nuclear units.

ii. Power uprates should be classified as "new" and allowed to be included state compliance plans.

The proposed guidelines should also recognize major capital investments undertaken between 2012 and 2020 to uprate nuclear units. These uprates provide additional zero emission generation and should be treated similar to renewable generation built during the same timeframe by allowing states to include this additional generation in its state plan to meet the final goals.

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According to NRC, utilities have used power uprates since the 1970s as a way to generate more electricity from their nuclear plants, and as of April 2014, NRC had approved 154 uprates that added generation capacity equivalent to about seven new reactors.[149] Undertaking a power uprate is a complex and time consuming process. Some uprates may involve major plant modifications, such as the replacement of the main turbines, or the modification or replacement of various components in order to accommodate a higher power level. The licensee must then submit a license amendment request for the uprate to NRC. NRC's technical and legal staffs review these complex technical analyses before approving an uprate request. *See id.* The final guidelines should allow states to include any such uprates in their compliance plans.

iii. EPA should not assume that nuclear units will be relicensed in perpetuity, and relicensed units should be classified as "new" and allowed as part of a state's compliance plan.

As described above, EPA proposes to include the projected output from nuclear units under construction when calculating state emission rate goals. EPA also proposes "that the emission reductions achievable by retaining in operation approximately six percent of each state's historical nuclear capacity [i.e., "at risk" units] should be factored into the state goals for the respective states." GHG Abatement Measures TSD at 4-34. The proposed guidelines further note that "the nuclear generating capacity reflected in building block 3 is already in operation or under construction." 79 *Fed. Reg.* at 34,890. Based on EPA's assumption that the so-called "at risk" units will continue to operate until 2030 and that the state reduction goals could be sustained beyond 2030, it is reasonable to conclude that EPA assumes that the remainder of the existing nuclear fleet will continue to be available through 2030, as no state goal appears to

[149] NRC, *Backgrounder on Power Uprates for Nuclear Plants* (Apr. 2014), http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html.

reflect any assumption by EPA of existing units coming off line, other than those already committed to retire.

This assumption ignores the fact that nuclear plants are licensed only for an initial term of 40 years. And while many plants have obtained, or are in the process of obtaining, a first license extension for an additional 20 years,[150] the process for obtaining a subsequent license extension is still evolving.[151] NRC has "begun a regulatory framework and technical justification review of the operating power reactor license renewal process to be prepared for anticipated subsequent license renewal applications that will request approval to renew a facility's operating license," but it has not yet decided on the terms under which it may grant second license renewal applications.[152] Even if NRC does grant additional license renewals, EPA has no valid basis to assume that every plant currently operating will receive license renewals that will allow them to operate for 60 years or into the indefinite future, as its current approach implicitly does.

Given the important role nuclear generation plays in providing zero-emissions power, the final guidelines should help incent the continued operation of all existing units by defining as "new" nuclear capacity any nuclear plants that have been relicensed to operate beyond 60 years—and

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[150] NEI, *Relicensing Nuclear Energy Facilities,* Fact Sheet (June 2013), http://www.nei.org/Master-Document-Folder/Backgrounders/Fact-Sheets/Relicensing-Nuclear-Energy-Facilities.

[151] The Atomic Energy Act provides that licenses are to be issued for an initial term "not exceeding forty years "and thereafter "may be renewed." 42 U.S.C. § 2133(c). The Atomic Energy Act is silent on the number of renewals that the NRC may approve.

[152] NRC, *Ongoing Staff Activities to Assess Regulatory Considerations for Power Reactor Subsequent License Renewal*, White Paper (Jan. 2014), http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2014/2014-0016scy.pdf.

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any plants that have not received license extensions to operate beyond their original 40-year license term before 2012—and allowing their full generation to be included in the state's compliance calculation, rather than assume that every nuclear unit will operate through at least 2030.

Over two-thirds of the nuclear fleet will reach the end of their first license extension period soon after the 2030 compliance deadline for this program. Currently, seventy-four of the 100 operating nuclear units have already received NRC approval to operate after 40 years, with the remaining 26 units either under NRC review or expected to file for review.[153] Approximately 31 GW of nuclear generating capacity will reach the end of their 60-year licenses between 2029 and 2035—thus requiring plant shutdown unless NRC approves a second license extension.[154] Without further significant financial investments and licensing action by the licensee, these units represent a power generation source with carbon-free emissions that are truly "at risk" of shutdown. As states are legally obligated to demonstrate continued compliance with the final state goals, sustaining these emission reduction targets will rely heavily on the continued operation of the existing nuclear facilities. Recognizing these relicensed units as new units will not delay or dilute a state's 2030 emission reduction targets, but it will contribute to ensuring that

[153] NRC is current reviewing license renewal applications for Indian Point 2 and 3, Diablo Canyon 1 and 2, Seabrook, Davis-Besse, South Texas 1 and 2, Limerick 1 and 2, Grand Gulf, Callaway, Sequoyah 1 and 2, Braidwood 1 and 2 and Byron 1 and 2. NRC anticipates receiving applications over the next four years or so from Fermi 2, Waterford 3, LaSalle 1 and 2, Perry 1, River Bend, STARS #6, Clinton and STARS #7. Note that the list of plants under NRC review or expected to file for license renewal includes a number of the plants at risk of premature shutdown due to adverse market conditions.

[154] NEI, *Subsequent License Renewal: Creating the Foundation for Nuclear Plant Operation Beyond 60 years* (Feb. 2013), http://www.nei.org/CorporateSite/media/filefolder/NEI-White-Paper-Subsequent-License-Renewal.pdf?ext=.pdf.

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the state goals can be maintained. The impact on U.S. CO_2 emissions of losing so much nuclear generation in such a short period of time should be reason enough to incent the continued operation of these units provided they can meet the necessary requirements.

Furthermore, much like the process for power uprates, NRC's license renewal review is a detailed process that includes significant capital investment and safety reviews, and typically takes about 30 months. According to the NRC's 1995 license renewal rule, extensions of up to 20 years can be granted, provided the company demonstrates to NRC that it will manage aging issues effectively during the renewal term. The review also addresses the potential environmental impacts of continued plant operation.[155] In order to continue to run beyond their initial 40-year license, nuclear plants must operate as if they were new plants, subject to the same safety and operational requirements. It is also likely that over the course of their 60- or 80-year lives, nuclear plants will have had most if not all of their operating components and systems replaced, effectively rendering them new.

The NRC Commissioners recently endorsed the use of existing, well understood *10 CFR 54* regulations to establish a basis for nuclear units to apply for a subsequent license extension to operate beyond 60 years. These existing regulations will be supported with enhancements to existing license renewal tools and guidance documents, adding additional aging-related system reviews and associated upgrades.

[155] See NEI, *supra,* n. 150 at 2-3.

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As a specific example, the NRC licenses for Dominion's existing nuclear stations begin to expire in 2032. Dominion has initiated an evaluation of the life of critical components, necessary equipment upgrades to preserve unit efficiencies and other modifications needed to ensure the safe and reliable long-term operation of these facilities beyond the current license period. The preliminary cost estimate for Dominion's Surry nuclear power station provides early evidence of the lead time and equipment upgrades needed to secure NRC relicensing to operate beyond the current 60-year period. While costs will vary for each type of reactor design and location, Dominion's projections for the Surry station, a typical pressurized water reactor, are comparable to the costs of constructing a new combined cycle natural gas unit.

The scoping analysis shows costs in range of $0.5 billion to $1.5 billion, dependent upon the actual components needing to be replaced to extend the operational performance required for a subsequent twenty-year license extension. It is reasonable to expect that such items may include (1) major components, such as steam generators and heat exchangers; (2) aging systems, such as analog control systems and ventilation systems; (3) high voltage power cables; and (4) aging structures.

EPA's plan recognizes the contribution of new nuclear units to help achieve the reductions in carbon dioxide in the power sector by allowing states to use generation from these facilities in their 111(d) compliance plans. The identical policy justifications are applicable to nuclear units relicensed to operate past 60 years.

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The continued operation of these zero-emitting resources require significant financial investments that are comparable to building new combined cycle gas units, yet without the associated carbon emissions that would be associated with the gas units. Dominion has under construction two 1,300-megawatt natural gas combined cycle units. Those facilities cost an estimated $1.2 billion, required less than two years to obtain the necessary permits, and will be constructed within three years.

The NRC relicensing time horizon requires that utilities begin planning today to determine if a subsequent license renewal is a viable option. Without an appropriate incentive to proceed with the NRC process, the lowest cost option for new or replacement base load generation, without regard to carbon emissions, is a new natural gas combined cycle unit. As such, these relicensed nuclear units deserve to be eligible for compliance in 111(d) plans because of their zero carbon profile and their significant contribution to maintaining the stability of the electric grid.

2. EPA has not recognized the value of new and imported hydropower in providing affordable, zero-emissions power.

As described below, EPA has failed to recognize the value of new and imported hydropower—both interstate imports and international imports, particularly hydropower imported from Canada—in providing affordable, zero-emissions power in certain regions of the country. EPA does not propose to allow states to include existing hydropower in state compliance plans. *See* 79 *Fed. Reg.* at 34,867. If EPA does determine to allow states to include existing hydropower for compliance, states should also be able to use imported hydropower.

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a. If states are able to use hydropower for compliance, this should include imported hydropower, assuming that there is no international double counting.

As proposed, the section 111(d) guidelines do not allow states to include generation from existing hydropower resources in compliance plans. *See* 79 *Fed. Reg.* at 34,867. EPA notes that hydropower was not used to quantify the amount of renewable generation in each state in 2012, which forms part of the basis of the state-specific emission rate goals, and therefore, cannot be used for compliance purposes. *See id.* As noted in section II.D., above, EPA takes hydropower resources into account to establish the state-specific emission rate goals because EPA relies on state RES requirements and most states RES programs include hydropower as eligible resources. If EPA is not going to allow existing hydropower as a compliance tool, the state goals cannot be based on RES requirements that include hydropower or in-state deployment of hydropower to date. Resources that cannot be used for compliance should not form the basis of the state emission rate goals.

EPA registers legitimate concerns about the annual variability of hydropower generation. *See id.* at 34,869. Furthermore, using existing hydropower to set state emission rate goals would create significant compliance risks for many states by making goals very stringent. However, if the final guidelines allow states to use existing hydropower, states should be allowed to use both interstate and internationally imported hydropower. EPA seeks comment on the potential role of international renewable resources in the Supplemental Proposal issued in November. *See* 79 *Fed. Reg.* at 65,496.

Many states already recognize the value of imported hydropower in helping meet their energy demand and clean energy goals. For example, Connecticut passed a law in June of 2013 that would allow for large-scale hydropower from outside the region to count toward the state's RES requirement in certain circumstances.[156] A 2008 agreement between Manitoba Hydro and the Wisconsin Public Service Corporation allows the latter to import 500 MW of power from two Nelson River projects. *See id.* In addition, NU Transmission Ventures Inc. is developing a $1.4 billion Northern Pass transmission line project that would allow for the transmission of 1,200 MW of hydroelectricity from Hydro-Quebec into New England's energy system. Clearly, states see a value in imported hydropower. *See id.*

Furthermore, allowing the use of imported hydropower could help states expand their use of other forms of renewable generation, helping to meet EPA's goals of both reducing CO_2 emissions and increasing the use of renewable energy and other zero-emitting sources. In some circumstances, hydropower can play the same role as natural gas-based units by providing backup for variable RE generation. According to Jacob Irving, President of the Canadian Hydropower Association, Canadian hydro should be marketed to the U.S. as a base load supplement for intermittent forms of generation, such as wind and solar. "What we're focusing on at the federal level is just trying to make it better known within the U.S.…about the existence and availability of Canadian hydro to help enable and develop U.S. renewables." *Id.*

[156] Michael Harris, Northern Exposure: Canadian Hydro in the Spotlight (Dec. 9, 2013), http://www.hydroworld.com/articles/hr/print/volume-32/issue-10/cover-story/northern-exposure-canadian-hydro-in-the-spotlight.html.

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The benefits of such an approach are exemplified in the partnership between Minnesota Power and Manitoba Hydro under which, beginning in 2020, Minnesota Power will use 250 MW of electricity supplied by Manitoba Hydro's Keeyask hydro plant to help balance a wind farm in North Dakota. According to Minnesota Power, "We think that the high-capacity wind in North Dakota, coupled with a base load resource like hydro and the system Manitoba has, is sort of like the holy grail of renewable energy." *Id.*

If states are permitted to include international hydropower in compliance plans, EPA should address concerns about potential double-counting of generation or emissions reductions from this resource. For example, states could be required to demonstrate that the emission benefits of the hydropower are not being used by other entities, either in the U.S. or in Canada.

b. The definition of new hydropower units should be expanded.

For reasons similar to those raised above regarding the importance of including new nuclear generation as a compliance tool for states to use, the final guidelines should also allow states to include generation from "new" hydropower generating capacity in a state's compliance plan. EPA notes this in the proposed guidelines in stating that "the exclusion of pre-existing hydropower generation from the baseline of this target-setting framework does not prevent states from considering incremental hydropower generation from existing facilities (or later-built facilities) as an option for compliance with states goals." *See* 79 *Fed. Reg.* at 34,867.

According to the National Hydropower Association (NHA), the U.S. has the potential to add 60 GW of new hydro capacity by 2025, with the technical potential estimated to be much larger.[157] For example, a recent study from Navigant Consulting estimates that there are more than 84 GW of total technical potential hydropower in the U.S. *See id.* Tapping this potential will require the use of a number of different technologies, including pumped storage, small hydro, converting non-powered dams and modernizing existing sites. The final guidelines should incent the development of these new hydropower resources—and their zero-emissions generation—by allowing states to include them in their compliance plans.

To recognize the value of zero-emitting hydropower resources, the final guidelines also should define "new" hydropower broadly to include:

- New hydropower plants that become operational after 2012;
- Power uprates at existing hydropower plants, including those undertaken during or after 2012 or a modified baseline period; and
- Any hydropower facilities that are relicensed during or after 2012 or a modified baseline period.

i. Power uprates at existing hydropower plants, including those undertaken since 2012 should be allowed as part of a state's compliance plan.

Some of the 60 GW of potential new hydro would come from modernizing and uprating existing hydro facilities. As described by NHA, "new technology employed at existing hydro sites represents an opportunity for new sources of power. By installing more efficient turbines and enhancing performance, the existing hydropower infrastructure can generate more power,

[157] *See* NHA, *Developing Hydropower*, http://www.hydro.org/tech-and-policy/developing-hydro/.

sustainably." *Id.* Undertaking these or other changes could allow existing hydro facilities to be uprated to a higher capacity and to produce more energy.

The energy benefits of uprating existing hydro plants are well known. According to a 2007 federal report on potential hydro development at existing federal facilities, the Bureau of Reclamation recognized as far back as the 1970s that "uprating existing hydroelectric power plants to fully use available water power for additional peaking capacity and energy was recognized as one of the better long-term improvements that could help alleviate the energy problem."[158] The report also noted that Reclamation's Power Uprating Program, as of July 2006, had led to uprates on 64 units and an increase in generator capacity of 1,902 MW. *See id.* The final guidelines should recognize the value of hydropower uprates by allowing their use by states as a compliance tool.

ii. Relicensed hydropower facilities should be treated as new units, and should be allowed as part of a state's compliance plan.

Similar to power uprates at existing hydro facilities, the relicensing of existing non-federal hydro facilities also should be encouraged by allowing the zero-emissions generation from these units to be part of a state's compliance plan. In accordance with the FPA, FERC issues hydropower licenses for a period between 30 and 50 years. When a license expires, the applicant may apply to FERC for a new long-term operating license. *See* FPA section 15(a)(1) and (e). Although the hydropower relicensing process is a lengthy and resource-intensive commitment for electric

[158] Department of the Interior, *Potential Hydroelectric Development at Existing Federal Facilities for Section 1834 of the Energy Policy Act of 2005*, at 18 (May 2007), http://www.usbr.gov/power/data/1834/Sec1834_EPA.pdf.

utilities, hydro relicensing does present opportunities to retain or expand zero-emissions generation.

According to FERC, approximately 7,420 MW of hydropower came up for licensing in 2007, and the top five states for expiring licenses are California, New York, Oregon, Washington and North Carolina, though re-license opportunities exist in many other states as well. Furthermore, projects undergoing relicensing (and not new projects) make up the majority of the proposals being evaluated by the hydropower licensing staff of FERC's Office of Energy Projects.[159] The final guidelines should recognize the value of hydropower relicensing by allowing generation from relicensed facilities to be used by states as a compliance tool.

C. EPA Should Not Discount the Value of Emission Reductions and Changes to the Interconnected Power System That Occur After 2012.

As discussed, the structure of the proposed guidelines, particularly the approach to calculating the proposed state-specific emission rate goals, does not recognize appropriately the efforts of states and utilities to reduce emissions before 2012. The structure of the proposed guidelines also serves to discount and creates disincentives for reductions achieved between 2012 and 2020. As a policy matter, EPA should allow states to recognize all reductions that occur after 2012, the baseline year selected by the Agency for calculating the state emission rate goals. Specifically, the final guidelines should recognize that states can bank and then use for compliance emission reductions that result from state requirements, measures and programs instituted after 2012 and prior to 2020. Further, the final guidelines also should affirm that states can include in compliance plans emission reductions that occur during the compliance period without reference to whether these reductions were achieved by measures that were "on the books" at the time the

[159] *See* FERC, *Opportunities for New Licenses (Relicensing)*, http://www.ferc.gov/industries/hydropower/gen-info/licensing/app-new.asp.

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guidelines were proposed. For purposes of the CAA, the relevant question in assessing any reductions that are achieved between 2012 and 2020 is not *why* reductions were achieved, but *whether* they were achieved.

EPA proposes two limits on states' ability to include reductions that occur after 2012 in state plans: first, states can only include those reductions that occur during the interim compliance period, which starts in 2020; second, states can only include those reductions that result from actions taken after a specified date. According to EPA, reductions from "existing measures" that were "on the books" at the time the proposed guidelines were issued cannot be included in state compliance plans, even if they achieve reductions during the interim compliance period. *See id.* at 34,918. However, EPA proposes that states can include generation that occurs after 2019 from any renewable generating facility, regardless of the in-service date of the facility. *See id.* at n.293.

Preliminarily, EPA should not limit states to those reductions that occur during the compliance period, but should allow states to bank and use for compliance emission reductions that are achieved between 2012 and 2020. In advance of the proposed guidelines, many states and companies were contemplating—or did implement—strategies that would achieve CO_2 reductions. To the extent that states and companies are able both to adopt and implement these strategies earlier than 2020, allowing banking could provide an incentive for earlier emission reductions. Authorizing states to include in compliance plans reductions from these pre-2020 strategies also would allow states to begin demonstrating compliance earlier and could help states more gradually phase in other emission reductions measures, as discussed in section III.A.,

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above. In recognition of this, EPA should allow the banking of reductions that occur between January 1, 2013 and December 31, 2019.[160]

In addition, EPA should allow states to use reductions that occur during the compliance period, regardless of whether they result from measures that were "on the books." EPA states that it is necessary to discount reductions that result from measures that were "on the books" or that were implemented before the guidelines were proposed (except for renewable generating units) because of the "forward-looking goal-setting approach." *See id.* at 34,918. This is inconsistent with EPA's assertion that the proposed emission rate goals are achievable because of existing state programs. As EPA notes in the preamble:

> EPA proposes that a 2020 start date for the interim goal plan performance period is achievable in light of the following additional considerations. First, *existing state programs will play a role in helping to achieve the rule's proposed emission performance levels*. Second, in advance of this proposal, many states already were contemplating design of strategies that would achieve CO_2 emission reductions equivalent to those that could be required by CAA section 111(d) emission guidelines.

Id. at 34,905 (emphasis added). EPA cannot rely on existing state programs and measures to bolster the assertion that the proposed goals are achievable, but deny states the right to use the reductions that are achieved by these measures to demonstrate compliance.

As a practical matter, measures that reduce emissions from existing affected units will be reflected in state average emission rates, regardless of when they occurred. For example, if a coal-based unit is retired in 2015 to comply with other environmental regulations—and this retirement was "on the books" before June 2014—this will be reflected when the state measures

[160] EEI member companies will include discussion of specific banking mechanisms in their own comments on the proposed guidelines.

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the emission performance of affected units in 2020, relative to the 2012 emission rate calculated by EPA, because that unit will no longer be operating. EPA certainly could not mean to require states to add emissions from units retired before 2020 back into any compliance demonstration because the retirements were already "on the books." Yet, the discussion of "existing measures" in the preamble implies this. The final guidelines should make clear that the "existing measures" limitation, if applicable to any measure in a state's compliance plan, is not applicable to actions that reduce affected unit emissions before 2020. This includes not only unit closures, but also HRI projects and changes in dispatch between existing coal-based units and natural-gas based units.

Similarly, EPA should affirm that it will not discount reductions from EE measures, other than to limit reductions to those that occur during the compliance period. Specifically, EE measures should be treated the same as RE measures. For CAA purposes, it does not matter when the EE measure was put in place—or whether that measure was in response to an existing state EE program or a new program—as long as reductions are achieved during the interim compliance period. The CAA does not ask why emission performance is achieved; it only requires that emission performance goals be met.

D. EPA Must Provide Clear Guidance on Crediting Emission Reductions Associated with Renewable Energy; EPA Should Not Discount EE Credit for States that Import Power.

EPA's proposed guidelines raise numerous interstate compliance challenges, beyond those related to RE and EE measures. With limited exceptions in Texas, Alaska and Hawai'i, all power, regardless of the generation fuel, is transmitted and traded across states lines and international boundaries. EPA acknowledges the challenges related to attributing RE and EE

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measures to particular states for compliance purposes, but does not provide clear guidance ensuring that states will have confidence that plans relying on these measures will be approved.

As EPA recognizes in the proposed guidelines, "the electricity system and wholesale electricity markets are interstate in nature. EGUs in one state provide electricity to customers in neighboring states. Power companies own EGUs in more than one state and manage them as a system. EGUs are dispatched both within and across state borders." 79 *Fed. Reg.* at 34,921. The interconnected, interstate nature of the power sector is not new, but interstate compliance issues have not been an issue under previous section 111 rulemakings. This is because standards were based on what could be achieved at the affected unit and the unit owners had the responsibility for ensuring that compliance was achieved.

Under the proposed section 111(d) guidelines, however, states have an obligation to develop a compliance plan not just for affected units, but also to address power sector emissions for the entire state. EPA asserts that "[t]his state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly." *Id.* at 34,853. Questions of legal authority aside, EPA's proposed approach to the emission guidelines for existing units under section 111(d) may "harness" emission reduction opportunities throughout the interconnected power system, but it also creates new and complex interstate compliance issues.[161]

[161] Whether EPA has the authority under the CAA to design section 111(d) standards that place the responsibility for compliance on the states is discussed *infra*, section IV.

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In the proposed guidelines, EPA expresses concern about how to appropriately address the interstate impacts of programs and measures included in state plans that may affect the performance of the interconnected electricity system beyond a state border. *See generally* 79 *Fed. Reg*. at 34,921-22. In particular, EPA focuses on the fact that RE deployment and demand-side EE measures may affect the emission performance of the interconnected electricity system beyond a state border and that many states already allow RE generated in other states to be used to meet state RES requirements. *See id.* However, EPA does not acknowledge or address the interstate and international compliance issues related to the transmission or trading of power, regardless of the generation fuel, across state and international boundaries. Issues raised by EPA's approach to the interstate effects of compliance measures are discussed below.

As a preliminary matter, however, if EPA allows states to use out-of-state RE for compliance, EPA should not limit states' ability to include renewable generation in state plans to that renewable generation that is represented by RECs. RECs are not the only way in which compliance with RES programs is measured. For example, electric utilities build in-state and out-of-state RE facilities; power from these facilities can be used to satisfy RES requirements without the creation of a REC. Further, companies also engage in bilateral contracts for renewable generation that can be used to satisfy RES requirements.

More importantly, EPA should not limit states to RES programs as the only mechanism for including renewable generation in compliance plans. As EPA notes, RES programs are not the only approach for encouraging deployment of RE. States also could consider performance-based incentives, financial assistance programs or other regulatory changes. Increased deployment of

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RE generation also could be the result of state integrated resource plans, which are approved by PUCs. *See* Abatement Measures TSD at 4-2 to 4-3; *see also* State Plan Considerations TSD at 64-71. Accordingly, EPA's final guidelines should clarify that states can pursue a range of options to increase RE deployment and that RECs are not necessarily the best or only way for states to credit or trade RE across state lines.

1. The proposed section 111(d) guidelines do not recognize that all power, not just certain renewable energy sources or EE measures, have interstate and international compliance benefits and implications.

EPA's proposed guidelines and supporting materials focus on interstate accounting of CO_2 reductions associated with RE and EE measures, but there are interstate and international implications related to the trading/transmission of *all* power, regardless of the fuel used to generate it. Four particular examples highlight the interstate implications that EPA does not address in in the proposed 111(d) guidelines.

All zero-emissions resources are traded/transmitted across state and international boundaries. For example, nuclear generation has interstate implications. Nuclear units rarely serve only the customers in the states in which they are located. Imports of nuclear power are one way that states reduce the need to build higher-emitting, in-state base load resources. To the extent that power from new and existing nuclear units could be included in state compliance plans, interstate "imports" of nuclear generation could be a potentially important compliance tool that EPA should recognize.

More importantly, failure to recognize the interstate impacts of nuclear generation could create significant compliance challenges for neighboring states. If nuclear units that serve multiple

states are prematurely retired—EPA assumes that all existing nuclear units operate for 80 years, see section III.B.1.f.iii., above,—all of the states that consume power from these units could face unexpected compliance challenges. These states may have to increase generation from existing affected fossil-based units to replace the nuclear generation.[162] If this was not contemplated in the state plan, the state may no longer be able to demonstrate that it is reducing its emission rate consistent with its projected compliance glide path.

Similarly, many states, particularly in the Pacific Northwest, rely on that region's extensive network of federal hydropower facilities to keep emissions low and to minimize the need to build higher-emitting base load resources. In fact, in some instances, hydropower can be used to help balance the variability of other renewable resources, like wind and solar.[163] In addition, states along the Canadian border rely on imports of hydropower generation to meet state RES requirements and serve customers with lower cost, non-emitting power. These important interstate and international uses of hydropower generation have no role in compliance under the proposed section 111(d) guidelines. As with nuclear generation, to the extent that EPA allows hydropower to be used for compliance, the Agency should recognize that, like other renewable generation, this power is transmitted and traded across interstate and international boundaries. Further, as with nuclear generation, the continued operation of existing hydropower generation is critical to the achievement of the state emission rate goals for many states. If this generation had to be replaced, this could create significant compliance challenges for many states.

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[162] States may also build new NGCC units to replace nuclear generation. While this may not affect a state's affected unit average emission rate, it would increase mass emissions, which would be inconsistent with overall emission reduction goals.

[163] *See* EPRI, *Quantifying the Value of Hydropower in the Electric Grid*, 2013 Technical Report (Feb. 2013), http://www1.eere.energy.gov/water/pdfs/epri_value_hydropower_electric_grid.pdf.

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Third, in recent years, some states have taken steps to decrease imports of coal-based electricity by replacing this power with that generated by new, in-state NGCCs. Overall, this decreases CO_2 emissions, but increases in-state emission rates. Not only do the proposed guidelines not recognize this interstate issue, they in fact saddle states that already have made investments in new NGCCs with stringent standards.

Finally, EPA's proposed guidelines place the entire burden of reducing emissions from existing affected units on the state in which an affected EGU is located. This does not recognize that power from in-state EGUs often serves customers in other states and unfairly saddles some states with the obligation to reduce emissions related to the power consumed in other states.

2. EPA should provide guidance on how to attribute reductions related to renewable energy to avoid double counting.

As EPA notes, the interstate effects of increased deployment of renewable generation could be attributed in different ways in the context of approvable state plans. EPA's preferred approach is to allow a state to take into account all of the CO_2 emission reductions from RE programs and measures implemented by the state, regardless of whether they occur in the state and/or in other states. *See id.* at 34,922. EPA notes that this is consistent with existing RES policies that allow states to use renewable energy generated out-of-state for compliance and the existence of RECs markets. *See id.*[164]

[164] Existing RES programs that allow for the use of out-of-state RECs for compliance do not create interstate compliance challenges because the point of compliance is the LDC or load-serving entity (LSE), not the state.

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As a preliminary matter, EPA's proposed approach—allowing states to use out-of-state RE for compliance with state 111(d) plans—recognizes the existence of RECs markets, but could create significant compliance challenges for certain states that produce more RE than they consume. These "source" states, like Idaho, New Mexico or Wyoming, have RE goals predicated, in part, on their high levels of RE generation in 2012. However, RE generation from these states is used by others to satisfy current demand or RES requirements, reducing the amount of RE generation that these states could rely upon for compliance with the proposed section 111(d) state goals. Further, these states have little control over whether and to whom the RE generation is sold (or whether and to whom the renewable attributes are sold). These states have ambitious goals, but limited tools with which to comply with them.

a. EPA must be consistent in how it attributes emissions reductions from renewable energy when setting standards and when measuring compliance.

EPA proposes that approvable state plans could differ in how they attribute reductions related to renewable generation and is taking comment on the option of allowing states to take into account only those CO_2 reductions associated with in-state RE generation. *See* 79 *Fed. Reg.* at 34,921. EPA has an obligation to provide clear guidance as to how states should attribute these reductions and ensure that there is no double counting.

As a preliminary matter, EPA must ensure that the approach to attributing emission reductions from renewable resources for compliance is consistent with the treatment of these resources when setting the state-specific emission goals. If a state cannot use certain RE generation for compliance, that generation should not form part of the basis for that state's emission rate goals. Put another way, EPA assumes that each state's 2012 RE production is relevant in determining a

state's potential for future, additional RE generation because EPA based the states' RE compliance goals, in part, on the level of in-state RE generation in 2012.[165] If EPA finalizes guidelines that allow for states to use out-of-state RE generation for compliance, the Agency must recalculate state goals to reflect where this generation was used for compliance in 2012, not where it was produced. It would be unfair to base a state's goals on RE generation that will be used by another state for compliance as it overestimates the potential for RE deployment in that state for compliance purposes. This issue is discussed in more detail in section II.D., above.

b. EPA must provide clear guidance as to how to allocate emission reductions to facilitate the development of realistic, workable compliance plans that do not double count renewable energy reductions.

EPA's proposed approach to accounting for the interstate impacts of RE generation likely could lead to double counting, as both a source state and a state in which RECs were used for RES compliance arguably could have competing claims to the reductions associated with renewable generation (particularly if EPA does not recalculate state goals, as discussed above).

The preamble suggests that the Agency be the final arbiter of whether a state has properly included RE emission reductions in a compliance plan. *See* 79 *Fed. Reg.* at 34,922. While this ultimately may avoid double counting, it creates great uncertainty for individual states, which would not know until after EPA assessed all submitted state compliance plans whether they could count all of the renewable generation included in a particular plan. This could undermine a state's ability to demonstrate that a plan would achieve the target emission rate goal, and could result in time-consuming and expensive plan revisions that delay the start of compliance.[166] This

[165] *See generally* 79 *Fed. Reg.* at 34,867 for a discussion of how EPA used 2012 RE generation data to calculate the state-specific emission rate goals. Section II.D, *supra*, also discusses other issues related to EPA's calculation of the RE portion of the states' emission rate goals.

[166] As part of a compliance plan submittal, each state would be required to project future CO_2 emission performance. As EPA notes, whether states can consider out-of-state renewable energy

is a less-than-optimal result for states that make good faith efforts to develop reasonable, workable compliance plans. To avoid plan revisions related to possible RE double counting and to ensure against double counting in the first instance, EPA should provide clear guidance as to how states should attribute RE reductions.

In particular, in the final guidelines, EPA should provide states with guidance on how to allocate RE built by electric utilities to serve customers in multiple states. For example, Kansas City Power & Light (KCPL) serves customers in two states, Kansas and Missouri. Most of KCPL's fossil generation owned by the company is located in Missouri, but most of the wind generation that has been built and is expected to be built in the coming years is in Kansas. Wind resources are allocated to each state, based on customer demand, without any need to transfer RECs. In such situations, the state that consumes the renewable generation should be able to use it for compliance with a 111(d) plan. Multi-state planning, which is discussed in more detail below, would help address this issue, but such plans may not be completed before states are required to submit them to EPA for approval. Accordingly, the final guidelines should address how utilities can allocate RE generation to different states, consistent with customer consumption patterns.

EPA also seeks comment on whether the Agency should require states to demonstrate that RE reductions included in plans will not be double counted in order to allow them to be used for compliance when filing annual emission performance reports. *See id.* at 34,922. The proposed guidelines do not specify how a state would make such a demonstration—but, in the absence of

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is a key threshold consideration when projecting future emissions. *See* Projecting EGU CO_2 Performance in State Plans TSD at 30-31.

clear guidance from EPA, it would seem to presuppose that states with potentially competing claims agree on how to apportion credit for RE reductions. Regardless of the methodology for demonstrating that a plan does not double count reductions, it appears that EPA may intend to foreclose the use of some RE emission reductions for compliance if states cannot agree on attribution. This would be unfair to states (and the owners of RE generation) as it could increase compliance costs by rendering some valid emission reductions unusable for compliance purposes simply because states could not agree. EPA should not disallow the use of RE generation because it may have been double counted. Instead, EPA should articulate clearly how RE generation will be credited to states to prevent against double counting and ensure that all reductions can be used for compliance.[167]

c. EPA should incentivize and provide sufficient time for states to develop multi-state plans to mitigate possible double counting concerns.

EPA proposes that states participating in multi-state plans would be allowed to "distribute the CO_2 emission reductions associated with renewable energy among states in the planning area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emission reductions from RE measures." 79 *Fed. Reg.* at 34,922. Multi-state planning would mitigate some double counting concerns.[168] Multi-state planning would also mitigate concerns about inefficient dispatch and siting created by a patchwork of state plans, where similar units in different states sharing a power market face substantially different CO_2 costs. However, states

[167] In particular, EPA's final guidelines should address how to credit "unbundled" RECs, which separate the energy generated from its renewable attributes. States have little control over how these credits are used—owners of the credits cannot be constrained in their ability to sell them—which limits states' ability to count on these credits when developing compliance plans.

[168] Of course, even if several groups of states devise multi-state plans, there may still be issues attributing RE emission reductions among different compliance regions.

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may not be able to design multi-state plans in the limited amount of time between finalization of the guidelines and the due date for compliance plans.

While EPA should incentivize multi-state planning, it should not punish states that are unable to develop regional compliance plans by limiting their use of RE reductions for compliance. Instead, EPA should minimize double counting concerns by providing clear guidance as to how to attribute reductions associated with RE before states submit compliance plans. Indeed, clear guidance on attribution might help to incent states to develop cooperative approaches for addressing the interstate effects of RE generation.

EPA also should ensure that the final guidelines provide sufficient time for states to attempt regional compliance. EPA proposes to allow states an additional two years to submit multi-state plans. *See* 79 *Fed. Reg.* at 34,915. If states are working on multi-state plans, but require more time to finalize them, EPA should provide it. The benefits of multi-state plans outweigh reasonable delays in plan submittal. In addition, as discussed in section III.A.2., above, EPA should allow states to revise compliance plans if they are able to develop multi-state compliance plans after 2020. Furthermore, EPA should allow states to join a multi-state plan after the start of the compliance period, when the benefits of multi-state coordination may become more apparent.

d. A streamlined multi-state trading approach should be allowed, and administrative barriers such as formal interstate trading agreements or consolidated interstate or regional plans should not be required.

Alternatives to full-fledged multi-state plans also may be useful for some states. For example, states could trade freely RE or EE credits with other states while retaining each state's individual goals. Each state would develop its own program, which could be either rate- or mass-based. A

federal tracking system for credits could be developed. EPA has substantial experience in developing and operating emission tracking systems. Alternatively, another entity could set up a credit accounting system to facilitate trading among multiple states.

If a state, or a source within a state, has surplus credits, the credits would be registered within the federal tracking system. The sources and other covered parties to the state program would need to demonstrate compliance with their respective requirements. However, in meeting those requirements, they could purchase or sell credits registered in the federal tracking system, either in the form of MWh or tons. Each year, a federal compliance true-up period could occur for the preceding year. Federally-approved evaluation, monitoring and verification protocols would ensure that credits are fungible and not double counted.

This is only one option, and there may be variations to this approach. While EPA may not adopt explicitly alternative approaches to trading RE and EE credits, EPA's final guidelines should provide as much flexibility as possible and should not exclude certain types of credits or trading programs that could be barred under the guidelines as proposed. A program that minimizes the need for states to complete complicated and time consuming interstate compacts or memoranda of understanding would expedite the development and implementation of state plans. Further, to incent state efforts to address interstate EE and RE concerns, states that are working to develop this type of approach should be eligible for the two year regional extension for submittal and approval of their respective section 111(d) plans.

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e. EPA should not foreclose states from using renewable generation from non-contiguous states or bar non-contiguous states from submitting multi-state plans.

EPA implies that states must be contiguous in order to engage in multi-state plans that would obviate the need to specifically assign reductions associated with RE generation. For example, EPA notes that "states could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in a *contiguous* electric grid region…." 79 *Fed. Reg.* at 34,922 (emphasis added). As a preliminary matter, EPA has not defined what an "electric grid region" may be. More importantly, EPA should not limit states to working only with contiguous states. There may be states in regions that are not contiguous, but still want to participate in multi-state planning.[169] Further, if EPA chooses to allow states to use out-of-state RECs or RE generation to demonstrate compliance with state plans, EPA must clarify the Agency will not limit states to RECs or RE generation from contiguous states.

Most states allow LDCs and LSEs to purchase RECs to satisfy their RES obligations. RECs are purchased and traded through the various RE credit tracking systems, which cover large, multi-state regions.[170] These entities also are authorized to acquire RE or the zero-emissions attributes of RE in a variety of other ways, including through bilateral contracts or building in-state or out-of-state RE generation. EPA, therefore, mischaracterizes state RES programs when it notes that

[169] Given that CO_2 becomes well-mixed in the atmosphere after it is emitted, unlike traditional air pollutants, requiring that reductions come from specific locations does not provide additional environmental benefits.

[170] *See* C2ES, *Renewable Energy Credit Tracking Systems*, http://www.c2es.org/us-states-regions/policy-maps/renewable-energy-credit-tracking.

they allow actions in "neighboring" states to be used for compliance. *See* 79 *id.* at 34,921.[171] Very few RES programs require that the power actually be delivered to in-state customers, which would only be feasible if the generator was in a neighboring state.[172] If EPA allows states to use out-of-state RECs or RE generation for compliance, states should not be limited to using RECs or RE generation from neighboring states.

Further, if EPA were to ban the use of non-contiguous RECs or RE generation, this would have the potential to increase the costs of compliance, not only for the proposed 111(d) guidelines, but also with existing state RES programs. States that allow out-of-state RECs do so because they recognize that these RECs could be more cost-effective than in-state development of additional RE projects. A ban on non-contiguous RECs would destroy existing RECs markets and drive up costs by requiring states to use more expensive renewable generation for compliance.

3. States that import electricity should not have to discount EE savings.

EPA also recognizes that the interconnected power system might have implications for the reductions associated with in-state EE measures. *See* 79 *Fed. Reg.* at 34,922. However, EPA's proposed approach to attributing reductions related to EE programs is the inverse of that proposed for RE attribution: EPA proposes that a state only be allowed to include in its plan

[171] Despite the preamble language, EPA's State Plan Considerations TSD clearly recognizes that states allow LDCs and LSEs to acquire RECs or RE generation in a variety of ways, from a variety of sources, without any discussion of whether the source is contiguous. *See* State Plan Considerations TSD at 62-63.

[172] Arizona and Wisconsin are notable exceptions because they allow REC trading but require that power from out-of-state RE generators actually be delivered to in-state customers. New York does not allow REC trading. *See* C2ES, *Detailed Table of State Policies*, http://www.c2es.org/us-states-regions/policy-maps/renewable-energy-standards.

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those CO_2 emission reductions that occur in the state as a result of demand-side EE programs and measures implemented in that state. *See id.*

EPA appears to be concerned that in-state EE measures cannot be clearly traced to reductions in generation at specific affected in-state units. In particular, EPA is concerned that in-state EE measures in states that import electricity would not result in the decreased utilization of in-state affected fossil-based units. *See id.* For this reason, EPA proposes that states would have to discount the CO_2 emission reductions related to EE to reflect the level of electricity imports. This could be done though modeling or a proxy net import factor. *See id.* For example, Virginia, which is a 35 percent net importer of electricity, could only get credit for 65 percent of the CO_2 emissions reductions associated with in-state EE programs and measures included in the state compliance plan. *See* State Plan Consideration TSD at 90, Table 3.

EPA's approach to attributing EE savings assumes that a state could trace exactly which affected units generate less electricity as a result of increased EE. However, even EPA recognizes that this is impossible, noting in the preamble that "some of the CO_2 emissions avoided through RE and demand-side EE measures may be from non-affected EGUs." 79 *Fed. Reg.* at 34,920. As discussed above in the context of reductions related to increased RE deployment, the nature of the interconnected electric system and the laws of physics make it impossible to directly link certain EE measures with reduced utilization of specific units, let alone specific affected units. EE will reduce the amount of generation needed to satisfy customer demand, but neither EPA nor the states can determine exactly which units were utilized less as a result.

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Notwithstanding this, EPA asks states to precisely assign "credit" for reductions associated with EE measures. Not only is this physically impossible, but it is conceptually at odds with EPA's general approach to EE measures. As a general matter, EPA is willing to accept a great deal of imprecision in determining the magnitude of reductions that result from EE measures, assigning an average 10-year life to such measures for purposes of calculating the amount of electricity saved. *See id.* at 34,873. Similarly, EPA includes EE in its definition of BSER, even though reductions are prospective and require rigorous EM&V protocols that, by definition, require states to make assumptions and to select between data sources—all of which adds uncertainty to the estimation of the emission reductions associated with EE programs. *See id.* at 34,920. It would be arbitrary if EPA allowed a general level of imprecision when calculating the benefits of EE, but then penalized states by requiring precise attribution of these estimated benefits for compliance purposes. Accordingly, EPA should allow states to include the full estimated benefits of in-state EE programs in state plans, regardless of whether a state imports or exports electricity.

Further, forcing states to discount EE reductions because of electricity imports may discourage states from using EE as a compliance tool. If, as EPA asserts, EE measures are the most cost-effective compliance option and will save electricity consumers money, *see, e.g., id.* at 34,874, EPA should not create disincentives that might prevent states from incorporating these measures in compliance plans.

E. EPA Appropriately Recognizes that States Have the Authority to Include Non-BSER Measures in Compliance Plans.

EPA proposes that states may submit compliance plans that include measures not specifically identified in the BSER determination. *See* 79 *Fed. Reg.* at 34,923. The use of these non-BSER

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compliance options is an important flexibility mechanism that allows states to design compliance plans that reflect the reductions opportunities available in each state. The final guidelines should clearly recognize that states have clear authority under the statute to use non-BSER measures in their compliance plans, as appropriately recognized in the proposed guidelines. EPA identified numerous potential compliance options that the Agency explicitly did not include in the determination of what constitutes BSER for existing EGUs. *See id.* The final guidelines should allow states to include non-BSER measures—both those identified by EPA in the guidelines and those not specifically included—in state compliance plans submitted to the Agency for approval.

1. States have the authority to include non-BSER measures in state compliance plans.

The CAA explicitly envisions that states will have more flexibility to design compliance plans than EPA does in determining BSER and the resulting emission limitation. While an emission limitation must be achievable through application of BSER, the standards of performance in state compliance plans need only "reflect the degree of [the] emission limitation." *See* CAA section 111(a)(1). State compliance plans, therefore, need not require use of the measures EPA proposes to determine are BSER. Moreover, the use of the word "degree" further reinforces that a state need not implement the specific system of emission reduction EPA used to set the emission limitation. State plans only are obligated to be as stringent as EPA determined is achievable and adequately demonstrated. So long as the state plan results in emissions that are consistent with the state goal, the standard is consistent with the authority granted to the states under section 111(d).

CAA section 111(d) references CAA section 110 and the state implementation plan procedure under section 110, noting that EPA should create a similar procedure for section 111(d)

compliance plans. Given the reference to section 110, the extensive case law interpreting this federal-state relationship under sections 109 and 110 is instructive in understanding the breadth and limits on EPA and state authorities to propose and evaluate compliance plans. In this regard, courts have been clear: Each state, not EPA, has discretion under section 110 to determine the best compliance mechanisms for its circumstances.[173] So long as the state's selection of measures in its plan satisfies the EPA-established goal," EPA may not "question the wisdom of a state's choices."[174] Accordingly, the proposed guidelines appropriately recognize that states have the discretion to include a range of measures, not just those EPA proposes as BSER, in compliance plans as long as they are designed to achieve emission rate goals.

2. The final guidelines should affirm that states can use non-BSER measures identified in the proposed section 111(d) guidelines, but are not limited to these measures.

The proposed guidelines identify several non-BSER compliance measures available to states in crafting state plans to achieve the proposed emission rate goals. *See* 79 *Fed. Reg.* at 34,923-5. EPA explicitly should recognize in final guidelines that these options are available to the states. Further, EPA should make clear that states are free to include other non-BSER measures in state plans, provided that these measures are consistent with the requirements of the Act and are projected to help states achieve the proposed emission rate goals.

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[173] *See Virginia v. EPA*, 108 F.3d 1397, 1410, *modified at* 116 F.3d 499 (D.C. Cir. 1997).

[174] *Train v. NRDC*, 421 U.S. 60, 79 (1975) ("The Agency is plainly charged by the Act with the responsibility for setting the national ambient air standards. Just as plainly, however, it is relegated by the Act to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards it has set are to be met.").

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As a preliminary matter, and as discussed earlier in these comments, the majority of the emission reductions that will be achieved through the implementation of state compliance plans will be the result of the Building Block measures that EPA proposes constitute BSER. The magnitude of the reductions required by the proposed guidelines are such that no non-BSER option could ever fully replace a Building Block measure given the cost and required level of emission reduction.[175] Instead, non-BSER measures provide states with some needed flexibility to choose how and when to implement the BSER measures. However, the availability of non-BSER measures does not obviate the need for EPA to address the serious concerns about the interim average compliance period discussed in section III.A., above. Using non-BSER measures will not make it feasible for states to achieve the significant reductions that the structure of the interim average goal requires before 2020. Non-BSER measures could provide important, but relatively small, emission reductions.

In the preamble, EPA discusses many measures that were considered, but not determined to be part of the proposed BSER, that states could include in compliance plans:

- Co-firing with natural gas or other, lower-emitting fuels
- Retrofit of partial carbon capture and storage (CCS) or "full capture" CCS
- Construction of full capture CCS units that reduce emissions beyond the levels required by the CAA 111(b) performance standards for new units
- Construction of NGCC units that use full or partial capture CCS
- Using integrated renewable technology (e.g., integrating solar and fossil-based generation)

[175] CCS conceivably could reduce CO_2 emissions at existing power plants. Hoever, EPA notes that CCS technology is not currently economically feasible and is thus not considered BSER. *See* 79 *Fed Reg.* at 34,923-24.

- Co-firing with "biomass-derived" fuels
- Heat rate improvement projects at NGCC or oil- and gas-based units
- Updates and yet-to-be-identified "technological advances and innovations" in pollution control technologies (e.g., more highly efficient scrubbers)
- Uprates at existing nuclear units and/or new nuclear generation
- Incremental increases in hydropower generation from existing or later-built facilities
- Increased utilization of electric storage technologies
- Using industrial CHP and cogeneration approaches to avoid emissions at affected EGUs, depending on the type of CHP or cogeneration identified
- Electricity T&D efficiency improvements

See 79 *Fed Reg.* at 34,923-24. Each of these identified measures could be an important option for particular states and electric utilities. Consistent with the Act, EPA's final guidance should reaffirm that these measures could be included in an approvable state compliance plan. Further, the final guidelines also should indicate that states are free to propose other non-BSER measures for inclusion in the state plans, regardless of whether they were explicitly recognized by EPA first. States and electric utilities should be encouraged to continue to pursue new, cost-effective measures for reducing emissions.

3. The final guidelines should affirm that states can include transmission and distribution efficiency improvements in compliance plans.

Line losses (the loss of power during transmission) can range from nearly zero to more than eight percent of the electricity being transmitted as a function of line and weather conditions. The current national average is that roughly six percent of power generated at central stations is lost during transmission to customers.[176] Various technologies can help reduce T&D losses, which in

[176] *See* EPA, e-GRID Version 1.0, Year 2010 Summary Tables, 9th ed. (Feb. 2014).

turn, reduce the amount of power that needs to be generated, leading to CO_2 reduction benefits. These technologies include volt/VAR optimization, high voltage direct current (HVDC) transmission lines and high temperature low sag lines. T&D systems are part of the interconnected power system upon which EPA relies as the basis for its proposed BSER. The final guidelines should encourage the deployment of grid modernization technologies—and the emissions reductions that they can help achieve—by allowing their inclusion in state compliance plans.

a. Volt/VAR Optimization (VVO) technology can help reduce T&D line losses and is an important non-BSER compliance option.

The concept of Volt/VAR management or control is essential to electric utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly, and to deliver power at an optimal power factor to minimize losses. Feeder voltage regulation ("Voltage") refers to the management of voltages on a feeder line with varying load conditions. VAR refers to Volt-Ampere Reactive power, the reactive power nearly all power system loads require in combination with real power (Watts). Experience has shown that the overall costs and performance of operating a power system can be best managed if voltage control and reactive power control are well integrated.[177]

The benefits of Volt/VAR management technologies are well-known, having been used by the power industry for over 30 years to reduce electric line losses and increase grid efficiency. Today those technologies have advanced to include Volt/VAR Optimization (VVO) sensors, equipment

[177] National Electrical Manufacturers Association (NEMA), *Volt/VAR Optimization Improves Grid Efficiency*, https://www.nema.org/Policy/Energy/Smartgrid/Documents/VoltVAR-Optimazation-Improves%20Grid-Efficiency.pdf.

and software. Through the use of these VVO systems,[178] utilities can optimize voltage profiles and VAR flow to reduce overall distribution line losses by two to five percent through tight control of voltage and current fluctuations, and achieve a variety of other objectives, including: reducing peak demand, targeting power factor levels to minimize energy losses and implementing Conservation Voltage Reduction (CVR). CVR-related strategies can lower overall system voltage and thereby reduce overall system demand by a factor of 0.7 to one percent for every one percent reduction in voltage.

Allowing VVO systems to be included in compliance plans can help encourage wider deployment of this technology, with benefits that include improved power quality and reduced peak demand in addition to carbon mitigation.

b. There are a range of other technologies that can also reduce T&D line losses and should be allowed as compliance measures.

In addition to VVO systems, there are a number of other technologies that can help reduce T&D losses, which in turn means utilities need to generate less power, leading to CO_2 reduction benefits. For example, high-temperature low-sag conductors can increase the capacity of the transmission network by making lines more capable of carrying higher volumes of power without overheating or sagging, which in turn can significantly reduce loss and increase the efficiency of the installed transmission infrastructure. Because they sag less, electricity flowing through the conductor experiences less resistance, meaning that the conductors can also reduce transmission losses of power by 25 to 40 percent of what otherwise might be lost. If

[178] VVO systems work in conjunction with a number of other technologies to optimize the electric system, including microprocessor-based controls and computing platforms, pervasive, high performance communications technologies, widely deployed sensor technology including AMI systems, and advanced software algorithms. *See id.* at 2.

transmission losses are reduced, less electricity generation is required to meet the same amount of load, reducing emissions from generators.[179]

In addition, high voltage direct current (HVDC) transmission lines offer a number of advantages over standard transmission lines, such as greater power carrying capacity, the ability to connect asynchronous AC electric systems, precise control of electric power flow, and longer underground and undersea transmission lines. Typically, overall losses in HVDC transmission are 30-50 percent less, and HVDC transmission lines can carry more current—up to 40 percent more—than standard transmission lines of the same size. The most notable advantage of HVDC transmission lines is their ability to transfer power underground and undersea over long distances, which could facilitate the growth of wind and solar energy by allowing solar energy from the Southwest or wind power from the Midwest to be transmitted to other parts of the country.[180]

There are a number of other technologies—such as dynamic line ratings, synchrophasors, grid-scale energy storage and smart solar inverters—that can also create incremental improvements of

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[179] Americans for a Clean Energy Grid, *High Temperature, Low Sag Conductor*, at 2-3, http://cleanenergytransmission.org/wp-content/uploads/2014/08/High-Temperature-Low-Sag.pdf.

[180] Americans for a Clean Energy Grid, *High Voltage Direct Current Transmission*, at 4-5 (Aug. 2014), http://cleanenergytransmission.org/wp-content/uploads/2014/08/High-Voltage-Direct-Current-Transmission.pdf.

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the transmission system. These technologies can help increase reliability, resiliency, and efficiency, all of which ultimately contribute to reducing CO_2 emissions.[181]

As shown above, T&D line loss reduction practices and strategies have potential environmental benefits. The ability of a utility to optimize power quality means that it has to generate less power to satisfy demand. Generating less power to serve the same demand reduces the amount of coal or natural gas burned, and therefore reduces CO_2 emissions. To the extent these strategies can be implemented to defer investment in new generation capacity or to address reduced capacity due to old generating assets being taken offline, the benefits can be enormous especially when load growth is small. The final guidelines should help incent the deployment of the innovative technologies—which not only could have the potential to reduce CO_2 emissions, but also are vital to the increased utilization of renewable generating resources, two of the objectives of the proposed guidelines—by allowing states to include them in their compliance plans.

F. The Final Guidelines Should Recognize the Role of the States in Regulating Important Aspects of the Power Sector and Should Not Encroach Upon State Authority.

EPA asserts that states will have flexibility in determining which Building Blocks—and at what level—to include in compliance plans. However, as a practical matter, it will not be possible to achieve the proposed emission reduction goals without implementing all four Building Blocks. To some extent, therefore, the guidelines dictate that states take certain actions or risk enforcement for failure to achieve the proposed emissions rate goals, contrary to the intent of Congress. The final guidelines should recognize Congress' intent when it reserved to the states the authority to regulate several important aspects of the power sector.

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[181] Usman M. Chaudhry, *Survey of Emerging Transmission Technologies*, Americans for a Clean Energy Grid, http://cleanenergytransmission.org/transmission-technology-series/.

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Many of the reduction measures and activities that states must include in the compliance plans in order to achieve the proposed emission rate goals are within the traditional purview of state regulators or other federal agencies, and not usually subject to the requirements of the CAA. This structure, as proposed, raises significant concerns about the encroachment of the proposed guidelines upon the regulatory authority reserved to the states.

Many elements of the electric system are subject to regulation by various federal agencies and arms of state government. These include economic, siting and environmental regulations, among others. The FPA vests FERC with jurisdiction over wholesale transactions and transmission of electric energy in interstate commerce. *See* FPA section 201(b)(1). In contrast, the FPA specifically excludes from FERC jurisdiction the generation and distribution of electricity and transactions of electric energy that are solely intrastate in nature. These activities, including the siting and permitting of generation and transmission facilities, are left within the jurisdiction of the individual states. *See id.* States regulate the terms and conditions of distribution service and the siting of generation and delivery systems. States also have primary siting authority over electric transmission, including intrastate facilities. State PUCs regulate the rates, terms and conditions of retail sales of electricity. In addition, programs designed to increase renewable generation and promote demand side and end use efficiency are regulated at the state level. Congress did not intend for FERC to regulate intrastate electricity transactions or mandate that states undertake specific programs designed to foster increased renewable generation or end-use efficiency measures. If FERC has limited authority in these areas, EPA must also.

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As a policy matter, EPA should not intrude into areas that are appropriately left to the state to regulate.

G. To Help States and Electric Utilities Design Compliance Plans, EPA Should Provide Greater Clarity on a Range of Compliance Issues.

To assist states in crafting compliance plans that are both workable and approvable, EPA's final section 111(d) guidelines should address a range of compliance issues. Specifically, the final guidelines should better explain how states can translate rate-based goals into mass-based goals. They also should address concerns that New Source Review (NSR) may discourage efforts to reduce emissions from existing coal-based EGUs, consistent with EPA's proposed Building Block 1 assumptions. If not in the final guidelines, EPA should explain how emissions from biomass will be calculated before states are required to submit state plans.

The final guidelines should ensure that states can use new NGCC units for compliance in a way that does not prohibit states from building needed base load or peaking units to meet increases in demand or meet other reliability requirements.

In addition, the final guidelines should broadly define the types of "corrective measures" that states could include in compliance plans to include methane reductions from natural gas distribution systems, among other options. EPA also should affirm the importance of electrification in reducing CO_2 emissions from other sectors, including the transportation sector, and accommodate states facing compliance challenges as a result of these efforts.

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Finally, EPA should recognize existing state EM&V protocols for EE measures; provide guidance on how states incorporate distributed generation (DG) in compliance plans; as well as address enforcement concerns for states and affected EGUs.

1. The final guidelines must provide clear guidance to states on how to translate rate-based goals into mass-based goals so states can make informed choices about compliance plan design.

EPA proposes to allow states to adopt either the rate-based goal as determined by EPA or an equivalent mass-based target. *See* 79 *Fed. Reg.* at 34,837. This is an important flexibility provided by the proposed guidelines. In order to allow states to be able to make an informed decision about which option to pursue, EPA recently issued additional guidance as to how to translate the proposed rate-based goals into mass-based goals. *See Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 *Fed. Reg.* 67,406 (Nov. 13, 2014); *see also* Mass-Based Equivalents TSD.[182]

Rate-based goals allow for increases in electricity consumption, which could be important in areas in which manufacturing or industrial development may be expected or expanded. They also would help the power sector facilitate the continued electrification of other sectors, particularly the transportation sector, which would contribute to significant emission reductions from other sectors. Given the overall climate benefits of electrification, especially as the

[182] Particular concerns about the revised numeric goal computation formula EPA used to translate the proposed emission rate goals to mass-based equivalents are discussed, *supra*, section II.F.

generating fleet transitions to cleaner sources of power, the power sector should not be penalized for assisting in the reduction of other sectors' emissions.[183]

As EPA has recognized, there also are merits to a mass-based approach to compliance. For example, mass-based approaches make it easier to recognize the role of zero-emitting resources, like nuclear and hydropower generation, even though EPA has not proposed a specific mechanism for using these resources in state compliance plans. *See, e.g.*, 79 *Fed. Reg.* at 34,923.

EPA should continue to work with the states to refine technical details of the conversion of rate-based goals to mass-based equivalents. For example, the Mass-Based Equivalents TSD describes an approach for translating the rate-based goals that does not assume any increase in generation at existing units. Future increases in generation from existing units could be important in states like California, where existing low average capacity factor NGCC units may be deployed more in the future to support renewables integration or increased electrification of the transportation sector. By failing to allow for any growth in generation at existing NGCC units, this approach establishes mass-based goals that may not be equivalently stringent with rate goals. It might be appropriate, therefore, for EPA to assign some of the increased generation associated with expected load growth to existing units.

2. EPA should take steps to ensure that New Source Review concerns do not impede efforts to improve heat rates at existing coal-based units.

In the proposed guidelines, EPA recognizes that heat rate improvements increase efficiency and "yield important benefits to affected sources by reducing their fuel costs." *See* 79 *Fed. Reg.* at

[183] The role of electrification, particularly of the transportation sector, in state plans is discussed further, *infra*, section III.G.5.

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34,928-29. EPA also recognizes a longstanding New Source Review (NSR) issue[184] in the proposal: Sources that attempt to increase their efficiency through HRI projects as part of a state compliance plan could "trigger" NSR if—as a result of these facility changes—the emissions of *any* regulated air pollutant also increase. While EPA states that it expects there will be few instances where an NSR permit would be required as a result of HRI projects, EPA and other parties have alleged in other circumstances that the HRI opportunities cited by the Agency in the proposed guidelines should have triggered NSR, resulting in both costly and protracted litigation and also expensive new emission control requirements in several instances. EPA should act to ensure that NSR concerns do not deter potential HRI projects that could be viable compliance options for states and unit operators.

a. NSR Concerns Will Create Disincentives for Improving Heat Rates at Existing Coal-Based Units.

EPA states in the proposed guidelines that it expects there will be "few instances" where "an NSR permit would be required." 79 *Fed. Reg.* at 34,859. Because HRI projects that boost efficiency often constitute routine repair and replacement of deteriorated components, very few efficiency improvement projects, if any, *should* trigger NSR. However, EPA and other parties have alleged in other circumstances that the HRI opportunities cited by the Agency in the proposed guidelines—including, for example, upgrading equipment such as economizers, turbines and air heaters—should have triggered NSR. The result of this has been costly and protracted litigation for unit operators.

[184] EPA has recognized that "the NSR program has impeded or resulted in the cancellation of projects which would…improve…efficiency." EPA, *New Source Review: Report to the President*, at 1 (June 13, 2002).

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Further, even if EPA believes that there would be "few instances" where an NSR permit would be required, state and citizen plaintiffs also have been active in litigating NSR suits over the past 15 years. Because of this history, EPA's statement that there will be "few instances" in which heat rate improvement projects would trigger NSR is not reassuring. Even when these suits have lacked merit, they serve to delay the implementation of the efficiency improvement projects at issue because of protracted and costly litigation.[185] Without assurances that actions taken as part of state compliance plans to improve unit heat rates will not trigger NSR, unit operators could be understandably reluctant to undertake these projects as envisioned by the Agency in the proposed guidelines.

b. EPA should take action in the final guidelines to avoid discouraging heat rate improvement efforts at existing coal-based units.

To ensure that unit operators are incented to undertake cost-effective HRI projects at existing coal-based units and not discouraged due to NSR concerns, EPA needs to address potential NSR impediments in the final guidelines. These actions could be an important compliance tool for states, and EPA should provide a clear statement in the final guidelines that any upgrades necessary to achieve efficiency improvements at existing coal-based units via HRI projects do *not* trigger NSR. Such a statement would encourage, rather than discourage, efforts to cost

[185] EPA asserts that NSR concerns can be addressed by states and sources, noting that states can "establish the standards of performance in their compliance plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR." *See* 79 *Fed. Reg.* at 34,928. EPA gives two examples of how states could avoid NSR concerns, but both involve limiting utilization of the very units that improve their heat rates. *See id.* It is unlikely that a unit owner would decide to invest in HRI projects unless the unit was expected to continue to operate at levels that would allow for the recovery of the costs in addition to other fixed and variable costs. As noted, *supra*, section II.B.3., long-term savings related to reduced fuel costs, by themselves, are not sufficient to offset the immediate capital investments needed to make efficiency improvements.

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effectively reduce emissions at the unit level by removing the threat of protracted and potentially unnecessary NSR litigation.

3. EPA should provide clarity regarding accounting for emissions from biomass before states are required to submit compliance plans.

As discussed in detail in Section II.D.4, EPA's treatment of biomass units is inconsistent when calculating the state baselines and in estimating the reductions that could be achieved through the increased deployment of renewable generation. Additionally, the proposed guidelines are not clear on the extent to which states and affected EGUs will be able to utilize the emission reduction benefits of biomass combustion for compliance. EPA discusses its in-progress efforts to develop an "Accounting Framework for Biogenic Emissions" in the preamble to the proposed guidelines, and notes that a draft has been reviewed by EPA's Science Advisory Board (SAB). In the draft framework, EPA concluded that "biomass had the potential to reduce the overall level of CO_2 emissions" in electricity generation but that the type of biomass used and its upstream "life-cycle assessment" were important considerations. *See* 79 *Fed. Reg.* at 34,924. A revised framework was released on November 19, 2014, but the SAB has yet to review or comment on it.

In the final rule, EPA should ensure consistent treatment of biomass for compliance purposes. To do otherwise would be inconsistent with EPA's approach to how other renewable resources are used to set the state-specific emission rate goals, which determines their potential role as compliance options that could be included in state plans. As EPA notes, "states likely will consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans…and...it is important to define a clear path for states to do so." *Id.* at 34,924. Before states are required to submit

compliance plans, EEI encourages EPA to be clear as to how states and electric utilities should account for biomass emissions in order to enable states to properly utilize these resources as compliance tools.

EPA's recent Biomass Memorandum begins to provide some clarity on the role of biomass in state compliance plans, but indicates that many feedstocks may not be deemed carbon neutral. Moreover, the Biomass Memorandum appears to indicate that EPA will address inclusion of biomass-based units in compliance plans on a state-by-state basis. *See* Biomass Memorandum at 3. To ensure that state can develop plans that EPA can approve, EPA should provide additional clarity on which types of biomass will be deemed carbon neutral before states have to submit plans.

4. States should be able to use new NGCCs to reduce emissions, support integration of new renewable generation and meet future increases in demand.

The proposed guidelines envision that customer demand through 2030 and beyond increasingly will be met with new renewable generation. While renewable generation will continue to grow going forward, there still may be a need for new base load generation resources. As EPA recognizes, this need largely will be met with new NGCC units, *see* 79 *Fed. Reg.* at 34,877, which have lower emission rates than coal-based generation and are able to flexibly backup variable renewable generation. The role of new NGCCs will be different in each state, given their different generation mixes and different proposed emission rate goals. EPA's final section 111(d) guidelines should recognize the different role that new NGCCs will play in different states. The final guidelines should allow states to use new NGCC units as part of their efforts to accomplish this, if they elect this option in compliance plans. However, the final guidelines

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should not limit states' abilities to build important base load resources when and where they are needed.

a. States have the option to use new NGCC units to reduce the average existing fleet emission rate.

EPA notes that state plans could reduce utilization of, and emissions from, affected existing EGUs through the construction of new NGCC units. *See* 79 *Fed. Reg.* at 34,923. States have the flexibility to design compliance plans to include a wide range of measures to reduce emission rates and are not limited to those measures EPA has defined as BSER. *See id.* at 34,900. Therefore, states have the discretion to include new NGCC units in compliance plans.[186] Other EPA regulatory programs allow states to build new NGCC units as a reliable and cost-effective way to comply with CAA standards and air quality goals.[187] Regulations under section 111(d) should be no different.

It is important that EPA's final guidelines clearly state that inclusion in a state compliance plan does not mean that any new NGCC unit becomes subject to regulation under section 111(d). Consistent with the legal structure of section 111, new NGCC units appropriately are subject to the emission rate standards EPA proposed under section 111(b) in January 2014. *See* 79 *Fed. Reg.* at 1,433. Using new NGCC units as compliance tools should not change their regulatory

[186] As EPA noted, whether new NGCCs must be included as enforceable measures in state plans is a function of the approach a state takes to compliance. Under some approaches, new NGCCs would not have to be included in state plans, but would have the effect of reducing utilization of affected EGUs. *See* 79 *Fed. Reg.* at 34,924-25.

[187] For example, some companies are building new NGCCs and retiring existing coal-based units to comply with MATS; other companies are taking similar actions to comply with regional haze requirements.

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status, and EPA has not articulated any policy or legal rationale for regulating these units under both of these subsections of CAA section 111 simultaneously.

It also is important that EPA's final guidelines clearly state that units built after the CO_2 emission standards for new units were proposed—January 8, 2014— and which are in compliance with those standards will not "become" 111(d) units at some point in the future. States will submit compliance plans in 2016 that are designed to achieve the 2030 goal relative to the 2012 emission rate that EPA calculated for each state. It would be inconsistent with the CAA and unfair to states if EPA changed the goals (or determined that states were no longer making progress toward the goal emission rates) after compliance plans are approved to address new NGCC units that were built after January 8, 2014. This would undermine state flexibility to use these units for compliance purposes. More importantly, this would undermine the certainty states and utilities need with respect to the final goals so that they confidently can invest resources to achieve them.

b. It would be appropriate to recognize administratively the emissions from new NGCC units if they are included in state plans.

If states choose to include new NGCC units in compliance plans, EPA requests comment on how to address emissions from these units. Specifically, EPA requests comment on how to account for emissions from new NGCC units in rate-based state plans. *See* 79 *Fed. Reg.* at 34,924.[188]

[188] EPA asserted that accounting for emissions from new NGCC units when making compliance demonstrations is only an issue if states choose a rate-based approach to compliance. This may not be true. EPA states that mass-based plans would reflect any emission reductions at affected EGUs resulting from the substitution of new NGCC generation from higher-emitting existing sources. *See* 79 *Fed. Reg.* at 34,923. As EPA notes, this is only the case under a mass-based approach in which an emission limit on affected EGUs assured achievement of the required level of emission performance. *See id.* Therefore, the relevant consideration is not whether a state chooses a rate- or a mass-based approach, but whether compliance is assured via emission limits

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The issue is whether emissions from new NGCCs (or, more specifically, these units' emission rates) should be considered when states are demonstrating compliance with the emission performance goal for affected units. *See id.* For states with emission rate goals that are greater than the permitted rate of new NGCC units, administratively including the emission rates of any new NGCCs when making a compliance demonstration would be appropriate.

Recognizing that new NGCCs are not zero-emitting resources would not hamper these states' ability to demonstrate compliance and would avoid unintended outcomes. For example, if the emissions of new NGCCs are not considered, a zero-emitting resource in a state with a goal rate greater than emission rate permitted new NGCC units could be closed and replaced with new units without affecting the state's ability to demonstrate compliance with the emission rate goal, despite the fact that mass emissions would increase. To avoid this outcome, states or EPA administratively could adjust compliance demonstrations to reflect the emissions from new NGCCs that were included in compliance plans. To incentivize the building of the newest and most efficient NGCC technologies, any compliance adjustments should reflect the actual emission rate achieved by the new unit, which may be lower than the 1,000-lb CO_2/MWh standard applicable to all new NGCC units (with some accommodation for the fact that the initial efficiency and emission rate of the new unit will degrade over time).

c. States with goals less than 1,000 lb/MWh should be allowed to build new NGCCs to support integration of variable renewable resources, or to serve load.

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on affected units. Accordingly, because compliance is measured at the stack of affected units, accounting for new NGCCs could be an issue for both rate- and mass-based compliance plans.

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New NGCC units may not be a useful compliance option in more than half of the states. In 25 of the 48 states that are required to submit compliance plans, the proposed emission rate goals are more stringent than the 1,000 lb CO_2/MWh standard of performance that EPA has proposed under CAA 111(b). *See* Goal Computation TSD at 22, Appendix 3 – Summary of State Goals Under the Proposed Existing Source Performance Standard. In these states, accounting for the emission rates of any new NGCC units would be detrimental to their ability to demonstrate compliance. As a general matter, the structure of the CAA requires that existing unit standards be less stringent than new unit standards, in recognition of the fact that control technologies and improved processes can be incorporated more easily into the design of a new unit than that of an existing unit.

If these states had to adjust emission rate compliance demonstrations to account for new NGCC units, they would be functionally limited to building only zero-emitting generation going forward. At the present time, not all power system needs can be met using only new renewable generation and increased end-use efficiency. Further, the cost and long lead times involved in new nuclear generation render it an unlikely choice for many states. Therefore, new NGCC units may be needed for a variety of reasons, including: cost-effective integration of variable renewable resources, provision of other grid reliability services, and satisfying increases in demand. In these situations, a state should be allowed to build new NGCC units, consistent with the proposed section 111(b) standards, and the emissions from these units should not be included when determining compliance with the state emission rate goal.

5. The final guidelines should ensure that states are not penalized for reducing emissions from the transportation sector.

Transportation electrification represents a significant opportunity to reduce GHG emissions from the U.S. economy. However, the proposed guidelines could create significant disincentives for states and utilities to pursue these opportunities. Transportation is "electrified" when it is powered by electricity taken from the grid, increasing demand and production from affected EGUs. By definition, transportation electrification increases demand for electricity. For states that opt for a mass-based compliance plan, emissions would be capped. Increases in demand to serve electric transportation needs may result in increased generation, which could cause affected units to emit more than the capped level of emissions.[189] The final guidelines should assure states and electric utilities that increased transportation electrification—and the concomitant reduction in emissions from other sectors—will not cause a state to be out of compliance with its goal.

Perhaps the most widely-discussed electrification application today is the plug-in electric vehicle (PEV), a term that includes both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs), usually within the light-duty vehicle sector. PEVs have the potential to significantly reduce CO_2 emissions from light-duty vehicles, the biggest single energy user within transportation. Electrification of other modes of transportation sectors, including, for example, port electrification and other industrial applications, also has the potential to

[189] States that opt for rate-based compliance plans, especially those with emission rate goals lower than the NGCC emission rate, could also be challenged by electrification. Increasing output from an EGU does not increase its emission rate necessarily, but, to the extent that the proposed guidelines generally contemplate reduced utilization of existing coal-based units, their heat rates will degrade, increasing emission rates when these units are operated. The exact implications would be hard to measures and even harder to attribute to a particular increase in demand. For this reason, these comments focus on the effects of electrification on mass-based compliance plans.

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significantly reduce overall emissions, but could result in increased mass emissions from the electric generating fleet.

Finally, the guidelines need to be adaptable to address state circumstances, such as in California where transportation electrification is already a strategy to meet air quality goals.[190]

a. Electrification, particularly transportation electrification, has the potential to significantly reduce emissions.

A number of studies have shown the significant opportunity presented by electrification to reduce CO_2 emissions. For example, EPRI and the Natural Resources Defense Council (NRDC) considered the potential for electrification to reduce CO_2 for a subset of the transportation sector, namely light-duty vehicles. The 2007 study created nine scenarios for the year 2050 by varying the level of market penetration of PHEVs and the carbon intensity of electricity generation and found that annual GHG reductions were significant across all nine scenarios, ranging from 163 million metric tons to 612 million metric tons per year.[191] The National Research Council's Committee on Transitions to Alternative Vehicles and Fuels was tasked with evaluating how to achieve major GHG reductions in the light-duty vehicle fleet. This study demonstrated that a

[190] EPA's final guidance should allow states to address key factors that will influence the mass goals, including economic growth, transportation electrification and the level of electricity imports and exports. In California, and especially in the South Coast Air Basin, aggressive implementation of transportation electrification is a major strategy to meet federal criteria pollutant standards and Zero Emission Vehicle goals. However, since such exogenous drivers are highly uncertain over the time frame of EPA's proposed guidelines, EPA should allow plan revisions.

[191] EPRI and NRDC, *Environmental Assessment of Plug-In Hybrid Electric Vehicles, Vol. 1: Nationwide Greenhouse Gas Emissions* (July 23, 2007), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001015325.

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scenario with a high-penetration of PEVs could reduce GHG emissions by 31 percent by 2030 and 63 percent by 2050, compared to 2005 levels.[192]

EPA also has recognized the value of electrification in reducing transportation CO_2 emissions. EPA's vehicle emission standards create incentives for PHEVs. *See, e.g., 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards*, 77 *Fed. Reg.* 62,624 (Oct. 15, 2012).

b. EPA should not penalize states and electric utilities for reducing emissions from the transportation sector.

Relying on the interconnected nature of the power system, EPA's proposed BSER for existing affected fossil-based EGUs includes not just reductions that could be achieved at the unit-level or by increased generation from other sources, but also by end-users of electricity. *See* 79 *Fed. Reg.* at 34,835-36. This system-wide approach includes in its system boundary both electricity generation *and* use. EPA's approach to BSER focuses on the potential to *reduce* emissions from the power sector through end-use efficiency, but EPA cannot ignore increases in the end-use of electricity, particularly when those increases result in reducing emissions from other sectors of the economy. States and electric utilities should not be penalized for these reductions.
EPA specifically notes it is "not proposing that out-of-sector offsets be applied to demonstrate CO_2 emission performance from affected EGUs." 79 *Fed. Reg.* at 34,910. Notwithstanding this, the proposed guidelines can, however, recognize and account for the GHG benefits of electrification.

[192] National Research Council, *Transitions to Alternative Vehicles and Fuels* (2013), http://www.nap.edu/catalog.php?record_id=18264.

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Specifically, the final guidelines should provide that states can include information about increases in generation and emissions that are related to increased electrification in annual compliance reports. In particular, if annual compliance reports demonstrate that a state is not achieving emission reductions consistent with the projected reduction trajectory included in its compliance plan, a state should be able to administratively adjust the emission performance from affected units to reflect emissions that can be attributed to transportation electrification. EPA's final guidelines need not do more than recognize that states may adjust annual reports to reflect emissions increases related to transportation sector electrification, if necessary. There is ample time between the finalization of the guidelines and the 2022 due date for the first annual report for interested stakeholders to determine the best analytical approaches for quantifying and attributing emissions increases related to transportation electrification.

6. The final guidelines should adopt an expansive definition of corrective measures that includes methane reductions achieved by gas distribution companies.

The proposed guidelines provide that, unless a state compliance plan has "self-correcting" measures, the plan must specify "corrective actions" (sometimes referred to in the guidelines as "corrective measures"). *See* proposed 40 C.F.R. § 60.5815(b), 79 *Fed. Reg.* at 34,955. Under the guidelines, a state would be required to implement "corrective actions" during a compliance period if there was a discrepancy between the actual emissions performance of the state's affected EGUs and the projected performance under the plan. If the plan specifies and authorizes the corrective actions up front—i.e., when the plan is submitted to EPA—then the corrective actions would have to be implemented if there was a discrepancy of 10 percent or more. If the plan provides that the state will determine and adopt the corrective actions only after the discrepancy is identified, then the trigger would be 8 percent. *See id.*; *see also* 79 *Fed. Reg.* at

34,907. The proposed guidelines do not otherwise define or prescribe what types of measures could constitute a "corrective action."

EPA should allow states broad discretion to specify the types of abatement measures that can be "corrective actions." In particular, the Agency should allow such "corrective actions" to include quantifiable and verifiable reductions in methane emissions from natural gas LDC facilities. Methane is a recognized greenhouse gas, and gas LDCs around the country are carrying out innovative emission reduction projects. For example, the Natural Gas Downstream Initiative involves five power companies (Consolidated Edison Company of New York, National Grid, Pacific Gas & Electric, Public Service Electric and Gas Company and Xcel Energy) focusing on reducing methane leaks by encouraging programs that accelerate investments in infrastructure and promote outstanding operations, including modernizing their systems and utilizing next generation technologies.

The proposed guidelines likely would not allow states to include LDC methane reduction projects as part of the foundational "enforceable emission reduction measures" in their plans because such projects do not directly affect the emissions performance of affected EGUs. *See* 79 *Fed. Reg.* at 34,910. However, EPA notes that emission limits for affected EGUs that are included in state plans could include provisions that provide the ability to use offsets for compliance." *Id.* If EPA is willing to allow individual units to use offsets for compliance with emissions limits, it would be reasonable to provide states with similar flexibility by allowing them the broad discretion to specify LDC methane reductions, or other similar measures, as "corrective actions."

It is important to recognize that corrective actions play a limited and contingent role in the achieving the proposed emission rate goals. A state would implement a "corrective action" only if the state's EPA-approved compliance plan was not performing as both the state (and EPA) projected—despite full implementation of that plan.

However, if state plans are not performing as projected, it would, by definition, mean that the state would have to look beyond the electric-sector measures that the state previously had included in its compliance plan because they were determined to be practical and cost-effective. Limiting the state's "corrective actions" only to *further* power-sector measures could mean forcing the state to adopt measures it had already rejected as too costly or as requiring other system changes that may take several years to implement. By contrast, allowing already-achieved reductions in LDC methane emissions to count as "corrective actions" would provide a cost safety valve and could produce reductions immediately.

Furthermore, it is important to recognize that in many states there is a nexus between LDC facilities and affected EGUs. Utilities are the common denominator. The proposed guidelines already contemplate a major role for utilities as the entities that will carry out state compliance plans. Many of these same utilities also own natural gas distribution facilities and therefore can implement methane reduction projects. In other words, allowing LDC methane reductions as "corrective actions" only implies broadening the scope of permissible measures to the entire utility sector; it does not imply opening the door to the entire universe of potential offsets from forests, farms or other sectors of the economy.

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For the foregoing reasons, the final guidelines should find that an approvable state compliance plan could define "corrective measures" to include verifiable LDC methane reductions. Such a finding would not deprive EPA of its authority to review and approve any state plan that included methane reductions as a corrective measure. Further, EPA would retain the authority to review compliance reports that indicated that methane reduction corrective measures had been triggered and used.

7. The final guidelines should affirm that distributed generation can be included in state compliance plans if carbon reductions can be measured and verified.

EPA did not include DG on the list of non-BSER compliance options that could be included in state plan. See section III.E.1, above. In the State Plan Consideration TSD, EPA discusses appropriate monitoring, reporting and verification protocols for DG, implying that EPA would permit a state to include verifiable DG in both rate-based and mass-based state plans. *See* State Plan Considerations TSD at 80. In the past decade, DG activities and technologies using renewable and non-renewable energy sources have made significant progress and grown substantially. As a result, the past decade has seen supportive state policies and regulations—as well as significant technology cost reductions—contribute to the substantial growth of DG markets, particularly rooftop solar. The final guidelines should affirm that states can use DG as a compliance tool.

For non-renewable DG, utilities and states should be able to include emissions avoided as a result of DG activities in compliance plans as long as the avoided emissions reductions can be measured and verified, but, in the case of renewable DG, states and utilities should be able to

treat DG generation like they would treat any other renewable resource, as a source of zero emissions electricity, without having to convert that generation into avoided emissions. For purposes of compliance with the proposed guidelines, there should be no difference in how a state treats central station renewable generation and distributed generation. However, as EPA notes, "it is easier to quantify the renewable electricity generation resulting from some programs that it is for others." *See id.* at 70. EPA should provide clear guidance in the final guidelines regarding the standard by which EPA will review DG activities that are included in state plans.

8. EPA should clarify the legal obligations of EGU owners, utilities and other affected entities subject to state compliance plans.

The final emission guidelines should offer greater clarity regarding how obligations placed on EGU owners, electric utilities and others contained in state plans will be enforced. To that end, the approach to enforcement under section 111(d) plans should follow two principles: first, that affected EGUs will not be subject to enforcement if they are complying with any unit-specific emission limits that are imposed as part of the state compliance plan; and second, that states (and EGUs in such states) will not be subject to enforcement if annual reports demonstrate that emission reductions are occurring consistent with the trajectory included in the approved compliance plan, even if specific elements of the plan are not performing as expected.

The first principle is that an affected EGU has no enforcement exposure so long as it is complying with its obligations written into an EPA-approved state plan. EPA should make clear that the legal obligation on individual EGU owners, utilities, or other affected entities is to comply with the applicable requirements contained in the relevant state plan where that entity is located. So long as an affected entity complies with the specific obligations required of that entity under the state plan—for example, to hold emission allowances in a cap-and-trade

program, submit RECs under an RES, or invest a set amount of funds in energy efficiency programs—that entity will be considered in compliance and so cannot be subject to any enforcement actions by EPA or under the Clean Air Act citizen suit provisions. *See* CAA section 304.

Put another way, EPA should make clear that an affected entity is not at risk of enforcement action merely because a state's emission rate in a given year deviates from the trajectory it established in its state plan submission or, after 2030, from its goal. The fact that the state is off of its compliance pathway may be a basis for triggering corrective measures or otherwise modifying a state plan, but it is not a basis for pursuing enforcement action against an individual entity in an attempt to achieve additional emission reductions or other actions beyond those required by the EPA-approved state compliance plan.

EEI believes that this is what EPA intended regarding enforcement in the proposed guidelines; however this principle has not been unambiguously articulated.[193] There are significant concerns

[193] For example, the proposed guidelines describe, without making comment on, concerns raised by some stakeholders that EPA does not have the authority to make state policies regarding RE and EE programs federally enforceable. These stakeholders argue that states can impose such requirements under state law that serve merely as complementary measures to federally enforceable emission limitations on EGUs. *See* 79 *Fed. Reg.* at 34,902. This approach raises the significant concern that EGU owners will be deemed to be out of compliance and therefore subject to enforcement if an RE or EE measure set forth in an EPA-approved state plan: (1) is not enacted in the first instance; or (2) is enacted and fully implemented, but does not generate the expected level of emission reductions. EPA should make clear in its final rule that it does not agree with this approach to address stakeholder concerns because owners and operators of EGUs do not have control over such measures and therefore cannot be held accountable for them.

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that EPA or private parties[194] may attempt enforcement actions even if an EGU or utility is fully implementing the required measures included in a state plan, merely because RE, EE or other state or third-party actions do not result in the emission reductions built into the state's plan projections or because of unexpected circumstances such as increased electricity demand due to economic recovery. EPA should more clearly establish that an EGU or utility that is complying with its obligations under an EPA-approved state compliance plan is legally meeting all federally enforceable obligations and therefore cannot be subject to an EPA enforcement action or citizen suit.

The failure of a state to meet its projected emission rate may occur for many reasons that are beyond the control or responsibility of individual EGUs and utilities. Under the proposed guidelines, EPA has indicated that a state may choose to take on compliance obligations itself, such as by using a state commitment approach. *See* 79 *Fed Reg*. at 34,902. Similarly, a state may place obligations on non-EGU, non-utility entities under a portfolio approach. *See id*. at 34,901. In such circumstances, the state necessarily will have placed direct obligations on individual EGUs and/or utilities that, when added together, only will result in achievement of a portion of the state goal, consistent with the state's trajectory or 2030 goals.[195]

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[194] EPA has indicated that the citizen suit provisions of the Clean Air Act would apply to federally enforceable requirements under section 111(d) state plans. *See* State Plan

Considerations TSD at 17, n.17 ("We note that under the CAA, measures included in an approved 111(d) state plan would be federally enforceable by EPA, and that citizens would also have the ability to file citizen suits to compel enforcement of state plan obligations, under CAA Section 304 (42 U.S. Code Section 7604).").

[195] *See* 79 *Fed. Reg*. at 34,901 (Under this approach, "the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level.").

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This approach could be implemented with regard to individual EGUs or utilities in two main ways. First, EPA has proposed that a state may require affected EGUs (or a group of EGUs, such as all EGUs operated by an integrated utility) to meet emission standards less stringent than the state goal. In such circumstances, an affected EGU or utility that complies with the state-set emission standard will have fulfilled all of its obligations under the state plan and so there would be no enforcement, even if other affected entities in a state (including the state itself), did not meet their obligations or if, for whatever reason, the state's overall emission rate performance was not consistent with the level required by trajectory established in the approved compliance plan.

Alternatively, EPA has proposed that a state may "administratively adjust" the emission rate of affected EGUs based on actions taken by the state or other non-EGU entities.[196] If a state makes a commitment to administratively adjust the EGU or utility's emission rate, EPA should make clear that the failure to procure sufficient alternative generation or energy savings should not expose the EGU or utility to enforcement action.

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[196] *See* 79 *Fed. Reg.* at 34,902 ("Plans with rate-based emission limits could incorporate enforceable RE and demand-side EE measures by adjusting an EGU's CO_2 emission rate when demonstrating compliance through either an administrative adjustment by the state or use of a tradable credit approach."); *id.* ("The state plan would impose the full responsibility for achieving the emission performance level on the affected EGUs, but the state would credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures.").

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To be sure, there are circumstances where an affected entity's obligations under the state plan will change from those originally set out by the state plan submitted and approved by EPA. For example, if a state plan results in emission reductions that are not sufficient for the state to be within 10 percent of its approved emission reduction trajectory, that state will be required to impose corrective measures. *See id.* at 34,907.

If a state's corrective measures are still not enough for the state's emission rate to be consistent with the state's trajectory, or if the state has a change in circumstances, the state may have to modify its plan. *See id.* at 34,917. In such cases, principles of fairness and due process require that no new enforceable obligations for EGUs or utilities be created under the modified state plan without procedural protections including notice, and the opportunity to provide public comment on those modifications.

In any event, the appropriate remedy for a state whose plan is not resulting in expected emission rate reductions notwithstanding faithful execution is modification of the state plan, not an enforcement action against regulated entities. Under such circumstances, neither EPA nor private litigants may bring an enforcement action against EGUs or utilities for under-performance of the state plan. Additionally, neither EPA nor private parties may use an enforcement action to impose obligations on EGUs or utilities that were not already included in a properly approved plan.

The second principle is that no enforcement exposure exists for a state or EGU within the state if the state is on its emission rate compliance path established in its approved state plan. If a state

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is on its EPA-approved trajectory, the affected entities within the state should be deemed to be in compliance with the plan. This principle is important in cases where a state, for instance, is meeting its projected trajectory and is on track to meet the state goal, but makes a sovereign decision to modify its laws. Before the state has made corresponding modifications to its plan, affected EGUs or utilities may be put in a difficult position of choosing between complying with currently-effective state law and complying with the plan as originally submitted to and approved by EPA. Alternatively, affected EGUs might find themselves unable to meet obligations in the originally approved plan as the result of later state law or policy changes. For example, a state's originally submitted plan might have contemplated that affected EGUs or utilities meet their obligations by obtaining RECs, yet the state might later change its RES requirements, rendering the affected EGU's or utility's compliance impossible. Under such a scenario, the affected EGUs or utilities should not be subject to an enforcement action from EPA or citizens, particularly in cases where the state's emission rate is consistent with the trajectory included in the approved state plan.

Enforcement actions against a particular affected entity should only be available if: 1) the affected entity is failing to meet its legal obligations established under an approved state plan; 2) those legal obligations are in force as a matter of state law; and 3) the state is not currently meeting its emission rate or mass obligations established in its state plan. These principles can establish an enforcement system that simultaneously ensures states are on track to meet their 2030 goals and provides the necessary legal certainty for EGUs and utilities to invest the significant resources that will be required.

9. The final guidelines should facilitate the use of end-use efficiency measures for compliance.

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EE programs will be an important tool that states will include in their compliance plans. EPA should encourage the full deployment of EE measures for compliance by recognizing existing state EM&V protocols, minimizing reporting burdens, using gross energy metrics and allowing a range of EE measures, including new measures, to be included in state plans.

a. EPA should recognize and build on existing state EM&V protocols and reporting requirements.

EPA suggests that additional reporting and recordkeeping requirements for EE-related activities would be needed for states pursuing a rate-based or a mass-based portfolio approach for compliance, and indicates that it intends to develop guidance on acceptable EM&V methods for EE measures that are incorporated into state plans. Further, EPA proposes to establish different EM&V procedures for well-established, moderately well-established, and less well-established EE technologies. *See* 79 *Fed. Reg.* at 34,921; State Plan Considerations TSD at 48-50.

As a preliminary matter, such EM&V guidance is not needed, at least as it relates to existing programs that are subject to PUC oversight. As EPA notes, "every state has established demand-side energy efficiency policies," and "one typical [EE program reporting] requirement is the application of recognized EM&V protocols that specify industry-preferred approaches and methodologies for estimating savings from efficiency programs." *Id.* at 34,871-72. Further, as EPA notes:

> States are currently implementing a wide range of demand-side energy efficiency requirements, programs and measures…For example, energy efficiency programs subject to PUC oversight and review are frequently evaluated using rigorous evaluation procedures that are based upon several decades of research and experience. These energy efficiency programs are subject to a quasi-judicial, public and transparent review process, which can lead to adoption of EM&V protocols that convey a relatively high level of certainty for EM&V results.

State Plan Considerations TSD at 47.

The final guidelines should be flexible and recognize the wide range of state-approved EM&V measures, which will help facilitate the development of a suite of EE programs. Further, states that require third-party EM&V should not be required to provide additional reporting and recordkeeping, which will only increase the cost of EE programs for utilities and their customers. Such an approach would build on existing action and help facilitate increased deployment of EE actions, potentially including early actions, as states will have confidence that their existing measures will be allowed and can be used as a basis for additional EE efforts.

Imposing additional requirements would create unnecessary burdens and increase costs, which may hamper the development and deployment of EE measures. In particular, procedures that are overly rigorous for moderately- and less well-established EE technologies could impact their development and implementation. These new technologies are needed to increase EE savings throughout the country.

Finally, if EPA determines that it is necessary to establish new or expanded EM&V protocols, the Agency should make this known to the states well in advance of the deadline for submitting state plans to EPA for review and approval, as it could significantly alter the role that individual states choose for EE measures to play in compliance.

b. By allowing the use of gross energy savings to measure and document EE program achievements, EPA can minimize the record-keeping burden of states.

EPA should allow the use of gross energy savings for compliance purposes, rather than the proposed net energy savings. There are many reasons why gross energy savings is the

appropriate metric: (1) emissions reductions are based on gross savings, which represent the actual level of savings that occurs (and can be measured and verified), not net savings; (2) attribution of savings under the net saving approach (i.e., applying a net-to-gross ratio) is both difficult to determine accurately and not relevant for emission reductions resulting from the adoption of EE measures; (3) allowing for inclusion of spillover effects as well as free ridership in the determination of net savings is highly subjective; and (4) it will be much easier for states and utilities to evaluate and use gross savings rather than net savings, thereby facilitating inclusion of a broad range of EE policies and programs in state plans. The use of a gross savings approach in the final guidelines would be both more realistic and less cumbersome for states to implement, which would facilitate and encourage the deployment of EE-related measures.

c. States should be able to include new EE measures, including codes and standards, in compliance plans.

Given the key role that EE measures play in the proposed guidelines, and EPA's aggressive assumptions about their deployment in the calculation of the state-specific emission rate goals, the Agency should allow a wide range of EE measures to be included in state plans. As EPA notes in the preamble, there are already a number of utility-sponsored EE programs that are considered "well established" that can be included in state plans. *See* 79 *Fed. Reg.* at 34,884. In order to encourage as broad a deployment as possible of EE measures, other measures—including local and state building codes—should also be allowable compliance strategies. The final guidelines also should contain provisions for how states can include other EE measures for which the development of accepted EM&V protocols may be years away. Implementing new EE technologies should not be hampered by the lack of an accepted EM&V protocol.

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Together with appliance efficiency standards, building codes and/or standards that are well designed, implemented and enforced can lead to significant energy savings at the time of building construction or total renovation. New building codes and appliance efficiency standards have the potential to reduce electricity consumption dramatically. See IEE March 2013 Report at 12. Accordingly, the final guidelines should be explicit that states can include reductions from codes and standards in compliance plans.

IV. The Proposed Section 111(d) Guidelines Raise Significant Questions Surrounding EPA's Legal Authority under the Clean Air Act.

EPA's novel approach to regulation of CO_2 from existing EGUs under CAA section 111(d) raises numerous legal questions. The bulk of EEI's above comments address the guidelines as they have been proposed, in an effort to help create a workable structure for state and electric utility compliance, should the final guidelines survive judicial review. EEI members companies have differing views on the extent of EPA's legal authority to adopt the proposed 111(d) guidelines. While there is not unanimity among the membership on the extent of EPA's legal authority, this portion of EEI's comments identifies several key legal issues and arguments that may be raised in future litigation. The existence of these issues, many of which EPA has not addressed, raise the possibility that some portions of the guidelines may not survive the inevitable legal challenges. EEI member companies will make their own decisions regarding whether to participate in any future litigation and in what manner.

EPA relies upon section 111(d) of the CAA for its authority to promulgate the proposed guidelines. In relevant part, section 111(d) instructs EPA to "prescribe regulations which shall

establish a procedure…under which each state shall submit to the Administrator a plan which …establishes standards of performance for any existing source for any air pollutant" for which EPA has promulgated regulations for new stationary sources, and which meet further specified criteria. *See* CAA section 111(d).

"Standard of performance" is in turn defined at CAA section 111(a) as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

CAA section 111(a)(1). Thus, EPA has responsibility for determining the "best system of emission reduction… adequately demonstrated" for categories of sources.[197] In the proposed guidelines, EPA has interpreted BSER to go beyond at-the-unit emission controls to include changes to the overall electric system that may indirectly reduce utilization of, and therefore, emissions from, affected EGUs. *See* 79 *Fed. Reg*. at 34,851.

EPA's interpretation of and approach to BSER in the proposed guidelines is unprecedented and presents significant legal issues. Assuming EPA's interpretation of BSER stands, which it may not, there are also significant questions regarding the sufficiency of EPA's analysis to support its assertion that the particular electric grid-wide measures that the Agency has determined constitute BSER together have been adequately demonstrated.

[197] EPA set forth its approach to making BSER determinations, consistent with the Agency's view of the relevant case law, in the proposed standards for new units issued under CAA section 111(b) in Docket No. EPA-HQ-OAR-2013-0495. *See* 79 *Fed. Reg.* at 1,462-67. EEI filed comments objecting to EPA's interpretation of the case law on May 9, 2014, and renews these objections here. The relevant portion of these comments is attached as Appendix E.

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Through its 1976 implementing regulations, EPA also has claimed authority to determine the "emission limitation achievable through application of" BSER—termed an "emission guideline" or, in the case of this rule, a state "goal." *See* 40 *Fed. Reg.* 53,339 (codified at 40 C.F.R § 60.22). In the proposed guidelines, EPA has set state-specific goals based on a statewide evaluation of the electric system, rather than a nationwide standard for affected EGUs to be implemented by the states. This novel interpretation of the point of compliance for a section 111 rulemaking raises its own unique set of legal concerns.

Finally, as EPA is aware, there are threshold issues regarding EPA's interpretation of the 1990 Amendments to section 111(d), which go to the scope of EPA's authority to issue these guidelines in the first instance.

A. EPA's Approach to Determining BSER.

For the first time, EPA has claimed that BSER need not be based on implementation of a technological, fuel-input or operational system at regulated sources, but instead can include actions taken by non-regulated sources that may have an indirect impact on the utilization of some regulated facilities. Specifically, in the proposed guidelines, EPA claims it can meet its regulatory obligation to determine BSER by looking at measures throughout the electric system and even on the other side of the plug that could reduce utilization of existing EGUs, and not simply by looking at emission reduction measures taken at the individual affected EGUs. *See* Legal Memorandum at 34.

The proposed guidelines advance two alternative readings of EPA's authority under CAA section 111(a) to justify this approach. The first, primary interpretation reads "system of emission

reduction" to include actions taken anywhere in the "interconnected" electric system that could reduce emissions at affected EGUs. *See id.* Under this interpretation, the "best…adequately demonstrated" version of that interconnected system includes "increased zero- or low-emitting generation in specified amounts (Building Blocks 2 and 3), and increased demand side energy efficiency in specified amounts (Building Block 4), all of which have the effect of displacing generation from the higher-emitting affected sources." *Id.*

The second, alternative interpretation reads "system of emission reduction" to include reducing the generation output of affected EGUs. The "best…adequately demonstrated" version of that system quantifies the reduction as "the amount that can be replaced by, in general, increased zero- or low-emitting generation and eliminated by increased demand-side energy efficiency." *Id.*

Under either interpretation, the quantification of the "emission limitation achievable through the application of" BSER—that is, the state goals—is determined largely by actions that occur outside the fence-line of affected EGUs. Indeed, in each of the 49 states covered by the proposed guidelines, it would not be possible to achieve the resulting proposed interim and final goals without the use of these outside-the-fence measures. Neither of these two novel interpretations is consistent with Congress's intended delegation of authority to EPA under the Act.

Under the doctrine of *Chevron* review,[198] EPA's authority to interpret statutory provisions is constrained, both by the text of the statute determined by "applying the ordinary tools of statutory construction,"[199] and by the reasonableness of the Agency's interpretation.[200] Applying those tools of construction here raises questions as to whether EPA's interpretation of "system of emission reduction" to include measures beyond affected EGUs is either consistent with the plain language of section 111 or reasonable.

1. Section 111 forecloses EPA from including measures in BSER that occur both outside of EGUs and outside the control of EGU owners.

EPA's primary interpretation of BSER appears to be that, for an interconnected system such as the electric power system, "system of emission reduction" may include any measure that impacts the system and that may reduce emissions at affected EGUs. This interpretation relies on a broad reading of the term "system." *See* Legal Memorandum at 51. Citing the Oxford English Dictionary, EPA claims that "system of emission reduction" can include measures that occur beyond affected EGUs because a "system" is "a set of things working together as parts of a mechanism or interconnecting network." *Id.* So long as the system identified is interconnected, EPA reasons, any measures within that system that affect EGU emissions—including ones outside the control of the owners of individual regulated facilities—can be considered part of BSER. This interpretation is not consistent with the ordinary usage of BSER, the text and structure of section 111 or the legislative history of the Act.

a. The ordinary usage of BSER has been limited to measures taken at the regulated unit.

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[198] *See Chevron v. NRDC*, 467 U.S. 837 (1984).

[199] *City of Arlington, Tex. v. FCC*, slip. op. at 4.

[200] *Chevron,* 467 U.S. at 844.

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Over the past four decades, EPA has interpreted "system of emission reduction" to cover only measures that are within the control of owners at affected facilities. It has done so for over 85 categories and subcategories of sources regulated under section 111. *See* 40 C.F.R. part 60. A system of emission reduction has meant a system put in place at an affected facility that reduces emissions from that facility.

Section 111(d) itself has been rarely used, leaving little significant regulatory precedent regarding its scope. However EPA's novel interpretation addresses a term within the long-extant section 111 that already has an extensive history of interpretation. BSER is contained in the definition of "standard of performance," which is shared between sections 111(b) and 111(d). Pursuant to section 111(b), EPA has interpreted this same phrase over 85 times, including as part of numerous regulations concerning this same source category of EGUs. And yet, this is the first time it has determined BSER to include measures affecting utilization or demand for electricity that occur outside the fence-line of regulated units in the relevant source category.

Some commentators have cited to flexibility mechanisms in prior promulgations under section 111(d) as evidence that the interpretation in the Agency's proposed guidelines is not novel. For example, some cite the cap-and-trade program established by the Clean Air Mercury Rule (CAMR) and emission averaging for municipal waste combustors. This analysis, however, conflates a history of using economic incentives, averaging and other measures that occur among regulated sources as a cost-saving *compliance* mechanism with the basis on which EPA has set the *emission limit* in the first instance. The emission limits under CAMR, for example, were based solely on technologies applied to an EGU. In addition, cap-and-trade and averaging

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programs have been used as acceptable means of *compliance* but have not themselves served as the basis for determining BSER.

Others have cited waste management plans for hospital/medical/infectious waste incinerators. This example is not analogous for a number of reasons. First, while regulations for existing waste incinerators are set under section 111(d), CAA section 129 specifies that the standards themselves be based on Maximum Achievable Control Technology (MACT) and not BSER. Accordingly, the establishment of these standards did not involve interpretation of BSER. Second, the waste management plans involved waste reduction through recycling that occurs at the same site as the regulated unit. Therefore, the plans did not involve standards that require action beyond the fence-line at regulated facilities in the relevant source category or outside the control of regulated entities. *See* 62 *Fed. Reg.* 48,348, 48,359 (1997).

EPA carries the burden to justify a departure from this long history of past practice that it has not met here.[201] The proposed guidelines, therefore, must do more to demonstrate that EPA's novel interpretation will withstand scrutiny, and simply mentioning the promulgation of a flexible compliance mechanism under CAMR and a regulation allowing averaging amongst municipal waste combustors is an insufficient justification from EPA. *See* Legal Memorandum at 63.

b. Given that section 111 contemplates more stringent standards for new sources than for existing sources, EPA's interpretation of BSER to include outside-the-fence measures for existing sources is inconsistent with the structure of section 111 as a whole.

[201] *See Motor Vehicle Assn. v. State Farm*, 463 U.S. 29, 42 (1983) ("an agency changing its course…is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance.").

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The very structure of the Act rests on the premise that adding emission controls to new sources will be less costly than it is for existing sources, and thus that more stringent standards may be inappropriate. For 26 states, EPA's outside-the-fence interpretation of BSER for existing EGUs results in emission limitations (state goals) that are more stringent than the emission limitations EPA has proposed to determine are achievable and adequately demonstrated for any affected *new* EGU.[202] This result is "inconsistent with the design and structure of the statute as a whole" and so "does not merit deference."[203]

In each section of the CAA related to stationary sources, Congress has mandated more stringent emission controls for new sources than for existing sources. Under the PSD provisions of the Act, EPA does not even have authority over existing sources. *See* CAA section 165. In the nonattainment provisions, new and modified sources in nonattainment areas are required to meet the "lowest achievable emission rate" (LAER), *see* CAA section 173(a)(2), whereas existing facilities need only limit emissions consistent with "reasonably available control technology" (RACT). *See* CAA section 172(c)(1). Under the regional haze program, states are directed to take into account the remaining useful life of an existing source in determining the level of control technology required. *See* CAA section 169A(g)(2). For hazardous air pollutants under

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[202] The states with emission limitations less than the 1000 lb CO_2/MWh that constitute the most restrictive new source EGU standards (for large combustion turbines) are Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Idaho, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, Nevada, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Virginia, and Washington. In addition, Alabama, Alaska, New Mexico, and Pennsylvania also have emission standards more stringent than those set for steam generators and small combustion turbines.

[203] *UARG v. EPA*, slip op at 17 (citing *University of Tex. Southwestern Medical Center* v. *Nassar*, 570 U.S. ____, ___ (2013) (slip op., at 13)).

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section 112, emission standards for existing sources are expected to be less stringent than for new sources.[204] Under CAA section 111, EPA only has authority to set standards for new sources; the states set standards for existing sources. *See* CAA sections 111(b) and (d). In fact, EPA's own Legal Memorandum states that "Congress arguably contemplated that, once EPA has identified BSER for new plants, it should raise the performance of the existing fleet with the goal of *approaching new source levels* at existing plants." Legal Memorandum at 40 n.38.

Interpreting "system of emission reduction" in a way that imposes a stricter emission rate for existing sources than for new sources turns the intent of section 111 on its head. It produces the perverse result that the 26 states whose emission goals are below the proposed emission standard for new NGCC units cannot risk building a new NGCC even though that is currently allowable under section 111(b) because of the possibility that it will require additional compliance actions to meet the state goal.[205] Thus, EPA's interpretation of BSER in the proposed guidelines is inconsistent with the structure of section 111.

c. EPA's interpretation of the term "system" is inconsistent with how Congress defined the term in other sections of the Act.

In the 1990 Amendments, Congress modified the nonattainment provisions of the Act and added a requirement that EPA establish a "system of regulations" to control volatile organic compound (VOC) emissions from commercial and consumer products. *See* CAA section 183(e). In

[204] CAA section 112(d)(3) ("Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory…"); *see also* CAA section 112(f)(4); CAA section 112(i)(3).

[205] Even if EPA does exempt new NGCC units from state goals under section 111(d), this does not change what was Congress' likely intent to impose more stringent standards for newer units under EPA regulation. *See, supra*, section IV.A.1.b.

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defining that system, Congress explicitly included the authority to go beyond a single source by implementing economic incentives, such as marketable permits. In the U.S. House Energy and Commerce Committee report, Congress specifically stated that "the system of regulation under section 183(e) is intended to be quite broad."[206] Accordingly, Congress clearly knows how to provide EPA broad authority to go beyond a unit when that is what it intends.

There is no indication under section 111(d) that Congress intended to expand EPA's authority relative to existing units. Section 111 does not contain similarly broad language, nor do the relevant committee reports indicate that Congress intended EPA's authority to be so broad. *See* 1990 Amendments § 403. In the absence of these indicators and pursuant to ordinary tools of statutory construction, Congress should be presumed to have *not* authorized the use of "beyond the fence" actions in the construction of BSER.[207]

d. EPA's expansive BSER interpretation under section 111(d) is inconsistent with both its BSER for section 111(b) and with the structure of section 111(d) because EPA could not itself require such measures.

EPA has determined that BSER includes actions that the Agency cannot itself require of states and sources, despite the fact that it has a statutory duty to impose standards of performance should a state fail to submit a plan or submit a plan that is not approved by EPA. Most of the proposed BSER Building Blocks are outside the scope of EPA's authority to implement on its own. By way of example, EPA's proposed Building Block 3 requires the construction of new

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[206] CRS, A Legislative History of the Clean Air Act Amendments of 1990, at 3,278 (Nov. 1993) (CAA Legislative History).

[207] *See, e.g.*, *Keene Corp. v. United States*, 508 U.S. 200, 208 (1993) (quoting *Russello v. United States*, 464 U.S. 16, 23 (1983))("[W]here Congress includes particular language in one section of a statute but omits it in another . . . , it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.").

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renewable generation. Under the CAA, EPA does not have authority to impose RES requirements on utilities within a state, nor require new renewable energy construction through the integrated resource planning process. Similarly, with respect to Building Block 2, EPA has no control over wholesale electric market rules to impose changes in the dispatch of units. And, it does not have control over customer decisions about how much power they use or even the ability to approve rate recovery for utilities to invest in EE programs such as efficient appliance rebates.

EPA's lack of authority is evident from its approach to BSER in the section 111(b) rulemakings—where EPA is the exclusive regulating authority—for the same pollutant and source categories, as the Agency explicitly rejected system-wide approaches to determining BSER as inappropriate. *See* 79 *Fed. Reg.* at 34,983. With respect to the sources over which EPA has authority to directly regulate—new fossil fuel-fired EGUs—the Agency correctly found that it lacked the authority to adopt the system-wide approach it has developed in the proposed guidelines. This is telling, since it shows that EPA's BSER approach in the proposed guidelines is inconsistent with both its own prior determinations and the structure of CAA section 111.

The primary justification that EPA provides for this novel approach relies on the "interconnected nature of the electric system." However, EPA has recently proposed new source performance standards under section 111(b) for the very same category of sources that are part of the very same interconnected system; yet, EPA did not even evaluate an outside-the-fence approach to determining BSER for that proposed rule. *See* 79 *Fed. Reg.* at 1,430. In addition, EPA published a proposal to establish standards of performance for modified and reconstructed EGUs

concurrently with this proposed rule, also under section 111(b), and did little more than mention a Building Block approach to BSER for modified and reconstructed units without giving it any substantive consideration.[208] Yet, the proposed guidelines contain no argument that there is something unique about section 111(d) or about existing sources that necessitate or distinguish the term "system of emission reduction" in such a way as to support EPA's divergent approaches. To the contrary, "best system of emission reduction" has the same meaning under both section 111(b) and section 111(d), although the system that is "best" may differ for new and existing sources.

As outlined above, EPA's responsibility to determine the "best system of emission reduction" is found in the definition of "standard of performance" that is shared between sections 111(b) and 111(d). And yet, for the purpose of setting standards for new and modified EGUs, EPA has taken the more conventional approach, not its proposed novel approach for existing EGUs. This "sudden and unexplained change… may be arbitrary, capricious or an abuse of discretion."[209]

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[208] *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, 79 *Fed. Reg*. 34,960 (Jun. 18, 2014) (Modified Source Rule). At best, the Modified Source Proposal can be read to reject the Building Block approach because "this proposal will result in a federal rule that covers only those sources that modify or reconstruct" and "it is not possible in advance to determine which sources will do so." *Id.* Such a justification is not sufficient to discount out-of-hand the primary feature of a simultaneously issued proposed rule for the same category of sources. Moreover, EPA does not make clear how knowing in advance which sources will modify is relevant to determining the impact that measures beyond the control of the unit may have on that facility's emission rate. EPA cannot know for certain what, if any, impact future RE generation or EE measures will have on any particular existing EGU in 2030, nor whether such an EGU will even be operating at that time.

[209] *Smiley v. Citibank*, 517 US 735, 742 (1996) (citing *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 46-57 (1983)).

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EPA must justify its departure from past and concurrent interpretive practice and explain why adopting different interpretations of "best system of emission reduction" simultaneously is not arbitrary and unreasonable. EPA's actions regarding sources regulated under CAA section 111(b) show that the Agency tacitly recognizes the limits on its own authority, and that its BSER interpretation in the proposed guidelines is inconsistent with the structure of CAA section 111 by requiring actions of states that the Agency cannot take itself.

e. The legislative history of the term "standard of performance" does not support beyond-the-unit measures.

The legislative history of section 111 is a relevant tool of statutory construction used to determine whether Congress intended "system of emission reduction" to involve actions beyond the control of affected EGUs.[210]

The idea that the term "system of emission reduction" is intended to apply to actions *at the source* is embodied in the legislative history of section 111. The Conference Report to the 1970 CAA in which section 111 was enacted—including the definition of "standard of performance"—make clear that Congress did not intend EPA to consider systems of emission reduction beyond the control of a unit. In describing section 111 (as reconciled between the House and Senate), the Report states that "the agreement authorizes regulations to require that

[210] *See Zuni Public School District No. 89 v. Dep't of Education*, 550 U.S. 81, 90-93 (2007); *Bell Atlantic Telephone Companies v. FCC*, 131 F. 3d 1044, 1047 (D.C. Cir. 1997) ("Under the first step of Chevron, the reviewing court must first exhaust the traditional tools of statutory construction to determine whether Congress has spoken to the precise question at issue. The traditional tools include examination of the statute's text, *legislative history*, and structure…") (citations and quotations omitted). Legislative history may also be considered at *Chevron* Step 2. *See Babbitt v. Sweet Home Chapter of Communities For a Great Oregon*, 515 U.S. 687 (1995).

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new major industry plants such as power plants…achieve a standard of emission performance based on the latest available *control technology, processes, operating methods, and other alternatives*." 1970 Clean Air Act Leg. History at 130 (emphasis added). Control technology, processes and operating methods are all emission reduction measures implemented at and implementable by individual EGUs. While the phrase "and other alternatives" may suggest additional emission reduction tools EPA could determine to be BSER, this general phrase should be read to be consistent with the three specific terms that precede it,[211] and therefore should be read to also apply to measures, such as using lower emitting fuels at existing facilities, that take place at, and are under the control of, regulated EGUs.

The proposed guidelines make much of the history of amendments to the definition of "standard of performance." Specifically, EPA cites the 1977 amendment to section 111, which introduced a requirement that standards of performance must be based on the best *"technological"* system of emission reduction, followed by a 1990 Clean Air Act amendment that removed this term and returned to a formulation very similar to the original 1970 version. *See* Legal Memorandum at 56. However, for the reasons discussed below, this legislative history provides little clarity that the BSER interpretation in the proposed guidelines is consistent with Congressional intent.

First, while Congress made changes to the definition of "standard of performance" with respect to new and modified sources under CAA section 111(b) in the 1977 Amendments—and then again in the 1990 Amendments—the definition with respect to existing sources under section

[211] *See, e.g., Circuit City Stores, Inc. v. Adams*, 532 U.S. 105, 114-15 (2001)(explaining and applying the statutory interpretation principle of *ejusdem generis*).

111(d) remained consistent over time.[212] Congress' decision in 1990 to remove the term "technological" from the definition with regard to new sources has little bearing on the interpretation of the term as it applies to existing sources.

Second, Congress' intent in introducing and then removing the term "technological" was clearly about whether it approved of the practice of switching to low-sulfur coal as a primary emission reduction measure, and not about expanding the scope of BSER to actions that occur outside of and beyond the control of individual EGU owners. The U.S. House Committee on Interstate and Foreign Commerce report on the House's version of the 1977 Clean Air Act Amendments makes clear that the insertion of the term "technological" was for the express purpose of limiting reliance on low-emitting fuels.[213] The U.S. House Energy and Commerce Committee Report on the bill that ultimately would become the 1990 Amendments further demonstrates the limited purpose of Congress' change to section 111(b). In discussing the amendments to section 111, the House Energy and Commerce Committee clarified that "the effect of new standards will be to give units the flexibility to meet the emission rates established under the new standards through whatever combination of *fuels and emission controls the units choose.*"[214] This language makes clear that the change in the definition of standard of performance to remove the

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[212] *Compare* CAA section 111(a)(1)(C), 42 U.S.C. § 7411(a)(1)(C)(1976 & Supp. I 1977) *with* CAA section 111(a)(1) (1988 & Supp. II 1990).

[213] Report by the Committee on Interstate and Foreign Commerce to Accompany H.R. 6161, H. Rep. 95-294 at 11 (the amendment to section 111 "indicates that adequately demonstrated technology is to be the basis of the standard, not merely reliance on use of untreated fuels.")

[214] 1990 CAA Legislative History at 3,414 (emphasis added). Note that the House Energy and Committee's language amending section 111(a) was ultimately enacted as part of the 1990 Amendments. *Compare* 1990 Legislative History at 3,155 *with* 1990 Amendments, 104 Stat. at 2,631 (section 403).

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previously added "technology" was intended to provide sources the flexibility to use low emitting fuels at the regulated unit, which the 1977 Amendments had effectively prohibited. It was not intended to allow EPA to determine that the appropriate emission limitation should be based on a system of emission reduction implemented outside of the regulated unit. Congress removed the "technological" requirement in order to allow non-technological systems at the source, not to expand section 111 beyond individual sources. Individual sources are capable of taking both technological (e.g., scrubbers) and non-technological (e.g. coal switching) measures to reduce emissions. Congress' decision to allow performance standards that are based on the use of non-technological measures at individual sources is irrelevant to whether, as EPA claims, a standard of performance may be based on a system of emission reduction implemented beyond the source. From 1970 to the present, section 111 has always focused on measures that can be implemented at the individual source, whether "technological" or not.

2. Congress did not intend that BSER provide EPA with the authority to regulate non-emitting entities, the entire power system and consumer behavior.

EPA argues that the broad definition of "system" establishes that a system of emission reduction means "virtually any 'set of things' that reduce emissions." *See* Legal Memorandum at 51. Under traditional tools of statutory construction, only a clear statutory statement within the statutory text would authorize such sweeping regulation. That is, the proposed guidelines' interpretation of "system of emission reduction" should be constrained by what has come to be called the "*Benzene* canon." This plain statement rule of construction holds that "in the absence of a clear mandate…it is unreasonable to assume that Congress intended to give [an Agency]

unprecedented power over American industry…A construction of the statute that avoids this kind of open-ended grant should certainly be favored."[215]

The *Benzene* canon plain statement rule has been applied to the question of agency deference under the *Chevron* doctrine. In *FDA v. Brown & Williamson Tobacco Corp.*, the Supreme Court rejected the FDA's attempt to find authority in the Food, Drug and Cosmetic Act to regulate tobacco, after years of contrary interpretation. *See* 529 U.S. 120 (2000). In considering the extent to which the agency was owed deference to interpret the statute, the Court held that "Congress could not have intended to delegate a decision of such economic and political significance to an agency in so cryptic a fashion." *See Brown & Williamson*, 529 U.S. at 160. That is, without a plain statement from Congress, the Court was unwilling to validate the FDA's significant expansion of its regulatory authority over "an industry constituting a significant portion of the American economy." *Id.* Similarly, the CAA contains no plain statement from Congress that would support a significant expansion of EPA's authority over the electric power industry—an industry which certainly constitutes a significant portion of the American economy.

In *Utility Air Regulatory Group v. EPA*, which examined EPA's authority under the Act to impose permitting obligations on sources because they emit greenhouse gases, the Supreme Court reaffirmed its *Brown & Williamson* decision. The Court stated that "when an agency claims to discover in a long-extant statute an unheralded power to regulate a significant portion of the American economy, we typically greet its announcement with a measure of skepticism. We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast

[215] *Industrial Union Dep't v. American Petroleum Inst.*, 448 U.S. 607 (1980).

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economic and political significance." *UARG v. EPA*, No. 12-1146 (2014), slip op. at 19 (internal citations and quotations omitted). In writing the opinion for the majority, Justice Scalia clarified that an interpretation that "would bring about an enormous and transformative expansion of EPA's regulatory authority without clear congressional authorization" is "unreasonable." *Id.*

a. EPA's approach to BSER relies on a "system" that encompasses entities beyond the control of regulated EGUs and extends to virtually every consumer in the country.

EPA's novel interpretation of "system of emission reduction" is unprecedented. The Agency's interpretation involves an expansion of regulatory authority from actions that can be taken at an individual EGU to reduce emissions at that unit to reach actions implemented far beyond the control of the unit owner, including actions that can only be taken by independent transmission and distribution operators or by end users at the other side of their electric outlet. This expansive reach fundamentally affects every element of the U.S. economy that utilizes electricity, from the utilities that generate the electricity all the way through to the end-user. Regardless of the merits of such transformation, there is no clear authorization from Congress for such an enormous expansion of EPA's regulatory reach under CAA section 111(d).

EPA's expansive approach to BSER would give the Agency not just unprecedented control over regulated EGUs and end-use customers, but over the entire interconnected power system and the myriad of actors that are involved in its operation and regulations, expanding EPA's authority dramatically. Such an increase in regulatory authority could not have been contemplated by Congress when it authorized EPA to determine BSER for a particular source category under CAA section 111.

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b. Congress did not intend for EPA authority to extend to every actor in the complex power system.

An inherent issue with EPA's system-based approach to defining BSER is that the Agency cannot define the interconnected power system to include only a small subset of entities that it feels it has the ability to regulate using CAA section 111(d) guidelines. EPA must take the system as it exists, not as it wants—and a wide-ranging BSER interpretation to cover the interconnected power system not only regulates affected units, but also serves to extend that authority over a much more complicated and less centralized structure than the proposed guidelines recognize.

The proposed guidelines incorrectly assume there is centralized operation and control of the interconnected power system in order to justify the approach to BSER. The fact that EGUs are interconnected to a network of transmission and distribution lines does not mean that they are centrally controlled. The nationwide electric grid is not under the control of individual EGU owners, nor is it even controllable by individual states.

Further, EPA's system-wide BSER interpretation does not account for the complexity of the interconnected power sector, despite relying upon that interconnected nature. Thousands of independent organizations run different parts of the electric grid. To begin with, there are three distinct large Interconnected Systems (Western, Eastern, Texas) and isolated systems in Hawai'i and Alaska. *See* FERC Primer at 49. The three Interconnections operate virtually independently, tied together only by a very limited ability for energy transfer between interconnections. Each interconnected electric power system functions as a large, dynamic machine extending over thousands of miles of bulk power facilities. Changes in any one portion

of the system run by one independent organization can instantly affect the operation of other portions of the system run by other independent organizations.

Almost three thousand different entities are involved in operating these electric systems. There are almost two thousand municipally owned systems, almost 900 cooperative utilities, about 60 investor-owned utilities and many independent generators and independent transmission companies, as well as federal and state electricity utilities involved in the business of generating, transmitting or delivering electricity. *See* FERC Primer at 40. There are more than two thousand different entities involved in the reliable operation of these electric systems. There are approximately 1,900 entities registered to perform reliability related services under NERC mandatory standards (including Canadian entities) and 184 entities registered to perform transmission operations.[216]

A large segment of the nation's utilities remain vertically integrated. This means the same entity owns and operates generation, transmission and distribution facilities and generates or purchases the electricity that it delivers to end-use customers. Some vertically integrated utilities operate in a single state, and a few larger companies operate in as many as 10 or more different states. Some other vertically integrated utilities serve customers in one state but own generation in more than one state. The vertically integrated electric utility model no longer exists in large portions of the United States, including some of our most populous states, such as California, New York and Texas. However, even where utilities are vertically integrated, they must interact and

[216] *See NERC Compliance Registration Summary* (Aug. 2014), http://www.nerc.com/pa/comp/Registration%20and%20Certification%20DL/NERC_Compliance_Registry_Matrix_Summary20140827.pdf. NERC's role is discussed further, *infra,* section IV.2.C.

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connect with the larger grid on a regional basis, and are themselves just one actor in the interconnected power system. Vertically integrated utilities still operate in the complex, decentralized and dynamic environment that is the interconnected power system.

Many of the organizations that combine to make each element of the interconnected system work are often legally separate from the EGUs that have traditionally been subject to EPA regulatory authority under the CAA. Many independent entities own and operate EGUs, but not transmission or distribution facilities. Numerous EGUs only sell electricity in wholesale markets and not to end-use customers. Conversely, as a result of varying state policies, many transmission and distribution companies no longer own EGUs and only deliver power sold by others to end-use customers or purchase power for delivery to customers from competitive bidders, which may or may not include affiliated EGUs. Patterns vary with each state.

Moreover, there are major parts of the power sector that not only are not under the control of owners of EGUs, they also largely are outside the control of states. For example, there currently are seven RTOs and ISOs that together serve about two-thirds of electricity consumers in the United States through the provision of transmission services and generation dispatch, transmission planning and real time operations and many other reliability and system support services. *See* FERC Primer at 42. RTOs and ISOs offer their services on behalf of member utilities that have agreed to have the RTO or ISO independently coordinate operation of their transmission facilities with those of the other member utilities in the RTO of ISO. States do not have regulatory authority over RTOs/ISOs regarding the provision of these services.

RTOs and ISOs also operate energy markets and some also operate capacity markets. RTOs and ISOs have FERC-approved governance structures. FERC specifically requires that RTOs and ISOs are not subject to the control of EGUs, transmission owners or customers. These RTOs and ISOs often have complex stakeholder governance processes and procedures for policy development, market rules and tariffs. With the exception of ERCOT, they are "public utilities" under the FPA and their rates, as well as the terms and conditions of the services they provide, are subject to regulation by FERC, not the states.

The RTOs and ISOs operate extremely complex control systems, which manage the dispatch of generating units pursuant to market rules intended to achieve competitive wholesale markets for electricity, provide transmission and reliability support services, and conduct transmission planning and real-time operations. Outside RTOs and ISOs, primarily in the West (outside of California) and the Southeast, some large utilities work together to serve similar functions, and coordinate their generation and transmission practices to promote trade and preserve reliability. *See* FERC Primer at 42. Utilities that provide these services themselves are subject to FERC and NERC requirements.

EPA's systems approach to defining BSER pulls in all of these separate entities by definition. However, the Agency has defined the interconnected power system to include only a small subset of entities that it believes it has the ability to regulate through CAA section 111(d). EPA's wide-ranging BSER interpretation to cover the interconnected power system extends its authority over a much more complicated and less centralized structure than the proposed

guidelines recognize. Congress did not cabin this wide-reaching authority within CAA section 111(d).

c. EPA's interpretation of BSER is unreasonable because EPA lacks the expertise needed to determine the best configuration of utility units.

The doctrine of *Chevron* deference is based largely on a presumption that Congress intended expert agencies, rather than generalist courts, to construe ambiguities in statutes. However, Congress should not lightly be presumed to have crafted a statute providing EPA authority to make determinations about the "best system" that require transformation of the electric sector in order to reduce emissions when EPA's expertise does not extend to the operation of the electric system. EPA is not the agency equipped to determine optimal electricity system design within the federal government.

While EPA addresses the power sector in many of its environmental rules, and has knowledge about emission control technologies usable at power plants, it is not the agency to which Congress has delegated the authority to regulate the electric system, let alone the authority to intentionally remake that system in the context of environmental regulation. As indicated previously, FERC is the primary federal regulator of interstate wholesale rates, terms and conditions of operating the interconnected bulk power system. However, reliability is so important that in 2005 Congress approved the establishment of an independent North American electric reliability organization (ultimately NERC) under the supervision of FERC. *See* FPA Section 215. NERC, together with eight regional reliability entities, develops reliability standards and conducts compliance and enforcement for the entire interconnected bulk power system. *See* FERC Primer at 49-50. NERC's mission is to ensure that the system is designed and operated to meet these reliability standards, which are mandatory and enforceable by FERC.

As previously discussed in section I.B., above, despite the fact that NERC outlined concerns about many of the Building Blocks before the proposed guidelines were issued, EPA did not consider those concerns. In fact, the proposed guidelines relegate the importance of NERC to a footnote. *See* 79 *Fed. Reg.* at 34,888 n.235. EPA's decision to ignore the dynamics of the interconnected bulk power system and the complexities of maintaining reliability demonstrates that the Agency's BSER analysis (and the resulting state goals) is not a realistic application of specific system-wide measures affecting the interconnected electric system. As discussed in section I.B., above, there are many different kinds of constraints in the bulk power system; different electricity generation technologies and the electrons they produce are not perfectly fungible.[217]

By interpreting BSER to include the entire interconnected power sector, EPA has set for itself an analytical and regulatory task beyond its expertise. EPA's failure to fully analyze the impacts that the four BSER Building Blocks would have on the system, individually and in combination, as outlined in section II., above, is a reflection of that fact.

3. Congress did not intend EPA authority to encroach on areas of traditional state jurisdiction of utility regulation and utility generation fuel choices.

The ordinary tools of statutory construction, including interpretive canons meant to limit federal encroachment on state authority, suggest that Congress would not have provided EPA authority

[217] While most constraints probably can be addressed given enough time and money, many fixes may involve construction of new generating units and natural gas pipelines or electric transmission or distribution facilities, which must go through complex and often contentious permitting processes beyond the control of any utility or generator, and, sometimes, not even in the control of an individual state. There is a long record of siting disputes, including those under federal agency jurisdiction, taking an excessively long time to complete.

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to determine the "best" mix of electric generating resources when that authority is already clearly vested with the states, nor would Congress have provided EPA with the authority to effectively veto the decisions of states to modify energy policies.

In developing BSER, EPA leans heavily on state policies that encourage new low-carbon resources, such as state RES policies and energy efficiency programs. *See* 79 *Fed. Reg.* at 34,887-88. In effect, EPA is actually defining the "system" of emission reduction as the state *policy* system. The proposed guidelines rely on the idea that if a state can introduce energy policy that will reduce emissions at EGUs, that policy can be part of the "system of emission reduction."[218] Defining the "system of emission reduction" to include the state policymaking system further expands the scope of "best system of emission reduction" to be one that is almost completely unconstrained. Creative state policies could "interconnect" any group of otherwise disparate entities in any sector and require fundamental changes to the structure of that sector. For example, in order to address emissions from a particular process, a state could tax the consumption of products (e.g., Portland cement) from that process and subsidize its substitutes (e.g., plastic construction materials). As discussed above, Congress has not given any indication that this expansive view is what it meant by the term "system of emission reduction."

EPA's involvement in state policy making is not merely hypothetical. While states will have the flexibility to design their plans in the first instance, EPA has proposed to require states to clear any changes to their plan with the Agency, including changes to energy-sector provisions such as

[218] *See id.* at 34,878 ("We believe the combination of all four *Building Blocks fairly represents the range of measures that states and the industry will consider* when developing state plans and strategies for reducing CO_2 emissions from affected EGUs")(emphasis added).

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renewable portfolio standards, EE investments, and integrated resource plans, if those provisions were included in the approved state plan. *See* 79 *Fed. Reg.* at 34,917. EPA will therefore effectively be able to exercise veto power over the decisions of state legislatures or regulators to modify electricity policies. This goes beyond ensuring emission reductions at individual facilities and involves EPA in state policy decision-making beyond what Congress can reasonably be presumed to have intended.

a. EPA may lack the authority to compel states to take actions consistent with its BSER determinations.

There is no indication that Congress intended to provide EPA regulatory authority under section 111 to compel action by utilities that are traditionally within the exclusive jurisdiction of state utility regulators and legislatures.

Courts have been reluctant to find ambiguity—or to determine that an agency's interpretation of its authorizing law is reasonable in the face of ambiguity—when the interpretation implicates the relationship between the federal and state governments. Consistent with the federalism canon of construction,[219] courts will look with skepticism on agency rules "where the administrative interpretation alters the federal-state framework by permitting federal encroachment upon a traditional state power." *Solid Waste Agency of N. Cook Cnty. V. U.S. Army Corps of Eng'rs*, 531 U.S. 159, 173.

Regulatory oversight of electricity generation—and particularly decisions regarding the development and use of generation and demand-side resources by state-regulated public

[219] *See, e.g.*, *Gregory v. Ashcroft,* 501 U.S. 452 (1990).

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utilities—is a traditional state function.[220] Yet, EPA's interpretation of "system of emission reduction" in the proposed guidelines assumes and effectively requires that states impose very significant changes on the current utility generation portfolios, which in many cases are developed and operated with direction and oversight from state PUCs. Furthermore, Building Block 4 involves a system of emission reduction reliant on application of federally-determined amounts of demand-side EE to reduce end-use electric sales.

EPA notes that achieving the state goals does not require the implementation of any particular measure; yet, the fact that EPA does not actually require states to implement Building Blocks 2, 3 and 4 does not lessen EPA's encroachment into traditional state regulatory functions. EPA's interpretation of "system" yields state goals for which compliance is not possible without a state's imposition of these kinds of electricity regulatory policies. Particularly, as here, where technologies to reduce emission rates at affected EGUs to levels required under state goals do not exist, the proposed guidelines effectively would require states to make fundamental changes to their electric systems. It is quite an expansion of EPA authority to determine the meaning of the phrase "BSER adequately demonstrated" when applied to existing units to allow EPA to

[220] *See New York v. FERC*, 535 U.S. 1, 24 (2002)(favorably citing FERC's identification of traditional areas of state authority to include "the authority over local service issues, including reliability of local service; *administration of integrated resource planning and utility buy-side and demand-side decisions*, including DSM [demand-side management]; *authority over utility generation and resource portfolios*; and authority to impose non-bypassable distribution or retail stranded cost charges.")(emphasis added); *see also Elec. Power Supply Ass'n v. FERC*, No. 11-486, slip op. at 9 (D.C. Cir. 2014) (citing *Niagara Mohawk Power Corp.*, 452 F.3d 822, 824 (D.C. Cir. 2006) ("States retain exclusive authority to regulate the retail [electric] market.")).

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compel states to require new unit construction, new dispatch patterns and new policies to change customers' approaches to using electricity.[221]

b. Congress could not have intended to give EPA authority under the CAA that it did not give to expert agencies that regulate the power sector's operation and reliability.

EPA's proposed BSER also impermissibly encroaches on exclusive state authorities to regulate the mix of in-state electric generation and the level of electric consumption without any clear Congressional authorization to do this. Congress has always been extremely careful and precise in delineating between areas of state and federal jurisdiction over utility rate matters and utility fuel and generation choices. Even expert federal energy regulatory agencies have only narrow and tightly controlled regulatory authority over the power sector, rather than the plenary authority that EPA is claiming under the CAA. Given this stingy and careful delegation, it is hard to imagine that Congress intended to give EPA authority to regulate the entire electric system by the use of the general term "system."

For example, the FPA vests FERC with jurisdiction over "public utilities" (a term that generally excludes publicly-owned utilities and rural electric cooperatives) to establish "just and reasonable" rates, terms and conditions regarding the sale at wholesale of electric energy in interstate commerce and transmission of electric energy in interstate commerce. *See* FPA sections 205 and 206. FERC specifically regulates the rates, terms and conditions under which the RTOs and ISOs offer service as well as other interstate transmission services.

[221] Consistent with the constitutional avoidance canon of statutory interpretation, courts have also been reluctant to approve agency interpretations of statutes that implicate constitutional questions. For the reasons discussed above, EPA's interpretation raises Tenth Amendment concerns and so may be viewed as an unreasonable interpretation of the term "system." The absence of clear evidence of Congressional intention to displace state authority raises substantial questions under the Tenth Amendment to the Constitution as well.

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However, the FPA specifically excludes from FERC jurisdiction authority over facilities used for the generation of electricity, facilities used in local distribution of electricity and facilities used only for transmission in intrastate commerce. *See id.* In short, FERC has no authority to order the construction of generation facilities, and has only very limited authority regarding construction of transmission facilities. With the exception of licensing hydro facilities, FERC also has no authority to address the siting of generation facilities.[222] *See* FPA section 4(e). DOE has virtually no regulatory authority over utility generating, dispatch or customer business practices outside emergency situations. *See* Section 202 of the FPA, delegated to DOE. DOE also has limited authority to try to expedite the siting of utility facilities on federal land or otherwise requiring a federal approval.[223] FPA section 216(h). DOE establishes efficiency standards for utility transformers and for many electric powered customer appliances, *see generally* Title III, Part B of the Energy Policy and Conservation Act of 1975, Pub. L. 94-163, but DOE has no authority to require the purchase and use of such equipment.

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[222] The limited grant to FERC of backstop siting authority in FPA Section 216 does not apply if a state simply denies a siting request. *See Piedmont Envtl. Council v. FERC*, 558 F.3d 304, 313 (4th Cir. 2009), and thus has been rendered ineffective. NRC regulates the safety of nuclear plants, but states retain considerable economic regulatory authority if they serve in-state customers rather than the wholesale market. *See, e.g., Pacific Gas & Elec. Co. v. State Energy Res. & Dev. Comm'n*, 461 U.S. 190, 213 (2008); *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 411 (2nd Cir. 2013).

[223] Many federal agencies have authority to regulate the siting of generation and transmission facilities over federal lands, and when nuclear and hydro plants are being built. *See* Memorandum of Understanding Among the U.S. Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Environmental Protection Agency, the Council on Environmental Quality, the Federal Energy Regulatory Commission, the Advisory Council on Historic Preservation, and Department of the Interior Regarding Coordination in Federal Agency Review of Electric Transmission Facilities on Federal Land (Oct. 23, 2009). FERC also has authority to approve siting of natural gas transmission facilities, which will be important to achieving some of EPA's proposals. Siting proposals are often highly contentious and can take extremely long periods of time to resolve, if they can be resolved at all. The important point to note is that no single agency has centralized and complete control over siting facilities. Each agency is constrained by its unique mission and its input to the process.

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On the other hand, states retain considerable authority over utility operations. State PUCs generally regulate the rates, terms and conditions of retail sales of power, unless the state has deregulated the retail price of energy. All states continue to regulate the terms and conditions of distribution service (i.e., the system used to deliver power from the transmission network to end use customers) and siting of utility facilities—both generation and delivery systems.

It is not reasonable to read the term "system of emission reduction" to provide EPA with regulatory authority that encroaches on the state's regulatory role when Congress has so significantly constrained and divided the authority it has delegated to even the expert federal energy regulatory agencies.

B. EPA's Interpretation of BSER to be the Reduction in the Use of Affected EGUs. EPA proposes an alternative justification for the consideration of outside-the-fence measures. In effect, the alternative justification of BSER considers reduced utilization of EGUs to be a "system of emission reduction." This novel approach raises a number of legal questions.

First, reduced utilization is not consistent with the commonly understood meaning of a performance standard. A performance standard is commonly understood to mean a limit on emissions *per unit input or per unit output*, rather than a limit on the use of a unit overall. Reduced utilization may result in lower total emissions from an affected EGU, but it would not constitute improvement in the *performance* of the EGU. It defies ordinary usage that a performance standard would be less performance.

This ordinary understanding of "standard of performance" is consistent with the Congressional intent on the types of requirements that EPA would impose on sources under section 111. The CAA was intended to reduce emissions, but was not intended to constrain the amount of national electric generation (or other useful economic activity), or to dictate underlying means of production. In discussing amendments to section 111 in the bill that would ultimately become the 1990 Clean Air Act Amendments, the U.S. House Energy and Commerce Committee clarified that "the effect of new standards will be to give units the flexibility to meet the emission *rates* established under the new standards."[224] 1990 CAA Legislative History at 3,414. The use of the term "*rate*"—which is to say emissions per unit of fuel input or useful output—is evidence that Congress did not intend that the "best system of emission reduction" would include reductions in utilization of sources, as EPA's proposed alternative BSER justification would require. In fact, the concept of a "standard of performance" including reduced utilization is not consistent with the relevant EPA definition specific to section 111(d) promulgated in the 1975 implementing regulations.[225]

Moreover, an interpretation of "system of emission reduction" that relies primarily on reduced utilization has no clear limiting principle. Under this interpretation, EPA would have authority to determine that entire sectors should reduce output—or retire—in order to reduce emissions. And, under EPA's interpretation, the statute would provide little check on the level of output

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[224] Note that the U.S. House Energy and Commerce Committee's language amending section 111(a) was ultimately enacted as part of the 1990 Amendments. *Compare* 1990 Legislative History at 3,155 *with* 1990 Amendments, 104 Stat. at 2,631 (section 403).

[225] *See* 40 C.F.R. § 60.21(f) (defining "emission standard" to be "an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions," none of which are at issue here under this interpretation).

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EPA could mandate. However, such sector-based planning clearly is not what Congress intended for an environmental regulator. As discussed above, Congress should not be assumed to have authorized broad regulatory authority hidden within section 111(a)(1).[226]

The Agency's citation to *other* provisions of the CAA that allow for reduced utilization or retirement as a means of compliance provides little support for EPA's authority to consider reduced utilization as the "best system of emission reduction." *See* Legal Memorandum at 83-85. In fact, at best it provides support that Congress could *not* have intended for "system of emission reduction" to include reduced utilization. Congress clearly knew how to explicitly authorize such a drastic emission reduction step if that is what it intended. *See generally* CAA sections 402(a) and 404(a). Consistent with the plain statement *Benzene* canon of construction, EPA should view section 111's failure to include such explicit authorization as evidence that Congress intended no such authority.

Finally, while the justification for this alternative interpretation of BSER is different than the primary interpretation, the outcome is the same: a determination of BSER that relies on actions at facilities other than EGUs, outside the control of owners of EGUs, and often only in response to some EPA-conceived state policy. Therefore, the tools of statutory construction described in section IV.A.**Error! Reference source not found.**, above, that raise questions about whether EPA's primary interpretation of BSER, based on measures beyond the control of EGUs, is

[226] *See also Whitman v. American Trucking Ass'n, Inc.*, 531 U.S. 457, 468 (2001) ("Congress, we have held, does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes.").

permissible under the text and statutory context of section 111(d) would apply to equal effect in evaluating the alternative BSER interpretation.

C. EPA's Justification that the Four BSER Building Blocks are Adequately Demonstrated or Achievable Either Individually or Collectively.

Even if the legal questions regarding EPA's broad systems-based interpretation of BSER as the combination of the four Building Blocks are answered in EPA's favor, the Agency has a statutory obligation to show that its BSER is "adequately demonstrated." *See* CAA section 111(a)(1). As discussed at length previously in Section II of these comments, EPA has assumed that it is sufficient to assert that the individual building blocks are adequately demonstrated. This does not satisfy EPA's requirement to show that its BSER determination is adequately demonstrated. Because EPA defined BSER to be the combination of the four Building Blocks, EPA has the burden of showing that such combination, at the emission reduction levels EPA asserts are possible, is technically feasible—and, more importantly, technically feasible while still assuring that the power sector can still meet its overarching obligation to provide reliable electricity to the public. EPA did not undertake this step, and instead simply added the estimated reductions achievable from the individual building blocks without assessing the impact of the BSER Building Blocks on each other or the interconnected power system.

The result is that EPA has set state goals that are not demonstrated to be achievable. EPA cannot have it both ways when it considers the interconnected power system: it cannot use the nature of the system to reach outside the affected fossil-based facilities in order to drive more stringent emission reduction targets, but then ignore the interconnected nature of that system by asserting that its BSER determination is adequately demonstrated as a technical matter without ever

assessing the impacts on the system. This raises legal questions as to whether the particular BSER EPA has proposed meets the statutory requirements under the CAA.

1. The proposed guidelines do not demonstrate that the four Building Blocks meet the legal criteria for BSER under section 111(a) because the Agency has not demonstrated the Building Blocks can achieve the proposed state goals when operated together as a system.

The proposed guidelines do not establish that the four Building Blocks achieve the proposed levels of emission reductions when taken together *as an integrated system*, and therefore EPA's proposal has not shown that EPA's BSER determination has been adequately demonstrated and reflects an appropriate consideration of the required statutory criteria. EPA, therefore, has not met its burden under the Act for determining that the combination of the four Building Blocks as BSER can achieve the proposed levels of emission reductions.

a. The proposed guidelines do not analyze the operation of the interconnected power system when evaluating each Building Block individually, overestimating the potential emissions reductions as a result.

Section II of these comments outline in significant depth the incorrect assumptions and unsupportable conclusions regarding the achievability, costs and energy impacts of each of the individual Building Blocks. Read together, these sections show that EPA has not met its obligation for each individual BSER Building Block given the actual real-world constraints and requirements of the electric system as it exists:

- EPA's analysis of Building Block 1 fails to account for causes outside of the control of EGU operators that impact heat rates; the impact that reduced load factor caused by the increased use of renewables will have on heat rates; the heat rate impacts of pollution control technologies installed to meet other environmental regulations; and expected post-2012 unit closures (when assessing fleet-wide heat rate improvement potential). It also fails to incorporate realistic cost estimates of fuel savings from heat rate improvements. *See* section II.B., above.

- EPA's analysis of Building Block 2 fails to account for natural gas pipeline infrastructure constraints and other gas-electric interdependency issues; the operation of competitive markets and principles of security-constrained economic dispatch; and physical,

technical, reliability and financial constraints of the gas and electric systems, among other technical obstacles to increasing the utilization of existing NGCC units to 70 percent. *See* section II.C., above.

- The renewable energy component of Building Block 3 fails to account for the fact that many state RES policies are founded on political considerations rather than on technical determinations of resource potential; does not sufficiently address the technical grid management challenges associated with increased penetration of renewables; and fails to fully account for the reliability impacts that can be introduced by variable renewable resources. *See* section II.D., above.

- EPA's analysis regarding the level of achievable end-use energy efficiency under Building Block 4 fails to account for funding and cost recovery constraints on utility-run energy efficiency programs; time constraints in implementing new energy efficiency programs needed to bring a state's annual incremental savings to 1.5 percent; and the "pinching" effect of codes and standards on achievable EE savings rates. *See* section II.E., above.

The Agency must demonstrate that the level of emission reductions it believes are achievable by the states can be achieved when its four Building Blocks operate concurrently as part of the interconnected power system. It is clear that, given the interconnected nature of the power system, the emission reductions EPA assumes are achievable by each individual Building Block might not be technically feasible given the complex interactions that exist between each of these Building Blocks as part of that same interconnected system. By pursuing an additive approach to calculate the emission reductions available from individual Building Blocks outside the context of the interconnected power system, EPA has not demonstrated the reductions its claims are available are achievable, as required by CAA section 111(a)(1).

b. The legal criteria must be satisfied with respect to BSER when combined, not merely as discrete measures.

The statutory text of CAA section 111 makes clear that EPA's obligations to make findings with respect to emission reductions, adequate demonstration, costs, nonair environmental impacts and energy requirements is an obligation to make findings with respect to the best system of emission

reduction and not merely with respect to the emission limitation that, in the case of this rule, constitutes the state goals. *See* CAA section 111(a)(1).

Further, while the section 111(a) definition of "standard of performance" specifies that the emission limitation must be "achievable," *see* CAA section 111(a)(1) (defining standard of performance as a "standard for emissions of air pollutants which reflects the degree of emission limitation achievable…"), the limitation must be "achievable" by the regulated source "*through application of*" BSER. *Id.* That is, in order to set the emission limitation, EPA must make a finding about the achievability of that limitation specific to the system of emission reduction it uses to set that limitation. The Agency must show that the limitation (the state-specific emission rate goal) is achievable using the particular BSER measures EPA has identified when combined as an integrated system. Therefore, achievability as an integrated system is an additional requirement for which the Agency *must* make an affirmative finding when broadly defining BSER on a system-wide basis. EPA must also provide the requisite analysis to support that finding.

However, in the very section of the proposed guidelines justifying BSER as the combination of the four Building Blocks, EPA primarily argues that the *state goals* meet the relevant criteria.[227] In so doing, EPA relies significantly on the flexibility it has provided to states by imposing only an emission goal and allowing the state to tailor application of emission reduction measures

[227] *See* 79 *Fed. Reg.* at 34,885 ("*The analysis the EPA performed* to assess the costs, benefits, and other impacts *of the proposed goals*...indicate that *the proposed state goals are readily achievable* with no adverse impacts on electricity system reliability, and that impacts on retail electricity prices are modest…")(emphasis added).

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including but not limited to those that make up BSER.[228] State flexibility to implement the emission limitation through other means is important, but cannot be a shield against insufficient analysis of the proposed BSER measures used to set the emission goal in being able to meet that goal for affected units or on a statewide basis. In every section 111 rulemaking, regulated units clearly have the flexibility to take measures other than the specific BSER technology EPA has determined is adequately demonstrated, and EPA cannot bar states from taking verifiable, demonstrable and innovative measures to achieve reductions. It is EPA's responsibility, however, to evaluate the proposed BSER against the statutory criteria and determine that the BSER meets the statutory criteria. EPA has not done so in the proposed guidelines.

c. The proposed guidelines do not evaluate whether the combination of the four Building Blocks meets the BSER criteria.

EPA's proposed guidelines fail to adequately *consider* whether these Building Blocks work together as a *system* of emission reduction that is compatible with the technical, cost-effective, and reliable operation of the interconnected electric system. The proposed guidelines contain two short and largely repetitive sections ostensibly considering various combinations of the BSER blocks together. *See* 79 *Fed. Reg.* at 34,877-78 and 85. However the discussion of these combinations is not sufficient. There is no analysis of the interactive effects of each of the Building Blocks when implemented together, nor is there analysis of changes in the cost of reductions or electric reliability impacts when the Building Blocks are combined.

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[228] *See* 79 *Fed. Reg.* at 34,885 ("[T]he flexibility available to states and regulated entities to rely more extensively in their plans and strategies on whichever measures best suit their particular circumstances will further improve cost effectiveness. The analysis the EPA performed…

reflects this compliance flexibility…Further, the costs tend to decline over time as states and regulated entities *take advantage of the available flexibility*….")(emphasis added).

As discussed above, EPA assumes that each state can simultaneously expand significantly the usage of existing and under construction NGCC units, generate an increased quantity of electricity from renewable and nuclear power units, and avoid demand for electricity generation through end-use energy efficiency programs as part of BSER. That is, in calculating each state's goal as a combination of the Building Blocks, EPA has made implicit assumptions about the pace and timing of the future transformation of the electric system without considering practical constraints such as reliability obligations, natural gas pipeline capacity limits, competing demands from consumers for natural gas during the winter, delays in approving needed transmission infrastructure, among other practical considerations in implementing the proposed system.

As courts reviewing EPA actions have explained, "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule rests with the Agency…. [B]y failing to explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated, the Agency [will have] not satisfied this initial burden."[229] This determination cannot be a "crystal ball inquiry."[230]

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[229] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980). Note that because BSER has always been determined based on a technological standard, there is little precedent as to what a court will consider sufficient to justify that a system of emission reduction constituting actions taken outside of affected EGUs is feasible, adequately demonstrated and reasonably costly. It would be reasonable for a court to require a more significant showing or analysis from EPA given that there is no particular technology—deployed or modeled— to which EPA can point.

[230] *Int'l Harvester Co. v. EPA*, 478 F.2d 615, 629 (D.C. Cir. 1973).

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Yet, the EPA's justifications for its interpretation that the four Building Blocks, taken together, constitute the "best…adequately demonstrated" system that achieves the reductions proposed by the Agency are cursory.[231] By expanding BSER to include a system-wide basis for regulation and determining potential reductions from fossil-based units, EPA commits itself to demonstrating that its BSER determination works in the context of that interconnected system. EPA has not done so, and the Agency's determination, therefore, is not consistent with the statutory criteria of adequate demonstration, technical feasibility, costs, emission reductions and reliability concerns for finding a system to be BSER.

D. The Creation of a State-Focused Regulatory Scheme.

EPA's imposition of state-wide goals, rather than source-specific emission standards, is inconsistent with CAA section 111(d) and EPA's own implementing regulations. By setting state-wide goals without reference to particular sources of emissions, the proposed guidelines stray from the source-focused structure of section 111.

1. The text of section 111(d) clearly authorizes the regulation of sources, not states.

Section 111(d) requires states to "establish[ ] standards of performance for any existing [stationary] source." *See* CAA section 111(d)(1)(A). Section 111 defines "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." *See* CAA section 111(a)(3). Section 111 contains numerous other references to *sources*, and section 111(d) also requires the EPA and the states to consider the "remaining useful lives" of regulated sources in promulgating standards.

[231] *See* 79 *Fed. Reg.* at 34885 (asserting that because Building Blocks 3 and 4 are achievable at reasonable cost, the combination of Building Blocks 1, 2, 3, and 4 would be achievable at lower cost than just Building Blocks 1 and 2).

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In analyzing the section's structure, it is useful to view the initial portion of section 111(d)(1) with the applicable definitions fully interposed:

> each State shall submit to the Administrator a plan which
>
> (A) establishes [*a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated*][232] for any [*building, structure, facility, or installation*] [*other than a new source*][233] [*which emits or may emit any air pollutant*][234] for any air pollutant…

The full text suggests that standards promulgated under 111(d) must consider both "the degree of emission limitation achievable" as well as "the best system of emission reduction" for *any existing stationary source*.

Additionally, EPA advanced a source-oriented interpretation of the statute in its implementing regulations, which provide that the Agency will issue guidance on the best system of emission reduction adequately demonstrated "for designated facilities," and that EPA will consider "sizes, types, and classes of designated facilities," in setting guidelines for state plan development. *See* 40 C.F.R. § 60.22(b).

However, the proposed guidelines deviate from this source-based framework by basing standards entirely upon the state in which an affected EGU is located, rather than the attributes of any

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[232] This inserts the *full* definition of "standard of performance" into the context of section 111(d)(1).

[233] This inserts the *full* definition of "existing source" into the context of section 111(d)(1).

[234] This inserts the *full* definition of "stationary source" into the context of section 111(d)(1).

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specific source. EPA states as much, noting that "the EPA sets out proposed state-specific CO_2 emission performance goals," but that "the EPA's guidelines contain no emission standards that the state must apply directly to a specific EGU." *See* 79 *Fed. Reg.* at 34,892 and 34,925. This is a questionable approach in light of the structure of the statute, as well as EPA's prior interpretation of it in the implementing regulations. Nothing in section 111(d) clearly authorizes EPA to set emission goals based upon a large, heterogeneous set of units aggregated across a state. Instead, for EPA to regulate CO_2 emissions (or emissions of any other type of pollutant) from existing sources, the regulations should be based on the sources themselves—and on a standard of performance attainable by implementing measures at those sources—rather than an aggregation of sources that happen to be within a particular state.

2. The cross-reference in section 111(d) to section 110 does not provide EPA a statutory basis to use state-based instead of source-based goals.

Section 111(d) instructs EPA to "prescribe regulations which shall establish a *procedure* similar to that provided by [Section 110] … under which" states submit plans to EPA establishing standards of performance for existing sources for criteria air pollutants and providing for the implementation and enforcement of those standards. This cross-reference to section 110 does not form a statutory basis for the establishment of state-based, instead of source-based, emission limitations in the proposed guidelines.

Section 110 governs state plans for achieving the National Ambient Air Quality Standards (NAAQS). However, section 110 does not itself provide the basis for establishment of the NAAQS. Rather, it is section 109 that provides that foundation of authority. In other words, section 110 outlines the procedures and authorities of the states in meeting an emission limitation that is established under the auspices of a separate section of the statute. Section 110 prescribes

the scope of state planning authorities in meeting the substantive limitation established by EPA under section 109.

Accordingly, when Congress included a cross-reference to the "procedure" of section 110, it intended to harness the state-based planning process of section 110; it did not intend also to establish the scope of EPA's substantive authority to set the emission limitation that a state plan must achieve. Rather, the scope of the authority to set an emission limitation is provided by the rest of section 111, which, as discussed above, clearly contemplates the application of standards of performance *for sources.* In this way, section 111 is distinct from section 109, which contemplates ambient air quality standards, without regard to particular sources.

For these reasons, it is not valid to read the section 111(d) cross-reference to section 110 as authority for EPA to impose state-based emission limitations.

3. EPA has not sufficiently shown that the proposed BSER meets the legal criteria on a state-specific basis.

EPA has not made any findings that the particular BSER mix used to set each state-specific emission limitation is achievable, demonstrated, cost-effective, and considers energy impacts specific to any of the states. For example, EPA has not conducted a state-by-state cost analysis of the Building Blocks for the proposed guidelines, nor has EPA conducted a state-by-state reliability analysis. EPA's analyses are mostly national and at best regional.

EPA highlights the fact that BSER in the context of section 111(b) has been interpreted such that EPA need only find that the system is achievable for some sources; it need not find that it is achievable for every source. *See* Legal Memorandum at 39-40. EPA argues this approach

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should be applied to the BSER determination under section 111(d) based on the Clean Air Act's discussion of a state's ability to take into account a source's remaining useful life. The proposed guidelines, however, draws the wrong analogy. Even if EPA need not show that BSER is achievable for every *source,* EPA has not set source-specific standards in this rule. Instead, it has determined BSER on a *statewide basis.* Yet EPA has not demonstrated that the particular mix of BSER Building Blocks is achievable for every *state*. In fact, EPA has effectively conceded that the BSER Building Blocks may *not* be achievable by a particular state. *See* 79 *Fed. Reg.* at 34,893.

This approach raises legal questions particularly *because* EPA has established a BSER methodology that sets state-specific emission rates. EPA is, in effect, claiming that while the rate was set based on the particular state's circumstances, it need not evaluate whether those circumstances *actually* are consistent with the mix of Building Blocks the EPA has determined are achievable. The proposed guidelines do not establish that the four Building Blocks can be implemented together as an achievable, adequately demonstrated, cost-effective "system" for each state.

E. Regulation of a Source Category under CAA Section 111(d) and Section 112.

EPA's authority to regulate CO_2 emissions from existing EGUs relies on CAA section 111(d) of the Clean Air Act, the operative text of which is unclear. Correspondingly, in its Legal Memorandum accompanying the proposed guidelines, EPA itself identifies a significant risk that the regulation of EGUs under CAA section 112 makes section 111(d) unavailable as a tool for regulating that same source category. *See* Legal Memorandum at 98.

Section 111(d) as codified in the U.S. Code provides authority to EPA to require states to establish standards of performance for:

> any existing source for any air pollutant for which air quality criteria have not been issued or which is not included on a list published under section 108(a) [for criteria air pollutants] *or emitted from a source category which is regulated under section 112 of this title…*

See 42 U.S.C. § 7411(d) (emphasis added). While CO_2 is not an air pollutant listed under CAA section 108, it *is* emitted by EGUs, a source category regulated under section 112 (pertaining to hazardous air pollutants).[235] On its face, this would prevent EPA from regulating CO_2 emissions from EGUs under section 111 (EPA refers to this reading as the "Section 112 Exclusion"); however, EPA argues that the text of section 111(d) as codified in the U.S. Code is an incomplete reflection of the applicable law.

When section 111(d) was amended as part of the 1990 Clean Air Act Amendments, two amendments to section 111(d) were included in the final bill passed by Congress and signed by President Bush. One, from the House bill, is at section 108(g) of the 1990 Amendments. This amendment is codified in the U.S. Code. The second amendment, from the Senate bill, is at section 302(a) of the 1990 Amendments. The second amendment, which is uncodified, would only bar the use of section 111(d) for *pollutants* that are included on a list of hazardous air pollutants at section 112(b). Because CO_2 is not included on the list of hazardous air pollutants at section 112(b), EPA argues that this second, uncodified amendment would not prevent EPA from regulating CO_2 from EGUs using section 111(d).

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[235] *See National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, 77 Fed. Reg. 9,304 (Feb. 16, 2012).

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EPA claims that the fact both amendments were included in the final bill requires the Agency to harmonize the amendments and provides it sufficient discretion to interpret the law to allow regulation of GHGs from power plants under section 111(d). Moreover, the Legal Memorandum asserts that the inclusion of two conflicting amendments creates an ambiguity such that the agency is permitted to "reasonably construe the Section 112 Exclusion to authorize the regulation of GHGs under section 111(d)." *See* Legal Memorandum at 23.

EPA's confidence that both amendments must be given legal effect is misplaced. While substantive conflicts within a statute should be harmonized, it is not clear that both the amendment in section 108(g) and the amendment in section 302(a) are substantive. The amendment originating in the House is contained in section 108 of the 1990 Amendments with a collection of substantive amendments titled "Miscellaneous Provisions." This is contrasted to section 109, which is titled "Conforming Amendments." The amendment originating in the Senate is contained at section 302, titled "Conforming Amendments." A mere conforming amendment does not have true substantive effect, and so it should not be given equal weight to the clearly substantive amendment at section 108.

The reading giving effect to only the House amendment is, in fact, supported by EPA's initial interpretation of this statutory issue years ago. In 1994, in a supporting document on regulation of Municipal Solid Waste Landfills under section 111(d), EPA had its first opportunity to interpret the amendments and determined that "section 108(g) is the correct amendment."[236] The

[236] EPA, Air Emissions from Municipal Solid Waste Landfills – Background Information for Final Standards and Guidelines, Pub. No. EPA-453/R-94-021, at 1-5 (1994).

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Agency reasoned that section 302(a) was intended merely as a "simple substitution of one subsection citation for another, without consideration of other amendments of the section…."[237] In other words, EPA prioritized the section 108(g) amendment over the section 302(a) amendment.

However, even if the appropriate treatment of two amendments to the same section is to attempt to read them together, it is also not clear that EPA's reading is reasonable. Each amendment could be read as intended to place a specific *limit* on the scope of section 111(d). When read together, therefore, it is only reasonable that they should each be viewed as placing independent limits on section 111(d). The reading advanced by the Agency, however, reads the two amendments together to *expand* the scope of section 111(d) beyond what either of the individual amendments would have allowed individually. In short, EPA reads the amendments in such a way that if a pollutant is on the section 112 pollutant list *and* the relevant category is regulated under section 112 that only then will the Section 112 Exclusion apply. Congress quite clearly did not intend to limit the effect of either amendment, and so any reasonable harmonization must read each as independent exclusions.

There is no affirmative judicial precedent on if and how the conflicting amendments to section 111(d) should be harmonized,[238] nor any clear precedent as to how to treat conflicting

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[237] *Id.*

[238] EPA cites Supreme Court decisions in *Massachusetts v. EPA,* 549 U.S. 497 (2007), and *Am. Elec. Power v. Conn.*, 131 S.Ct. 2527 (2011), in support of its authority to issue this regulation. Neither opinion contains a holding clearly resolving this issue. Moreover, both opinions were issued before EPA's regulation of EGUs under section 112 and so were not required to consider the impact of the Section 112 Exclusion on the applicability of section 111(d).

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amendments generally. Thus, significant legal questions remain regarding EPA's authority to issue the proposed guidelines in the first instance.

Appendix A

NERC's Potential Reliability Impacts of EPA's Proposed Clean Power Plan

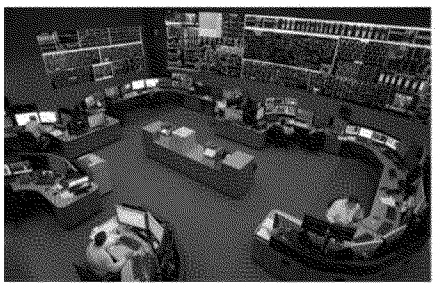
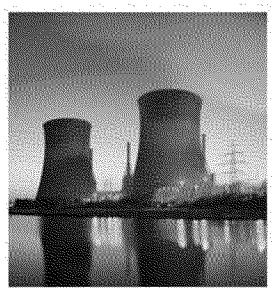
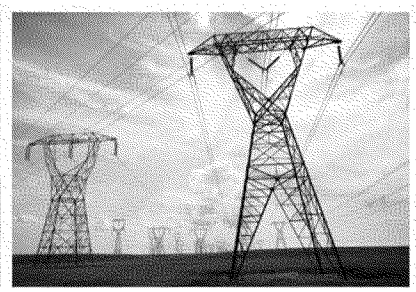
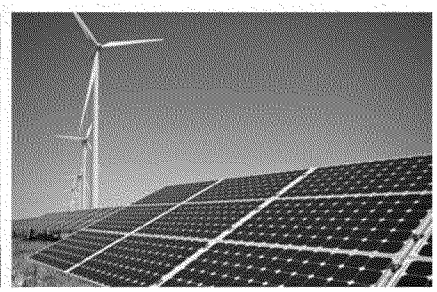
November 2014

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Initial Reliability Review
November 2014

RELIABILITY | ACCOUNTABILITY

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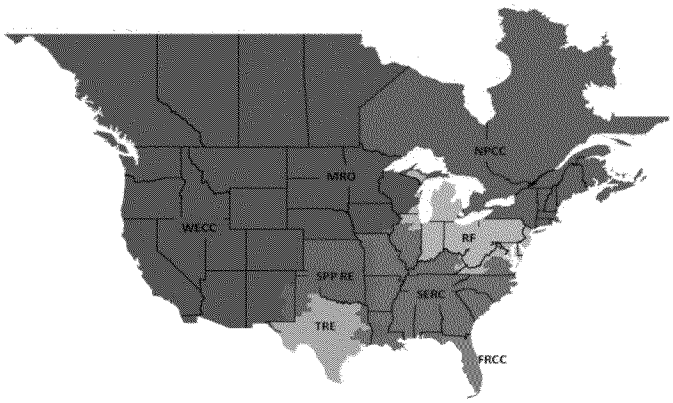
Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

NERC Regions and Assessment Areas



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards -setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

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Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- Provide an evaluation and comparison of the assumptions supporting the CO_2 reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO_2 emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:[3]

Building Block 1: Heat rate improvements
Building Block 2: Dispatch changes among affected electric generating units (EGUs)
Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

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Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO_2 reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).[4] The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While

[4] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

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the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC's initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach** that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins
The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints
The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country's resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP
Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance
The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a "reliability back-stop." These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power
Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services
ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)
ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

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Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC's plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA's proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

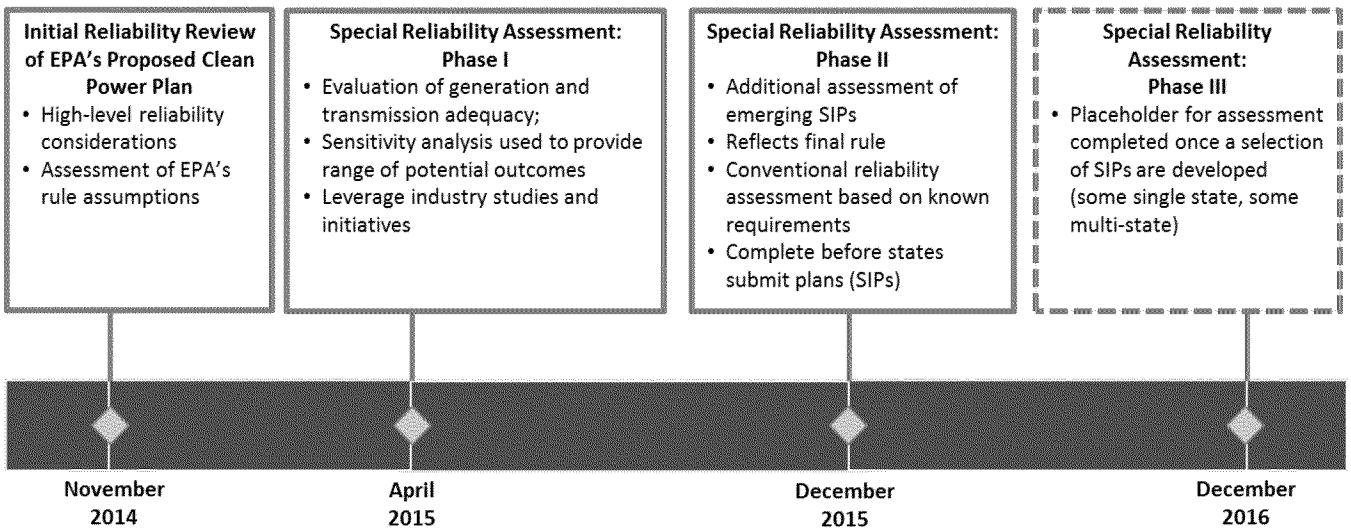

Figure 1. NERC's Assessment Actions and Schedule Timeline

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Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO_2 emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO_2 reductions are required under State Implementation Plans. Under the EPA proposal, CO_2 reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).[5]

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;[6] (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[7] Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.[8] NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO_2 from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO_2 and protecting public health and the environment.[9]

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO_2 reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO_2 reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

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[5] State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

[6] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

[7] 79 FR 34854 https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating page 34854.

[8] EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

[9] EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector "*The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans.*" http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-benefits.pdf.

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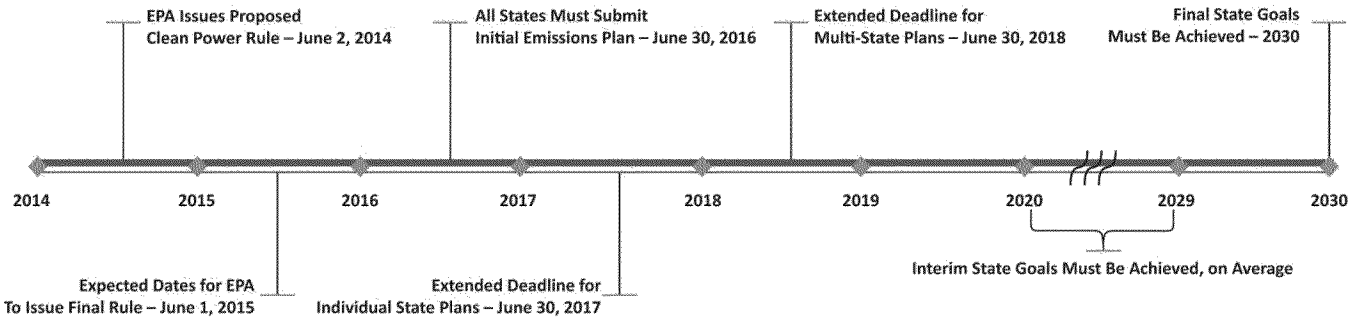

Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state's specific information, yielding a carbon intensity rate for each state.[10] There is a wide range of potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

EPA's Proposed Clean Power Plan: Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2: Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO_2 by applying four different BSER Building Blocks.[11] Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

[10] EPA Fact Sheet: Clean Power Plan - National Framework for States.

[11] EPA Clean Air Act: Section 111(d) authorizes EPA to apply "best system of emission reduction" to this section's affected sources.

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The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Renewable Energy

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

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Clean Power Plan – Assumption Review

This section provides a critical review of the EPA's assumptions for state-specific CO_2 emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

Plant Efficiency

The EPA's heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.[12] The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA's assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO_2 emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:[13] (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.[14] Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet's average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO_2 reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

[12] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.
[13] These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).
[14] Coal-Fired Power Plant Heat Rate Reductions (January 2009).

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Building Block 2 – Gas Unit Re-Dispatching

Natural Gas

The EPA assumes that reductions in CO_2 emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than $33/metric ton CO_2.[15] In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.[16]

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA's Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO_2 emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an "all-hazards" approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.[17] When including the 54 GW of nameplate coal capacity already announced to retire by 2020[18] (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources.

As observed during the 2014 polar vortex,[19] the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

[15] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.

[16] Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation.

[17] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).

[18] Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.

[19] NERC 2014 Polar Vortex Review: http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

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Fuel Supply and Delivery

- Natural gas interruptions
  - supply injection
  - compressor outages
  - one pipeline explosion
- Oil delivery problems
- Inability to procure gas
- Fuel oil gelling

Extended Low Temperatures

- Low temperature limits for wind turbines
- Icing on hydro units
- Failed auxiliary equipment
- Stress of extended run times
- Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors)

Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

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Building Block 3 – Clean Energy

Renewable Energy

Building Block 3 describes the EPA's method to reduce CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state's nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO_2 emission rate goal calculations.[20] The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO_2 reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA's assumed non-hydro renewable generation in a given state, the lower the state's calculated CO_2 emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.[21] The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA's *Regulatory Impacts Assessment* (356 TWh/year by 2030).[22]

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[23] RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps "to compare RPS policies on equal footing."[24] To determine the state effective levels in 2020, the EPA added each state's tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS "type" considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region's aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast's target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining "the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

[20] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.
[21] *Annual Energy Outlook 2013* (EIA April 2013) reference case data.
[22] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.
[23] http://www.dsireusa.org/.
[24] DSIRE. DSIRE RPS Field Definitions. April 2011. http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf p.1.

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region's historic (2012) generation to reach that region's RE target"[25] by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include: hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.[26] According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.[27] New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO_2 emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.[28] Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.
- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.
- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.
- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

[25] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.
[26] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.
[27] http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf.
[28] DSIRE http://www.dsireusa.org/.

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these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,[29] needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[30] as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO_2 reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.
- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.
- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

[29] See NERC's Essential Reliability Services Task Force website for more information: http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[30] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

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Building Block 4 – Energy Efficiency

Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO_2 emissions. In calculating individual state CO_2 emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.[31] The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.[32] Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.[33] Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.[34] Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

[31] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.
[32] Electric Power Research Institute (EPRI) and EIA.
[33] *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).
[34] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

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The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are "breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,"[35] yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies' sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA's AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA's AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA's assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

[35] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

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By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO_2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.[36]

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO_2 reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[36] *NERC 2014 Long-Term Reliability Assessment.*

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Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP's Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

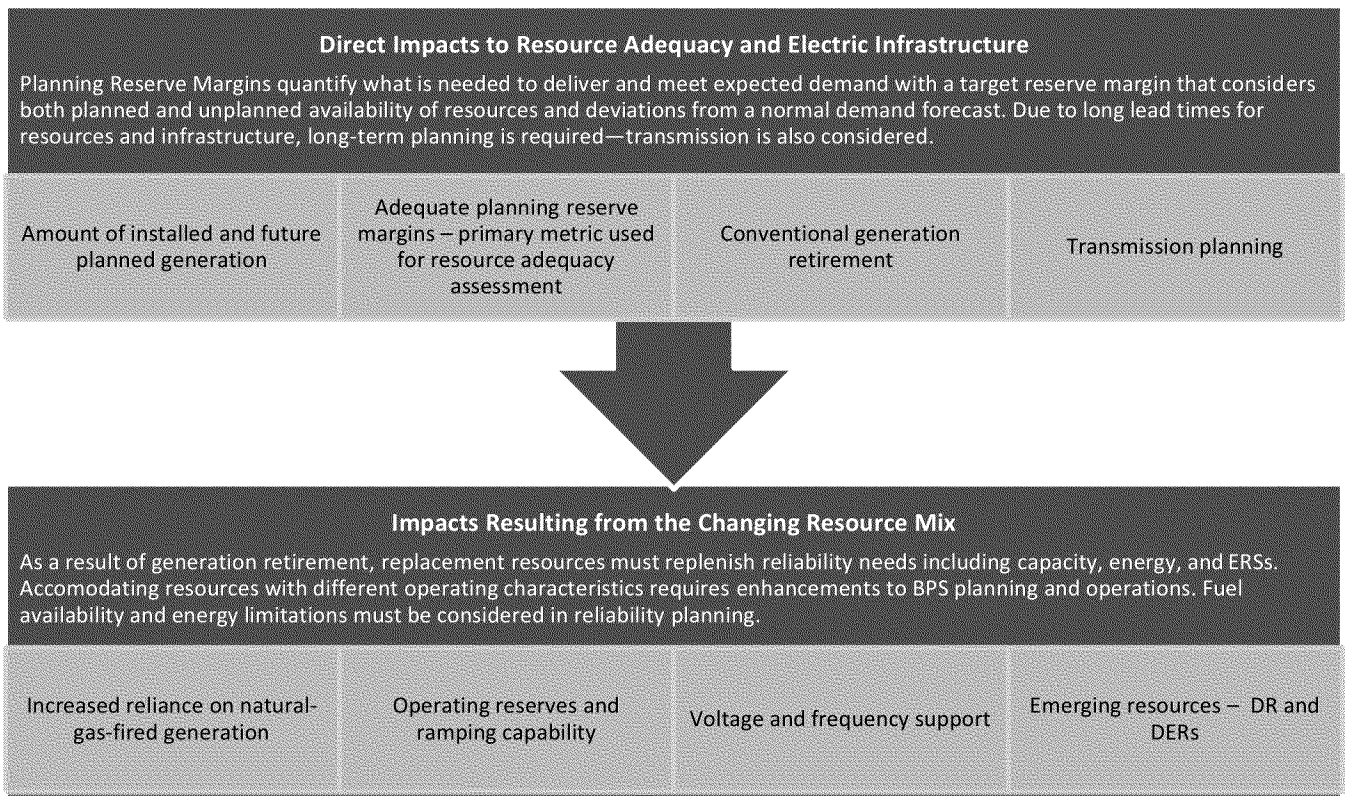

Figure 4. Summarized Reliability Challenges

Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area's Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the

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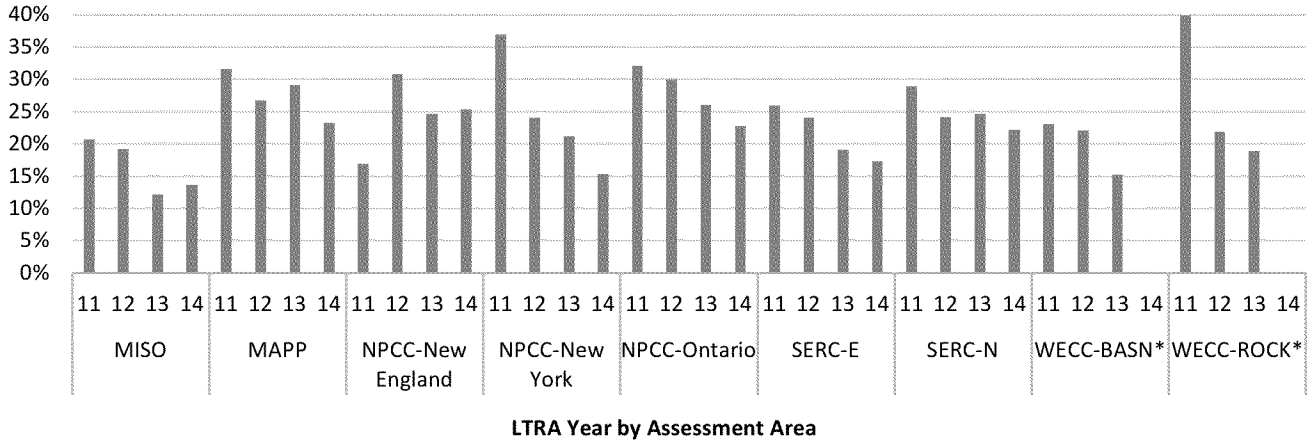
residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing decline in load growth rates (Figure 6).[37]



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

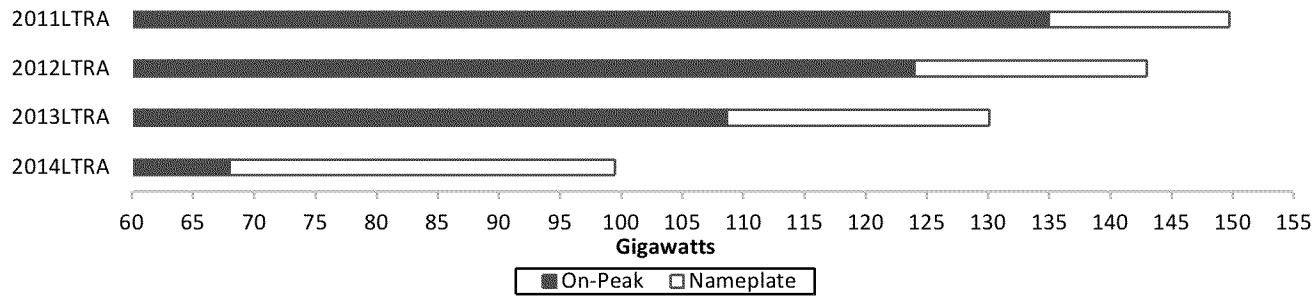


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA's supporting documents estimate that up to 19 percent of the nation's coal plants will become "uneconomical" as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into *2014 LTRA* and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis,* the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.[38]

[37] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[38] EPA Technical Support Document –Resource Adequacy and Reliability Analysis http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf.

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The EPA's analysis assumes the electric system will maintain resource adequacy, even with the ongoingretirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will beneeded to support these new resources. The EPA's modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA's base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA's base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the *2014LTRA* reference case. According to the *2014LTRA* reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[39] These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (Figure 7).

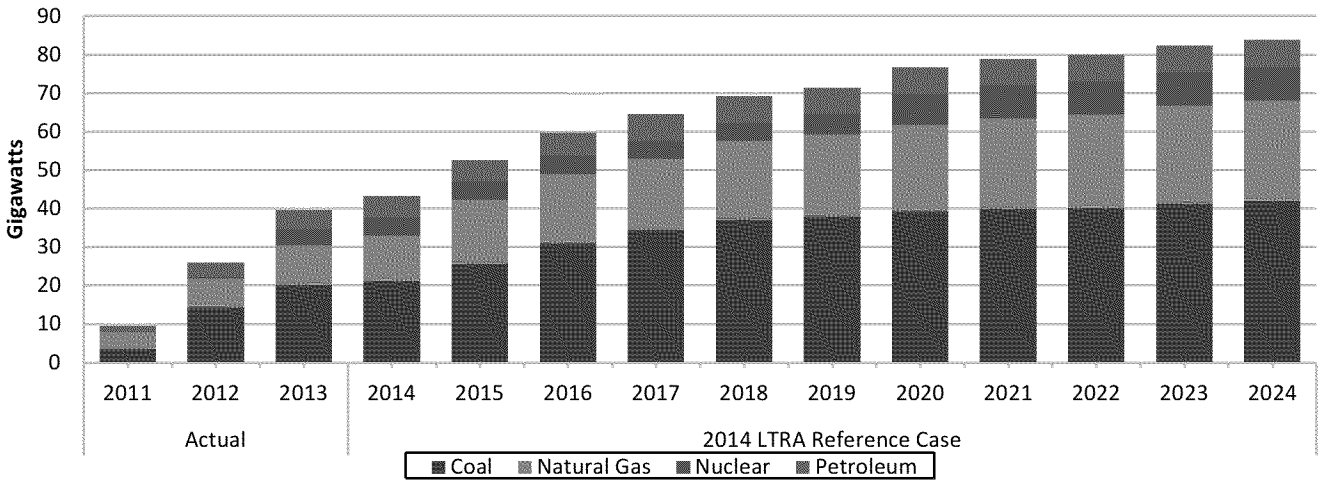

Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result ina reduction in coal to 193 GW by 2025. Option 1 and the *2014LTRA* reference case are shown in Figure 8 and Table 2.[40]

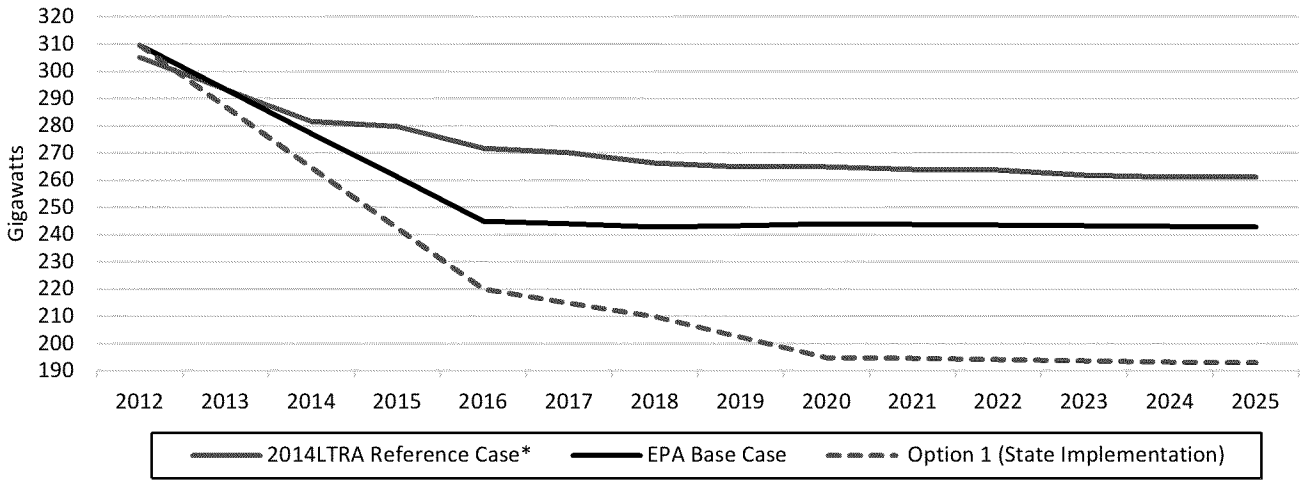

Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

[39] While the assessment period for the *2014LTRA* is 2015–2024, projected retirements for 2014 are included in NERC's *2014LTRA* analysis.

[40] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

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Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

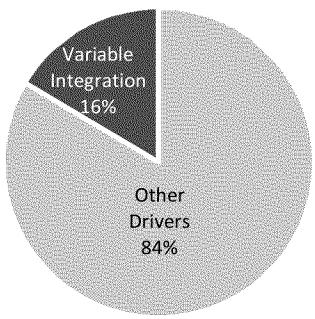
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take muchlonger than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[41] Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies.The transmission planning process will not be able to fully incorporate the impacts of potential retirements until thoseresource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

[41] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

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NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in in 2016 it will operate at the reliability level of approximately 2-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.[42] Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.[43] The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[44]
- Increased exports to PJM and the removal of non-Firm imports[45]
- Inadequate Tier 1 capacity additions[46]

[42] Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.

[43] MISO GHG Regulation Impact Analysis – Initial Study Results.

[44] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[45] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[46] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

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SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.[47] The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

[47] SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule http://www.spp.org/publications/SPC%20Materials%20081914.pdf.

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Direct Impacts to Resource Adequacy and Electric Infrastructure Summary and Recommendations

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

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Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.[48] The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[49]

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity[50]

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gasfired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.[51] This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

[48] See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: Phase I and Phase II.

[49] Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

[50] Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment*.

[51] NERC Polar Vortex Review Report http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

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While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.[52] Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[53] as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.[54]

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by $1/MWh to $18/MWh under the CPP[55] as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.[56] As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

[52] Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

[53] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D)

[54] NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[55] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

[56] According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040, this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. 2014 Annual Energy Outlook.

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- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
• Specific generator retirement studies • Specific generator interconnection studies • Specific generator operating parameters • Power flow (thermal, voltage) • Stability and voltage security • Offsite power for nuclear facilities	• Resource adequacy • Power flow (regional) • Stability and voltage security (regional) • Gas interdependencies; pipeline constraints • Operating reserves and ramping • System restoration/blackstart

Impacts Resulting from the Changing Resource Mix
Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

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Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop specialreliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impactsof the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with theindustry and states as they develop their implementation plans.

Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**
   The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**
   Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, includingresource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achievingthe EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**
   NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

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Appendix B

Excerpt from EEI's Comments in Docket No. EPA-HQ-OAR-2013-0603 filed October 16, 2014, regarding applicability

Standards of Performance for Carbon Dioxide Emissions from Modified and Reconstructed Stationary Sources: Electric Utility Generating Units

79 *Fed. Reg.* 34,960 (June 18, 2014)

V. EPA Proposes Changes to Applicability Requirements and Emission Standards that Would Have Implications for Both New and Existing Requirements That Must Be Carefully Considered

In the January 2014 proposal addressing GHG standards for new fossil-based EGUs, EPA proposed four changes to the applicability requirements for new units relative to the existing regulations under Subpart Da and KKKK. *See* 79 *Fed. Reg.* at 1,459. EEI submitted comments on the proposed changes, with particular focus on the proposed one-third sales test criterion for CTs. *See* EEI May 9 Comments, Appendix A at 79-94.

As described below, in this proposed rule for modified and reconstructed sources, it appears that EPA is proposing to modify further the proposed applicability requirements for all steam EGUs and CTs to determine if they are subject to GHG standards under subpart Da or KKKK, respectively, or, possibly under the new combined subcategory under subparts TTTT and UUUU. It also appears that EPA's proposed changes to the applicability requirements would affect not only new units and modified and reconstructed units that may subject to 111(b) standards but also existing units that may be subject to 111(d) units.

A. EPA's Proposed Changes to the Applicability Requirements for Subpart Da Units Should Not Subject Limited-Use Oil-Based Units or Biomass Units to Regulation under CAA section 111(d).

EPA states that "to clarify that existing boiler and IGCC facilities would continue to be included in CAA section 111(d) state programs regardless of their actual electric sales or fossil fuel use" the Agency is deleting certain applicability requirements for these units. 79 *Fed. Reg.* at 34,979. These include the requirement that a unit actually sell one-third of its potential electrical output and 219,000 MWh on an annual basis and the exemption for facilities that burn fossil fuel for 10

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percent or less of their heat input. *See id.* Accordingly, it appears that EPA intends for the same requirements to govern the applicability of standards affecting existing units under section 111(d) **and** existing units that undertake modification and reconstruction under section 111(b).[1] EPA's proposed changes to the applicability requirements must be addressed in the context of the current proposal.[2] In particular, EPA's efforts to harmonize the applicability requirements for both types of emission standards raise concerns about the appropriate regulation of limited-use, oil-based units and biomass-based units under both sections 111(b) and (d).

The comments that follow focus on the implications of the proposed change to the applicability requirements for units that may be subject to regulation under 111(d). EPA should create an exemption for these units consistent with a similar exemption included in the final MATS. With respect to biomass-based units, EPA's proposed changes to the applicability requirements cannot be fully assessed without more explicit guidance from the Agency as to how biomass units will be used in setting 111(d) state-specific emission goals and whether these units can be used for compliance. Stakeholders cannot comment meaningfully in the absence of complete

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[1] It does not appear that EPA is proposing to change the applicability requirements for **new** subpart Da units, such that the minimum sales criterion and low fossil fuel use exemption would still be relevant in applicability determinations for new units. *See* proposed 40 C.F.R. § 60.46Da(a), 79 *Fed. Reg.* at 1502. EPA states that "[t]he rationale for following applicability criteria is different from the January 2014 proposal…existing boiler and IGCC facilities would continue to be included in CAA section 111(d) state programs regardless of their actual sales or fossil fuel use…" 79 *Fed. Reg.* at 34,979. If EPA is proposing to change the applicability requirements for these units, the Agency must make this clear and provide an opportunity for meaningful comment on the applicability requirements for new subpart Da units.

[2] Given the interrelated nature of the proposed standards under section 111(b) and (d), EEI reserves the right to provide additional comments on this issues raised by this proposal in subsequent comments filed in response to the proposed 111(d) guidelines.

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information. EPA should issue a separate rulemaking that addresses all biomass issues holistically.

1. Reliability-critical, limited-use oil-based units should not be subject to numeric standards under CAA section 111(b) or (d).

EPA's proposal to change the applicability requirements for existing units regulated under section 111(b) in order to treat them as modified or reconstructed units and under 111(d) does not recognize the critical reliability role of limited-use, low capacity factor, oil-based units.

With respect to the proposed 111(b) standards for modified or reconstructed units, EPA states that it is appropriate to delete the one-third sales criterion from the applicability requirements because the standards for these units are less stringent than the proposed standards for new units "and are achievable by low capacity factor facilities." 79 *Fed. Reg.* at 34,979. However, EPA does not provide any evidence regarding the achievability of the proposed standards by low capacity units. Furthermore, as a practical matter, it is unlikely that a coal-based unit (whether a boiler or IGCC facility) that ran at low capacity factors would be modified or reconstructed (consistent with the definitions of those terms under the section 111(d) implementing regulations) and still continue to operate at low capacity factors.

The more salient concern, however, is how the changed applicability requirements affect existing units that are subject to 111(d). Of particular concern is the effect of the changed applicability requirements on limited-use oil-based units. Deleting the requirement that a unit actually sell one-third of its potential electrical output will subject these units to regulation under 111(d). Many EEI members believe subjecting these units to regulation under section 111(d) is not

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appropriate, for the reasons discussed in EEI's forthcoming comments on the proposed 111(d) guidelines.

As EPA has consistently recognized, these units operate only in emergency situations and are critical to ensure reliability. For this reason, EPA created a limited-use subcategory in the final MATS rule. *See* 77 *Fed. Reg*. at 9,370. This subcategory exempts units that operate at a capacity factor of eight percent or less, as measured over a two-year block period, from MATS. *See* 40 C.F.R. § 63.10042. The MATS exemption for these units recognizes that these units do not run frequently, which reduces their contribution to air pollution. The MATS exemption also recognizes that these units will be retired instead of retrofitted with expensive control technologies because they cannot recover these costs through increased operations. For these reasons, it was reasonable and appropriate not to subject these units to MATS requirements.

Similarly, it is reasonable and appropriate to exempt these units from regulation under section 111. From an emission control perspective, there is no control technology retrofit that would address CO_2 emissions from these units. Moreover, efforts to improve these units' heat rates would prove ineffective given the limited operations of these units[3] and may result in the closure of these units if the costs of the heat rate improvement projects cannot be recouped through increased operation, which generally would be expected to be the case.

[3] EEI's comments in response to the proposed standards for existing units under CAA section 111(d) will discuss in detail issues related to heat rate improvements at coal-based units. As a general matter, however, heat rate is correlated with capacity factor; units that run consistently at higher capacity factors have lower heat rates and emit less CO_2 on a per MWh basis. Investments to improve a unit's heat rate will not result in lower emissions if the unit is not consistently run at higher capacity factors.

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With respect to state plans, it would be unworkable for states to attempt to address emissions from these units since the proposed section 111(d) building blocks[4] will not have any impact on these units' operations or emissions. First, heat rate improvements at coal-based units will not have any effect on oil-based unit emissions. Second, increased utilization of NGCC units will not displace generation from these units because they are only dispatched during or after emergencies. By definition, these units are running because other units cannot. Third, increased deployment of renewable generation or other zero-emissions generation will not displace generation from these units because they are not competing to serve the same load. Finally, end-use efficiency will not reduce generation from these units because they will only run in response to the type of customer demand that is immune to efficiency measures—electricity demand to provide basic services like heat, light and water in the wake of a hurricane or during an unexpected cold snap. Accordingly, EPA cannot show that the proposed BSER for existing units under section 111(d) is the best system of emission reduction that has been adequately demonstrated for limited-use oil-based units.

Moreover, including these units in state plans could create compliance challenges for states. Given the variable nature of the operations of limited-use oil-based units—they could run at an eight percent capacity factor one year and not at all the next—states may be required to address unexpected increases in emissions not considered when state plans were submitted to EPA. In

[4] EPA proposed to define BSER for purposes of the section 111(d) guidelines as the combination of four Building Blocks: 1) heat rate improvements at coal-based units; 2) increased utilization of existing NGCC units; 3) increased deployment of renewable generation and certain other zero-emissions resources; and 4) increased end-use efficiency. *See* 79 *Fed. Reg*. at 34,836.

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this regard, EPA's use of a single year (2012) to calculate baseline emission rates for purposes of setting state-specific emission goals is particularly problematic. If a limited-use oil-based unit did not run in 2012, the state goals were derived as if this unit does not exist. If a sudden emergency situation requires the limited use of this unit to ensure reliability in the future, the resulting emissions will make it that much more difficult for the state to achieve its goals because these emissions may not have been taken into account in the state compliance plan.

Accordingly, EPA should not use emissions from limited-use oil-based units to set state-specific emission rate goals under section 111(d) and should not require states to address these units or their emissions in compliance plans. Instead, EPA should modify the proposed applicability requirements to exempt limited-use oil-based units from regulation under section 111. This exemption should mirror the MATS exemption for these units.

2. EPA should conduct a separate rulemaking that addresses how biomass units will be regulated.

EPA proposes to delete the low fossil use exemption for existing boilers and IGCC units. This exemption applies to units that burn fossil fuel for 10 percent or less of the heat input during a three-year rolling period. *See* 79 *Fed. Reg.* at 34,979. EPA states that this exemption was "designed to exempt facilities that are capable of combusting fossil fuel, but burn primarily non fossil fuels…e.g., wood-fired EGUs…" *Id.* If EPA deletes the low capacity factor exemption, existing biomass-based units will be subject to the proposed standards for modified and reconstructed units under section 111(b). These units also would become subject to regulation under section 111(d), and states would be required to address emissions from these units in state compliance plans. Without guidance from EPA as to how biomass emissions will be addressed, it is premature to comments on the applicability requirements or standards for these units.

EPA solicits comment on whether to create a subcategory for these units in recognition of the fact that they are inherently less efficient than fossil-based EGUs. *See id.* Consistent with EPA's statutory obligations, the Agency should ensure that the 111(b) standards for biomass-based units are achievable. Creating a separate subcategory for these units and subjecting them to appropriate standards would satisfy EPA's CAA section 111(a)(1) mandate that emission standards be achievable. It is premature, however, to comment on what standard would be achievable as EPA has not proposed any numerical standard for these units and there are no data in the record to support any such standard.[5]

Moreover, it is not possible to address appropriate standards for these units under either section 111(b) and (d) until EPA provides guidance as to whether certain types of biomass are carbon neutral, and, if not, how emissions from certain types of biomass will be determined. As EPA notes in the preamble to the proposed 111(d) guidelines, the EPA Science Advisory Board has reviewed a draft of the accounting framework for emissions from biogenic sources, and EPA is in the process of revising the framework. *See* 79 *Fed. Reg.* at 34,924-25. According to EPA, "the draft framework concluded that while biomass and other biogenic feedstocks have the

[5] EPA also seeks comment on whether the heat input limitation for this possible new subcategory should be measures on an annual or three-year rolling basis, and notes the complexities of coordinating standards measured on a 12-month rolling average basis with applicability requirements determined over a three-year rolling average period. See 79 *Fed. Reg.* at 34,979. If and when EPA creates a new subcategory for biomass-based units, it would be easier to measure applicability and compliance with standards over the same time period—over a 12-month rolling period. The three-year rolling average period is important for CTs that follow load and may have different capacity factors from one year to the next. Biomass-based units largely are used as baseload resources. Units have more control over heat input than they do over capacity factor, which makes the three-year averaging period less necessary to control for unexpected operational variability.

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potential to reduce the overall level of CO_2 emissions resulting from electricity generation, the contribution of biomass-derived fuels to atmospheric CO_2 is sensitive to the type of biomass feedstock used, and the way in which the feedstock is grown, processed, and ultimately combusted as a fuel for energy production." *Id.* at 34,924. Accordingly, at this time, there is no guidance and little certainty about how emissions from biomass-based units will be determined and addressed.

It is difficult for stakeholders to provide meaningful comment on issues related to biomass-based units before EPA publishes the accounting framework. In addition, the fact that EPA raises issues related to the regulation of biomass emissions in multiple related rulemakings makes it difficult to assess exactly what EPA is proposing with respect to these units. Accordingly, EPA should conduct a separate rulemaking to address holistically all issues related to the regulation of GHG emissions from biomass-based units and to afford stakeholders the opportunity to provide meaningful comment on EPA's proposed treatment of these units.

B. Section 111(b) Standards for Combustion Turbines Must be Achievable at the Time of Proposal.

In the January 2014 proposal addressing CO_2 emission standards for new units, EPA proposed new applicability criteria for CTs regulated under subpart KKKK. In particular, EPA proposed to exempt CTs that sold less than one-third of their potential electrical output to the grid. *See* 79 *Fed. Reg.* at 1,459. As EPA noted, this would have the effect of exempting most simple-cycle CTs. *See id.* EEI supported the minimum sales requirement and resulting exemption because: 1) the proposed standards for CTs could only be achieved by new NGCC units; and 2) exempting new simple-cycle CTs recognizes that these units are designed and operated to respond to more sudden changes in load, to integrate variable renewable resources into the grid and to provide a

range of other grid support services.[6] As a result, these units' heat rates fluctuate, which results in higher CO_2 emission rates. EEI further suggested that EPA increase the minimum sales requirement to 40 percent to ensure that simple-cycle CTs can perform the range of functions for which they are built. *See* EEI May 9 Comments, Appendix A at 79-94.

EEI's May 9 Comments also addressed concerns about the achievability of the proposed standards for new NGCC units. In particular, EEI noted that EPA must set standards that are achievable for these units. *See* EEI's May 9 Comments, Appendix A at 55-77. In order to be achievable, the standards must reflect all operating conditions and anticipate that, in the future, NGCC units will be needed to help integrate increasing amounts of variable renewable generation into the grid. *See id.* EPA's proposed section 111(d) guidelines, which contemplate a dramatic increase in the deployment of wind and solar generation, underscore these concerns. *See* 79 *Fed. Reg.* at 34,867. As more renewables are brought onto the system, NGCC units will ramp up and down more frequently, or, will run at lower capacity factors generally, which will degrade heat rates and increase emission rates. *See* EEI's May 9 Comments, Appendix A at 63-66.

In this proposal, EPA seeks comment on "additional approaches" to the applicability requirements for CTs. *See* 79 *Fed. Reg.* at 34,979. If adopted in the final rule, these "additional approaches" not only would modify further the proposed applicability requirements for new CTs, but also would serve to change the proposed standards for these units. EPA solicits comment on a wide range of options that would affect both the applicability requirements and standards for

[6] The relevant parts of EEI's May 9 comments in Docket No. EPA-HQ-OAR-2013-0495 are attached as Appendix A.

simple-cycle CTs and NGCC units. While some of these "additional approaches" may seem reasonable in theory, EPA still has a statutory obligation to demonstrate that the standards for all units are achievable. *See e.g.*, *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973). EPA cannot finalize any standards that the Agency cannot demonstrate are reasonable or standards for which EPA has not provided stakeholders sufficient opportunity for notice and meaningful comment.

1. Simple-cycle CTs should not be subject to section 111(b) standards that do not recognize the range of services these units provide to the grid.

As stated in EEI's May 9 Comments, many EEI members continue to believe that excluding new stationary simple-cycle CTs from 111(b) regulation in this action is appropriate because these units provide important grid services that facilitate renewables integration and support reliability.[7] In some circumstances, simple-cycle turbines are used to support the integration of renewable resources into the grid and may operate more frequently. As noted with respect to NGCC units, simple-cycle units that accommodate the increased use of renewable generation should not be penalized by emissions standards that fail to recognize that overall emissions are decreasing, even though unit emissions might increase. In addition, simple-cycle units play an important role in meeting peak demand and providing spinning and non-spinning reserves. Both spinning and non-spinning reserves must be available within 10 minutes of dispatch.[8] These

[7] Other EEI members commented that these units should be regulated under section 111(b), but subject to achievable alternative numeric or work practice standards.

[8] A spinning reserve is the on-line reserve capacity that is synchronized to the grid system (CTs can be kept spinning without producing any energy as a way to reduce the length of time required to bring them online when needed) and ready to meet electric demand within 10 minutes of a dispatch instruction and can operate continuously for at least two hours once it is brought online. Spinning reserve is neededto maintain system frequency stability during emergency operating conditions and unforeseen load swings. Non-spinning reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction. Non-spinning reserve is needed to maintain system

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roles cannot be met by NGCC units, which take at least one hour, if not longer, from startup to full load. An exemption will allow maximum operating flexibility for these units to perform these necessary functions.

As a result of the diverse roles that simple-cycle CTs play, both in terms of backfilling renewables and providing grid support services, the range of emissions rates for these units varies widely. Thus, it would be difficult for EPA to determine an emissions standard for these units that would be achievable across all simple-cycle CT units and uses. Certainly, EPA could not do so on the basis of the administrative record developed for either this proposal or its previous proposal for new units. Accordingly, EPA has a reasonable basis to exempt these units from the proposed CO_2 standards and should do so.

EPA notes that the proposed one-third sales test could create incentives to install, modify or reconstruct smaller, less efficient simple-cycle CTs rather than build newer, more efficient NGCC units, resulting in higher overall mass emissions. *See* 79 *Fed. Reg.* at 34,979 and 34,980. To address this concern, EPA seeks comment on two options for changing the one-third sales test. Under both options, EPA would determine applicability with reference to a simple-cycle CT's design net efficiency and would allow larger, more efficient units to sell more power to the grid than smaller, less efficient units without the imposition of a GHG standard. *See id.* at 34,980.

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frequency stability during emergency conditions. *See* California ISO, Spinning and Non-Spinning Reserves, Settlements Guide (Jan. 31, 2006), http://www.caiso.com/Documents/SpinningReserveandNonSpinningReserve.pdf; and Energy Vortex.com, Energy Dictionary, http://www.energyvortex.com/energydictionary/spinning_reserve__non_spinning_reserve.html.

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Under the first of these "alternate approaches," more efficient, large simple-cycle CTs would be able to sell approximately 38 percent of their potential electrical output on a three-year rolling average before an emission standard would apply. *See id.* Under the second alternate approach, these larger, more efficient units would be able to sell approximately 42 percent of their potential output. *See id.* Under both alternate approaches, smaller, less efficient new simple-cycle CTs would be able to sell less of their potential electric output before standards would apply. These approaches are consistent with EEI's May 9 Comments, which advocated for a 40 percent minimum sales criteria, to ensure maximum operating flexibility. These approaches also would incentivize the building of the most efficient new simple-cycle units. This appears to balance environmental concerns with recognition of the important role that simple-cycle CTs play in maintaining reliability and supporting the integration of renewable energy into the grid.

However, if EPA chooses to finalize one of these approaches, the Agency must clarify that these applicability requirements apply only to new units and not to modified, reconstructed and existing units. EPA notes that the goal of the applicability requirements is to encourage the building of newer, more efficient simple-cycle CTs. *See id.* While EPA's proposed approach is intended to reward unit efficiency, this logic cannot apply to modified, reconstructed or existing units which have already been constructed. These units could be dispatched based on location, local demand, weather and transmission capacity concerns—the unit's efficiency is not a factor in these decisions, and utilities often cannot run larger and more efficient units more often due to these specific transmission or reliability constraints. As a result, EPA must maintain the

minimum sales criteria—and cannot use an efficiency-based metric—to determine whether units are subject to regulation under section 111(d).

2. Consistent with EPA's statutory obligations, standards for new simple-cycle CTs units must be achievable when proposed.

EPA solicits comment on "whether the percent sales of potential electric output is sufficient to account for the potential increased use of simple cycle CTs due to the expected increased percentage of electricity generated from renewable generation in the future." *Id.* at 34,980. EPA also solicits comment on the extent to which simple-cycle CTs will be used to support renewable generation; the costs and GHG emissions of energy storage systems; and demand response programs as tools to balance demand and generation from renewable generation. *See id.*

Preliminarily, it is unlikely that any stakeholder would have credible, reliable data on the extent to which simple-cycle CTs will be used to support renewable generation going forward. Any such analysis would be dependent on a number of assumptions, including assumptions about the deployment of renewable generation (which will vary greatly in different jurisdictions), future demand for electricity, future wholesale electric prices and the costs of new simple-cycle CTs, among others. The most important assumption, however, may relate to the potential impacts of EPA's final GHG standards for new and existing natural gas-based units. These standards will be significant factors influencing which flexible gas-based units are used to support renewables generation. For example, if states choose to increase utilization of existing NGCC units to comply with the state-specific emission rate goals proposed in the 111(d) guidelines, it is likely that simple-cycle CTs—both new and existing—would be needed to facilitate renewables integration. Conversely, if EPA's final standards for new units under section 111(b) place significant operating limits on simple-cycle CTs, existing CTs and existing NGCCs could play a

larger role in renewables integration. Renewables are an intermittent resource. The only resources that can be reliably dispatched quickly enough to compensate for significant swings are simple-cycle CTs and hydro. If EPA's goal is to foster the development of renewable energy, imposing strict limits on the main backup generating source may be counterproductive.

Similarly, it is not clear what EPA can do, in the context of setting achievable standards for simple-cycle CTs, without information about energy storage systems and demand response. It is true that energy storage systems and demand response could reduce the need to rely on natural gas-based units in the future to balance variable renewable generation, but this is not relevant to the current rulemaking to develop achievable standards under section 111(b) for simple-cycle CTs. Standards must be achievable at the time they are proposed.

Consistent with its statutory obligations, EPA cannot base applicability requirements or immediately enforceable standards for new simple-cycle CTs on assumptions about the future deployment of renewable energy or energy storage or increased demand response. At present, it is more than reasonably foreseeable that these units will be used for renewables integration, especially given the developmental status of energy storage technologies. As discussed at length in EEI's May 9 Comments, this will require these units to cycle more frequently, which will increase both heat rates and CO_2 emission rates.[9] Accordingly, EPA must develop applicability requirements and standards that recognize the role that these units will play now in the integration of renewable generation, without reference to how future circumstances might be different.

[9] *See* EEI's May 9 Comments, Appendix A at 63-66.

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Appendix C

Excerpt from EEI's Comments in Docket No. EPA-HQ-OAR-2013-0495 filed May 9, 2014, regarding new NGCC units

Standards of Performance from Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

79 *Fed. Reg.* 1,430 (Jan. 8, 2014)

V. The Proposed Emissions Standards For New Natural Gas-Fired Combustion Turbines Must Be Achievable Over The Range of Current And Expected Future Normal Operating Conditions.

The proposed CO_2 emissions standards for new combustion turbines are 1,000 lb CO_2/MWh for units with design heat input greater than 850 mmBtu/h and 1,100 lb CO_2/MWh for units with design heat input less than or equal to 850 mmBtu/h, but EPA requests comment on a range of other potential emissions limits, from 950 to 1,100 lb CO_2/MWh for the larger units and from 1,000 to 1,200 lb CO_2/MWh for the smaller units. *See* 79 *Fed. Reg.* at 1446-47, 1461 and 1486-87. The proposed subcategorization of CTs is based on EPA's conclusion that "…differences in several types of equipment used in the differently sized units…" affect the efficiency of the units. *See* 79 *Fed. Reg.* at 1486. **To ensure that all new NGCC units are able to achieve the proposed standards without running the risk of periods of operations out of compliance, EPA should set a single emissions limit of at least 1,100 lb CO_2/MWh and simple cycle units should be exempted from the proposed emissions standards**.[1]

EPA's analysis concluded that despite promulgation of a separate coal standard, few, if any, new coal units are projected to be built through 2025. *See* 79 *Fed. Reg.* at 1434. As a result, the industry will be relying on natural gas-based units in the near future to meet the need for new capacity. Thus, the importance of an achievable standard for NGCCs and other combustion turbines cannot be overstated. If NGCC units are the Agency's preferred technology for reducing GHG emissions from new EGUs, these units should not be at risk of exceeding

[1] See also comments of the Gas Turbine Association (GTA) filed in Docket No. EPA-HQ-OAR-2013-0495. GTA advocates for a single standard for all NGCC units of at least 1,200 lb CO_2/MWh. EEI encourages EPA to consider carefully the comments of the manufacturers of these turbines, which are expert in their operations and compliance capabilities.

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emissions performance standards over the range of normal and expected future operating conditions.

A. If Natural Gas Combined Cycle Units Cannot Comply with the Proposed Standards under Current and Expected Normal, Real-world Operating Conditions, the Standards are Not Achievable.

As discussed above, CAA section 111(a)(1) requires that new source performance standards reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into consideration the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Accordingly, section 111 requires EPA to identify the emissions standards that are "achievable" with "adequately demonstrated" technology. In the case of natural gas turbines subject to regulation under subpart KKKK, EPA again has determined that NGCC units are the BSER. *See* 79 *Fed. Reg.* at 1485.

EEI does not challenge this BSER determination, insofar as it applies to NGCC units,[2] but **EPA has not met its burden with respect to demonstrating that the proposed emissions standards for NGCCs are achievable**. "In order for EPA to demonstrate the achievability of the standard…it must: (1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the [ ] data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard." *National Lime*, 627 F.2d 416, 434.

[2] Concerns about the proposed treatment of simple cycle CTs are discussed below. *See* section V.B, *infra*.

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A review of the supporting documentation included in the docket indicates that EPA has identified and considered some, but not all, relevant variables when proposing an emissions standard for NGCC units. In particular, and as discussed in more detail below, EPA has failed to fully consider the effect of the expected increase in renewables deployment and the concomitant effects of increased cycling of NGCC units to support the integration of variable renewable resources. "[D]ue consideration must be given to the possible impact on emissions of recognized variations in operations and some rationale offered for the achievability of the [standards] given the tests conducted on the relevant variables identified." *National Lime,* 637 F.2d at 434. Without such consideration, EPA's analysis cannot be said to be reasonable, nor can the resulting emissions standard be deemed "achievable."

1. The proposed standards for new stationary combustion turbines should be based on actual emissions data, not design specifications that do not reflect normal, real-world operations.

In the 2012 Proposal, EPA estimated the standard emissions rate for a new NGCC unit by adjusting the design performance specifications provided in Gas Turbine World for "operation at non-design ambient temperatures, the use of post-combustion controls, normal degradation of combustion turbine components, and the operations at part load" and not actual emissions data.[3] EEI objected to the use of design specifications, instead of actual emissions data, to set section 111 standards for new NGCC units. EEI asserted that the variable emissions rates from modern NGCC units built from 2006-2011 provide a more accurate representation of how these units

[3] EPA, Office of Air Quality Planning and Standards, Memorandum to Docket No. EPA-HQ-OAR-2011-0660, Design Data for New Combined Cycle Facilities (Apr. 2012). It is not appropriate for EPA to assess whether units would meet proposed CAA section 111(b) standards over the life of NGCC units when compliance will be measured on a rolling 12-month basis, not over the life of a unit.

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perform in the real world. Design performance specifications project the expected performance in an ideal, steady-state situation, which is rarely found in normal, real-world operations. By definition, design performance specifications are not demonstrated via actual operations and, therefore, cannot be said to reflect the emissions limits that have been determined to be "achievable," as required by CAA section 111(a)(1).

EEI's analysis of actual monthly emissions data from NGCC units that commenced operation in the period 2006-2011 indicated that in 20 percent of these months, emissions exceeded the proposed 1,000 lb-CO_2/MWh standard. In comments on the 2012 Proposal, EEI argued that these exceedances are due to variations in operating load and the subsequent, normal degradation of heat rate. Hence, units would not be in compliance 100 percent of the time—and not even in compliance 95 percent of the time, as EPA had asserted. *See* 77 *Fed. Reg*. at 22414.

This variability in emissions can be attributed to several factors. The efficiency of an NGCC unit and the CO_2 emissions rate are affected by:

- Operating at part load: Emissions (on an output basis) increase significantly as load is reduced. Many NGCC units, even those designated as "baseload," are required to operate at lower capacities to accommodate integration of renewables and other system, grid or electricity market needs. Combined cycle units that have a two-on-one or three-on-one configuration may have occasion to operate while one combustion turbine is out of service for maintenance, which reduces efficiency due to reduced heat input into the steam cycle.

- Use of backup fuel: The proposed standard does not appear to incorporate the use of oil as a backup fuel. The use of oil in times of natural gas curtailment (e.g., severe weather events, such as hurricanes) will increase the average CO_2 emissions rate.[4]

[4] *See* GTA comments, *supra*, n.86 at 16.

- Startup and shutdowns: According to gas turbine manufacturers,[5] the CO_2 mass emissions per MWh during SS events are extremely high, cannot be controlled and greatly exceed emissions achievable during steady state operation. Further, at startup, an NGCC unit operates essentially as a simple cycle unit until the steam generator is heated and brought into operation. This is part of the design of an NGCC unit.

- Performance degradation: The standards do not account for the fact that each unit is specific in design (*e.g.*, number and efficiency of inlet filters) and operating site conditions (e.g., dusty open plants, high ambient temperature), and the fact that the percent degradation over time is variable. Again, referring to the "What You Should Know About Design Ratings" document included in the 2012 Proposal docket, "power and heat rate may degrade by 2-6 percentage points during the first 24,000 hours of operation."[6] To the extent that some degradation can be recovered, it is not always possible or feasible to correct a slightly degraded function immediately, as repairs often involve extended tear downs and must be scheduled well in advance.

- Other factors: Higher elevations, as are common in the Western part of the U.S., have a noticeable negative impact on the generation of electricity, which would increase CO_2 emissions per MWh. It also appears that smaller combustion turbines (*i.e.*, less than 300 MW) may have higher emissions profiles.[7] (EPA did propose to set a separate standard for units that are less than 100 MW in the Proposal.) Ambient temperature and seasonal temperature variations affect plant operational efficiency and therefore also affect the emissions rate.

None of these factors is within the control of the unit operator. EEI argued that EPA should modify the proposed standard to at least 1,100 lb CO_2/MWh to better reflect actual emissions and the factors that affect the efficiency of new NGCC units. Moreover, EEI argued that modifying the standard would help accommodate partial load operations, specific unit design and operational site characteristics, as well as the use of backup fuel in emergencies. EEI's 2012 Comments are attached as Appendix A.

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[5] *See id.*

[6] *See* EPA, *supra*, n.88.

[7] *See, e.g.*, Matthew J. Kotchen and Erin T. Mansur, *How Stringent is EPA's Proposed Carbon Pollution Standard for New Power Plants?*, Univ. of Cal. Ctr. for Energy and Envtl. Economics (Apr. 25, 2012), http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2046238.

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2. **EPA's own analysis demonstrates that a less stringent standard is necessary to address factors beyond the control of NGCC operators that effect emissions rates.**

We appreciate that EPA reviewed and responded to some of our concerns with the 2012 Proposal, as outlined above. According to the *Standards of Performance for Natural Gas-Fired Combustion Turbines Technical Support Document* (NG TSD) included in the docket for this Proposal, EPA analyzed the actual CO_2 emissions and other operating characteristics for a study population consisting of 307 NGCC units to propose the standard for new units, which is more appropriate than the design specifications used in the 2012 Proposal. The EPA study population represented units that met certain parameters, including having commercial operations dates on or after January 1, 2000, reporting gross output data from both the primary CT and steam generator during the analysis dates (2007-2011) and reporting no cogeneration. Using this study population, EPA conducted analyses to evaluate the correlation between exceeding the proposed standard and: 1) pollution controls; 2) elevation; 3) temperature; 4) cycling; and 5) number of startups and shutdowns. *See* NG TSD.

In the NG TSD, EPA concludes that there was no correlation between CO_2 rates and the presence of pollution controls, nor between CO_2 rates and elevation. EPA also evaluated study population data for any correlation between temperature and CO_2 rates. Temperature clearly has an impact on CO_2 emissions (Figure 1) and is beyond the unit operator's control. In EPA's analysis, no difference between the overall summer and winter months CO_2 emission rates was seen. *See* NG TSD at 5. However, EPA notes that the proposed 12-month rolling average compliance determination allowed the "large majority" of the study population units to avoid exceedances "by smoothing out any increases in CO_2 rate that may occur due to ambient

temperature." *Id.* This implies that without EPA's proposed modifications to the compliance determination methodology, discussed in more detail in section V.A.6., below, more exceedances would occur due to different temperature environments. Increasing the proposed emissions standards to 1,100 lb CO_2/MWh for all NGCC units, regardless of size, would better ensure that new units would not be in exceedance of the standard.

There is no evidence in the NG TSD or elsewhere in the administrative record that EPA considered the potential impacts of increases in both the amount of cycling and the number of startups and shutdowns that will result from known, expected increases in renewables deployment. These issues are discussed in more detail in section V.A.4, below.

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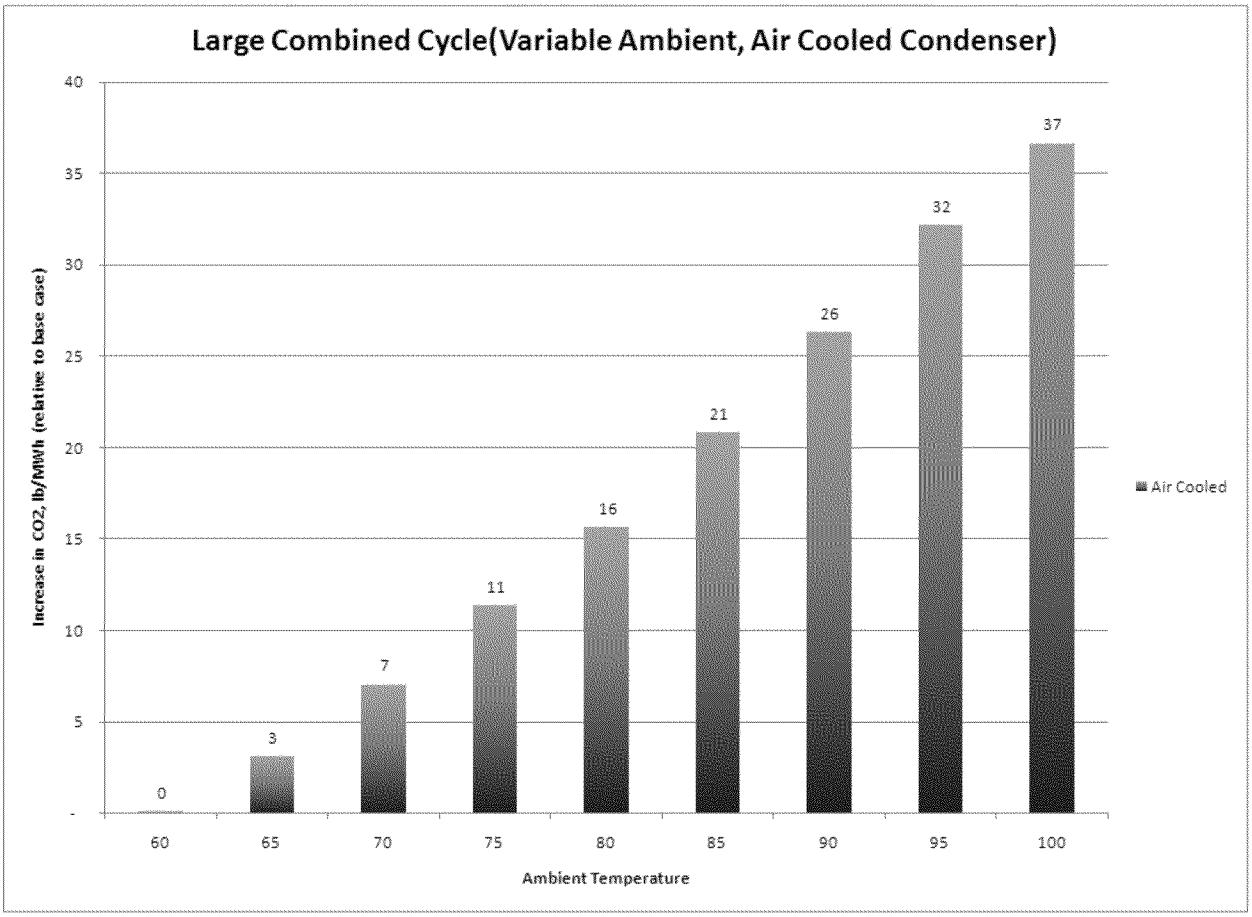
Figure 1. Relationship Between Ambient Temperature and CO_2 Emission Rate



Source: Gas Turbine Association, *Proposed NSPS for GHG Emissions*, presentation to OIRA/OMB (Aug. 1, 2013).

3. EPA's study population may not be representative of operational characteristics of recently built NGCC units.

It is important to note that 295 units were excluded from the NG TSD study population because gross output data from the steam generator was not reported. The reporting of these data is optional.[8] Thus, the study population represents only about half of the newest NGCC units and, therefore, may not be representative of current operational characteristics of recently built NGCC units. Including data from the steam generator increases the number of MWhs available for

[8] Reporting output from the steam generator is optional. *See* 40 C.F.R. part 75.

consideration in EPA's assessment of whether NGCC units are able to comply with the proposed CO_2 standards.

Moreover, it is telling that, even in units with complete gross output data, exceedances of the proposed standards (1,000 lb CO_2/MWh and 1,100 lb CO_2/MWh) still occurred among newly built NGCCs. Twenty-five units in the NG TSD study population had maximum 12-month rolling average CO_2 rates of 1,000 or greater and 23 of those units also reported additional exceedances (i.e., rates less than the maximum 12-month rolling average but above the proposed standard).[9] The cause of these exceedances is most likely one or more of the variables discussed above that are beyond the control of the unit operator. As EPA has determined that BSER for natural-gas based combustion turbines is NGCC technology, it would follow that a new NGCC unit purchased from any vendor should be able to meet the standard. Instead, however, EPA continues to propose a standard that even relatively new existing NGCC units cannot meet continuously under normal, real-world operating conditions.

4. A less stringent standard for new natural gas CTs is necessary to facilitate increased integration of variable renewable resources into the electric grid.

Another factor that affects an NGCC unit's ability to meet 1,000 lb CO_2/MWh consistently is increased cycling to support the integration of variable renewable resources into the grid. Increased cycling stresses baseload units, which operate most efficiently and effectively in a steady state. NGCC units often are chosen to support renewables integration because they can be ramped up and down more easily and more quickly than other baseload units. While EPA concluded in the NG TSD that there was no correlation between cycling/partial load and the subsequent startup and shutdown of the unit and exceedances of the proposed standard, this data

[9] *See* NG TSD, Excel Spreadsheet.

is retrospective. *See* NG TSD at 6. EPA fails to take into account the operation of new NGCC units in a future with increased penetration of renewables and distributed generation. Thirty states have mandatory RES and seven states have voluntary programs. Many of the RES not only have long-term targets, but also have near-term incremental targets as well. See Table 1, below.[10] New NGCCs will be built in an environment that will require increased cycling due to the increased deployment of intermittent, non-baseload energy sources. Therefore, EPA cannot rely on a retrospective analysis of NGCC emissions, but instead must assess whether known increases in renewables penetration will affect emissions rates.

Moreover, EPA has not addressed the achievability of the standard over the lifetime of new NGCCs, which can operate for 30 years or longer. A recent North American Electric Reliability Corporation (NERC) and California ISO study (2013 Special Reliability Assessment) concluded that increased supply variability introduced into the electric system associated with significant penetration of variable renewable generation will cause more frequent dispatches and the starting and stopping of flexible, gas-based generators, which will potentially incur more wear and tear.[11] This wear and tear has the potential to degrade heat rates and increase emissions. There is little data that addresses the possible magnitude of the degradation of a new unit's heat rate over time as it is required to cycle ever more frequently to accommodate renewables integration. Given

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[10] *See* Center for Climate and Energy Solutions, Renewable and Alternative Energy Portfolio Standards, Detailed Table of State Policies, http://www.c2es.org/docUploads/State%20rps%20aeps%20details%20July%202013%20update.pdf.

[11] NERC & California ISO, *2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach*, at 15 (November 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf .

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that the standards are applicable continuously and for the life of the unit, EPA must consider the achievability of the proposed standards over time.

Table 1. Examples of Incremental RES Requirements

STATE	RES TARGET	INCREMENTAL TARGET REQUIREMENTS
CA	33% by 2020	20% by end of 2013; 25% by end of 2016
CO	20% by 2020	20% by 2015; 30% by 2020
HI	40% by 2030	15% by 2020
KS	20% by 2020	15% by 2016
MN	26.5% by 2025	17% by 2017; 20% by 2021 except Xcel - 31.5%/2020 25% by 2017; an additional 1.5% solar by 2020
MO	15% by 2021	5% by 2014; 10% by 2018
NC	12.5% by 2021	6% by 2015; 10% by 2018
NH	23.8% by 2025	13.8% by 2015
NM	20% by 2020	15% by 2015
NV	25% by 2025	increase 3% every 2 years until 20% by 2015
OR	25% by 2025	15% by 2015
WA	15% by 2020	9% by 2016
WV	25% by 2025	10% by 2015

The overall impact of cycling is to reduce **overall** emissions because fossil units are being used less, even though increased cycling leads to increased short-term GHG emissions by the units that are ramping up and down because of the negative effect on heat rates. In these cases, while the emissions increases due to cycling may result in a unit operating out of compliance with the proposed CO_2 standards for new units, these increases are likely to be dwarfed by the GHG emissions avoided when renewable facilities are operating. Accordingly, EPA's Proposal for new natural-gas based units would serve to punish, rather than reward, those units that are required to undergo more frequent cycling to accommodate renewable resources. EPA should

not penalize practices that foster the emissions benefits associated with increased operation of variable, renewable resources. Increasing the proposed emissions standards for all NGCC units to at least 1,100 lb CO_2/MWh would help avoid periods of noncompliance for these NGCC units.

5. The proposed standards must accommodate lower utilization rates and more frequent periods of startup and shutdown.

In the Proposal, the numeric emissions limit proposed by EPA is intended to be effective during all operating hours. *See* 79 *Fed. Reg.* at 1448. In previous rules, EPA has differentiated between startup and shutdown (SS) periods and periods of normal operation, providing work practice standards to minimize emissions during SS periods. Significantly, EPA did this both in the final industrial boiler MACT rule and in the MATS rule.

As EEI has commented previously on past rules, the Agency's rationale for imposing numeric emissions limits during SS periods instead of work practice standards appears to be based on incorrect, overly broad assumptions about utility operations. Units that are utilized at lower capacity factors than those associated with baseload operations generally have frequent SS periods, which results in increased CO_2 emissions.[12] It is not correct to assume that the majority of natural gas-based units operate at high capacity factors all of the time—which would correspond to less frequent SS periods—when, in fact, just the opposite is true. NGCC units are designed to be flexible, capable of responding relatively quickly to changing load and supply. In fact, the NG TSD notes that the mean annual capacity factor for the 307 NGCC units in the study population over 2007-2011 was only 36 percent. Failing to account for lower utilization rates

[12] *See also* GTA comments, *supra*, n.86 at 3, 12 ("An exemption from startup and shutdown will be necessary to support a rapidly growing installed base of non-dispatchable renewable generation." "Reduced load operations (as well as startup and shutdown) result in a level of CO_2 emissions above the proposed level because gas turbine efficiency declines significantly at off-design operating loads.").

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and more frequent SS periods punishes NGCC units for the flexibility for which they are regularly designed and built. While the TSD also asserts that there is no relationship between periods of SS and exceedances of the standard, this analysis, as discussed above, is based on an analysis of only half of the newly built NGCC units, is retrospective in nature and fails to account for the future operational characteristics of new NGCCs in accommodating increasing amounts of intermittent renewables and distributed generation. The 2013 Special Reliability Assessment also notes that increased renewables integration will result in a greater number of SS periods and lower capacity factors for natural gas-based units, which will damage equipment. *See* 2013 Special Reliability Assessment at 15. EPA should increase the proposed standard for new units to accommodate actual usage and emissions data from the full range of NGCC unit operations.

EPA also should be aware of a high likelihood of unintended consequences if it fails to exclude SS emissions from the compliance calculation. If an NGCC unit is only requested by an ISO or RTO to run on an intermittent basis with frequent SS, or even at low capacity factors, causing CO_2 emissions to be high, units would be at risk of noncompliance. Rather than risk noncompliance, a utility would be likely to withhold a unit from the market, or only offer it into the market at times when the unit could be dispatched at high loads. Such practices would risk distorting electricity markets and not producing a least-cost outcome for consumers.

[Sections V.A.6 – V.B.Omitted]

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1. If EPA does not explicitly exempt simple-cycle CTs, the Agency needs to provide clarity on a range of compliance issues.

As discussed above, EPA has proposed several changes to the applicability criteria that determine whether a unit is an "electric generating unit" that must comply with the proposed CO_2 standards. One of the proposed changes would require that a unit sell more than one-third of its potential electric output, measured on a three-year rolling average basis, in order to be an "electric generating unit." *See* 79 *Fed. Reg.* at 1459. EPA calls this the "one-third sales criterion" or the "one-third sales test." *See id.*

As discussed above, EEI believes that the record does not support applying NGCC-based limits to simple-cycle CTs. An explicit exemption for simple-cycle CTs is reasonable and will provide the most regulatory certainty for these units. However, if EPA retains a sales-based approach to applicability instead of explicitly exempting simple-cycle CTs, EPA must address a range of compliance issues that were not addressed in the Proposal to ensure that simple cycle CTs are not subject to unachievable emissions standards. As EPA notes, there are implementation issues that arise when a unit that was not built to achieve a standard becomes subject to that standard at some point in the future. *See* 79 *Fed. Reg.* 1461. EPA's historical emissions and sales analysis appears to indicate that most simple-cycle CTs that have been recently brought online would pass the one-third sales test (that is, sell less than one-third of their potential electrical output on a rolling three-year average basis) and would not be subject to any CO_2 standard proposed under subpart KKKK. *See* 79 *Fed. Reg.* at 1459. As discussed in the context of NGCCs, however, given the expected increased deployment of renewables in the near-term, historical emissions and sales may not be an appropriate indicator of the future operations of these units. It does not

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appear from the record that EPA considered these issues when assessing the reasonableness of the proposed changes to the applicability requirements.

Accordingly, EPA must address what would happen to those simple-cycle units that fail any sales-based test. It appears, although EPA does not explicitly state this in the Proposal, that EPA would subject these units to CO_2 standards that were developed for NGCC units, based on NGCC emissions. Given that, as EPA acknowledges, simple-cycle CTs are not as efficient as NGCC units when operated at high capacity factors, these units would not be able to comply with the proposed CO_2 standards. Accordingly, these units would have to cease operations in order to comply.

If EPA intends to subject simple-cycle CTs that fail a sales-based test to some emissions standards, EPA must take into consideration their ability to achieve those standards. It would be inconsistent with EPA's CAA obligations and legal precedent to require simple-cycle CTs to comply with standards based on NGCC emissions that have not been shown to be achievable for those units. In the final rule, EPA must provide a reasonable compliance path for simple-cycle units that exceed a sales-based test. Without some clarity as to how units that exceed that would be treated, EPA will create a great deal of regulatory uncertainty for electric utilities that are considering whether to build new simple-cycle CTs. These units provide essential load following and grid support functions, as discussed above and in more detail below. See section

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V.B.3.[13] EPA should not use the proposed CO_2 standards to create barriers to the future construction of these units to serve these important functions.

EPA also must address whether simple-cycle units that exceed any sales-based limit would be subject to an emissions limit only for those periods in which sales exceeded the limit or, once the test has been failed, would be required to comply for all operating periods going forward, regardless of whether sales later return to levels that would entitle the simple-cycle CT to take advantage of the proposed changes to the applicability requirements. EPA states that it seeks comment on whether to subject these units only to emissions standards during those periods when sales exceeded the threshold level. *See* 79 *Fed. Reg.* at 1461. EEI notes that EPA legally could not subject these units to an emissions standard that they cannot ever achieve—i.e., the proposed 1,000 or 1,100 lb CO_2/MWh standards for NGCCs—during periods when sales of their potential electrical output exceeded any applicability limit. Some other standard would have to apply.

[13] See also comments of EEI member El Paso Electric Company filed in Docket No. EPA-HQ-OAR-2013-0495.

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Appendix D

EEI's Building Block 2 Analysis

EEI Analysis of the NGCC fleet

Like EPA, EEI used EIA forms 860 and 923 for 2011-2013, and only considered operating NGCC units in 2012 with nameplate capacity of 25 MW or greater. However, for ease of analysis, EEI accessed this forms through Energy Velocity, Ventyx, Inc.

EPA found 465 plants whereas EEI's analysis reveals 478 plants. EEI does not believe that this discrepancy is in any way significant and believes that both EPA's and EEI's analyses are comparable and that both are analyzing the same universe of power plants.

The tables below are based on EEI's list of 478 power plants.

Table 1. NGCC industrial composition

	Power sector	Industrial sector/CHP	Total
2012 Average Capacity Factor (%)	41.6	45.4	42.8
2012 Total Generation (MWh)	852,884,482	164,563,570	1,017,448,052
Share of total generation 2012	84%	16%	
Number of units	326	152	478
Share of number of units	68%	32%	

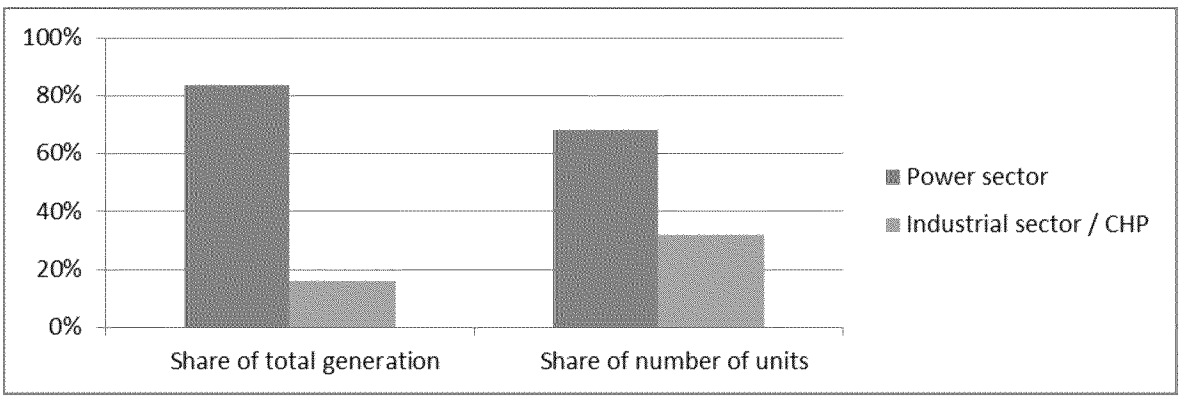

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Table 2. NGCC distribution by utilization rate

	# units	Of which: Power sector	Industrial sector/CHP
0-4%	26	16	10
5-9%	28	21	7
10-14%	23	15	8
15-19%	21	14	7
20-24%	23	12	11
25-29%	18	15	3
30-34%	33	24	9
35-39%	38	29	9
40-44%	33	21	12
45-49%	35	30	5
50-54%	34	27	7
55-59%	43	31	12
60-64%	36	24	12
65-69%	23	17	6
70-74%	29	20	9
75-79%	15	4	11
80-84%	12	5	7
85-89%	5	0	5
>90%	3	1	2
	478	326	152

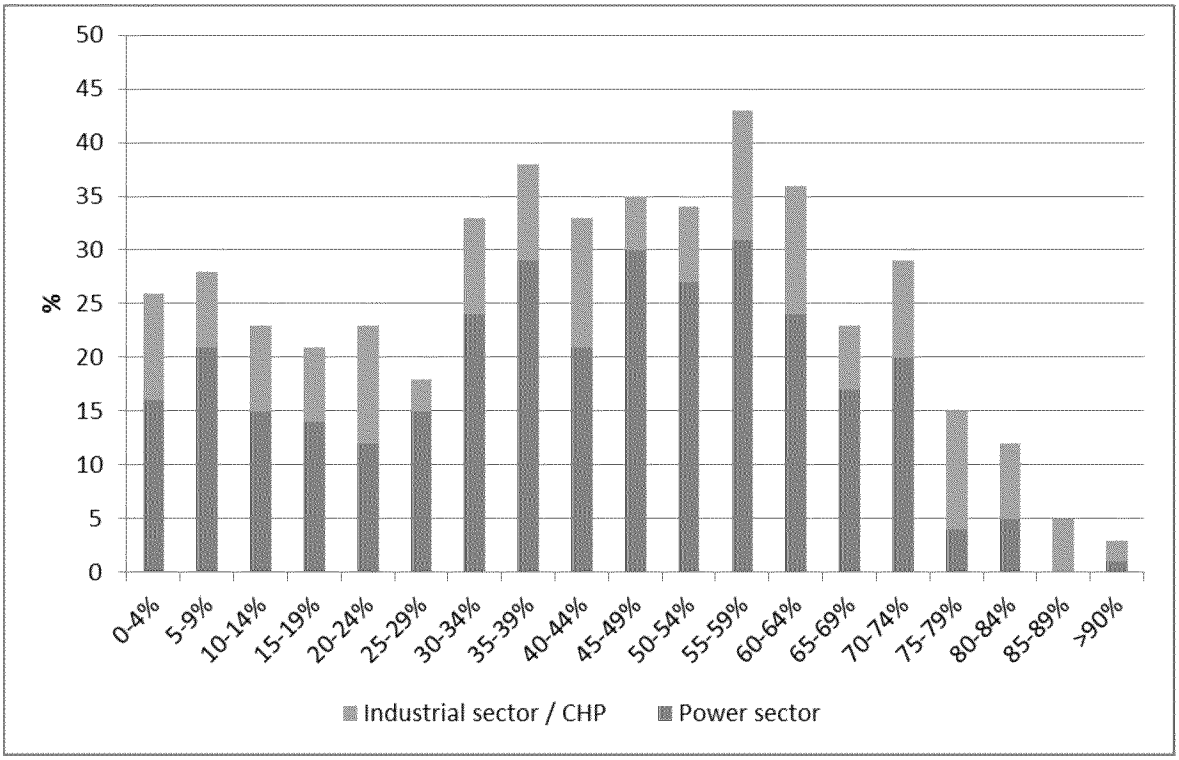

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Table 3. NGCC capacity factors in 2011 and 2012

Capacity factor in 2012	# units	Share generation 2012	Capacity factor 2011	Capacity factor 2012
50-60	77	25.6%	49.1%	55.2%
60-70	59	24.2%	55.9%	64.3%
70-80%	44	11.5%	67.5%	74.0%
>80%	20	4.7%	78.3%	84.6%

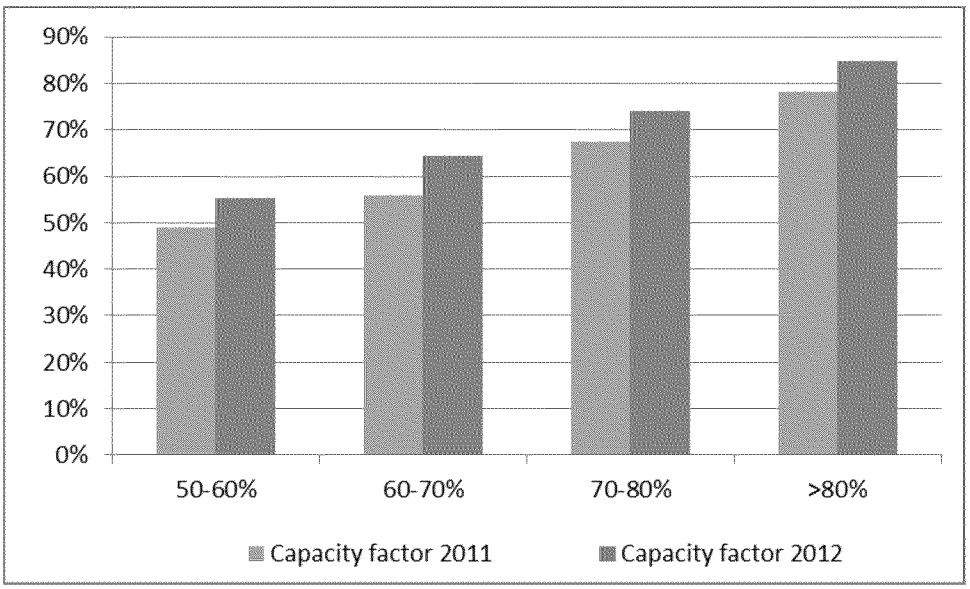

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Table 4. Capacity factor by state, 2012

	2011	2012	Plants at CF>70%, 2012	Share of plants at CF>70%, 2012
AK	72.8	63.6	1	1.6%
AL	54.6	60.5	3	4.7%
AR	24.7	30.2	1	1.6%
AZ	20.2	30.0		
CA	46.6	52.5	20	31.3%
CO	17.5	20.5		
CT	58.6	51.8	1	1.6%
DE	37.5	49.4		
FL	39.3	44.3	3	4.7%
GA	37.1	50.2	1	1.6%
IA	6.2	9.8		
ID	31.9	35.9		
IL	17.9	25.8		
IN	34.9	47.9		
LA	42.7	47.0	1	1.6%
MA	30.3	30.5		
MD	21.9	26.7		
ME	37.5	32.0		
MI	41.4	50.1	1	1.6%
MN	9.5	19.8		
MO	21.1	25.5		
MS	29.4	40.4	1	1.6%
NC	28.9	38.4		
NE	7.6	15.1		
NH	49.9	50.5		
NJ	32.7	38.9	1	1.6%
NM	33.7	37.4	1	1.6%
NV	46.2	49.2	2	3.1%
NY	31.7	36.2	4	6.3%
OH	36.1	58.2	1	1.6%
OK	35.1	40.5	1	1.6%
OR	30.9	40.2		
PA	41.2	53.2	5	7.8%
RI	41.7	40.7		
SC	47.2	51.2	2	3.1%
SD		4.0		
TN	51.5	55.4		
TX	49.6	44.9	8	12.5%
UT	37.2	44.3		
VA	45.6	61.0	4	6.3%
WA	26.1	31.2	2	3.1%
WI	17.4	29.5		

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Appendix E

Excerpt from EEI's Comments in Docket No. EPA-HQ-OAR-2013-0495 filed May 9, 2014, regarding EPA's approach to BSER

Standards of Performance from Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

79 *Fed. Reg.* 1,430 (Jan. 8, 2014)

III. EPA's Approach to BSER Is Inconsistent With The Clean Air Act And Judicial Precedent.

In the Proposal, EPA has outlined the following standards of performance: For fossil-fuel based units subject to regulation under subpart Da, EPA proposes an emissions limit of 1,100 lb CO_2/MWh, based on the Agency's assessment that partial CCS is the "best system of emission reduction" (BSER) for these units. For natural gas-based CTs, EPA proposes an emissions limit of 1,000 or 1,100 lb CO_2/MWh, depending on the size and use of the unit, based on the Agency's determination that natural gas combined-cycle (NGCC) units are BSER for units regulated under subpart KKKK. *See* 79 *Fed. Reg.* at 1433.

EPA has proposed these standards of performance pursuant to its authority under CAA section 111. Section 111 authorizes EPA to adopt standards for performance for sources within designated industrial categories. *See* 42 U.S.C. § 7411. CAA section 111(a)(1) defines "standard of performance" as:

> . . . a standard for emissions of air pollutants which reflects the degree of emission limitation *achievable* through the application of the *best system of emission reduction* which (**taking into consideration the cost of achieving such reduction and any nonair quality health and environmental health impact and energy requirements**) the Administrator has determined has been **adequately demonstrated**.

42 U.S.C. §7411(a)(1) (emphasis added).

The Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has made clear that section 111(a)(1) involves two separate inquiries: a determination that the system of emission reduction is adequately demonstrated and then a separate determination that the emission limitation using that system is achievable. *See Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F2.d

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775, 785 (D.C. Circ. 1976) ("[I]t is the system which must be adequately demonstrated and the standard which must be achievable.") In making these determinations, EPA must take into account cost, nonair quality health and environmental health impact and energy requirements.

Under the test outlined by the D.C. Circuit, it is not possible for EPA to justify its proposed standard of performance for fossil fuel-based EGUs because—as further explained in section IV—there is no record of deployment of partial CCS at scale at an EGU, and its costs of implementation are prohibitively high.

EPA nevertheless asserts the validity of both its determination that partial CCS is BSER, and its proposed 1,100 lb CO_2/MWh standard. The Agency reaches these conclusions based on a gross mischaracterization of the statutory requirements, legislative history and judicial precedents.

First, as discussed in greater detail below, the Proposal asserts that certain cases and legislative history support the proposition that a system of emission reduction that has never been used at scale at an EGU nevertheless can be found to be "adequately demonstrated." Yet, in the cases cited, the issue in question was not whether a particular system of emission reduction was "adequately demonstrated" but rather whether the proposed emission standard using the system would be "achievable"—a question that is not even reached if the underlying system is not "adequately demonstrated." EPA also asserts that section 111 judicial precedents authorize the Agency to consider an emerging technology as "adequately demonstrated" by looking to the "regulatory future" or to promote "technological innovation." However, the cases cited by EPA for these propositions also are inapposite. Indeed, in the case upon which EPA places its primary

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emphasis, the D.C. Circuit held that an emerging technology was *not* "adequately demonstrated" because the pilot scale data in the record did not provide sufficient evidence that the technology was feasible for commercial-scale plants. Finally, it is clear from the case law on section 111 that a system may be "adequately demonstrated" only if it can be implemented by a broad cross-section of the source category. EPA argues that certain legislative history points to the contrary, but the legislative history cited by the Agency is not on point.

Also discussed in greater detail below is the Proposal's mischaracterization of EPA's authority under section 111(a)(1) to consider the costs of implementation. The Proposal implies that certain case law permits EPA to promulgate a standard that is exorbitantly costly at the plant level provided that the costs are not unreasonable on a regional or national level. This interpretation is not consistent with the case law cited by the Agency, and is arbitrary and capricious in any event.

Finally, as discussed below, the Proposal asserts that a particular case supports EPA's consideration of various "policies" "implicit" in section 111 and that these policies undergird the proposed standards of performance. However, as explained below, the policies: (1) do not trump specific statutory criteria; and (2) were specific to the case in question. Moreover, the Proposal "cherry picks" among the policies, ignoring policy mandates to promote long-term economic growth and use of regionally available fuels.

Accordingly, EPA must revise the Proposal to accurately reflect the statutory requirements for setting BSER, consistent with judicial precedent. EPA should not use the novel, impermissible

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approach to determining BSER propounded in this Proposal in the final rule or in any other CAA section 111 rulemaking, including any future rulemaking addressing BSER for existing sources under CAA section 111(d). Further, because EPA's proposed determination that partial CCS is BSER is not the product of reasoned decision-making, EPA cannot use CCS as the basis for any CO_2 standards promulgated in a final rule addressing GHG emissions from new EGUs.

A. EPA Misinterprets and Misapplies the Case Law and Legislative History on CAA Section 111(a), which does not Support a Finding that Partial CCS Is "Adequately Demonstrated."

1. No Case Law Supports EPA's Conclusion that a System of Emission Reduction can be "Adequately Demonstrated" in the Absence of Any Data Showing Use of that System in the Source Category.

Under section 111(a)(1), a standard of performance is valid only if EPA determines that: (1) the system of emission reduction upon which the emission limitation is based is "adequately demonstrated; and (2) the emission limitation is "achievable." Also, EPA acknowledges that, under section 111, "to be 'adequately demonstrated,' the system must be 'reasonably reliable, reasonably efficient, and … reasonably expected to serve the interests of pollution control without being exorbitantly costly in an economic or environmental way.'" 79 *Fed. Reg.* at 1464 (quoting *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973)).

As discussed in IV below, partial CCS has not been deployed at scale at any existing EGU. Nevertheless, EPA insists that several cases support its proposed approach to BSER and the conclusions that partial CCS is "adequately demonstrated" and that a 1,100-lb CO_2/MWh emission rate is "achievable." However, as discussed in greater detail below, the BSER in all but one of these cases cited by EPA was already in commercial scale use at *some* sources in the source category or in a source of comparable design and function. Furthermore, in the one case

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in which a system of emission reduction had not been in commercial scale use—the dry scrubbing technology discussed in the *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981)—the court specifically held that the system could *not* qualify as BSER because of the absence of anything but pilot scale data. Accordingly, EPA fails to identify any case law that supports the proposition that a system of emission reduction can be "adequately demonstrated" where it has never been deployed by the affected source category.

For example, EPA asserts that the *Essex Chemical* decision justifies its proposed determinations that partial CCS is "adequately demonstrated" and that the 1,100-lb CO_2/MWh emission rate is achievable. 79 *Fed. Reg.* at 1463. According to the Agency's interpretation, *Essex Chemical* stands for the proposition that a standard is "achievable" even if the data show that it was not regularly met. EPA reasons: "The fact that the plant had achieved the standard on at least a few occasions, even though the plant had not done so on the great majority of occasions, 'adequately demonstrated' that the standard was 'achievable.'" 79 *Fed. Reg.* at 1463.

This is a gross misstatement of the statutory scheme. EPA conflates the "adequately demonstrated" and "achievable" tests. These are in fact two separate tests, and the former is a threshold determination for the latter. As the D.C. Circuit explained in *Nat'l Asphalt Pavement Ass'n* v. *Train*, "it is the system which must be adequately demonstrated and the standard which must be achievable." 539 F.2d at 785; *see also Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973). Thus, there are two separate inquiries when assessing the reasonableness of a proposed emissions standard under CAA section 111: (1) whether the system identified by EPA as "best" has been adequately demonstrated; and (2) whether the standard that

EPA selects, predicated on the Agency's BSER determination, is achievable using BSER.[1] EPA's efforts to elide the separate statutory requirements of "adequately demonstrated" and "achievable" are inconsistent with the clear requirements of the Act and legal precedent. In other words, EPA cannot even reach the achievability test if it fails—as it does in the Proposal—to meet its evidentiary burden of showing that the underlying system of emission reduction is "adequately demonstrated."

Indeed, in the *Essex Chemical* case itself, there was no question about whether the proposed BSER was adequately demonstrated. The only issue was whether the data supported EPA's determination that the proposed standard was achievable using that BSER. *See Essex Chemical,* 486 F.2d at 436 ("Petitioners do not object to the EPA's selection of dual absorption as the 'best system of emission reduction' which has been 'adequately demonstrated' for use in elemental sulfur burning plants . . . It is the designation of 4.0 lbs of sulfur dioxide [(SO_2)] per ton of sulfuric acid produced as the 'limitation achievable' through use of the dual absorption system that strikes the discordant note."). Because EPA fails to provide <u>any</u> data showing that partial CCS is "adequately demonstrated" for fossil fuel-based EGUs, the Agency has no basis for determining whether the proposed emissions rate using partial CCS is "achievable." In the words of the *Essex Chemical* decision, EPA's proposed CCS-based standard is not "achievable" because it is "purely theoretical or experimental." 436 F.2d at 434. Therefore, even if *Essex Chemical* could be read to suggest that EPA enjoys some level of deference in its determination

[1] The case law is clear that, even if a system of emission reduction has been adequately demonstrated, EPA still has to demonstrate the reasonableness of the emissions limits that flow from the use of that system. EPA cannot argue that all standards predicated on an adequately demonstrated BSER are achievable without a separate demonstration of their reasonableness. *See Portland Cement*, 486 F.2d at 395.

of "achievability,"[2] the Agency may not harness that deference to support a determination of "adequate demonstration" in the absence of any data in the record on the actual full-scale use of the underlying system of reduction.

2. EPA May Not Justify a BSER Finding on the Basis of Authority to Look into the "Regulatory Future."

EPA also cites *Portland Cement* in support of its Proposal, noting the court's statement that "[s]ection 111(d) looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present, since it is addressed to standards for new plants." *Portland Cement*, 486 F.2d at 391. From this statement, EPA reasons that a "standard of performance is achievable if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard." 79 *Fed. Reg*. at 1463.

EPA mischaracterizes *Portland Cement.* As in *Essex Chemical*, petitioners in *Portland Cement* did not challenge EPA's determination that the relevant emissions control technology was "adequately demonstrated." The system of emission reduction at issue in *Portland Cement* had already been in use. Instead, the question in *Portland Cement,* as in *Essex Chemical,* was whether the proposed emission rate using that system was "achievable." *See* 486 F.2d at 391 ("It is the 'achievability' of the proposed standard that is in issue.").

[2] In any event, EPA's characterization of the facts in *Essex Chemical* erroneously suggests that the court set a far lower bar for the sufficiency of achievability data. In *Essex Chemical,* the court found that the proposed standard "was exceeded on two occasions, equaled on another, and nearly equaled on the average of nineteen different readings." 486 F.2d at 437. In EPA's self-serving summary, this data translates into a finding that the standard had not been met "on the great majority of occasions." 79 *Fed. Reg*. at 1463.

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Thus, *Portland Cement* was not a case in which EPA was basing standards on a prediction about the adequate demonstration of particular emissions reduction system—the threshold question EPA must answer. Instead, it was a case about achievability of the standards—the second step in the 111(a)(1) test. Accordingly, *Portland Cement* provides no applicable precedent on what constitutes an "adequately demonstrated" system of reduction. The decision's statements on that issue are dicta.

In any event, even if *Portland Cement* can be read to address the "adequately demonstrated" prong in the 111(a) test, the decision hardly lowers the bar for EPA. For example, assuming for the sake of argument that *Portland Cement* supports the proposition that a system of emission reduction need not be in "routine use" in the relevant sector to be "adequately demonstrated" that does not mean it supports the proposition that a system that has **not been used at all** can meet that test.

Furthermore, EPA omits any mention of *Portland Cement's* important caveats, which have particular relevance for this rulemaking. The *Portland Cement* court noted:

> [T]he question of availability is partially dependent on 'lead time,' the time in which the technology will have to be available. Since the standards here put into effect will control new plants immediately, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed.

486 F. 2d at 391-92 (citations and quotations omitted). Of course, the standards here will control any new plant constructed after the date that the Proposal was published in the *Federal Register*. *See* CAA § 111(a)(2). Therefore, the "regulatory future" is **now**. Yet, EPA is positing that partial CCS is perfectly feasible for the *next* new fossil fuel-based power plant, even though the

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Agency cannot identify a single *existing* fossil fuel-based power plant that currently utilizes this technology. In other words, EPA is not relying on "actual tests" but rather "prediction." Assuming for the sake of argument that *Portland Cement* is good law on the issue of what is "adequately demonstrated," the decision suggests a substantial burden of proof for the Agency under these circumstances—which the Agency has failed to meet in the Proposal with respect to partial CCS.

Furthermore, the D.C. Circuit has cautioned that while it is "conceivable" that an emission control system could be both an "emerging technology" and an "adequately demonstrated" technology, "there is inherent tension between the two concepts." *Sierra Club v. Costle,* 657 F.2d at 341 n. 157. The *Costle* decision provides important benchmarks for determining the circumstances under which an emerging technology may be considered "adequately demonstrated." In the *Costle* case, the court held that EPA's rulemaking record *failed* to support a finding that a then-emerging SO_2 emission control technology—dry scrubbing—was "adequately demonstrated."

In support of this holding, the *Costle* decision quotes findings from a report in the rulemaking record:

> In summary, dry systems do offer potential advantages over wet systems, especially in the areas of energy savings and costs. However, *crucial issues such as waste disposal and demonstration of commercial-scale systems, which may continue to limit the overall acceptability of this technology, remain to be answered.*

Costle, 657 F2d. at 341 n. 157 (quoting "Survey of Dry SO_2 Systems" 16-18 (EPA Pub. No. 600/7-80-030 (Feb. 1980)) (emphasis supplied in the court's decision)). The *Costle*

court's focus on waste disposal and absence of commercial-scale systems certainly echoes findings about CCS in the record for this rulemaking, which demonstrate that CCS currently is not being deployed at commercial scale and that EOR is not available in all geographic areas, as EPA itself notes. *See* 79 *Fed. Reg*. at 1481. And even EPA would have to concede that CCS provides no offsetting "advantages" with respect to "energy savings" or "costs." CCS imposes an energy penalty in terms of the energy needed to compress, transport and inject the captured CO_2 for storage; these efforts also entail additional costs.

The *Costle* court was further troubled by the absence of any full-scale operating dry scrubber systems, and the corresponding reliance on the information from prototype units. *Id.* The court held: "We see no basis on this record which would justify extrapolating from the pilot scale data to the conclusion that dry scrubbing is adequately demonstrated *for full scale plants throughout the industry*." *Id.* (emphasis added).

Accordingly, none of the case law on CAA section 111(a) provides support for EPA's proposition that it may consider "adequately demonstrated" an "emerging" system of emission reduction for which there is no record of commercial-scale use in the relevant source category or by a source of comparable design and function. Rather, the available case law shows that a system of emission reduction may not be considered "adequately demonstrated" if the only available data on its performance comes from pilot scale projects.

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3. EPA Must Show that the System of Emission Reduction is Demonstrated and the Standard Achievable for the Industry as a Whole.

As discussed in VI, below, the Proposal effectively would make it impossible to construct new fossil fuel-based power plants in the many parts of the country that otherwise would use coal but do not have the good fortune to have geological conditions favorable for geologic sequestration. Yet, EPA insists that section 111 allows the Agency to promulgate a standard that is not achievable by substantial segments of a regulated source category. *See* 79 *Fed. Reg.* at 1466. EPA mischaracterizes case law and legislative history in support of this view. In fact, the available case law on section 111 makes clear that Congress intended such standards to be valid only if achievable "throughout the industry."

For example, as discussed above, the *Costle* court found that dry scrubbing was not "adequately demonstrated" because the court saw no basis in the rulemaking record "which would justify extrapolating from the pilot case data to the conclusion that dry scrubbing is adequately demonstrated for full scale plants *throughout the industry*." 79 *Fed. Reg.* at 341 n. 157 (emphasis added).

This requirement that section 111 standards be broadly achievable across a regulated industry is perhaps best illustrated in *Nat'l Lime Ass'n v. EPA,* 627 F.2d 416 (D.C .Cir. 1980). There, the D.C. Circuit concluded that section 111 standards were unsupported because "the record d[id] not support the 'achievability' of the promulgated standards *for the industry as a whole*." *Id.* at 431 (emphasis added); and at 439 (concluding that "the industrywide achievability of the standard [had not been] adequately justified"). The court reiterated that holding throughout the case, and further indicated that EPA itself has long recognized this fundamental rule. *See*, *e.g.*,

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id. at 433 ("EPA itself acknowledged in this case that 'standards of performance…must...[assure achievability of the standard for the industry as a whole] for *all variations of operating conditions being considered anywhere in the country*" (emphasis in the original)). Given *Nat'l Lime's* repeated emphasis on the fact that a standard must be broadly achievable throughout an entire industry, the Proposal's failure to address this case at all is arbitrary and capricious.

The *Portland Cement* case also reaffirmed the basic principle that section 111 standards must be achievable by a broad, representative range of new sources in the source category. *See* 665 F.3d at 190. In *Portland Cement,* the D.C. Circuit considered industry claims that EPA failed to consider the impact on portland cement kilns of older design that, if modified, could become subject to section 111 standards. *Id.* The court concluded that industry petitioners' argument failed "because contrary to [their] contention, EPA demonstrated how all regulated kilns could meet [the] standards. EPA based its [particulate matter (PM)] and [SO_2] limits 'on control technologies that can be applied to *any* kiln type and achieve the same control levels that would be expected with a new kiln at similar costs.'" *Id.* (citing 75 *Fed. Reg.* 54,970, 54,995-96 (Sept. 9, 2010) (emphasis in the original)).

Instead of addressing *Nat'l Lime* and *Portland Cement* in the Proposal, EPA points to cases interpreting other, quite distinct sections of the Act. In particular, EPA cites to *Int'l Harvester Co. v. Ruckelshaus*, a case interpreting section 202 of the CAA, which addresses mobile sources. 478 F.2d 615 (D.C. Cir. 1973). In *Int'l Harvester,* petitioning automakers failed to meet their burden to show that the controls required under section 202 were not "available," which would have triggered a one-year suspension of EPA rules. In reaching its decision, the Court accepted

EPA's reasoning that a suspension was not warranted because the public's "basic demand" could be met even if not all models and engine types could feasibly install the required controls. *Id.* at 626; *see also id.* at 640 (agreeing that the "driving preferences of hot rodders are not to outweigh the goal of a clean environment").

This case offers weak, if any, support for EPA's proposed approach to CAA section 111. First, the case addresses EPA's authority under CAA section 202, not section 111.[3] Moreover, *Int'l Harvester* dealt very specifically with the definition of the word "available" "within the meaning of section 202(b)(5)(D)" of the CAA. This provision no longer exists, but was designed, according to the court, to address the special issue of automobile pollution with "drastic" measures. *Id.* at 629, 639. This provision involves very different contextual questions (i.e., whether or not a compliance suspension might be available, as opposed to what underlying standard applies, whether the system of emission reduction has been "adequately demonstrated," or whether the corresponding standard is "achievable").[4]

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[3] CAA section 202 explicitly allows for EPA to delay the effect of standards to account for the time required to develop new automotive technology. CAA section 202(a)(2) provides that any regulation "shall take effect as the Administrator after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period." This is in sharp contrast with section 111(b), which requires new sources to meet any standards for new units from the date of their proposal.

[4] In *Portland Cement*, the Court noted that the standard at issue is "analogous" to the one examined in *Int'l Harvester*, but the Court made clear that the analogy rested on the fact that both standards required the Administrator to make projections based on existing technology, subject to the constraints of reasonableness. *See* 486 F.2d at 391-92. This "analogy" does not mean that EPA can import other, unrelated CAA section 202 concepts into section 111. Indeed, the idea that EPA could set standards that are not uniformly achievable throughout a regulated source category is contrary to one of the purposes of section 111, which was to establish uniform nationwide standards for new or modified stationary sources, regardless of location and local air quality.

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The relevance of *Int'l Harvester* is limited not only by its different statutory context, but also by its quite different facts. In *Int'l Harvester,* the court's validation of the rule only denied automobile enthusiasts access to some types of luxury goods (i.e., "hot rod[s]"). Here, by contrast, EPA's Proposal would impose an effective moratorium on fossil fuel-based EGUs. Such a moratorium could have substantial implications on the delivery of electricity, which hardly counts as a luxury consumer good. Accordingly, EPA's reliance on *Int'l Harvester* is inapposite, as it compares apples with oranges, and therefore cannot support the proposition that standards need not be achievable across the regulated source category.

EPA also attempts to rely on *Natural Resources Defense Council v. EPA*, a case involving standards established pursuant to CAA section 112. *See* 79 *Fed. Reg*. 1467 (citing 489 F.3d 1364 (D.C. Cir. 2007). In *Natural Resources Defense Council,* the court upheld a Maximum Achievable Control Technology (MACT) standard despite the fact that one subcategory of sources would have greater trouble meeting the standard. *Id.* at 1367. This case also is inapposite. CAA section 112 requires EPA to establish MACT standards based on the "best" controlled similar sources. *See* 42 U.S.C. § 7412(d)(3). Therefore, section 112 *explicitly* and by design directs EPA to base the standard on the performance of only a particular segment of the regulated sector. CAA section 112 also explicitly authorizes EPA to set more stringent standards than a floor level, and, importantly, provides that "cost is not a factor that EPA may permissibly consider in setting a MACT floor." *Natural Resources Defense Council*, 489 F.3d at 1376. Thus, the fact that EPA may establish section 112 MACT standards that some sources may have trouble meeting (or indeed, that some sources may not meet at all) is irrelevant to EPA's authority to establish standards under section 111. Because section 111 requires that standards

be achievable based on data that is representative of the *entire* industry, EPA's claim that standards are valid even if achievable only by a small segment of the sector is unsupportable.

EPA also misuses legislative history to support its view. First, EPA cites sections of the 1970 Senate Committee Report that make the point that Congress intended all major new sources to meet the uniform performance standards regardless of their location. 79 *Fed. Reg.* at 1466 (citing S. Rep. 91-1116 at 16 (1970)). But, this legislative history also supports the proposition that EPA should promulgate section 111 standards for which location is not an unreasonable obstacle to compliance.

EPA quotes additional legislative history, again from the Senate Committee Report, suggesting that Congress understood that CAA measures could prevent certain construction of new sources in "pollution havens." *Id.* at 2. This legislative history does not address the new source performance standards provisions in CAA section 111, but rather the provisions under section 110. The distinction is crucial. The section 110 provisions of the statute establish mechanisms that Congress specifically intended EPA to use to ameliorate localized pollution and promote attainment of the National Ambient Air Quality Standards (NAAQS). These mechanisms include the NSR provisions, which require certain major new or modified sources of pollutants to obtain a pre-construction permit that imposes emission limits calibrated to the level of attainment in the region in which the source seeks to locate.[5] Importantly, the statute explicitly provides that an applicable section 111 standard constitutes the "floor" for a source specific

[5] The "New Source Review" provisions collectively refer to sections of the CAA imposing certain pre-construction permitting requirements in attainment areas (the PSD provisions, CAA section 165), and provisions imposing certain pre-construction permitting requirements in nonattainment areas (the Nonattainment New Source Review provisions, CAA section 173).

emissions limit in an NSR permit.[6] In other words, Congress intended a particular interaction between section 111 standards and NSR: the section 111 standards would establish uniform and therefore broadly-applicable standards, while the NSR provisions would be the mechanism by which EPA and the states could impose potentially more stringent emissions limits on a source-by-source basis, tailored to local pollution conditions. Accordingly, EPA cannot rely on legislative history surrounding the section 110 attainment provisions to support the reasonableness of promulgating section 111 performance standards that are infeasible throughout large parts of the country.

In any event, even EPA acknowledges that the infeasibility of its Proposal in several regions has nothing to do with "pollution havens"—which are not possible with a globally-mixed pollutant such as GHGs—but rather result from "economic or technical reasons." 79 *Fed. Reg.* at 1467. Yet, EPA insists that this result is "consistent with Congress's recognition that certain sources may be precluded from locating in certain areas." *Id.* In doing so, however, EPA fails to point to any legislative history or case law that supports a view that section 111 standards may preclude construction of sources throughout major regions of the country.

[6] *See* CAA section 169(3) (defining the "best available control technology" standard for PSD permitting, and providing that "[i]n no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section [111] or [112] of this title.") *See also* CAA section 171(d) (defining the "lowest achievable emission rate" for NNSR permitting, and providing that "[i]n no event shall application of this term permit a proposed new or modified source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance.").

4. A Policy of Promoting "Technological Innovation" Under Section 111(a) Does not Provide an Alternative Basis for Justifying as BSER a System of Reduction That is Not Otherwise "Adequately Demonstrated."

In the preamble, EPA cites the *Costle* decision for the proposition that "technological innovation" is a "subfactor" that EPA should weigh in determining BSER under section 111(a)(1). 79 *Fed. Reg.* at 1465, *quoting Costle,* 657 F.2d at 347. On this basis, EPA concludes that technological innovation "should be considered . . . in determining the 'best system of emission reduction[.]'" 79 *Fed. Reg.* at 1465. EPA further asserts that CAA section 111 standards "can promote technological innovation through (i) the expanded use of the technology that is considered to be the best demonstrated technology; (ii) the further development of the best demonstrated technology; and (iii) the development of technology that is emerging, but that is not necessarily on a path to become the best demonstrated technology." *Id.*

In the first instance, there is no reference to promoting "technological innovation" in section 111. Moreover, even if "technological innovation" is a valid "subfactor," it does not provide an independent, alternative basis for selecting a BSER that does not otherwise meet the express statutory criterion of being "adequately demonstrated."

This conclusion is supported by the *Costle* case itself. In *Costle,* EPA promulgated a section 111 standard to address SO_2 emissions from power plants. In its original proposed rule, EPA identified "wet scrubbing" as BSER and proposed that the emissions standard should correspond to 85 percent removal of potential uncontrolled SO_2 emissions. *See* 657 F.2d at 326. In the final rule, however, EPA adopted a more lenient, variable percentage reduction standard, consisting of a range between 70 and 90 percent. *Id.* at 316. One of the rationales EPA proffered for the less

stringent variable percentage reduction approach was that it would have the co-benefit of encouraging some plants to use the then-emerging dry scrubbing technology for SO_2 removal. *Id.* at 327. Specifically, EPA reasoned that a uniform 90 percent removal requirement would discourage deployment of dry scrubbing, while a 70 percent alternative would promote deployment of the technology by plants using low sulfur coals.

Thus, encouragement of the emerging technology of dry scrubbing was a rationale for EPA's promulgation of a less stringent standard than it would have adopted otherwise. EPA's reliance on the *Costle* decision to justify a more stringent standard turns the case on its head.

Furthermore, it is important to recognize that, in *Costle,* the already widely-used "wet scrubbing" technology remained the BSER upon which the final standard was based. The *Costle* court noted some ambiguity about whether EPA also had determined that "dry scrubbing" was an "adequately demonstrated" technology. *Id.* at 314 n. 157 ("[A]t times EPA's discussion comes close to suggesting that dry scrubbing may be adequately demonstrated"). To avoid doubt, the *Costle* court, as discussed above, expressly held that the record did *not* support a finding that dry scrubbing was an "adequately demonstrated" system of reduction. *Id.* In other words, if EPA had promulgated an SO_2 standard based on the emerging technology of dry scrubbing as BSER, the *Costle* court would have invalidated that standard.

Accordingly, *Costle* does not provide support for the proposition that promoting "technological innovation" provides a rationale for EPA to identify as "adequately demonstrated" a system of

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emission reduction for which there is a total absence of commercial-scale experience.[7] Indeed, the *Costle* court itself issued this important caveat: "Recognizing that the Clean Air Act is a technology-forcing statute, we believe **EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible** and will produce the improved performance necessary to meet the standard." *Id.* at 364 (emphasis added). Notably, the *Costle* court concluded that pilot scale data was not sufficient evidence to meet this test.

EPA's citation of legislative history is also unavailing. The Agency strings together highly general quotations suggesting that Congress believed that the section 111 should promote technological innovation. For example, EPA quotes a 1970 Senate Committee report (not a conference report) that said that the section 111 standards should "provide incentives for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources." 79 *Fed. Reg.* at 1465, *citing* S. Rep. 91-1196 at 16 (1970). EPA also quotes a 1977 Senate Committee report (again, not a conference report) that looked back and concluded that the earlier 1970 Congress must have intended section 111(b) to "stimulate the development of new technology." 79 *Fed. Reg.* at 1465 *citing* S. Rep. 95-127 at 17 (1977). These highly generalized quotations from the legislative history do not trump the express statutory requirement that the section 111 standards be based on a system of emissions

[7] In the Proposal, EPA notes that the *Costle* case pre-dates the Supreme Court's decision in *Chevron U.S.A., Inc. v. NRDC,* 467 U.S. 837 (1984), which outlined a two-step framework for statutory construction in federal rulemaking. However, the Proposal concedes that the *Costle* court's interpretations are "fully consistent with the *Chevron* framework." 79 *Fed. Reg.* at 1466. Therefore, the Agency acknowledges the *Chevron* standard of judicial review also would have resulted in a holding that dry scrubbing technology was not "adequately demonstrated" based on the record in question in *Costle.*

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reduction that has been "adequately demonstrated." If EPA cannot provide sufficient record evidence that an emerging technology is "adequately demonstrated," then this legislative history does not help the Agency.

At most, the legislative history helps shine a light on the provisions in section 111 that expressly frame how EPA should address emerging technologies, and which the Agency has ignored in the Proposal. For example, section 111(b)(1) requires EPA to review, and as appropriate, revise section 111(b) standards at least every eight years. This provision clearly requires EPA to take into account emissions control technologies that have crossed over from pilot scale to industry-wide commercial use—the possible status of CCS in some years hence. If EPA believes CCS is just a few years away from becoming a feasible commercial-scale technology for fossil fuel-based power plants nation-wide, then the Agency fails to explain why it would not be more reasonable to invoke its CAA section 111(b)(1) review-and-revise authority at that time rather than impose an infeasible and unachievable CCS-based standard now.

Similarly, the Proposal fails to address another provision in section 111 that expressly concerns technology innovation: CAA section 111(j). Section 111(j) authorizes EPA to grant a conditional waiver from performance standards to a regulated source that wants to use an innovative system of emission reduction that is not yet adequately demonstrated but is eventually capable of achieving or exceeding the standard.

The *Costle* court reasoned that Congress intended "substantial use" of section 111(j). *See* 657 F.2d at 347. Furthermore, the *Costle* court interpreted a "symbiotic" relationship between

section 111(a) and section 111(j). Specifically, the court reasoned that if EPA were to set section 111 standards that were *too stringent* it could frustrate the Congressional objectives behind the waiver provision, holding that the "ability to grant section 111(j) waivers would be unduly restricted or entirely foreclosed if the [section 111 emissions reduction requirements] were set too high." *Id.* In other words, the *Costle* court reasoned that EPA would defeat the Congressional scheme under section 111 for promoting technological innovation if it set the performance standards for new units at a level that assumed use of an as-yet-undemonstrated emerging emission reduction technology. Indeed, such an approach could discourage the evolution of the technology by prematurely mandating its use throughout the industry. Instead, under the "symbiotic" section 111(a)-111(j) framework, EPA should set the performance standards at a level corresponding to an adequately demonstrated technology, and use 111(j) waivers to encourage use of the emerging technology.

As explained in Section IV, the Proposal runs directly contrary to the *Costle* reasoning. By requiring all new fossil fuel-based EGUs to implement the unproven partial CCS technology immediately, the Proposal would inhibit the construction of such plants, thereby *discouraging* instead of encouraging deployment of CCS. By contrast, it would be more consistent with *Costle* and more reasonable generally for EPA to set emissions standards for new fossil fuel-based EGUs based on highly efficient generation technology as the BSER, while inviting applications for 111(j) waivers from those plant developers who would like to use partial CCS. Such waivers could attract interest from those plant developers who, with time, could assemble the myriad components needed at this point to move forward with CCS—including federal

funding, CO_2 pipeline rights-of-way, CO_2 injection arrangements, etc. EPA should move forward with the *Costle* approach or explain why the *Costle* approach is not mandated here.

In the end, the interpretation of "adequately demonstrated" that EPA offers in the Proposal with respect to the emerging technology of CCS is essentially circular. The Agency implicitly argues that in determining whether CCS is "adequately demonstrated" it may consider whether by having EPA *deem* CCS "adequately demonstrated" it will *become* so—because if EPA requires every new fossil fuel plant to use partial CCS then partial CCS necessarily will become "adequately demonstrated" as quickly as new plants are constructed. This interpretation is contrary to section 111(a) and arbitrary and capricious. Congress could not have intended this interpretation because it would allow EPA to find even a purely theoretical system of emissions reduction to be "adequately demonstrated" solely by exercise of regulatory fiat. Instead, **the only reasonable interpretation of section 111 is that it requires EPA to identify a system of emissions reduction that already has been "adequately demonstrated." Section 111 does not empower EPA to "adequately demonstrate" new systems of emission reduction by means of imposing a new regulatory obligation.**

B. EPA Misinterprets the Case Law on Section 111(a), which Prohibits EPA from Promulgating Standards that Are Exorbitantly Costly on a Unit Basis.

1. EPA's Interpretation of "Cost" to Allow it to Consider Costs on a National Basis Irrespective of Exorbitant Unit-Specific Costs is Not Reasonable nor Supported by Case Law.

EPA asserts that case law on section 111 provides that "to be 'adequately demonstrated,' the system must be 'reasonably reliable, reasonably efficient, and … reasonably expected to serve the interests of pollution control without being exorbitantly costly in an economic or

environmental way.'" 79 *Fed. Reg.* at 1464 (quoting *Essex Chemical*, 486 F.2d at 433). Cost is also a consideration in the "achievable" prong of the section 111(a) test. *See Nat'l Lime Ass'n*, 627 F.2d at 431, n.46 ("The statutory standard is one of achievability, given costs. Some aspects of 'achievability' cannot be divorced from consideration of 'costs.'").

However, EPA further claims that it has the authority to "consider the various factors it is required to balance on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking." 79 *Fed. Reg.* at 1465. The Agency draws this inference from the *Costle* decision, in which the court stated that section 111 "gives EPA authority when determining BSER to weigh cost, energy and environmental impacts in the broadest sense—at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Costle*, 657 F.2d at 330.

The Proposal's recitation of the court's analysis in *Costle* is generally unobjectionable. However, it is important to recognize that the *Costle* decision only provides that EPA's cost analysis authority is not *limited* to a plant-level analysis. That is not the same as saying that EPA may disregard a plant-level analysis altogether. Plant-level costs will necessarily factor into the initial determination as to whether the system has been "adequately demonstrated." In other words, if the costs of implementing a technology are so extreme as to preclude the use of a system of emission reduction at regulated sources, then the system is not "adequately demonstrated" and the standard is not "achievable"—and therefore national or regional level impacts of imposing the standard are immaterial to the analysis.

In particular, it is impossible to read *Costle* as EPA suggests it be read—that is, to authorize EPA to promulgate section 111 standards that are exorbitantly costly at the plant level so long as these costs are somehow "reasonable" when spread across the entire economy. Indeed, the facts in *Costle* are the complete inverse of this scenario. As discussed above, in *Costle,* EPA initially proposed a standard of performance corresponding to an 85 percent removal of SO_2 emissions, and presumably found the costs of such a standard to be reasonable. However, EPA ultimately finalized the less stringent variable percentage reduction standard. One of EPA's rationales for finalizing a more lenient standard was that the original, more stringent standard would have imposed unreasonably high costs on a regional and national basis. *See* 657 F.2d at 336-338 (describing EPA's econometric analysis and findings). The *Costle* court held that it was permissible for EPA to consider these broader cost impacts in settling on a more lenient variable percentage standard, even after initially finding that the 85 percent standard was adequately demonstrated and achievable at individual plants.

Accordingly, *Costle* does not provide support for an interpretation of section 111(a) under which EPA could promulgate a standard that was exorbitantly costly at the plant level if it found that the standard would not impose unreasonable regional and national costs. Indeed, such an interpretation would be arbitrary and capricious because it effectively would allow EPA to select a BSER and set a resulting performance standard that was unreasonably costly for each individual source in a source category—thereby preventing construction of *any* new facilities in that category—provided that EPA determined that this ban on construction of new facilities would not have an unreasonable impact on U.S. gross domestic product. Congress could not

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have intended section 111 to provide EPA with the authority to impose a construction moratorium in the various regulated source categories, including the electric power sector.

Thus, whether at the initial "adequately demonstrated" stage or in determining what system is "best," EPA cannot use national-level cost analysis to issue a standard that ultimately is not adequately demonstrated or achievable at the plant level, or as a way to overcome the fact that plant-specific costs are exorbitant and unreasonable. Rather, as in *Costle,* EPA may use such a "grand scale" analysis to shift to a less stringent standard if the Agency finds that the standard would achieve comparable environmental benefits at lower overall cost.

2. EPA May Not Ignore a System of Reduction's Exorbitant Costs on the Basis of the Magnitude of Reductions It Can Achieve.

EPA also quotes an extended excerpt from *Costle* that places emphasis on the magnitude of emissions from fossil fuel-based power plants. *See* 79 *Fed. Reg.* at 1464 (quoting *Costle*, 657 F.2d at 313). Though EPA does not expressly state as much, EPA suggests that this alone supports the imposition of more stringent and costly standards for fossil fuel-based power plants. This rationale is not supported by the case law generally and also ignores critical contextual distinctions in *Costle* discussed below.

Costle involved a rulemaking under the 1977 version of the CAA, which included a legislative mandate that EPA issue separate percentage reduction requirements for coal-based sources in particular. *See* 42 U.S.C. § 7411(a)(1)(A)(ii) (1982). Thus, coal-based power plants received "special" attention under the 1977 CAA's version of section 111. The same cannot be said under the provision in the U.S. Code today.

Furthermore, nothing in *Costle* itself supports the implication that standards may be imposed upon fossil fuel-based power plants that are not based on a BSER determined with consideration of costs. In fact, the court in *Costle* specifically rejected arguments by environmental group petitioners that EPA must base section 111 standards on an assumption that all plants would use the system of emissions reduction corresponding to the "maximum technologically feasible level of control." 657 F.2d at 329. Instead, the *Costle* court upheld EPA's issuance of a variable percentage reduction standard based on EPA's determination that a less stringent, variable standard "would achieve virtually the same emission reductions at a national level as a uniform approach but at substantially *lower* costs." 657 F.2d at 327 (emphasis added). In other words, the *Costle* decision only affirmed EPA's consideration of total reductions and cost as a rationale for selecting a *more lenient* emissions standard than the one preferred by environmental group petitioners.

Finally, EPA evidently wants to have it both ways. On the one hand, the Agency implies that a standard based on partial CCS is required—regardless of feasibility and cost—because it will result in substantially greater reductions than would result if new fossil fuel-based power plants did not use CCS. Yet, the Agency also insists that the additional costs from the proposed standards "will, on a nationwide basis, be small because no more than a few new coal-based projects are expected." 79 *Fed. Reg.* at 1480. Assuming for the sake of argument that EPA is correct that costs will be low because only a few new coal-based plants would be built anyway, then EPA has no rational basis for also arguing that a meaningful additional amount of total emissions reductions would result from requiring partial CCS instead of basing the section 111 GHG standards on highly-efficient coal-based generation technology.

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3. It is arbitrary and capricious for EPA to use highly speculative "revenue enhancements" to justify proposed standards that otherwise would impose exorbitant costs.

EPA interprets section 111 as allowing EPA to consider "any revenues generated by the sale of any by-products of the control process," and concludes that the costs of pollution control "should be offset" by such revenues. 79 *Fed. Reg.* at 1464, 1478. Yet, EPA concedes that "no D.C. Circuit case addresses how to account for revenue generated from the byproducts of pollution control" but concludes that "it is logical and a reasonable interpretation of the statute that the costs of the control technology should be offset by any revenues from the sale of pollutants or pollution control byproducts associated with those controls." *Id.*

EPA fails to identify any section 111 rulemakings in which the Agency has taken into account the revenues from pollution control byproducts in considering the costs of its proposed standards. In addition, the statutory text says nothing about any balancing the costs of a standard with potential revenues; rather, it is the *costs* in particular that must be considered in determining whether technology is "adequately demonstrated" and whether a standard is "achievable." Finally, EOR revenues would not be available everywhere, but only theoretically in locations where EOR is occurring and there is a market for captured anthropogenic CO_2 to be used for EOR.

In any event, even if EPA is permitted to consider "revenue enhancements," it is not permitted to consider enhancements that are as speculative and variable as potential revenue from EOR. As discussed in section IV below, the EOR market is highly region-specific. Furthermore, EOR providers have shown themselves to be particularly uninterested in the obligations associated

with permanent sequestration. Accordingly, EPA has failed to meet its burden of demonstrating that "revenue enhancements" from EOR are a sufficiently plausible element of future CCS projects that they may be considered as offsets in any reasonable cost analysis.

C. EPA Cannot Rely on Extra-Statutory "Purposes" to Justify its Determination of a Standard of Performance.

In addition to considering the four factors of feasibility, cost, emissions and technological innovation, EPA claims that it "must be mindful of the purposes of §111" in determining BSER. 79 *Fed. Reg.* at 1463. EPA attempts to base this assertion on *Costle* and the "six purposes" identified in that decision. However, such an interpretation is a misreading of the decision and its factual context. As noted above, *Costle* considered certain "purposes" of section 111 in the highly specific context of whether EPA could issue a *variable* percentage reduction standard under the 1977 version of CAA section 111, as opposed to a uniform standard applicable to all plants. *See* 657 F.2d at 325 ("During [the 1977 legislation's] passage through Congress the Conferees issued a clarifying statement that EPA may promulgate a variable percentage reduction standard so long as the agency determines that the standard does not undermine the essential purposes of the Act."); *see also id.* at 339 (noting that the legislative history instructs that the CAA's six purposes "must be accommodated *whenever EPA chooses to vary the percentage reduction standard*" (emphasis added)). Thus, as a first matter, the discussion of statutory purposes in *Costle* has nothing to do with the definition of a section 111 "standard of performance" generally.

Moreover, assuming for the sake of argument that the "purposes" identified in the *Costle* case are relevant to **all** section 111 rulemakings, then EPA should consider all six purposes cited in the decision. Instead, in the Proposal, EPA "cherry-picks" among them, citing only four ("not

giv[ing] a competitive advantage to one State over another in attracting industry;" "reducing emissions as much as practicable;" "forc[ing] the installation of all the control technology that will ever be necessary on new plants at the time of construction;" and "forc[ing] the development of improved technology").

EPA also selectively edits even those four purposes it asserts are relevant. Specifically, as discussed above, the Proposal quotes the fourth purpose as "reducing emissions as much as practicable." The full statement of the purpose in *Costle* is: "The standards must *maximize the potential for long-term economic growth* by reducing emissions as much as practicable" (emphasis added). As further explained by the court, this purpose reflects a goal to "increase the amount of industrial growth possible within the limits set by the air quality standards." 657 F.2d at 325. By focusing purely on one part of this statutory purpose (to maximize emissions reductions) while ignoring the other component (to maximize long-term economic growth), the Proposal distorts both legislative history and *Costle*.

Last, the Proposal overlooks other purposes considered relevant in *Costle*. In particular, *Costle* considered a purpose of "maximizing the use of locally available fuels." 657 F.2d at 339. There is no indication in the Proposal that EPA considered this factor in determining BSER. In fact, given EPA's acknowledgment that partial CCS could not be implemented in many parts of the country, EPA arguably violates this statutory purpose. This follows a pattern in the Proposal where EPA selectively favors broad statutory purposes and "key factors" over core section 111 requirements set forth in the statute itself, i.e., that section 111 standards must be "achievable"

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based on the “best” system “adequately demonstrated” for the regulated industry, in light of the relevant statutory considerations, including costs.

Message

From: POWER-GEN International [subscriptions@PollutionEquipmentNews.com]
Sent: 10/12/2015 11:57:12 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: What Are the Issues Facing Our Industry?

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From: Sierra Club [information@sierraclub.org]
on behalf of Janet Byrd Ex. 6 Personal Privacy (PP)
Sent: 10/30/2013 2:43:10 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Suspend toxic neonicotinoids to save our food supply

Oct 30, 2013

Administrator Gina McCarthy

Dear Administrator McCarthy,

We request that the EPA act now to immediately suspend registration of neonicotinoids

United States bee populations are in a nationwide free fall, putting our food supply in jeopardy. Not only have we seen widespread honeybee deaths and disappearances, called "Colony Collapse Disorder" (CCD). We have also seen a dramatic decrease in the wild bee population. Massive and continuing declines in the bee population threaten the survival of the fruits and vegetables grown on our soil.

In the past several months, four separate studies have added substantial weight to the growing body of evidence showing that widespread use of neonicotinoids -- like imidacloprid and clothianidin -- is linked to Colony Collapse Disorder. One study found that colonies exposed to neonicotinoids produced 85 percent fewer queens, meaning the creation of 85 percent fewer hives! United States Department of Agriculture bee expert Jeffery Pettis rightly calls the findings "alarming."

Sincerely,

Janet Byrd
Meramec Ex. 6 Personal Privacy (PP)
Ex. 6 Personal Privacy (PP)

Message

From: EUCI Events [events@eucievents.com]
Sent: 9/6/2016 12:39:18 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: B - 2016 EPA Fish & Shellfish Impingement Conference - Early Bird Rates End Friday!

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From: EUEC 2017 [pdayal@euec.ccsend.com]
on behalf of EUEC 2017 [pdayal@euec.com]
Sent: 12/6/2016 12:17:17 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Discounted Registration for EUEC 2017: Feb 8-10, San Diego, CA

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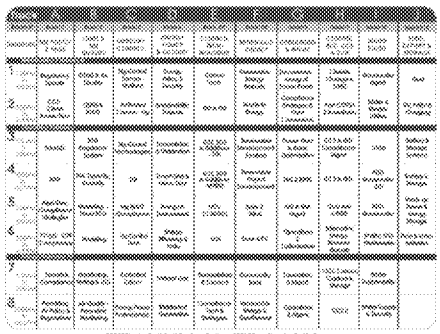

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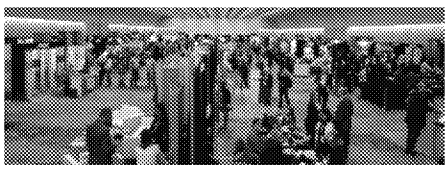

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Message

From: KnowWho Auto Mailer [automail@knowwho.com]
Sent: 5/8/2016 7:03:08 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Please fully study the impacts of fracking pollution on our drinking water

Dear Hon. Regina A. McCarthy,

I'm writing to urge the EPA to listen to its Science Advisory Board and clarify the conclusions of your draft assessment of potential impacts of fracking on drinking water, and to work to fill in the gaps in this study.

Fracking poses a serious public health risk, especially to expectant mothers and their children. The chemicals used in fracking include well-known carcinogens, hormone disruptors, and chemicals that can harm fetal health. More than 15 million people live within a mile of a fracking well and research has found that living near fracking operations increases the risk of some birth defects by up to 30 percent. Other studies have found that living near fracking wells can lead to an increased risk for heart defects, premature birth, and high-risk pregnancy. Overall, studies have linked fracking chemicals to infertility, miscarriage, low birth weight, impaired fetal growth, birth defects, and premature birth.

The draft assessment did show evidence of drinking water contamination from fracking operations, yet the topline findings of the report suggested to the general public that fracking was safe, ignoring both evidence to the contrary and the significant uncertainties that remain. These deficiencies have led to confusion, and have allowed the industry and politicians to mislead the public, which hampers efforts to protect our health and environment from toxic contamination. For these reasons, I ask you to address the concerns of your Science Advisory Board, and ensure the final assessment is accurate and transparent in its findings and limitations.

Thank you.

Sincerely,

Judith Medoff,
Ex. 6 Personal Privacy (PP) Meramec Ex. 6 Personal Privacy (PP)

Ex. 6 Personal Privacy (PP)

SOUTHERN ENVIRONMENTAL LAW CENTER

Telephone 919-967-1450 | 601 WEST ROSEMARY STREET, SUITE 220 CHAPEL HILL, NC 27516-2356 | Facsimile 919-929-9421

August 31, 2016

VIA EMAIL AND U.S. MAIL

Mr. S. Jay Zimmerman, Director
DEQ Division of Water Resources
Wastewater Permitting, Attn: Dan River Permit
1617 Mail Service Center
Raleigh, N.C., 27699-1617
publiccomments@ncdenr.gov
jay.zimmerman@ncdenr.gov

RE: Duke Energy Carolinas Dan River Combined Cycle Station, NPDES No. NC0003468

Dear Mr. Zimmerman:

On behalf of the Roanoke River Basin Association, the Southern Environmental Law Center submits the following comments on the draft National Pollutant Discharge Elimination System ("NPDES") permit for the Dan River Combined Cycle Station of Duke Energy Carolinas, LLC, Permit No. NC0003468 (the "Dan River Permit").

As set out below, DEQ has failed to protect the Dan River and its tributaries and to require appropriate limits on numerous coal ash pollutants. This failure is even more egregious in light of the Dan River coal ash spill. The Dan River spill caused arsenic levels of 35 times the maximum contaminant level in the river, and the U.S. Fish and Wildlife Service reported that coal ash lines the river bed for 70 miles downstream, reaching all the way to the Kerr Reservoir. When Duke Energy stopped its cleanup efforts, it left over 90 percent of the coal ash in the Dan River.

Significantly, Duke had no permit authorizing any discharge from the pipe that caused the spill. DEQ now proposes to legalize more previously unpermitted discharges, including seeps from earthen dams that it knows "may result in dam failure," as stated in the Permit's Fact Sheet. In 2013, DEQ filed an enforcement action against Duke Energy for unpermitted seep discharges at Dan River, among other violations, but it now seeks to immunize Duke Energy from prosecution for these same discharges. Moreover, DEQ has failed to impose any limits for many coal ash pollutants discharged to the Dan River by Duke Energy before, during, and after the spill.

The draft NPDES permit for Duke Energy's Dan River coal ash facility (the "Dan River Permit") has a number of serious deficiencies:

Amnesty for Unpermitted Discharges

The Dan River Permit claims that Duke Energy Carolinas is authorized to "[c]ontinue to discharge the following . . . Seep Outfalls 102, 103, 104," but in fact these "seep outfalls" are leaks from the lagoons and are previously illegal, unpermitted discharges that were prohibited by the previous permit, which authorized discharges only from the permitted outfalls from which the lagoons were designed to discharge, pursuant to the requirements of the Clean Water Act.

Rather than attempting to legalize these previously unpermitted discharges, DEQ should require Duke Energy to take action to stop these discharges. That should not be difficult at Dan River, where Duke Energy is already committed to excavating its coal ash to lined, dry storage. Indeed, Duke Energy's own spokesman recently confirmed as much: "Brooks noted that the seeps would be eliminated once the storage ponds have been drained and the ash that's now under several feet of water is moved to a nearby, lined landfill for permanent disposal." Taft Wireback, "Hearing tonight weighs Duke Energy's coal ash plan," Greensboro News & Record, August 31, 2016 (attached as Exhibit 1).

Including a schedule of compliance to remove the source of the seeps and pollution of jurisdictional streams would further the goals of the Clean Water Act, rather than subverting them by attempting to paper over Duke Energy's violations.

Allowing Duke Energy to Use Public Waters as Its Private Wastewater System

As the Dan River Permit states (A.23), these seeps are surface waters of the State, and as jurisdictional tributary streams they are therefore also waters of the United States. Yet the Dan River Permit would designate these streams as "outfalls" – that is, components of Duke Energy's private wastewater treatment system. This is a blatant violation of the Clean Water Act. Duke Energy cannot be allowed to appropriate public waters for its private wastewater system.

An NPDES permit that purports to authorize the use of waters of the United States as internal components of a wastewater treatment system will not shield the polluter. *See Cape Fear River Watch, Inc. v. Duke Energy Progress, Inc.*, 25 F. Supp. 3d 798 (E.D.N.C. 2014).

DEQ Cannot Permit the Seeps into Railroad Branch Stream

NPDES permits control pollution by setting (1) limits based on the technology available to treat pollutants ("technology based effluent limits") and (2) any additional limits necessary to protect water quality ("water quality-based effluent limits") on the wastewater dischargers. 33 U.S.C. §§ 1311(b), 1314(b); 40 C.F.R. § 122.44(a)(1), (d). An NPDES permit must assure compliance with all statutory and regulatory requirements, including state water quality standards. 33 U.S.C. § 1342(a)(1)(A); 40 C.F.R. § 122.43(a); 15A N.C. Admin. Code 2H .0118.

Similarly, North Carolina law provides that "[n]o permit may be issued when the imposition of conditions cannot reasonably ensure compliance with applicable water quality standards." 15A N.C. Admin. Code 2H .0112(c); *see also* N.C. Gen. Stat. §§ 143-215.6a-c

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(authorizing civil and criminal penalties and injunctive relief for violations of surface water standards).

According to the Dan River Permit itself and Duke Energy's own reports, Duke Energy is violating surface water standards in the Railroad Branch stream that flows to the Dan River. The Dan River Corrective Action Plan report submitted to DEQ notes significant exceedances of tributary surface water standards for every listed constituent: aluminum, arsenic, chromium, cobalt, copper, cobalt, and lead – and there may be others as well, in light of the seep sampling described below.

DEQ cannot permit the seep discharges to Railroad Branch as long as surface water quality standards are being violated in the tributary. Instead, DEQ should include provisions in the permit setting out a schedule of compliance based on the coal ash removal activities at Dan River, and evaluate water quality in the stream after removal of the source is complete.

No Limits on Seep Pollutants

The seeps designated as so-called Outfalls 102-103 lack technology-based limits for arsenic – allowing 340 ug/L or 34 times the federal maximum contaminant level to be discharged to Railroad Branch stream – and they lack any limits at all for selenium, chromium, and many other coal ash pollutants. Sampling of these seeps by conservation groups has revealed elevated concentrations of coal ash pollutants including arsenic, boron, chromium, selenium, lead, and zinc. Arsenic concentrations from these seeps have been sampled as high as 221 ppb, over twenty times the maximum contaminant level, and lead concentrations were sampled at almost 100 times the standard.

Outfall 104 lacks limits for arsenic, chromium, and many other coal ash pollutants. Sampling of the seep in this location by conservation groups found arsenic at 187 parts per billion ("ppb"), or over 18 times the maximum contaminant level, along with elevated levels of boron, lead, chromium, cadmium, iron, manganese, copper, zinc, and total suspended solids.

Allowing Duke Energy to Convert Streams Into Wastewater Ditches

This permit illegally allows Duke Energy to convert streams – which are public waters, waters of North Carolina, and waters of the United States – into wastewater ditches.

The Dan River Permit would exempt Duke Energy from having to meet state water quality standards in state waters. The Permit purports to allow Duke Energy to designate the seeps – which the Permit itself admits are waters of the State – as "effluent channels." And indeed, according to the Permit (A.23), Duke Energy has already begun this process.

However, Duke Energy cannot designate a jurisdictional stream as an effluent channel "in accordance with the requirements of 15A NCAC 02B.0228," as the Permit claims, nor under the Clean Water Act.

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The CWA provides no mechanism to convert jurisdictional waters *into* point source discharges. The CWA "requires permits for the discharge of 'pollutants' *from* any 'point source' *into* 'waters of the United States.'" 40 C.F.R. § 122.1(b)(1)(emphasis added). By definition, a "point source" cannot be a "water of the United States;" a point source conveys pollutants *to* a water of the United States. Coal ash and coal ash wastewater are pollutants regulated under the Clean Water Act. In theory, an "effluent channel" could be a type of point source but only if that effluent channel is not a "water of the United States." *See* 33 U.S.C. § 1362(14)(defining point source as "any discernible, confined and discrete conveyance, including but not limited to . . . [a] channel"). In sum, jurisdictional waters cannot be point sources. Instead, water quality standards must be met in the jurisdictional waterbody – in other words, in the so-called seep.

North Carolina law incorporates the same foundational assumption – that a point source cannot be a water of the United States. "Effluent channel means a discernable confined and discrete conveyance which is used for transporting treated wastewater *to* a receiving stream or other body of water." 15A N.C. Admin. Code 2B .0202 (emphasis added). Restated, an effluent channel conveys wastewater to a receiving stream or body of water; the effluent channel cannot itself be the receiving stream. But North Carolina law goes beyond the federal CWA by prohibiting designation of an effluent channel if that channel "contain[s] natural waters except when such waters occur in direct response to rainfall events by overland runoff." 15A N.C. Admin. Code 2B .0228(2). "Natural waters" includes ground and surface waters. As with the CWA, North Carolina law prohibits designation of an effluent channel if that channel contains natural, jurisdictional surface waters. North Carolina law also prohibits designation of an effluent channel if that channel contains groundwater. In other words, an effluent channel can only be designated if that channel would be dry except during rainfall events and as a result of transporting waste water. The seeps identified by Duke Energy are both jurisdictional surface water tributaries and are influenced by natural ground water, preventing their designation as "effluent channels." This approach cannot be implemented consistent with federal and state law.

The Draft Permit Violates the Clean Water Act's Anti-Backsliding Requirements

The proposed permit would allow Duke Energy to operate a leaking wastewater treatment system. By definition, these leaks do not discharge through the permitted outfall structures, which include risers that are designed to ensure that settled pollutants remain in the lagoons and water is discharged from the top of the lagoon to the outfall discharge pipes. Thus, the proposed permit would allow Duke Energy to avoid even the minimal treatment technology in place for its currently permitted ash basin outfall.

The Clean Water Act's NPDES permitting program is structured around progressive improvements in pollution control technology. The requirement of Best Available Technology ("BAT") is predicated on the concept that as treatment technology improves, it will be incorporated into National Pollutant Discharge ***Elimination*** System permits in order to make

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progress towards Congress's "national goal" of eliminating discharges of pollutants to waters of the United States. 33 U.S.C. §§ 1251(a)(1).

For this reason, the CWA includes anti-backsliding requirements to ensure that the limits and conditions imposed new or modified NPDES permits for a facility are at least as stringent as those in previous permits. 33 U.S.C. § 1342(o); 40 C.F.R. § 122.44(l)(1) ("[W]hen a permit is renewed or reissued, interim effluent limitations, standards or conditions must be ***at least as stringent*** as the final effluent limitations, standards, or conditions in the previous permit . . . .").

The CWA's anti-backsliding requirements apply to *all* NPDES permit provisions, not just effluent limits based on BPJ. 40 C.F.R. § 122.44(l)(1); *In the Matter of Star-Kist Caribe, Inc., Petitioner*, 2 E.A.D. 758 at *3 (E.P.A. Mar. 8, 1989) (emphasis added). EPA, NPDES Permit Writers' Manual Chapter 7, § 7.2.2, p. 7-4 (Sept. 2010), *available at* http://water.epa.gov/polwaste/npdes/basics/upload/pwm_chapt_07.pdf.

The proposed permit would, for the first time, allow Duke Energy to avoid using even its existing treatment technology in favor of uncontrolled releases of leaking wastewater. For this reason, the proposed permit violates the CWA's anti-backsliding requirements. Among other things, the proposed permit would for the first time: (1) allow uncontrolled and undesigned releases from the coal ash lagoons; (2) permit a set of undesigned and uncontrolled releases as "outfalls"; (3) allow uncontrolled and undesigned releases from a permitted wastewater treatment facility; (4) allow a permitted wastewater treatment facility to leak and spew polluted water from the facility into State waters and navigable waters; (5) allow a permitted wastewater facility to operate in a way that circumvents and goes around its permitted and designed treatment system and to leak and discharge polluted water; (6) allow the facility to release discharges that are prohibited under its current permit; (7) create a new meaning and permitted category of "outfall" to allow uncontrolled, undesigned leaks and flows of polluted water; and (8) allow previously-prohibited discharges of pollutants into Railroad Branch stream that are currently violating water quality standards.

For the same reasons, the proposed permit's attempt to authorize the seeps violates the CWA's anti-backsliding provisions because it contradicts the Removed Substances provision of the current Dan River NPDES permit, which provides an important limitation in the permit to prevent the entrance of pollutants removed in the course of settling treatment from entering State and navigable waters.

The State of North Carolina has included an important standard condition in its NPDES permits for waste treatment systems like the Dan River coal ash lagoons, known as the Removed Substances provision. The Removed Substances provision of the current Dan River NPDES permit, Part II.C.6, provides:

> "Solids, sludges . . . or other pollutants removed in the course of treatment or control of wastewaters shall be utilized/disposed of . . . in a manner such as to *prevent any pollutant from such materials from entering waters of the State or navigable waters of the United States*." (emphasis added)

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This is a common-sense provision to prevent pollutants removed by waste treatment facilities from escaping out into the environment. The Removed Substances provision is an important component of the Clean Water Act's protections, and prevents waters of the United States from being polluted by waste treatment facilities such as the Dan River coal ash settling lagoons. *Yadkin Riverkeeper, Inc. v. Duke Energy Carolinas, LLC*, 141 F. Supp. 3d 428, 446 (M.D.N.C. 2015) (Removed Substances provision in N.C. coal ash lagoon NPDES permit "aims to ensure the integrity of wastewater treatment and control systems"); *In the Matter of: 539 Alaska Placer Miners*, Nos. 1085-06-14-402C & 1087-08-03-402C, 1990 WL 324284 at *8 (EPA 1990) (inclusion of Removed Substance provision "is based on the simple proposition that there is no way one can protect the water quality of the waters of the U.S. if the [polluter] is allowed to redeposit the pollutants collected in his settling ponds") (Doc. 26-9); 40 C.F.R. § 440.148(c) (Removed Substances provisions ensure that "measures shall be taken to assure that pollutants materials removed from the process water and waste streams will be *retained in storage areas*") (emphasis added).

The Removed Substances provision is also the implementation of a required permit component under the implementing regulations of the Clean Water Act. The implementing regulations for the Clean Water Act require that "[t]echnology-based effluent limitations shall be established under this subpart for solids, sludges, filter backwash, and other pollutants removed in the course of treatment or control of wastewaters in the same manner as for other pollutants." 40 C.F.R. § 125.3(g). Under the prior permit issued to Duke Energy for the Dan River plant, DEQ treated zero liquid discharge as the BAT for contaminated seeps from a coal ash impoundment. That is, consistent with the requirement to set TBELs for pollutants removed by the wastewater treatment ash ponds, the prior permit prohibited *any* discharge of removed substances to waters of the United States.

DEQ itself has cited Duke Energy for violating this provision at Dan River by allowing pollutants to enter waters of the State and navigable waters due to uncontrolled releases from the Dan River coal ash lagoons. In a February 28, 2014 Notice of Violation, DENR cites the discharge "of coal combustion residuals from the ash pond to the Dan River, class C waters of the State" as violating the Removed Substances provision: "Failure to utilize or dispose solids removed from the treatment process in such a manner as to prevent pollutants from entering waters of the State (Part II, Section C. 6. of NPDES permit)." Part II.C.6 of the Dan River NPDES Permit contains the Removed Substances permit provision.

The proposed Dan River Permit would allow pollutants removed in the course of treatment to enter waters of the State and United States via leaks of polluted wastewater that may spring out of the lagoons and start discharging to public waters at any time until the ash is removed. As such, the proposed permit's approach to authorizing the seeps violates the existing permit's Removed Substances Provision, and to the extent it contradicts the Removed Substance Provision, it violates the CWA's anti-backsliding requirements in this additional way.

In addition, it is unclear from the permit language whether Duke Energy could obtain authorization under the permit for a new seep without going through public notice and comment. These notice and comment procedures are essential if the permit is to be modified to include any new discharge.

Compared to 2013 permit, the current draft Permit also eliminates limits on discharges of iron, and increases the limits for Oil & Grease and total suspended solids. There is no justification for these changes when Duke Energy proposes to discharge all the remaining wastewater from the basins into the Dan River. If anything, tighter limits should be required.

Inadequate Protections for Decanting and Dewatering

This permit would legalize Duke Energy's dumping of untreated coal ash water into the Dan River – exactly what happened in the infamous Dan River spill.

The Dan River Permit (A.3) would allow Duke Energy to pump out the free water into the Dan River with no limits on arsenic, selenium, and numerous other pollutants, and does not even require monitoring for toxic pollutants like lead and hexavalent chromium that are associated with Duke Energy's coal ash basins throughout North Carolina.

The same defects apply to the dewatering section of the Permit (A.4), which would allow the even more toxic water that has saturated the Dan River coal ash to be discharged without any limits on these toxic pollutants.

This permit thus authorizes a dumping of large quantities of coal ash polluted water, loaded with heavy metals and toxics, into the Dan River.

Fish tissue monitoring (A.24) for arsenic, selenium, and mercury cannot substitute for enforceable effluent limitations.

Duke Energy's spokesman claimed recently in the press that Duke would treat the wastewater it will pump out of the Dan River coal ash pits: "Brooks of Duke Energy said that under terms of the permit, the utility would treat that water before discharging into the river." Exhibit 1. Currently, however, no such treatment is required in the permit. Since Duke Energy apparently plants to treat its wastewater discharges, DEQ should make treatment an enforceable condition of the Permit and impose appropriate technology-based limits on the toxic pollutants and others missing from the current draft, as explained below.

The Clean Water Act requires this NPDES permit to impose technology-based effluent limits ("TBELs") reflecting "the minimum level of control that must be imposed in a permit." 40 C.F.R. § 125.3. For the pollutants at issue in the Dan River Permit, TBELs must reflect the pollution reduction achievable by "application of the best available technology economically achievable" ("BAT"). 40 CFR 125.3(a)(2)(iii)-(v). Duke Energy must comply with the effluent limitations that could be achieved by the BAT. The BAT sets a stringent treatment standard that requires "elimination of discharges of all pollutants if . . . such elimination is technologically and economically achievable." 33 U.S.C. § 1311(b)(2)(A).

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In this case, DEQ has already imposed technology-based effluent limitations for decanting and dewatering of coal ash basins at the Sutton facility in Wilmington. The Sutton NPDES permit (attached as Exhibit 2) contains technology-based limits for arsenic (monthly average 10 ug/L, daily max 50 ug/L), selenium (monthly average 5 ug/L, daily max 56 ug/L), and lead (monthly average 25 ug/L, daily max 33.8 ug/L), in addition to the mercury limit of 47 ng/L.

These limits are achievable today and their inclusion in the Sutton permit has not been challenged by Duke Energy, which is bound by the terms of that permit. At a minimum, these same limits must be included in the Dan River Permit as well.

Inadequate Monitoring

During decanting and dewatering, Duke Energy should be required to take daily samples. These activities are not part of the normal operation of the plant because they are not part of its wastewater treatment function. Special care needs to be taken to ensure the limits in the permit are enforced. Some of the limits in the Permit have only monthly sampling, which is totally inadequate because Duke Energy can discharge all or most of the wastewater without sampling for these parameters.

Groundwater Contamination Remains a Serious Concern

More than a dozen private homes lie within a two-mile radius of the ash ponds or ash landfill, and five public drinking water wells are located within a five-mile radius of the site. Since at least 1993, elevated levels of pollutants from the coal ash have been found in groundwater under, at, and around Dan River facility. These substances include toxic pollutants including arsenic, antimony, chromium, and lead; as well as other pollutants including sulfate, boron, iron, manganese, and total dissolved solids.

Despite the well-documented contamination of residential water supply wells around Duke Energy coal ash pits in North Carolina, DEQ has failed to require groundwater monitoring for hexavalent chromium in the Dan River Permit. This parameter must be added.

Conclusion

The draft permit is inconsistent with the requirements of North Carolina and federal law for these reasons described above. For these reasons, we ask that the permit be withdrawn, rewritten, and reissued for the public to comment on an NPDES permit that protects water quality and the public interest.

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Thank you for your consideration of these comments.

Sincerely,

Frank S. Holleman III
Senior Attorney

Nicholas S. Torrey
Staff Attorney

cc: Gina McCarthy, EPA Administrator
Heather McTeer Toney, Regional Administrator, Region 4

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EXHIBIT 1

Hearing tonight weighs Duke Energy's coal ash plan
News & Record, 8/31/16

Hearing tonight weighs Duke Energy's coal ash plan

Andrew Krech/News & Record

A worker walks along the train tracks past a coal ash pond at the Dan River Steam Station on Thursday, Jan. 14, 2016, in Eden.

What: Public hearing, wastewater permit Dan River plant

When: 6 p.m. today, speaker registration starts at 5 p.m.

Where: Eden City Hall, 308 E. Stadium Drive

Posted: Wednesday, August 31, 2016 12:00 am

By Taft Wireback taft.wireback@greensboro.com

•

State environmental officials are holding a public hearing this evening on a proposed permit that would enable Duke Energy to drain and excavate the coal ash ponds that triggered the retired Dan River Steam Station's infamous 2014 spill.

The hearing scheduled to begin at 6 p.m. in Eden City Hall focuses on a proposed wastewater permit for the two ponds and the gas-powered Duke Energy Combined Cycle plant nearby that replaced the company's steam station several years ago.

Utility officials say that Duke needs the discharge permit to successfully close the ponds, excavate the ash that is submerged there and move it to a lined landfill. The ash accumulated over the years as waste from the coal-fired steam station that Duke shuttered in 2012.

"The NPDES permits are a necessary step in completing the excavation of the ash basin at Dan River, which is something that environmentalists have said they want," Duke spokesman Jeff Brooks said, using the acronym

for the National Pollution Discharge Elimination System.

A law passed by state legislators after the Dan River spill two years ago requires Duke to drain those ponds, dig up the now-submerged ash and dispose of it in a lined landfill by August 2019.

But some environmentalists are skeptical of procedures detailed in the proposed Dan River permit, contending the proposal simply gives the utility a license to pollute.

"It's hard to believe that North Carolina's environmental agency would authorize Duke Energy to dump millions of gallons of untreated coal ash polluted water into the Dan River Basin after the catastrophe of the 2014 Dan River spill," said Frank Holleman, senior attorney for the Southern Environmental Law Center in Chapel Hill.

Holleman alleged the permit would authorize Duke Energy "to put unlimited arsenic, mercury and lead from its coal ash pits" into the Dan ecosystem.

The permits would allow so-called "seeps" from the earthen walls of the ponds, leakage into the river that is not treated but which utility officials and regulators say is necessary to preserve the walls' structural integrity.

Brooks noted that the seeps would be eliminated once the storage ponds have been drained and the ash that's now under several feet of water is moved to a nearby, lined landfill for permanent disposal.

DEQ Communications Director Mike Rusher said that the proposed permits include limitations on how much can be released as well as testing requirements that protect both surface water and groundwater.

He said that the proposed permit is still in its formative stage, that DEQ is holding the hearing to gather opinions about it and that the agency welcomes all points of view for suggested improvements.

But Rusher said no permit would allow Duke to damage the ecosystem with impunity.

"Even though this per-mit is in an initial draft phase, any violations of the Clean Water Act could result in enforcement action from the state environmental department," Rusher said.

In addition to regulating wastewater from the new gas plant that is not sullied by coal ash, the proposed permit defines how the utility can drain the remaining pond water that contains varying amounts of coal ash pollutants.

Brooks of Duke Energy said that under terms of the permit, the utility would treat that water before discharging into the river.

The overall Dan River site started with about 3 million tons of stored ash, roughly 1.6 million of which is held in the two ponds.

The remainder is stored dry in stacks elsewhere on the Dan River plant's property, and that material already is being removed in great volumes to make room for a lined landfill that Duke Energy envisions building to hold the ash excavated from the ponds during the next few years.

EXHIBIT 2

Sutton NPDES Permit No. NC0001422

December 3, 2015

STATE OF NORTH CAROLINA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES
DIVISION OF WATER RESOURCES

PERMIT

TO DISCHARGE WASTEWATER UNDER THE

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of North Carolina General Statute 143-215.1, other lawful standards and regulations promulgated and adopted by the North Carolina Water Quality Commission, and the Federal Water Pollution Control Act, as amended,

Duke Energy Progress, LLC

is hereby authorized to discharge wastewater from a facility located at the

L. V. Sutton Energy Complex
801 Sutton Steam Plant Road, Wilmington
New Hanover County

to receiving waters designated as the Cape Fear River and Sutton Lake in the Cape Fear River Basin in accordance with the discharge limitations, monitoring requirements, and other applicable conditions set forth in Parts I, II, III, and Appendix A.

This permit modification shall become effective December 7, 2015.

This permit and the authorization to discharge shall expire at midnight on December 31, 2016.

Signed this day December 3, 2015.

Original signed by S. Jay Zimmerman

S. Jay Zimmerman P.G., Director
Division of Water Resources
By the Authority of the Environmental Management Commission

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SUPPLEMENT TO PERMIT COVER SHEET

All previous NPDES Permits issued to this facility, whether for operation or discharge are hereby revoked. As of this permit issuance, any previously issued permit bearing this number is no longer effective. Therefore, the exclusive authority to operate and discharge from this facility arises under the permit conditions, requirements, terms, and provisions included herein.

Duke Energy Progress, LLC is hereby authorized to:

1. Continue to discharge cooling water, low volume wastes, stormwater, and treated wastewater from internal wastewater outfalls 005, 006, 007, and 009 to the Effluent Channel, and internal stormwater outfalls SW001, SW002, SW003, SW004, SW005, SW006, and SW007 to the Effluent Channel (the Effluent Channel discharges via external Outfall 008 to the Sutton Lake); ash pond discharge, groundwater, treated wastewater, and stormwater runoff (Outfall 001, Outfall 002 and Outfall 004); at a facility located at Sutton Steam Electric Plant, 801 Sutton Steam Plant Road, Wilmington, New Hanover County, and

2. Discharge wastewater (via Outfall 002, Outfall 004, and Outfall 008) from said treatment works at the locations specified on the attached map into the Sutton Lake which is classified C waters in the Cape Fear River Basin.

3. Discharge wastewater and groundwater (via Outfall 001) from said treatment works at the location specified on the attached map into the Cape Fear River, classified C-Swamp waters in the Cape Fear River Basin.

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Part I

A. (1.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 001-normal operation)[7] [15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge to the Cape Fear River from **Outfall 001** - removing the free water above the settled ash layer that does not involve mechanical disturbance of the ash **(recirculation cooling water, non-contact cooling water, and treated wastewater from outfalls 002, and 004)**. Such discharges shall be limited and monitored[6] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location[1]
Flow, MGD			Daily	Estimate or pump logs	Effluent
Temperature[1,2], ^{0}C			Quarterly	Grab	U, D
Temperature[2], ^{0}C			Daily	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		Weekly	Grab	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Weekly	Grab	Effluent
Total Suspended Solids, mg/L	30.0 mg/L	100.0 mg/L	Weekly	Grab	Effluent
Total Nitrogen (NO_2 + NO_3 + TKN), mg/L			Weekly	Grab	Effluent
Total Phosphorus, mg/L			Weekly	Grab	Effluent
Dissolved Oxygen, mg/L			Weekly	Grab	Effluent
Acute Toxicity[3]			Monthly	Grab	Effluent
Total Mercury[4]	47.0 ng/L	47.0 ng/L	Weekly	Grab	Effluent
Total Arsenic	10.0 µg/L	50.0 µg/L	Weekly	Grab	Effluent
Total Selenium	5.0 µg/L	56.0 µg/L	Weekly	Grab	Effluent
Total Iron	1.0 mg/L	1.0 mg/L	Weekly	Grab	Effluent
Total Lead	25.0 µg /L	33.8 µg /L	Weekly	Grab	Effluent
Total Cadmium	2.0 µg /L	15.0 µg /L	Weekly	Grab	Effluent
Total Aluminum			Weekly	Grab	Effluent
Total Copper, µg/L			Weekly	Grab	Effluent
Total Zinc, µg/L			Weekly	Grab	Effluent
Turbidity[5]			Weekly	Grab	Effluent

Notes:

1. U: Upstream, 2700 feet above outfall. D: Downstream, 1.25 miles below outfall.
2. The receiving water's temperature shall not be increased by more than 2.8°C above ambient water temperature and in no case exceed 32°C, except in the mixing zone described as follows: Extending from the eastern shore to the centerline of the river and extending not more than 1.25 miles downstream nor more than 2700 feet from the point of discharge. The cross-sectional area of the mixing zone shall not exceed 9% of the total cross sectional area of the river at the point of discharge nor 2.5% at the mouth of Toomer's Creek.
3. Acute Toxicity Limit (Fathead Minnow, 24 hour at 90%); Part I, Condition A. (10.).
4. The facility shall use EPA method 1631E.
5. The discharge from this facility shall not cause turbidity in the receiving stream to exceed 50 NTU. If the instream turbidity exceeds 50 NTU due to natural background conditions, the discharge cannot cause turbidity to increase in the receiving stream.
6. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).
7. The drawdown rate shall not exceed 1 foot/week to maintain the integrity of the dams, unless approved by the DEQ Dam Safety Program.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (2.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 001-dewatering phase)[8] [15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the commencement date of the dewatering operation and lasting until expiration, the Permittee is authorized to discharge to the Cape Fear River from **Outfall 001** ***Dewatering-removing the interstitial water/ash pore water*** **(recirculation cooling water, non-contact cooling water, and treated wastewater from outfalls 002, and 004)**. Such discharges shall be limited and monitored[6] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location[1]
Flow		2.1 MGD (applies only to ash pond discharge)	Daily	Estimate or pump logs	Effluent
Temperature[1,2], ^{0}C			Quarterly	Grab	U, D
Temperature[2], ^{0}C			Daily	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		Daily	Daily	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Weekly	Grab	Effluent
Total Suspended Solids mg/L[7]	30.0 mg/L	100.0 mg/L	Weekly	Grab	Effluent
Total Nitrogen (NO_2 + NO_3 + TKN), mg/L			Weekly	Grab	Effluent
Total Phosphorus, mg/L			Weekly	Grab	Effluent
Dissolved Oxygen, mg/L			Weekly	Grab	Effluent
Acute Toxicity[3]			Monthly	Grab	Effluent
Total Iron	1.0 mg/L	1.0 mg/L	Weekly	Grab	Effluent
Total Cadmium	2.0 µg /L	15.0 µg /L	Weekly	Grab	Effluent
Total Aluminum			Weekly	Grab	Effluent
Total Lead	25.0 µg /L	33.8 µg /L	Weekly	Grab	Effluent
Total Arsenic	10.0 µg/L	50.0 µg/L	Weekly	Grab	Effluent
Total Selenium	5.0 µg/L	56.0 µg/L	Weekly	Grab	Effluent
Total Mercury[4]	47.0 ng/L	47.0 ng/L	Weekly	Grab	Effluent
Total Copper, µg/L			Weekly	Grab	Effluent
Total Zinc, µg/L			Weekly	Grab	Effluent
Turbidity[5]			Weekly	Grab	Effluent

Notes:

1. U: Upstream, 2700 feet above outfall. D: Downstream, 1.25 miles below outfall.
2. The receiving water's temperature shall not be increased by more than 2.8°C above ambient water temperature and in no case exceed 32°C, except in the mixing zone described as follows: Extending from the eastern shore to the centerline of the river and extending not more than 1.25 miles downstream nor more than 2700 feet from the point of discharge. The cross-sectional area of the mixing zone shall not exceed 9% of the total cross sectional area of the river at the point of discharge nor 2.5% at the mouth of Toomer's Creek.
3. Acute Toxicity Limit (Fathead Minnow, 24 hour at 90%); Part I, Condition A. (10.).
4. The facility shall use EPA method 1631E.
5. The discharge from this facility shall not cause turbidity in the receiving stream to exceed 50 NTU. If the instream turbidity exceeds 50 NTU due to natural background conditions, the discharge cannot cause turbidity to increase in the receiving stream.
6. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).
7. The facility shall continuously monitor TSS concentration and the dewatering pump shall be shutoff automatically when the limits are exceeded.
8. The drawdown rate shall not exceed 1 foot/week to maintain the integrity of the dams, unless approved by the DEQ Dam Safety Program.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (3.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 002-normal operation)[4, 5]

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge to Sutton Lake and/or to the 1971 ash pond from **Outfall 002** - removing of free water above the settled ash layer that does not involve mechanical disturbance of the ash **(Old Ash Pond – coal pile runoff, low volume wastes, ash sluice water, and stormwater runoff)**. Such discharges to Sutton Lake shall be limited and monitored[3] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Weekly	Pump Logs or similar	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Weekly	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	Weekly	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		Weekly	Grab	Effluent
Total Copper, µg/L			Weekly	Grab	Effluent
Total Zinc, µg/L			Weekly	Grab	Effluent
Total Arsenic	10.0 µg/L	50.0 µg/L	Weekly	Grab	Effluent
Total Selenium	5.0 µg/L	56.0 µg/L	Weekly	Grab	Effluent
Total Mercury[1]	47.0 ng/L	47.0 ng/L	Weekly	Grab	Effluent
Total Iron	1.0 mg/L	1.0 mg/L	Weekly	Grab	Effluent
Total Aluminum			Weekly	Grab	Effluent
Chronic Toxicity [2]			Quarterly	Grab	Effluent

Notes:

1. The facility shall use EPA method 1631E.
2. Chronic Toxicity Limit (*Ceriodaphnia dubia* at 90%); Part I, Condition A. (21.).
3. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).
4. The facility shall submit EPA Form 2C for Outfall 002 as soon as practicable, but no later than 180 days from the effective date of this permit.
5. The drawdown rate shall not exceed 1 foot/week to maintain the integrity of the dams, unless approved by the DEQ Dam Safety Program.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (4.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 004-normal operation)[4, 5]

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge to Sutton Lake and/or to Outfall 001 from **Outfall 004** - removing of free water above the settled ash layer that does not involve mechanical disturbance of the ash **(New Ash Pond – ash sluice water, coal pile runoff, low volume wastes, and stormwater runoff)**. Such discharges to Sutton Lake shall be limited and monitored[3] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Weekly	Pump Logs or similar	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Weekly	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	Weekly	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		Weekly	Grab	Effluent
Total Copper, µg/L			Weekly	Grab	Effluent
Total Zinc, µg/L			Weekly	Grab	Effluent
Total Arsenic	10.0 µg/L	50.0 µg/L	Weekly	Grab	Effluent
Total Selenium	5.0 µg/L	56.0 µg/L	Weekly	Grab	Effluent
Total Mercury[1]	47.0 ng/L	47.0 ng/L	Weekly	Grab	Effluent
Total Iron	1.0 mg/L	1.0 mg/L	Weekly	Grab	Effluent
Total Aluminum			Weekly	Grab	Effluent
Chronic Toxicity [2]			Quarterly	Grab	Effluent

Notes:

1. The facility shall use EPA method 1631E.
2. Chronic Toxicity Limit (*Ceriodaphnia dubia* at 90%); Part I, Condition A. (21).
3. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).
4. The facility shall submit EPA Form 2C for Outfall 004 as soon as practicable, but no later than 180 days from the effective date of this permit.
5. The drawdown rate shall not exceed 1 foot/week to maintain the integrity of the dams, unless approved by the DEQ Dam Safety Program.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (5.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 005)

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]
Beginning with the commencement of this discharge and lasting until expiration, the Permittee is authorized to discharge from ***Internal Outfall 005*** **(Combined Cycle Plant – ultrafilter water treatment system filter backwash, closed cooling water cooler blowdown, Reverse Osmosis/Electrodeionization system reject wastewater, and other low volume wastewater)** to the Effluent Channel. Such discharges shall be limited and monitored[1] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	EFFLUENT LIMITATIONS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Daily	Pump Logs or similar	Influent or Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	2/Month	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	2/Month	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		2/Month	Grab	Effluent

Notes:

1. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (6.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 006)

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]
Beginning with the commencement of this discharge and lasting until expiration, the Permittee is authorized to discharge from ***Internal Outfall 006*** **(Combined Cycle Plant – low volume wastewater including the Heat Recovery Steam generator blowdown and auxiliary boiler blowdown)** to the Effluent Channel. Such discharges shall be limited and monitored[1] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	EFFLUENT LIMITATIONS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Daily	Pump Logs or similar	Influent or Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	2/Month	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	2/Month	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		2/Month	Grab	Effluent

Notes:

1. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (7.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 007)

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge from ***Internal Outfall 007*** **(stormwater flows from the closure activities for coal-fired units, separate from stormwater outfalls SW001 through SW007)** to the Effluent Channel. Such discharges shall be limited and monitored[2] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Weekly	Pump Logs or similar	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Monthly	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	Monthly	Grab	Effluent
Total Arsenic, µg/L			Quarterly	Grab	Effluent
Total Selenium, µg/L			Quarterly	Grab	Effluent
Nitrate/nitrite as N, mg/L			Quarterly	Grab	Effluent
Total Mercury[1], ng/L			Quarterly	Grab	Effluent

Notes:

1. The facility shall use EPA method 1631E.
2. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (8.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 009)

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge from ***Internal Outfall 009*** **(low volume wastes from a new simple cycle combustion turbine)** to the Effluent Channel. Such discharges shall be limited and monitored[1] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location
Flow, MGD			Weekly	Pump Logs or similar	Effluent
Oil and Grease	15.0 mg/L	20.0 mg/L	Monthly	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	Monthly	Grab	Effluent
pH	$6.0 \leq$ pH ≤ 9.0		2/Month	Grab	Effluent

Notes:

1. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (9.) EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS (Outfall 008)[5, 7]

[15A NCAC 02B .0400 et seq., 02B .0500 et seq.]

During the period beginning on the effective date of the permit and lasting until expiration, the Permittee is authorized to discharge to Sutton Lake from **Outfall 008 (from internal wastewater outfalls 005, 006, 007, and 009, and internal stormwater outfalls SW001 through SW007)**. Such discharges shall be limited and monitored[6] by the Permittee as specified below:

EFFLUENT CHARACTERISTICS	LIMITS		MONITORING REQUIREMENTS		
	Monthly Average	Daily Maximum	Measurement Frequency	Sample Type	Sample Location[1]
Flow, MGD			Daily	Estimate or pump logs	Effluent
Temperature ^{0}C			Daily	Grab	Effluent
Temperature [1,2], ^{0}C			Daily/Weekly	Grab	Instream
Oil and Grease	15.0 mg/L	20.0 mg/L	Monthly	Grab	Effluent
Total Suspended Solids	30.0 mg/L	100.0 mg/L	Monthly	Grab	Effluent
Total Nitrogen (NO_2 + NO_3 + TKN), mg/L			Monthly	Grab	Effluent
Dissolved Oxygen, mg/L			Monthly	Grab	Effluent
pH	6.0 ≤ pH ≤ 9.0		Daily	Grab	Effluent
Total Phosphorus, mg/L			Monthly	Grab	Effluent
Chronic Toxicity[3]			Quarterly	Grab	Effluent
Total Mercury[4], ng/L			Quarterly	Grab	Effluent
Total Arsenic, µg/L			Quarterly	Grab	Effluent
Total Selenium, µg/L			Quarterly	Grab	Effluent
Total Copper, µg/L			Quarterly	Grab	Effluent
Total Zinc, µg/L			Quarterly	Grab	Effluent

Notes:

1. Instream: 1000 feet from outfall. The facility is allowed 12 months from the effective date of the permit to begin daily instream temperature monitoring. The time is allowed for the facility to budget, design, and install the automatic monitoring station. In the interim, the instream temperature monitoring shall be conducted on a weekly basis.
2. The receiving water's temperature shall not be increased by more than 2.8°C above ambient water temperature and in no case exceed 32°C. The limit is not being implemented until further notice (Please see A. (26.)).
3. Chronic Toxicity Limit (*Ceriodaphnia dubia* at 90%); Part I, Condition A. (21.).
4. The facility shall use EPA method 1631E.
5. The facility shall install a screen or a barrier at the end of the Effluent Channel to minimize fish migration into the Channel. The design of the screen/barrier shall be submitted to the Division for approval no later than 6 month from the effective date of the permit. The screen/barrier shall be installed no later than 6 months after Division approval.
6. No later than 270 days from the effective date of this permit, begin submitting discharge monitoring reports electronically using NC DWR's eDMR application system. See Special Condition A. (23.).
7. The facility shall submit EPA Form 2C for Outfall 008 as soon as practicable, but no later than 180 days from the effective date of this permit.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

A. (10.) ACUTE TOXICITY LIMIT (QUARTERLY)- OUTFALL 001

[15A NCAC 02B .0200 et seq.]

The permittee shall conduct acute toxicity tests on a *monthly* basis using protocols defined in the North Carolina Procedure Document entitled "Pass/Fail Methodology For Determining Acute Toxicity In A Single Effluent Concentration" (Revised-July, 1992 or subsequent versions). The monitoring shall be performed as a Fathead Minnow (*Pimephales promelas*) 24 hour static test. The effluent concentration at which there may be at no time significant acute mortality is 90% (defined as treatment two in the procedure document). Effluent samples for self-monitoring purposes must be obtained during representative effluent discharge below all waste treatment.

All toxicity testing results required as part of this permit condition will be entered on the Effluent Discharge Monitoring Form (MR-1) for the month in which it was performed, using the parameter code TGE6C. Additionally, DWR Form AT-2 (original) is to be sent to the following address:

Attention: North Carolina Division of Water Resources
Water Sciences Section/Aquatic Toxicology Branch
1623 Mail Service Center
Raleigh, North Carolina 27699-1623

Completed Aquatic Toxicity Test Forms shall be filed with the Environmental Sciences Section no later than 30 days after the end of the reporting period for which the report is made.

Test data shall be complete and accurate and include all supporting chemical/physical measurements performed in association with the toxicity tests, as well as all dose/response data. Total residual chlorine of the effluent toxicity sample must be measured and reported if chlorine is employed for disinfection of the waste stream.

Should there be no discharge of flow from the facility during a month in which toxicity monitoring is required, the permittee will complete the information located at the top of the aquatic toxicity (AT) test form indicating the facility name, permit number, pipe number, county, and the month/year of the report with the notation of "No Flow" in the comment area of the form. The report shall be submitted to the Environmental Sciences Section at the address cited above.

Should any test data from either these monitoring requirements or tests performed by the North Carolina Division of Water Resources indicate potential impacts to the receiving stream, this permit may be re-opened and modified to include alternate monitoring requirements or limits.

NOTE: Failure to achieve test conditions as specified in the cited document, such as minimum control organism survival and appropriate environmental controls, shall constitute an invalid test and will require immediate follow-up testing to be completed no later than the last day of the month following the month of the initial monitoring.

A. (11.) GROUNDWATER MONITORING, WELL CONSTRUCTION, AND SAMPLING

The permittee shall conduct groundwater monitoring to determine the compliance of this NPDES permitted facility with the current groundwater Standards found under 15A NCAC 2L .0200. The monitoring shall be conducted in accordance with the Sampling Plan approved by the Division.

A. (12.) STRUCTURAL INTEGRITY INSPECTIONS OF ASH POND DAMS

The facility shall meet the dam design and dam safety requirements per 15A NCAC 2K.

A. (13.) BEST MANAGEMENT PRACTICES PLAN

The Permittee shall continue to implement a Best Management Practices (BMP) Plan to control the discharge of oils and the hazardous and toxic substances listed in 40 CFR, Part 117 and Tables II

and III of Appendix D to 40 CFR, Part 122, and shall maintain the Plan at the plant site and shall be available for inspection by EPA and DWR personnel.

A. (14.) INTAKE SCREEN BACKWASH

Continued intake screen backwash discharge is permitted without limitations or monitoring requirements.

A. (15.) NO DISCHARGE OF PCBs

As specified by 40 CFR 423.13 (a), there shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

A. (16.) BIOCIDE CONDITION

The permittee shall not use any biocides except those approved in conjunction with the permit application. The permittee shall notify the Director in writing not later than ninety (90) days prior to instituting use of any additional biocide used in cooling systems which may be toxic to aquatic life other than those previously reported to the Division of Water Resources. Such notification shall include completion of Biocide Worksheet Form 101 and a map locating the discharge point and receiving stream. Completion of a Biocide Worksheet 101 is not necessary for the introduction of a new biocide into an outfall currently being tested for toxicity.

A. (17.) FISH TISSUE MONITORING NEAR ASH POND DISCHARGE – OUTFALL 001, and OUTFALLS 002/004

The facility shall conduct fish tissue monitoring at two locations (Sutton Lake and Cape Fear River) annually and submit the results with the NPDES permit renewal application. The objective of the monitoring is to evaluate potential uptake of pollutants by fish tissue near the Ash Pond discharge. The parameters analyzed in fish tissue shall be arsenic, selenium, and mercury. The monitoring shall be conducted in accordance with the Sampling Plan approved by the Division. After the plan is approved by the Division, it will become an enforceable part of the permit.

A. (18.) CLEAN WATER ACT SECTION 316(B)

The permittee shall comply with the Cooling Water Intake Structure Rule per 40 CFR 125.95. The permittee shall submit all the materials required by the Rule with the next renewal application.

A. (19.) ASH POND CLOSURE

The facility shall prepare an Ash Ponds Closure Plan in anticipation of the ash pond closure. This Plan shall be submitted to the Division one month prior to the closure of the ash ponds.

A. (20.) LOWER CAPE FEAR MODELING

The permittee may elect to conduct a water quality model of the dilution factor for Outfall 001. Contingent upon EPA approval of the Lower Cape Fear Modeling and its results, the Reasonable Potential Analysis will be conducted again and the permit limits will be based on the new flow numbers established by the model.

A. (21.) CHRONIC TOXICITY PASS/FAIL PERMIT LIMIT (QUARTERLY) – OUTFALLS 002, 004, 008

[15A NCAC 02B .0200 et seq.]

The effluent discharge shall at no time exhibit observable inhibition of reproduction or significant mortality to ***Ceriodaphnia dubia*** at an effluent concentration of 90.0%.

The permit holder shall perform at a minimum, *quarterly* monitoring using test procedures outlined in the "North Carolina *Ceriodaphnia* Chronic Effluent Bioassay Procedure," Revised December 2010, or subsequent versions or "North Carolina Phase II Chronic Whole Effluent Toxicity Test Procedure" (Revised- December 2010) or subsequent versions. The tests will be performed **during the months**

of February, May, August, and November. These months signify the first month of each three-month toxicity testing quarter assigned to the facility. Effluent sampling for this testing must be obtained during representative effluent discharge and shall be performed at the NPDES permitted final effluent discharge below all treatment processes.

If the test procedure performed as the first test of any single quarter results in a failure or ChV below the permit limit, then multiple-concentration testing shall be performed at a minimum, in each of the two following months as described in "North Carolina Phase II Chronic Whole Effluent Toxicity Test Procedure" (Revised-December 2010) or subsequent versions.

All toxicity testing results required as part of this permit condition will be entered on the Effluent Discharge Monitoring Form (MR-1) for the months in which tests were performed, using the parameter code **TGP3B** for the pass/fail results and **THP3B** for the Chronic Value. Additionally, DWR Form AT-3 (original) is to be sent to the following address:

Attention: North Carolina Division of Water Resources
Water Sciences Section/Aquatic Toxicology Branch
1623 Mail Service Center
Raleigh, North Carolina 27699-1623

Completed Aquatic Toxicity Test Forms shall be filed with the Water Sciences Section no later than 30 days after the end of the reporting period for which the report is made.

Test data shall be complete, accurate, include all supporting chemical/physical measurements and all concentration/response data, and be certified by laboratory supervisor and ORC or approved designate signature. Total residual chlorine of the effluent toxicity sample must be measured and reported if chlorine is employed for disinfection of the waste stream.

Should there be no discharge of flow from the facility during a month in which toxicity monitoring is required, the permittee will complete the information located at the top of the aquatic toxicity (AT) test form indicating the facility name, permit number, pipe number, county, and the month/year of the report with the notation of "No Flow" in the comment area of the form. The report shall be submitted to the Water Sciences Section at the address cited above.

Should any test data from this monitoring requirement or tests performed by the North Carolina Division of Water Resources indicate potential impacts to the receiving stream, this permit may be re-opened and modified to include alternate monitoring requirements or limits.

NOTE: Failure to achieve test conditions as specified in the cited document, such as minimum control organism survival, minimum control organism reproduction, and appropriate environmental controls, shall constitute an **invalid test** and will require immediate follow-up testing to be completed no later than the last day of the month following the month of the initial monitoring.

A. (22.) INSTREAM MONITORING

The facility shall conduct semiannual instream monitoring (1000 ft. upstream and 1000 ft. downstream of the Outfall 001, and 1000 ft from Outfall 004) for total arsenic, total selenium, total mercury (method 1631E), total chromium, total lead, total cadmium, total copper, and total zinc. The monitoring results shall be submitted with the NPDES permit renewal application.

A. (23.) ELECTRONIC REPORTING OF DISCHARGE MONITORING REPORTS (STATE ENFORCEABLE ONLY) [G.S. 143-215.1(b)]

Proposed federal regulations require electronic submittal of all discharge monitoring reports (DMRs) and specify that, if a state does not establish a system to receive such submittals, then permittees

must submit DMRs electronically to the Environmental Protection Agency (EPA). The Division anticipates that these regulations will be adopted and is beginning implementation in late 2013.

NOTE: This special condition supplements or supersedes the following sections within Part II of this permit (*Standard Conditions for NPDES Permits*):

- Section B. (11.) Signatory Requirements
- Section D. (2.) Reporting
- Section D. (6.) Records Retention
- Section E. (5.) Monitoring Reports

1. Reporting [Supersedes Section D. (2.) and Section E. (5.) (a)]

Beginning no later than 270 days from the effective date of this permit, the permittee shall begin reporting discharge monitoring data electronically using the NC DWR's Electronic Discharge Monitoring Report (eDMR) internet application.

Monitoring results obtained during the previous month(s) shall be summarized for each month and submitted electronically using eDMR. The eDMR system allows permitted facilities to enter monitoring data and submit DMRs electronically using the internet. Until such time that the state's eDMR application is compliant with EPA's Cross-Media Electronic Reporting Regulation (CROMERR), permittees will be required to submit all discharge monitoring data to the state electronically using eDMR and will be required to complete the eDMR submission by printing, signing, and submitting one signed original and a copy of the computer printed eDMR to the following address:

NC DENR / DWR / Information Processing Unit
ATTENTION: Central Files / eDMR
1617 Mail Service Center
Raleigh, North Carolina 27699-1617

If a permittee is unable to use the eDMR system due to a demonstrated hardship or due to the facility being physically located in an area where less than 10 percent of the households have broadband access, then a temporary waiver from the NPDES electronic reporting requirements may be granted and discharge monitoring data may be submitted on paper DMR forms (MR 1, 1.1, 2, 3) or alternative forms approved by the Director. Duplicate signed copies shall be submitted to the mailing address above.

Requests for temporary waivers from the NPDES electronic reporting requirements must be submitted in writing to the Division for written approval at least sixty (60) days prior to the date the facility would be required under this permit to begin using eDMR. Temporary waivers shall be valid for twelve (12) months and shall thereupon expire. At such time, DMRs shall be submitted electronically to the Division unless the permittee re-applies for and is granted a new temporary waiver by the Division.

Information on eDMR and application for a temporary waiver from the NPDES electronic reporting requirements is found on the following web page:

http://portal.ncdenr.org/web/wq/admin/bog/ipu/edmr

Regardless of the submission method, the first DMR is due on the last day of the month following the issuance of the permit or in the case of a new facility, on the last day of the month following the commencement of discharge.

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2. **Signatory Requirements [Supplements Section B. (11.) (b) and supersedes Section B. (11.) (d)]**

All eDMRs submitted to the permit issuing authority shall be signed by a person described in Part II, Section B. (11.)(a) or by a duly authorized representative of that person as described in Part II, Section B. (11.)(b). A person, and not a position, must be delegated signatory authority for eDMR reporting purposes.

For eDMR submissions, the person signing and submitting the DMR must obtain an eDMR user account and login credentials to access the eDMR system. For more information on North Carolina's eDMR system, registering for eDMR and obtaining an eDMR user account, please visit the following web page:

http://portal.ncdenr.org/web/wq/admin/bog/ipu/edmr

Certification. Any person submitting an electronic DMR using the state's eDMR system shall make the following certification [40 CFR 122.22]. NO OTHER STATEMENTS OF CERTIFICATION WILL BE ACCEPTED:

"I certify, under penalty of law, that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations."

3. **Records Retention [Supplements Section D. (6.)]**
The permittee shall retain records of all Discharge Monitoring Reports, including eDMR submissions. These records or copies shall be maintained for a period of at least 3 years from the date of the report. This period may be extended by request of the Director at any time [40 CFR 122.41].

A. (24.) APPLICABLE STATE LAW (STATE ENFORCEABLE ONLY) [G.S. 143-215.1(b)]

This facility shall meet the requirements of Senate Bill 729 (Coal Ash Management Act). This permit may be reopened to include new requirements imposed by Senate Bill 729.

A. (25.) STORMWATER POLLUTION PREVENTION PLAN

The permittee shall **develop and implement** a Stormwater Pollution Prevention Plan (SPPP). The SPPP shall be maintained on site unless exempted from this requirement by the Division. The SPPP is public information. The SPPP should also specifically and separately address deconstruction, demolition, coal, and/or coal ash hauling or disposal activities. The SPPP shall include, at a minimum, the following items:

1. **Site Overview**. The Site Overview shall provide a description of the physical facility and the potential pollutant sources that may be expected to contribute to contamination of stormwater discharges. The Site Overview shall contain the following:

   (a) A general **location map** (USGS quadrangle map or appropriately drafted equivalent map), showing the facility's location in relation to transportation routes and surface waters; the name of the receiving waters to which the stormwater outfalls discharge, or if the discharge is to a municipal separate storm sewer system, the name of the municipality and the ultimate receiving waters; and accurate latitude and longitude of the points of stormwater discharge associated with industrial activity. The general location map (or alternatively the site map) shall identify whether any receiving waters are **impaired** (on the state's 303(d) list

of impaired waters) or if the site is located in a **watershed for which a TMDL has been established**, and what the parameters of concern are.

(b) A **narrative description** of storage practices, loading and unloading activities, outdoor process areas, dust or particulate generating or control processes, and waste disposal practices. A **narrative description** of the potential pollutants that could be expected to be present in the stormwater discharge from each outfall. The narrative should also reference deconstruction, demolition, coal, and/or coal ash hauling or disposal activities where applicable.

(c) A **site map** drawn at a scale sufficient to clearly depict: the site property boundary; the stormwater discharge outfalls; all on-site and adjacent surface waters and wetlands; industrial activity areas (including storage of materials, disposal areas, process areas, loading and unloading areas, and haul roads); site topography and finished grade; all drainage features and structures; drainage area boundaries and total contributing area for each outfall; direction of flow in each drainage area; industrial activities occurring in each drainage area; buildings; stormwater Best Management Practices (BMPs); and impervious surfaces. The site map must indicate the percentage of each drainage area that is impervious, and the site map must include a graphic scale indication and north arrow.

(d) A **list of significant spills or leaks** of pollutants during the previous three (3) years and any corrective actions taken to mitigate spill impacts.

(e) Certification that the stormwater outfalls have been evaluated for the presence of non-stormwater discharges. **The permittee shall submit the first certification no later than 90 days after the effective date of this permit to the Stormwater Permitting Program Central Office and shall re-certify annually that the stormwater outfalls have been evaluated for the presence of non-stormwater discharges.** For any non-stormwater discharge identified, the permittee shall indicate how that discharge is permitted or otherwise authorized. The certification statement will be signed in accordance with the requirements found in Part II, Standard Conditions, Section B, Paragraph 11.

2. **Stormwater Management Strategy**. The Stormwater Management Strategy shall contain a narrative description of the materials management practices employed which control or minimize the stormwater exposure of significant materials, including structural and nonstructural measures. This strategy should also address deconstruction, demolition, coal, and/or coal ash hauling or disposal activities where applicable. The Stormwater Management Strategy, at a minimum, shall incorporate the following:

(a) **Feasibility Study**. A review of the technical and economic feasibility of changing the methods of operations and/or storage practices to eliminate or reduce exposure of materials and processes to rainfall and run-on flows. Wherever practical, the permittee shall prevent exposure of all storage areas, material handling operations, and manufacturing or fueling operations. In areas where elimination of exposure is not practical, this review shall document the feasibility of diverting the stormwater run-on away from areas of potential contamination.

(b) **Secondary Containment Requirements and Records**. Secondary containment is required for: bulk storage of liquid materials; storage in any amount of Section 313 of Title III of the Superfund Amendments and Reauthorization Act (SARA) water priority chemicals; and storage in any amount of hazardous substances, in order to prevent leaks and spills from contaminating stormwater runoff. A table or summary of all such tanks and stored materials and their associated secondary containment areas shall be maintained. If the secondary containment devices are connected to stormwater conveyance systems, the connection shall be controlled by manually activated valves or other similar devices (which shall be secured closed with a locking mechanism). Any stormwater that accumulates in the containment area shall be observed for color, foam, outfall staining, visible sheens and

dry weather flow, prior to release of the accumulated stormwater. Accumulated stormwater shall be released if found to be uncontaminated by any material. Records documenting the individual making the observation, the description of the accumulated stormwater, and the date and time of the release shall be kept for a period of five (5) years. For facilities subject to a federal oil Spill Prevention, Control, and Countermeasure Plan (SPCC), any portion of the SPCC Plan fully compliant with the requirements of this permit may be used to demonstrate compliance with this permit.

In addition to secondary containment for tankage, the permittee shall provide drip pans or other similar protection measures for truck or rail car liquid loading and unloading stations.

(c) **BMP Summary**. A listing of site structural and non-structural Best Management Practices (BMPs) shall be provided. The installation and implementation of BMPs shall be based on the assessment of the potential for sources to contribute significant quantities of pollutants to stormwater discharges and on data collected through monitoring of stormwater discharges. The BMP Summary shall include a written record of the specific rationale for installation and implementation of the selected site BMPs. The BMP Summary should also address deconstruction, demolition, coal, and/or coal ash hauling or disposal activities where applicable. The permittee shall refer to the BMPs described in EPA's Multi-Sector Permit (MSGP) and Industrial Stormwater Fact Sheet for Steam Electric Power Generating Facilities (EPA-833-F-06-030) for guidance on BMPs that may be appropriate for this site. The BMP Summary shall be reviewed and updated annually.

3. **Spill Prevention and Response Procedures**. The Spill Prevention and Response Procedures (SPRP) shall incorporate an assessment of potential pollutant sources based on a materials inventory of the facility. Facility personnel responsible for implementing the SPRP shall be identified in a written list incorporated into the SPRP and signed and dated by each individual acknowledging their responsibilities for the plan. A responsible person shall be on-site at all times during facility operations that have increased potential to contaminate stormwater runoff through spills or exposure of materials associated with the facility operations. The SPRP must be site stormwater specific. Therefore, an oil Spill Prevention Control and Countermeasure plan (SPCC) may be a component of the SPRP, but may not be sufficient to completely address the stormwater aspects of the SPRP. The common elements of the SPCC with the SPRP may be incorporated by reference into the SPRP.

4. **Preventative Maintenance and Good Housekeeping Program**. A preventative maintenance and good housekeeping program shall be developed and implemented. The program shall address all stormwater control systems (if applicable), stormwater discharge outfalls, all on-site and adjacent surface waters and wetlands, industrial activity areas (including material storage areas, material handling areas, disposal areas, process areas, loading and unloading areas, and haul roads), all drainage features and structures, and existing structural BMPs.

   The program shall establish schedules of inspections, maintenance, and housekeeping activities of stormwater control systems, as well as facility equipment, facility areas, and facility systems that present a potential for stormwater exposure or stormwater pollution where not already addressed under another element of the SPPP. Inspection of material handling areas and regular cleaning schedules of these areas shall be incorporated into the program. Compliance with the established schedules for inspections, maintenance, and housekeeping shall be recorded and maintained in the SPPP. The program should also address deconstruction, demolition, coal, and/or coal ash hauling or disposal activities where applicable. The Good Housekeeping Program shall also include, but not be limited to, BMPs to accomplish the following:

   (a) Minimize contamination of stormwater runoff from oil-bearing equipment in switchyard areas;
   (b) Minimize contamination of stormwater runoff from delivery vehicles and rail cars arriving and departing the plant site;

(c) Inspect all residue-hauling vehicles for proper covering over the load, adequate gate-sealing, and overall integrity of the container body. Repair vehicles as necessary; and

(d) Reduce or control the tracking of ash and residue from ash loading and storage areas;

5. **Facility Inspections**. Inspections of the facility (including tanks, pipes, and equipment) and all stormwater *systems* shall occur as part of the Preventative Maintenance and Good Housekeeping Program at a minimum on a semi-annual schedule, once during the first half of the year (January to June), and once during the second half (July to December), with at least 60 days separating inspection dates (unless performed more frequently than semi-annually).

6. **Employee Training**. Training programs shall be developed and training provided at a minimum on an annual basis for facility personnel with responsibilities for: spill response and cleanup, preventative maintenance activities, and for any of the facility's operations that have the potential to contaminate stormwater runoff. The facility personnel responsible for implementing the training shall be identified, and their annual training shall be documented by the signature of each employee trained.

7. **Responsible Party**. The SPPP shall identify a specific position or positions responsible for the overall coordination, development, implementation, and revision of the SPPP. Responsibilities for all components of the SPPP shall be documented and position assignments provided.

8. **SPPP Amendment and Annual Update**. The permittee shall amend the SPPP whenever there is a change in design, construction, operation, site drainage, maintenance, or configuration of the physical features which may have a significant effect on the potential for the discharge of pollutants to surface waters. **All aspects of the SPPP shall be reviewed and updated on an annual basis**. The annual update shall include:

   (a) an *updated list of significant spills or leaks* of pollutants for the previous three (3) years, or the notation that no spills have occurred (element of the **Site Overview**);

   (b) a written *re-certification that the stormwater outfalls have been evaluated for the presence of non-stormwater discharges* (element of the **Site Overview**);

   (c) a documented re-evaluation of the effectiveness of the on-site stormwater BMPs (*BMP Summary* element of the **Stormwater Management Strategy**).

   (d) a *review and comparison of stormwater sample analytical data* to any applicable limits or benchmark values (if applicable) over the past year.

   If the Director notifies the permittee that the SPPP does not meet one or more of the minimum requirements of the permit, the permittee shall have 30 days to respond. Within 30 days of such notice, the permittee shall submit a time schedule to the Director for modifying the SPPP to meet minimum requirements. The permittee shall provide certification in writing to the Director that the changes have been made.

9. **SPPP Implementation**. The permittee shall implement the Stormwater Pollution Prevention Plan and all appropriate BMPs consistent with the provisions of this permit, in order to control contaminants entering surface waters via stormwater. Implementation of the SPPP shall include documentation of all monitoring, measurements, inspections, maintenance activities, and training provided to employees, including the log of the sampling data and of actions taken to implement BMPs associated with the industrial activities, including vehicle maintenance activities. Such documentation shall be kept on-site for a period of five (5) years and made available to the Director or the Director's authorized representative immediately upon request.

A. (26.) TEMPERATURE LIMIT COMPLIANCE SCHEDULE- OUTFALL 008

The facility shall develop the plan for compliance with the State temperature standard and submit the plan to the Division within 1 year from the effective date of the permit. The plan shall contain

milestones and the specific action items. After the plan is approved by the Division, it will become an enforceable part of the permit.

A. (27.) ADDITIONAL CONDITIONS AND DEFINITIONS

1. EPA methods 200.7 or 200.8 (or the most current versions) shall be used for analyses of all metals except for total mercury.
2. All effluent samples for all external outfalls shall be taken at the most accessible location after the final treatment but prior to discharge to waters of the U.S. (40 CFR 122.41(j)).
3. The term *low volume waste sources* means wastewater from all sources except thouse for which specific limitations are otherwise established in this part (40 CFR 423.11 (b)).
4. The term *chemical metal cleaning waste* means any wastewater resulting from cleaning any metal process equipment with chemical compounds, including, but not limited to, boiler tube cleaning (40 CFR 423.11 (c)).
5. The term *metal cleaning waste* means any wastewater resulting from cleaning [with or without chemical cleaning compounds] any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning (40 CFR 423.11 (d)).
6. For all outfalls where the flow measurement is to be "estimated" the estimate can be done by using calibrated V-notch weir, stop-watch and graduated cylinder, or other method approved by the Division.
7. During normal operations removing of the free water above the settled wet ash layer shall not involve mechanical disturbance of the ash.

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Appendix A.

Plan for Identification of New Discharges (attached).

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Summary Remarks from the Administrator and discussion with SAB Members and Liaisons
Excepted from the Meeting Minutes December 4, 2013

Administrator Gina McCarthy began her remarks by thanking SAB members for their service. She emphasized the importance of science to EPA's mission, both to understand the risks to be addressed and to develop solutions. She said that science drives agency decisions and that EPA requires both science and the law to do its work. She welcomed the SAB to "help think through" the science questions relating to EPA's actions regarding sustainability, environmental justice and climate change. She acknowledged the contributions of the Science Advisor to the Administrator, Dr. Glenn Paulson, and the significance of the appointment of the EPA's new Science Integrity Officer, Dr. Francesca Grifo. She also noted that EPA must begin to identify future environmental challenges. It would be helpful to seek SAB advice in identifying those challenges.

After the Administrator concluded her remarks, she engaged chartered SAB members in discussion. The SAB Chair, Dr. David Allen, noted that the SAB has provided advice or is developing advice on the topics of environmental justice, sustainability, air, climate and energy. He asked whether she saw other areas where the SAB should examine the impacts of climate change. The Administrator responded that the major substantive topic of discussion at the most recent EPA Senior Executive Service meeting was adaptation to climate change, which affects the entire agency. A major challenge for the EPA is to articulate climate change as a public health issue that impacts the most vulnerable populations, including children, the elderly and environmental justice communities. She welcomed an opportunity to talk with the SAB about how to prioritize adaptation activities so that the most vital needs are addressed in the most expeditious way.

An SAB member asked how the agency will maintain its commitment to science, given current budget challenges. The Administrator responded that EPA must plan in the face of budget uncertainties, where Congress has not passed a budget for many years. This uncertainty is difficult not only for the agency, but also for states that cannot rely on federal support. She stated that effective communication of EPA science to citizens is critical to broader public engagement with environmental science issues. The EPA must communicate how federal budget cuts affect not only the EPA but also the protections EPA brings to communities. The Administrator noted that she did not like across-the-board cuts and is talking with managers about the smartest ways to take cuts. Setting priorities is important.

Another member asked whether the Administrator supported the idea of building a risk assessmnt community outside the EPA. This idea has been discussed publicly by the Director of the Office of Research and Development's (ORD) National Center for Environmental Assessment (NCEA). The Administrator responded that risk assessments provide the critical underpinnings of agency decisions. She commended Dr. Kenneth Olden, the NCEA Director, for responding to recommendations from the National Research Council and for the credibility he brings with outside entities. She emphasized that EPA cannot rely just on its own resources for risk assessment. Capacity building outside the agency is important and the EPA must help to make that capacity robust, to understand it and embrace it.

Dr. H. Christopher Frey, chartered SAB member and Chair of the Clean Air Scientific Advisory Committee (CASAC), briefly summarized the major science challenges CASAC has identified for EPA: multimedia air quality management; secondary standards for oxides of nitrogen and

sulfur oxides; revising the list of criteria pollutants; interactions between climate change and National Ambient Air Quality Standards (NAAQS); difficulty of establishing thresholds for health effects; and assessment of health effects close to background levels. He commended the EPA for developing a weight-of-evidence approach for causality of health effects, which may provide a model for reviews conducted as part of EPA's Integrated Risk Information System (IRIS). He noted that CASAC provides advice at the end of each NAAQS review cycle regarding research needs and asked what EPA is doing to advance the science supporting evaluation of criteria pollutants and whether it is possible to do more, partnering with other agencies. The Administrator welcomed an opportunity to talk with Dr. Frey about CASAC issues. She agreed that assessments of criteria pollutants provide a model for strengthening the IRIS process. CASAC's persistent attention to characterizing uncertainty has been very important and has provided the "push" to improve agency assessments. She expressed excitement over President Obama's appointment of Dr. Thomas Burke as the next Assistant Administrator for ORD. She expected him to provide strong leadership for risk assessment.

Another SAB member asked whether the Administrator had an interest in using decision science to help the agency make science-based decisions. He noted that decision science research shows that simply making science available does not necessarily improve decision making. The Administrator responded that she had a strong interest in talking with him about how decision science could be helpful. She noted that "economists don't have the answers" to all of decision makers' questions and that people don't always act in rational, science-based ways. Motivating individuals and organizations to change can be complex. The EPA's leadership has a strong interest in how to influence people's behavior by providing the right information to them.
The final question came from a chartered SAB member who asked how the Administrator insulates science from policy or political considerations. He noted that many questions at her confirmation hearing pertained to EPA's 316(b) rule. The Administrator responded that EPA scientists and the SAB should not be reluctant to do their jobs because of political concerns. The agency will do the best it can to explain agency science on Capitol Hill. She encouraged the SAB to "stick to SAB's historic work." The SAB should help the agency make sure that the EPA protects the Board from politics entering the science advisory process. The EPA must do its job to make sure that the SAB can do its job.

Dr. Moo-Young concluded the discussion by thanking the Administrator for taking time to meet with the Board.

Message

From: Greenpeace [info@wdc.greenpeace.org]
on behalf of Stephanie Kusmer Ex. 6 Personal Privacy (PP)
Sent: 1/28/2014 8:00:59 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Withdraw approval of Sulfoxaflor

Jan 28, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

Please reconsider your decision to allow the broad use of the neonicotinoid pesticide sulfoxaflor. The EPA's own reports have found that sulfoxaflor is highly toxic to bee populations, which are under increased stress due to widespread Colony Collapse Disorder.

The significant decrease of bees both in the wild and in agriculture puts natural ecosystems and our food at risk. Follow the lead of the European Union and ban the use of neonicotinoids in order to save bee populations from complete collapse.

Thank you.

Sincerely,

Ms. Stephanie Kusmer
Ex. 6 Personal Privacy (PP) Meramec Ex. 6 Personal Privacy (PP)
Ex. 6 Personal Privacy (PP)

Message

From: EUEC [pdayal@euec.ccsend.com]
on behalf of EUEC [pdayal@euec.com]
Sent: 8/1/2016 3:06:55 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: ENERGYNews: Wastewater, FGD, ZLD, ELG, 316(b)

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Wastewater, FGD, ZLD, 316(b)

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TRACK I

Water, FGD, 316(b)

I1. Wastewater Management

EUEC 2016

Water, FGD, 316(b)

I5. FGD Wastewater

FRONTIER WATER SYSTEMS

PRE-FABRICATED PROCESS EQUIPMENT SOLUTION TO MEET ELG & CCR STANDARDS - James Peterson, President, Frontier Water Systems

REACTOR VESSELS TO MANAGE & TREAT WASTEWATER AT ASH PONDS & LANDFILLS - Mark Kropilak, CEO, Liberty Hydro, Inc

ENERGY NEUTRALITY IN WASTEWATER TREATMENT - Tom Stanley, CTO, GE Water & Process Technologies, GE Power & Water

MINIMIZING WATER FOOTPRINT BY IMPLEMENTING SEMI-BATCH REVERSE OSMOSIS - Rick Stover, EVP, Desalitech

ELG COMPLIANCE AT COAL FIRED POWER STATIONS - Michael Preston, Section Leader, Black & Veatch

NATIONAL NUTRIENT REDUCTION STRATEGY UPDATE - Diane Martini, Senior Water/Wastewater Consultant, Burns & McDonnell; Sarah Gilstrap

AN UPDATE ON THE WATER RESEARCH CENTER - Tyler Cromey, Research Engineer, Southern Company Services, Inc

I2. Water & Electric Utilities

MODELING ELECTRICITY SECTOR VULNERABILITIES RELATED TO WATER TEMPERATURES - Jordan Macknick, NREL; Macknick, Brinkman, Ibanez, Tomberlin, Hunsberger, Kandt & Miara

THE LATEST TECHNOLOGICAL UPDATES IN OIL SPILL CONTAINMENT SYSTEMS - Bill Gannon, President, Solidification Products International; John Panaro

ENERGY SAVINGS THROUGH PIPE SELECTION - Rosemary Smud, Sales Engineer, American Cast Iron Pipe; Maury Gaston

ENHANCE COORDINATION BETWEEN ELECTRIC AND WATER UTILITIES - Nushat Thomas, Team Leader, U.S. EPA; Lauren Wisniewsk

BR RISK MGMT; PREDICTIVE MODEL DEVELOPMENT FOR DISINFECTION BYPRODUCTS - Brian Mastin, Senior Consultant, Parsons

SCE STORM WATER MGMT & FLOOD PREPAREDNESS IMPROVEMENT INITIATIVE - Denise Yaffe, Mgr., Southern California Edison; Lakes, Barr, Akunyili & Johnson

I3. 316(b)

EFFECTS OF MERCURY CONTROL TECHNOLOGIES ON FGD WASTEWATER QUALITY -Mandi Richardson, Sr. Chemist, AECOM; Blythe, AECOM; Dene, EPRI; Acharya, Southern Co.

ELG AND CCR COMPLIANCE - THE DOLLARS ARE IN THE DETAILS - Dennis Fink, Senior Project Manager, CH2M; Dr. Thomas E. Higgins

ELG COMPLIANCE SOLUTIONS - AN IN-DEPTH LOOK AT FGD FLOWRATE IMPACTS- Jeromy Jones, AQCS Manager, Burns & McDonnell

RECENT ADVANCES IN WASTEWATER MEASUREMENTS OF HG, AS AND SE USING AFS - Warren Corns, R&D Mgr., P S Analytical; Cornelius Brombach

EFFECT OF OPERATING CONDITIONS OF FGD UNIT ON FORM OF SELENIUM IN LIQUOR - Hiroyuki Akiho, Research Scientist, CRIEPI; Naoki Noda, Hiromi Shirai & Shigeo Ito

I6. 316(b), ELG, Wastewater

APPROACHES TO ELG COMPLIANCE FOR FGD WASTE WATERS - Kristen Bell, Senior Associate, Sargent & Lundy

GREEN ALTERNATIVES FOR WATER SUPPLY DEVELOPMENT - Henry Hunt, Sr. Project Mgr., Layne-Ranney Collector Wells

CONTROL OF DREISSENID MUSSELS WITH A MORE RATIONAL USE OF COPPER - David Hammond, Ph.D., Senior Scientist, Earth Science Labs, Inc.

COMPLIANCE WITH BOTH 316(B) AND THE ENDANGERED SPECIES ACT - Harriet Nash, NOAA's National Marine Fisheries Services; Ashfield, US Fish & Wildlife Svcs

316(B) STRATEGIES FOR ADVANCED INTAKE SCREEN RETROFITS - Mark David Bell; Sales Manager, Bilfi nger Water Technologies

316(B) OVERVIEW OF IMPINGEMENT TECHNOLOGY SELECTION PROCEDURE - Mehrdad Salehi, Sr. Associate, Sargent & Lundy LLC; Ken Snell & Joy Rooney

I7. Water Sustainability

THE ENERGY-WATER NEXUS: RESILIENT, SUSTAINABLE COMMUNITIES AND CHP - Scott Hutchins, Stakeholder Engagement, U. S. Department of Energy

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EPA'S 316B RULE: HOW TO ACHIEVE COMPLIANCE - Greg Seegert, Chief Ichthyologist, EA Engineering, Science & Technology

IMPACTS OF EPA 316(B) ON POWER PLANT COOLING WATER INTAKES - Roman Carter, National Account Manager, Intralox/ Hydrolox; Tim Woodrow

CLEAN WATER ACT RULE: EXPANDING RISK & LIABILITY FOR PROJECT PROPONENT - Gerald Kerry McGrath, Associate, Hunton & Williams; Deidre Duncan

316(B) IMPINGEMENT COMPLIANCE: UNDERSTANDING DE MINIMIS - Radhika, Sr. Project Mgr, HDR Engineering; Mark Bailey

316(B) - OVERVIEW OF TECHNICAL FEASIBILITY AND COST EVALUATION STUDY - Joy Rooney, Senior Associate, Sargent & Lundy; Ken Snell & Mehrdad Salehi

IMPLEMENTING U.S EPA'S 316(B) RULE - Sean Ramach, Environmental Scientist, U.S. EPA

I4. FGD Wastewater - ZLD

ZLD APPROACH BY APPLYING SPRAY DRYER EVAPORATOR (SDE™) TECHNOLOGY - Paulo Oliveira, Product Marketing Manager, Alstom, Inc.; Phil Rader

THERMAL ZLD SYSTEM USING A SDE IN A WASTE TO ENERGY PLANT - Robert Van Durme, P.E., Key Account Manager, Lechler Inc.; Ashwin Patni

FGD ZLD PROCESS IMPACT ON HEAT RATE & OTHER PLANT PARAMETERS - Benjamin Laurent, Senior Process Engineer, Heartland Technology Partners

PROCESSING POWER PLANT WASTE TO HIGH MARKETABLE COMMODITIES - Robert Bobeck, Technical Sales, Dustex; Patrick Paul

UPDATE ON B&W ZLD ACTIVITIES - Steven Feeney, Product Line Mgr., Babcock & Wilcox; Mike Klidas

FORWARD OSMOSIS BASED HIGH WATER RECOVERY SOLUTIONS - MaryTheresa Pendergast, Director, Oasys Water; John Tracy

WATER BALANCE ANALYSIS, MONITORING, & MGMT. TOOL FOR POWER PLANTS - Charlie He, Assoc. VP, Carollo Engineers; E. McLeskey, G. Carpenter, J. Dresang & C. Chiu

SUPPORTING THE HEART OF THE WATER - ENERGY - FOOD NEXUS - Maury Gaston, Manager of Marketing Services, American Cast Iron Pipe

MONETIZING WATER EFFICIENCY - THE RESNET WATER EFFICIENCY RATING INDEX - Steve Baden, Executive Director, RESNET

PREVENTIVE SAFETY MEASURE FROM POLLUTED SURFACE WATER LEAKAGE IN BLDNGS - Nasser Alhemiddi, Professor, King Saud U.; A. Alhemiddi, M. Arch. & A. Alhemiddi, B. Arch

WATER REUSE FOLLOWING GROUNDWATER EXTRACTION & TREATMENT -Christina Rain, P.E., Project Engineer, Langan Treadwell Rollo; Graber, Glenn & Shipman

I8. Water Supply & Security

A SOLUTION TO OUR WATER SUPPLY PROBLEM- Maury Gaston, Manager - Marketing Services, American Cast Iron Pipe, John Wilson

DREDGING YOUR RESERVOIR: ENHANCING THE RESILIENCY OF YOUR WATER SUPPLY - Sarah Howard, Sr. Scientist, Black & Veatch; Elizabeth Quinlan

AN INNOVATIVE SOLUTION TO PREDICTIVE WATER MODELING FOR UTILITIES SECTOR - Kenn Cygan, Director, Nalco; April YeYoung Yi

WEANING OURSELVES FROM OUR WASTEFUL WATER WAYS - Ned Daugherty, Principal Architect, H2O Futures

ENGAGING A UNIVERSITY ON WATER CONSERVATION -Kyle Mann, Energy Efficiency Program Specialist, CA State University Fullerton

GIS-FORECASTED SURFACE HYDROLOGY FOR REDUCING RISKS OF FOOD PRODUCTION - Abdrabelnabi Abdelhady, Professor, Damanhour Univ; Aggag, Abdelaty & Bahnassy

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Sent by pdayal@euec.com

Message

From: Environment Missouri [action@environmentmissouri.org]
on behalf of salvatore cento Ex. 6 Personal Privacy (PP)
Sent: 3/26/2014 6:45:08 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Thank you for protecting Missouri's rivers!

Mar 26, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

All our waterways should be clean enough to drink from, fish from and swim in without risk of pollution -- from our local rivers and streams, to iconic waters like the Meramec and the Missouri River. Unfortunately, loopholes in the Clean Water Act have left many of our smaller waters unprotected, including those that feed and filter the drinking water for 2.4 million Missourians.

Thank you for taking a major step forward to restore Clean Water Act protections to Missouri's streams and wetlands and for your commitment to protecting our waterways.

Please move forward as quickly as possible to finalize a strong rule that will restore Clean Water Act protections to all Missouri's waterways and protect our environment and health.

Sincerely,

Mr. salvatore cento
Ex. 6 Personal Privacy (PP)

Message

From: EUEC [pdayal@euec.ccsend.com]
on behalf of EUEC [pdayal@euec.com]
Sent: 7/26/2016 3:08:29 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: 7/31 Deadline Approaching for EUEC 2017: San Diego, CA

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Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of Judith Medoff [nrdcinfo@nrdconline.org]
Sent: 9/15/2014 5:01:09 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Require full reporting of all chemicals used during fracking

Sep 15, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

I urge you and your agency to move swiftly to propose tough new rules that will require fracking chemical manufacturers and processors to report all the chemicals used during fracking as well as the risks they pose to EPA, and to require that EPA provide this critical information to the public.

Fracking is on the rise in communities across the country, producing a full-fledged chemical assault on our water and air. More than 15 million Americans now live within one mile of a fracking site. We deserve to know the full extent of the threat that fracking poses to our communities, our health and our environment. Please put people before polluters and require mandatory reporting and public disclosure of all chemicals used during fracking. Thank you.

Sincerely,

Ms. Judith Medoff
Ex. 6 Personal Privacy (PP) Meramec
Ex. 6 Personal Privacy (PP)

Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of marilyn sandweis [nrdcinfo@nrdconline.org]
Sent: 7/18/2016 12:01:34 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Ban tar sands tanker traffic in U.S. waters

Jul 17, 2016

Administrator of the EPA Regina McCarthy

Dear President Obama: Administrator of the EPA McCarthy,

I am alarmed that the oil industry plans to ship 1.5 million barrels per day of tar sands crude from Canada to the United States by pipeline and tanker -- flooding America with twice as much tar sands crude as the Keystone XL pipeline would have, choking our atmosphere with 350 million metric tons of carbon pollution and threatening virtually all of our coastlines and three major rivers with nearly impossible-to-clean-up oil spills. I urge you to direct your Coast Guard and EPA to impose an immediate ban on all tar sands tanker and barge traffic in U.S. waters.

I applaud you for responding to the dire threat of climate change by securing a breakthrough climate accord in Paris, cracking down on power plant pollution and rejecting the Keystone XL tar sands pipeline. But with evidence mounting that our climate is warming far more rapidly than predicted, we must act swiftly when new threats emerge. Please do not leave this issue for the next president to address -- act now to secure your legacy of climate leadership by blocking this tar sands onslaught. Thank you.

Sincerely,

marilyn sandweis
Ex. 6 Personal Privacy (PP) Meramec Ex. 6 Personal Privacy (PP)

Ex. 6 Personal Privacy (PP)

Message

From: Skelley, Dana [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=AA274940663748979EB8DA23879FA7A4-SKELLEY, DANA]
Sent: 2/11/2013 2:02:17 PM
To: Mccarthy, Regina [McCarthy.Gina@epa.gov]
Subject: ***ACTION REQUIRED*** You must read and respond to this litigation hold notice

This is a reminder that EPA requires your assistance with respect to preserving and/or collecting information in the matter referred to below.

You are receiving this message because you have not yet clicked on the link below and/or answered the questions in the notice after the link.

Once you have read the hold notice, you must answer the question(s) at the end of the notice certifying that you have read and understand these instructions. Please answer all questions to the best of your ability. Failure to answer all questions will result in repeat reminders to your inbox until the requested information is submitted. **Please make sure that you use Internet Explorer to access the link below.**

If you believe you received this notice in error or have any questions regarding this matter, please contact the case attorney immediately.

You have received this notice in addition to the litigation hold in this matter to ensure that all current and former EPA employees or contractors who may have information relevant to this matter (i.e., who are "custodians") are identified.

As you have been notified, the United States Environmental Protection Agency ("EPA" or "Agency") is implementing a litigation hold because the Agency reasonably anticipates litigation against or between Ameren Missouri, St. Louis Missouri, pursuant to the Clean Air Act regarding violations of the Prevention of Significant Deterioration provisions of the Clean Air Act, the Missouri State Implementation Plan, and Title V of the CAA with respect to the Labadie, Meramec, Rush Island and Sioux Power Stations (the Facilities) owned and operated by Ameren Missouri throughout eastern Missouri. This litigation hold also applies to documents related to EPA's interpretation or implementation of the New Source Review regulations and any documents that discuss projects and pollution control technologies typically performed at coal-fired Electricity Generating Units. Accordingly, all Agency employees with potentially relevant information are directed to preserve the information until further notice.

Please click the link below to review the current custodian list and answer the questionnaire. NOTE: You must be logged into the EPA Network to access this link.

The legal team recognizes that your time is valuable and appreciates your cooperation and continued support.

Failure to promptly respond to the questions found at the end of the notice will result in automatic reminders to your email account until you respond.

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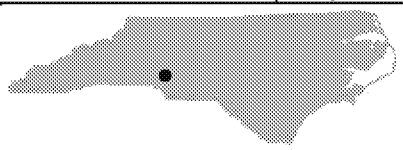
Attachment 3

DENR/DWR Fact Sheet for NPDES Development
Riverbend Permit Renewal NC0004961
2015

DENR/DWR
FACT SHEET FOR NPDES PERMIT DEVELOPMENT
PERMIT RENEWAL
NPDES No. NC0004961

Facility Information			
Applicant/Facility Name:	Duke Energy Carolinas, LLC – Riverbend Steam Station		
Applicant Address:	P.O. Box 1006, Charlotte, North Carolina 28201		
Facility Address:	175 Steam Plant Road; Mount Holly, North Carolina 28120		
Permitted Flow	No limit		
Type of Waste:	100% industrial Prim.SIC Code: 4911 – Electric Services		
Facility/Permit Status:	Class I/Active; Renewal		
County:	Gaston County		
Miscellaneous			
Receiving Stream:	Catawba River (Mt. Island Lake)	Regional Office:	Mooresville
Stream Classification:	WS-IV and B-CA	State Grid / USGS Quad:	F15Sw
303(d) Listed?	No	Permit Writer:	Sergei Chernikov, Ph.D.
Subbasin:	03-08-33	Date:	May 21, 2014
Drainage Area (mi^2):	1800		
Summer 7Q10 (cfs)	80		
Winter 7Q10 (cfs):			
30Q2 (cfs)			
Average Flow (cfs):	2700		
IWC (%) for Outfall 002:	0.4 – discharge 2.7 – dewatering	001: Lat. 35° 21' 28" N Long. 80° 58' 12" W 002: Lat. 35° 22' 06" N Long. 80° 57' 31" W 002B: Lat. 35° 21' 51" N Long. 80° 58' 11" W 011: Lat. 35° 21' 38" N Long. 80° 58' 38" W	

SUMMARY

Duke Energy's Riverbend Steam Station was a coal fired steam electric plant in Gaston County, the electricity generation was discontinued on 04/1/2013. The facility has 5 permitted outfalls in the current NPDES discharge permit. The sources of wastewater for these outfalls include non-contact cooling water, ash basin discharge, sanitary waste, stormwater from process areas, sump overflows, and potentially contaminated groundwater seeps. The facility has no FGD scrubber. Currently, discharge of cooling water has discontinued and discharge from the ash pond significantly decreased.

In addition to NPDES Permit NC0004961, the facility also holds 0388R20 (air permit) and NCD024717423 (Hazardous wastes). The facility is subject to 40 CFR 423 – Steam Electric Power Generation.

The following descriptions of the wastes at each outfall are offered:

001 – Once through cooling water consisting of intake screen backwash and water from the plant chiller system, turbine lube oil coolers, condensate coolers, main turbine steam condensers and the intake tunnel dewatering sump.
Since the facility was shut down, the discharge from this outfall is not anticipated.

ED_006610_00000066-00002

002 – Ash basin discharge consisting of induced draft fan and preheater bearing cooling water, stormwater from roof drains and paving, treated groundwater, track hopper sump (groundwater), coal pile runoff, laboratory drain and chemical makeup tanks and drums rinsate wastes, general plant/trailer sanitary wastewater, turbine and boiler rooms sumps, vehicle rinse water, and stormwater from pond areas, upgradient watershed, and miscellaneous stormwater flows. Most of the waste streams have discontinued, but some will remain.

002A- Yard drain sump overflow, discharge occurs rarely.

010 – Combined flow from all seeps.

011 – Former stormwater Outfall 1. Contains stormwater and groundwater flow, also includes wastewater from 10,000 gallon oil separator tank #3. The drainage basin includes a 2.7 acre portion of the main switchyard and 8,700 ft^2 of the plant yard between power house and combustion turbine area. The powerhouse covers about 1.5 acres of the drainage basin. 100% of the drainage basin is paved or roofed.

This facility discharges to the Mountain Island Lake (Catawba River) in sub-basin 03-08-33. The receiving stream is not listed as impaired.

Duke Energy Submitted Application dated May 15, 2014. The current permit expires February 28, 2015.

Duke Energy is required by the Coal Ash Management Act to remove all ash from the site by August 1, 2019.

The discharge pipe NPDES outfall 002 from the secondary ash basin discharge tower at Riverbend Steam Station will be slip lined to ensure integrity. While this pipe is being slip lined, an alternative arrangement to convey wastewater to the permitted NPDES outfall 002 will be utilized. Temporary piping will be positioned in the secondary ash basin and the treated wastewater will be pumped to the NPDES outfall 002 discharge flow weir, located before the concrete flume that discharges into Mountain Island Lake. Once the slip line repairs are completed, the system will be returned to its original configuration. NPDES monitoring requirements will continue to be collected during the slip line project at the NPDES outfall 002 discharge flow weir.

SEEPS-OUTFALL 010

The facility identified 12 unpermitted seeps from the ash settling basin. Seeps can be classified as either engineered seeps (toe drains) from the earthen dam or non-engineered seeps that occur as wastewater moves from the ash settling basin into groundwater and then into surface water, either directly or after emerging on land. Engineered seeps can be captured and routed through a permitted outfall.

The non-engineered seeps represent a treatment system that has the potential to contaminate groundwater and surface water. The original design and location of the impoundment are such that wastewaster is not contained and directed to only engineered outfalls as the NPDES program generally contemplates, but wastes are also being released to groundwater and emerging in the form of seeps at the surface at diffuse and remote locations, with wastewater then flowing into surface waters depending on site specific factors. Potential groundwater contamination is regulated through North Carolina's 2L program. The CWA NPDES permitting program does not

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normally envision permitting of uncontrolled releases from treatment systems; such releases are difficult to monitor and control, and it is difficult to accurately predict their impact on water quality. Releases of this nature would typically be addressed through an enforcement action requiring their elimination rather than permitting.

The non-engineered seeps at this facility represent a unique circumstance, where the occurrence of the seeps is attributable to an original pond design that will require long-term action to fully address. Recent North Carolina legislation (Coal Ash Management Act of 2014) establishes a framework for addressing all coal ash impoundments in the state to ensure that groundwater and surface water are adequately protected through closure or other measures. However, action to close or otherwise address coal ash impoundments and their threats to surface waters and groundwater will occur over a long term of those actions. In light of the long-term nature of action to fully address these impoundments, the Division is proposing, as an interim measure, to ensure that all non-engineered seeps are appropriately identified, monitored, and subject to protective effluent limits by including the seep discharges as authorized discharges in the facility's NPDES permit. The permit includes requirements to regularly inspect for new seeps, monitoring requirements for all identified seeps, and applicable effluent limits which ensure that the seeps will not result in unacceptable impacts to the receiving stream.

The facility identified 12 unpermitted seeps and conducted chemical analysis of the discharges. The total flow from the seeps was measured at 0.14 MGD. Although, all seeps don't have a permanent discharge and discharge from all seeps does not reach the surface water, for the purposes of the permitting it was assumed that all seeps reach the surface water. The seeps are not located on the walls of the dike, they appear as an emerging groundwater in a swampy area adjacent to the lake.

The maximum allowable parameter concentration for seeps was determined by multiplying the highest concentration for a baseline seep data by 10. These values are substantially lower than the allowable concentration determined by the Reasonable Potential Analysis for the combined seep flow. The maximum allowable concentrations for Pb and TDS were established at the level of the water quality standards.

ASH POND DAMS

Seepage through earthen dams is common and is an expected consequence of impounding water with an earthen embankment. Even the tightest, best-compacted clays cannot prevent some water from seeping through them. Seepage is not necessarily an indication that a dam has structural problems, but should be kept in check through various engineering controls and regularly monitored for changes in quantity or quality which, over time, may result in dam failure.

REASONABLE POTENTIAL ANALYSIS (RPA)

The Division conducted EPA-recommended analyses to determine the reasonable potential for toxicants to be discharged at levels exceeding water quality standards/EPA criteria by this facility **from outfall 002 (Ash Pond).** Calculations included: As, Be, Cd, Total Phenolic Compounds, Cr, Cu, CN, Pb, Hg, Mo, Ni, Se, Ag, Zn, and Fe (please see attached). The renewal application listed 0.19 MGD as a current flow. The analysis indicates no reasonable potential to violate the surface water quality standards or EPA criteria. However, the monitoring will continue per recommendation of the hearing officer during the last renewal.

The Division also considered data for other parameters of concern in the EPA Form 2C that the facility submitted for the renewal. The majority of the parameters were not detected in the

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discharge. The Division reviewed the following parameters that were detected in the discharge and have applicable state standards or EPA criteria for Class C WS-IV stream: fecal coliform, nitrate, Al, Ba, B, Co, Mn, Sb, and Tl. Most of these parameters were well below the state standards/EPA criteria. Only 1 parameter exceeded EPA criteria: Al (162 ug/L is above 87 ug/L). Considering the in-stream waste concentration of only 0.4%, even Al is not expected to violate applicable water quality criterion.

The RPA was also conducted for the combined flow from all the seeps. The highest concentration for each constituent was chosen from one of the 12 seeps and used for the RPA. The RPA was not considered for the parameters that don't have an applicable state water quality standard. Calculations included: As, Cd, Chlorides, Cr, Cu, F, Pb, Hg, Ni, Se, Zn, Ba, Fe, and Mn (please see attached). The analysis indicates no reasonable potential to violate the water quality standards or EPA criteria. The combined flow volume for all the seeps was measured at 0.14 MGD. However, the flow of 0.5 MGD was used for the RPA to incorporate a safety factor, account for potential new seeps that might emerge in the future or increase in flow volume at the existing seeps.

The RPA was also conducted for the Outfall 011. Calculations included: As, Cd, Chlorides, Cr, Cu, F, Pb, Hg, Ni, Se, Zn, Ba, Fe, and Mn (please see attached). The analysis indicates no reasonable potential to violate the water quality standards or EPA criteria. The flow volume for the Outfall 011 was measured at 0.00036 MGD. However, the flow of 0.001 MGD was used for the RPA to incorporate a safety factor and potential increase in flow.

The RPA analysis indicates that existing discharges from the facility outfalls will not cause contravention of the state water quality standards/ EPA criteria.

DEWATERING – OUTFALL 002

To meet the requirements of the Coal Ash Management Act of 2014, the facility needs to dewater two ash ponds and excavate the ash to deposit it in the landfills. The facility highest discharge rate from the dewatering process will be 1.45 MGD. The facility submitted data for the surface water in the ash ponds, interstitial water in the ash, and interstitial ash water that was treated by 20 μm filter and 0.45 μm filter. To evaluate the impact of the dewatering on the receiving stream the RPA was conducted for the wastewater that will be generated by the dewatering process. To introduce the margin of safety, the highest measured concentration for a particular parameter was used. The RPA was conducted for As, Cd, Chlorides, Cr, Cu, F, Pb, Mo, Hg, Ni, Se, Zn, Ba, Fe, and Mn, SO4, Al, B, Sb, and Tl (please see attached).

Based on the results of the RPA, the limit for Total Aluminum will be added to the dewatering effluent page.

TECHNOLOGY BASED EFFLUENT LIMITS OUTFALL002 AND OUTFALL 010

The existing federal regulations require development of Technology Based Effluent Limits (TBELs) for the parameters of concern. Since the EPA has not promulgated any new Effluent Guidelines for Power Plants since 1982, the Division has reviewed the performance of the existing coal-fired power plants to establish TBELs: Marshall Steam Station, Belews Steam Station, and Allen Steam Station. Two of these facilities (Belews and Allen) were used by EPA to establish the proposed Effluent Guidelines for Power Plants. The Division focused on the following parameters: Total Arsenic, Total Mercury, Total Selenium, and Nitrate/nitrite as N. These parameters are consistent with the parameters selected by EPA in the proposed Effluent Guidelines. The Division agrees with the EPA statement from the proposed Effluent Guidelines

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that justifies TBEL limitations for only four pollutants of concern: "Effluent limits and monitoring for all pollutants of concern is not necessary to ensure that the pollutants are adequately controlled because many of the pollutants originate from similar sources, have similar treatabilities, and are removed by similar mechanisms. Because of this, it may be sufficient to establish effluent limits for one pollutant as a surrogate or indicator pollutant that ensures the removal of other pollutants of concern."

Based on the review of the effluent data for the past 5 years the Division established the following TBELs for the coal-fired power plants in North Carolina. The monthly average limits for Total Arsenic and Total Selenium are based on 95th percentile of the effluent data, which is consistent with the EPA methodology, and daily maximum limits for these constituents are based on the 99.9th percentile of the effluent data. The Total Mercury limit is based on the Statewide Mercury TMDL implementation strategy and was established by the Division previously.

Total Arsenic – 10.5 µg/L (Monthly Average); 14.5 µg/L (Daily Maximum)
Total Selenium – 13.6 µg/L (Monthly Average); 25.5 µg/L (Daily Maximum)
Total Mercury – 47.0 ng/L (Monthly Average); 47.0 ng/L (Daily Maximum)

The Division does not have any long-term data for Nitrate/nitrate as N. Therefore, the limits for this parameter are based on the proposed EPA Effluent Guidelines.

Nitrate/nitrite as N – 0.13 mg/L (Monthly Average); 0.17 mg/L (Daily Maximum)

Facility is allowed 4.5 years from the effective date of the permit to comply with the TBELs (Outfall 002 only–Ash Pond Discharge). This time period is provided in order for the facility to budget, design, and construct the treatment system. The compliance schedule is consistent with the proposed EPA Effluent Guidelines that require compliance with the TBELs "as soon as possible within the next permit cycle beginning July 1, 2012". Since the permit cycle is 5 years, the Effluent Guidelines will allow the facility to comply with the TBELs by June 30, 2022. This permit has a more stringent requirements, the facility shall comply with the TBELs by the end of 2019.

In the interim, the facility shall comply with the BPJ temporary limits that are derived by multiplying the proposed TBELs by 5, please see below:

Total Arsenic – 52.5 µg/L (Monthly Average); 72.5 µg/L (Daily Maximum)
Total Selenium – 68.0 µg/L (Monthly Average); 127.5 µg/L (Daily Maximum)
Nitrate/nitrite as N – 0.65 mg/L (Monthly Average); 0.85 mg/L (Daily Maximum)

Although these interim limits higher than the proposed TBELs, they are significantly lower than the allowable concentrations determined by the Reasonable Potential Analysis (RPA) and should be protective of the water quality in the receiving stream. The RPA allowable concentrations are listed below:

Total Arsenic – 13,632.3 µg/L (Monthly Average); 91,690.8 µg/L (Daily Maximum)
Total Selenium – 1,363.2 µg/L (Monthly Average); 12,492.0 µg/L (Daily Maximum)

TEMPERATURE VARIANCE REMOVAL-OUTFALL 001

The facility historically had a temperature variance in accordance with CWA Section 316(a). In order to maintain the variance the facility had to conduct annual biological and chemical monitoring of the receiving stream to demonstrate that it has a balanced and indigenous

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macroinvertebrate and fish community. The latest BIP (balanced and indigenous population) report was submitted to DWQ in August of 2009. The ESS has reviewed the report and concluded that the Mountain Island Lake near Riverbend Station has a balanced and indigenous macroinvertebrate and fish community.

Since the facility discontinued electricity generation in 2013, *it does not wish to request continuation of the temperature variance.* Therefore, Effluent Sheet A. (1.) was modified to reflect temperature requirements without a variance.

CWA SECTION 316(B)

Since the facility discontinued electricity generation in 2013 and does not use cooling water, it will not be the subject to the Section 316(b) of Clean Water Act.

INSTREAM MONITORING-OUTFALL 002

The facility historically had 7 monitoring station, 2 located upstream and 5 located downstream. It is recommended that the monitoring will continue.

The permit also required semi-annual upstream and downstream monitoring of the ash pond discharge. Upstream site (Station B) is approximately 2 miles upstream of the discharge and downstream location (Station C) is approximately 0.5 miles downstream of the discharge. These monitoring stations have been established through the BIP monitoring program, which was required to maintain 316(a) temperature variance. The monitored parameters are: As, Cd, Cr, Cu, Hg, Pb, Se, Zn, and Total Dissolved Solids (TDS). The majority of the results are below detection level, the rest of the results are below water quality standards. These results are consistent with the previous monitoring results.

It is required that the monitoring at the stations B and C will continue until discharges from the station are ceased. It is also required that the facility uses low level method 1631E for all Hg analysis.

FISH TISSUE MONITORING-OUTFALL 002

The permit required fish tissue monitoring for As, Se, and Hg near the ash pond discharge once every 5 years. This frequency is consistent with EPA guidance. Sunfish and bass tissues were analyzed for these trace elements. The results were below action levels for Se and Hg (10.0 µg/g – Se, 0.40 µg/g – Hg, NC) and screening value for As (1.20 – µg/g, EPA). These results are consistent with the previous monitoring results.

TOXICITY TESTING- Outfall 002:

Current Requirement: 24hr Chronic P/F @ 10%
Recommended Requirement: 24hr Chronic P/F @ 2.7% (flow during dewatering)
Monitoring Schedule: January, April, July, October

This facility has passed all chronic toxicity tests during the previous permit cycle, please see attached. The change is the instream waste concentration was made based on the significant decrease in the discharge volume.

COMPLIANCE SUMMARY

Notwithstanding the civil lawsuit filed for unauthorized discharges and groundwater exceedances/violations, based on the monitoring required under the current version of the permit there were no violations of effluent standards contained in the permit.

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PERMIT LIMITS DEVELOPMENT

- The pH limits (Outfalls 002, 002A, and 010) in the permit are based on the North Carolina water quality standards (15A NCAC 2B .0200).
- The limits for Oil and Grease and Total Suspended Solids (Outfall 002 and Outfall 002A) are based on the Best Professional Judgment and are lower than prescribed in the 40 CFR 423.
- The limits for Total Copper and Total Iron (Outfall 002 and Outfall 002A) were established in accordance with the 40 CFR 423.
- The temperature limits (Outfall 001) are based on the North Carolina water quality standards (15A NCAC 2B .0200).
- The turbidity limit in the permit (Outfall 002) is based on the North Carolina water quality standards (15A NCAC 2B .0200).
- The Technology Based Effluent Limits (Outfall 002 and Outfall 010) for Total Arsenic, Total Mercury, Total Selenium, and Nitrate/nitrate as N are based on the requirements of 40 CFR 125.3(a) , 40 CFR 122.44(a)(1); 125.3(c) and (d).
- The Interim Technology Based Effluent Limits (Outfall 002) for Total Arsenic, Total Selenium, and Nitrate/nitrate as N are based on the requirements of 40 CFR 125.3(a) , 40 CFR 122.44(a)(1); 125.3(c) and (d).
- The Whole Effluent Toxicity limit (Outfall 002) is based on the requirements of 15A NCAC 2B .0500.
- The Total Aluminum limits (Outfall 002 dewatering) in the permit are based on the results of the statistical analysis of the interstitial water data.

REQUESTED MODIFICATIONS

With the permit application for renewal, Duke Energy Carolinas, LLC has requested the following modifications:

Monitoring Frequencies (Outfall 002)

Parameter	Present	Proposed
Flow	Weekly	Monthly
Total Nitrogen	2/year	1/year
Total Phosphorus	2/year	1/year
Total Copper	Quarterly	none
Total Iron	Quarterly	none

These requests could not be granted because the Division needs these data to assure compliance with the water quality standards and criteria during the upcoming ash pond decanting/dewatering process.

PROPOSED CHANGES:

- Monitoring requirements for Outfall 001 were adjusted due to the discontinuation of once-through cooling water discharges.
- The Ash Pond Closure Special Condition was updated (Please see A. (15.)).
- The Seep Outfall 010 (Please see A. (5.)) and Seep Pollutant Analysis Special Condition (Please see A. (17.)) were added to the permit.
- The Appendix A and Appendix B were added to the permit.
- A separate effluent page for the dewatering of the ash ponds (Outfall 002) was added to the permit (Please see Special Condition A. (3.)).
- The Boiler Cleaning Waste Special Condition was eliminated due to the discontinuation of the power generation.

- The Section 316(a) of CWA Thermal Variance Special Condition was eliminated due to the discontinuation of the power generation.
- The Section 316(b) of CWA Special Condition was eliminated due to the discontinuation of the power generation.
- The turbidity limit was added to the permit to meet the state turbidity standard per 15A NCAC 2B .0211(3) (k) (Outfall 002).
- The Technology Based Effluent Limits for Total Arsenic, Total Mercury, Total Selenium, and Nitrate/nitrite as N were added to the permit and are based on the requirements of 40 CFR 125.3(a) , 40 CFR 122.44(a)(1); 40 CFR 125.3(c) and (d) (Outfall 002 and Outfall 010).
- The Interim Technology Based Effluent Limits (Outfall 002) for Total Arsenic, Total Selenium, and Nitrate/nitrate as N were added to the permit and are based on the requirements of 40 CFR 125.3(a) , 40 CFR 122.44(a)(1); 125.3(c) and (d).
- Proposed federal regulations require electronic submittal of all discharge monitoring reports (DMRs) and specify that, if a state does not establish a system to receive such submittals, then permittees must submit DMRs electronically to the Environmental Protection Agency (EPA). The Division anticipates that these regulations will be adopted and is beginning implementation.

  The requirement to begin reporting discharge monitoring data electronically using the NC DWR's Electronic Discharge Monitoring Report (eDMR) internet application has been added to the permit. (Please see Special Condition A. (18.)).
- The Applicable State Law Special Condition was added to the permit to meet the requirements of Senate Bill 729 (Coal Ash Management Act, Please see Special Condition A. (19.)).
- The Outfall 011 (former Stormwater Outfall 1) was added to the permit (Please see A. (20.)).

PROPOSED SCHEDULE:

Draft Permit to Public Notice:	March 6 , 2015 (est.)
Permit Scheduled to Issue:	July 27, 2015 (est.)

STATE CONTACT:

If you have any questions on any of the above information or on the attached permit, please contact Sergei Chernikov at (919) 807-6393 or sergei.chernikov@ncdenr.gov

ED_006610_00000066-00009

Message

From: Care2 [petitionquestions@care2team.com]
on behalf of Annette Lancaster [info@care2.com]
Sent: 8/8/2015 3:03:41 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Protect People and Butterflies -- Ban Deadly Herbicide

Aug 8, 2015

Administrator of the EPA Regina McCarthy

1650 Pennsylvania Avenue, NW
Washington, DC 20528

Dear Administrator of the EPA McCarthy,

I am writing to urge you to protect human health and wildlife by immediately banning the use of the herbicide glyphosphate -- also known as Roundup and marketed by Monsanto.

As I am sure you are aware, the World Health Organization recently released a report linking glyphosphate and several other common agro-chemicals to cancer in humans and lab animals. You are obviously also aware that glyphosphate is indicated in recent studies as one of the main drivers in the decline of the iconic Monarch butterfly populations. Glyphosphate destroys milkweed and milkweed is the sole food source of monarch caterpillars. Monarchs, which are famous for their beautiful orange-and-black wings and their annual migration of thousands of miles, have declined by more than 90 percent in less than 20 years -- a period of time during which glyphosphate use grew exponentially due to the widespread adoption of corn and soy genetically engineered to be glyphosate tolerant.

The science is clear: Glyphosphate is a threat to human health and to wildlife, yet the Environmental Protection Agency recently approved increased use of glyphosphate in the United States.

We already use more than 250 million pounds of this harmful chemical every year.

Americans breathe glyphosphate -- a substance identified by the WHO as "probably carcinogenic to humans" -- into our lungs when it is sprayed nearby, and we consume it on fruits and vegetables found in produce aisles across the country.

Administrator McCarthy and Director Housenger, you have a responsibility to protect Americans' health and wildlife. I ask that you honor that responsibility today by immediately banning the use of toxic glyphosphate.

Sincerely,

M. Annette Lancaster
Meramec
Ex. 6 Personal Privacy (PP)

Message

From: EUEC [pdayal@euec.ccsend.com]
on behalf of EUEC [pdayal@euec.com]
Sent: 11/10/2016 8:59:02 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: ENERGYNews: WASTE WATER, ELG, FGD, & 316(b)

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I1. Wastewater Management ----------	**I5. FGD Wastewater & ELG** ----------

A UTILITY COMPLIANCE PERSPECTIVE TO WASTEWATER MANAGEMENT - Bill Skalitzky, Manager Environmental Generation Compliance, Alliant Energy Corp.

BROMIDE & DISINFECTION BY-PRODUCTS: SHOULD YOUR UTILITY PLAN FOR THEM? - Regina Rodriguez, Carbon Specialist, Carbonxt; C. Valcarce, D. Mazyck, E. Gonzaga & P. Kissiinger

RECLAIMED MUNICIPAL OR INDUSTRIAL WASTEWATER FOR POWER PLANT COOLING & BOILER FEED MAKEUP WATER - Kaveh Someah, Vice-President Energy Group, Ovivo USA

A PUSH FOR NON-POINT SOURCE NUTRIENT REDUCTION IN THE U.S. - Sarah Gilstrap, Senior Env. Scientist, Burns & McDonnell

I2. Remediation & 316(b)

PLANT UPGRADES COOLING WATER INTAKES TO MEET EPA'S 316(B) REQUIREMENTS - Greg Rocheleau, Program Manager & Ocean Engineer, Makai Ocean Engineering; Darryl Hayes, Intake Screens; Dale Jensen, Makai

NAVIGATING ENDANGERED SPECIES ACT REQUIREMENTS OF THE 316(B) RULE - Kerry McGrath, Associate, Hunton & Williams LLP

ROLE OF THE ENTRAINMENT STUDIES IN THE DIRECTOR'S BTA DETERMINATION - Christopher Wiggins, Sr. Aquatic Ecologist, Burns & McDonnell

CASE STUDIES OF FGD/ELG COMPLIANCE SOLUTIONS AT THREE POWER PLANTS - Nelson Fonseca, Senior Manager, GE Water & Process Technologies; Lanny Weimer

FGD COMPLIANCE : APPLYING WATER BALANCE TOOL FOR POWER PLANTS - Charlie He, Associate VP, Carollo Engineers; Jessica Dresang & Peter Bokor

TWIN FLUID SDA (SPRAY DRYER ABSORBER) DESIGN A VIABLE CHOICE - Robert Van Durme, P.E., Regional Sales Manager, Lechler Inc.; Gabriel Pacheco

COMBINING TECHNOLOGIES IN THE TREATMENT TRAIN FOR ASH AND FGD WATERS - Mark Kropilak, CEO, Liberty Hydro, Inc.

LESSONS IN GOING TO CLOSED LOOP BOTTOM ASH FOR ELG RULE COMPLIANCE - Clark Harrison, Sr. Manager, CH2M; Paul Chu, EPRI; D. Fink, L. Reid & C. Roby, CH2M

TRENDS IN BIOLOGICAL TREATMENT FOR FGD WASTEWATER - Diane Martini, Sr. Water & Wastewater Consultant, Burns & McDonnell; Sidney Vadbunker

I6. 316(b), ELG, Wastewater

DEMONSTRATION OF FRONTIER SEHAWK AT THE WATER RESEARCH CENTER - Tyler Cromey, Research Engineer, Southern Company

ASTM D6041- CUSTOM FIBERGLASS REINFORCED PLASTIC (FRP) PROOF OF DESIGN - Tony Zacharewych, Mechanical Engineer, RPS Composites

SELENIUM REMOVAL FROM COAL IMPACTED WATER USING A NOVEL LENA UF SYSTEM - Jaeho Ho, Process Engineer, Doosan Hydro Technology; Rob Broglio

WE'RE IN HOT WATER: ALTERNATE THERMAL EFFLUENT LIMITS UNDER THE CWA - Amy Antoniolli, Counsel, Schiff Hardin

ONLINE MONITOR PROVIDES LOW LEVEL SE ANALYSIS TO AID ELG COMPLIANCE - Vladimir Dozortsev P.h.D., Development Manager, Aqua Metrology Systems Ltd.

I7. Water Sustainability

USE OF NANOTECHNOLOGY FOR REMEDIATION OF UTILITY VAULT WASTEWATER - Allan Pronovost, CSO, Red Lion Chem Tech, LLC

SBC CapTec

SELENIUM REMEDIATION USING ALGAE - Samuel Shepherd, Director of Technology, SBC CapTec, LLC

I3. 316(b)

COLLABORATIVE 316(B) STUDY OF SEVEN OHIO RIVER POWER PLANTS - Greg Seegert, Chief Ichthyologist, EA Engineering, Science & Technology, PBC; Jason Rager & Joe Vondruska, EA; Doug Dixon, EPRI

PROTECTING THE FISH CAN BE THAT SIMPLE - Trent Gathright, Business Development, Ovivo USA

AIR QUALITY AND NOISE IMPACTS ASSOCIATED WITH 316(B) COMPLIANCE - Salahuddin Mohammad, Senior Engineer, Golder

LESSONS LEARNED FROM RECENT 316(B) INSTALLATIONS - Brett DeRousse, National Mgr., Hydrolox

VELOCITY REDUCTION AS A KEY COMPONENT IN OPTIMIZATION AND IMPROVEMENTS - Jim Turnage, Enviro. Solutions Director, Atlas Manufacturing Co.; Ford Wall

THERMAL PLUME MAPPING FOR MIXING ZONE AND 316(A) STUDIES - Gregory Howick, Senior Aquatic Ecologist, Burns & McDonnell

I4. FGD Wastewater & ZLD

CHEMICAL SOFTENING FOR FLUE GAS DESULFURIZATION WASTEWATER TREATMENT - Jeffery Preece, Technical Leader, Electric Power Research Institute

DEVELOPMENT OF FGD WASTE WATER COMPLIANCE OPTIONS FOR AEP COAL FLEET - William Heins, Global Market Development Leader, GE Water & Process Technologies; Thomas Hart, AEP

BIO-RECHARGE : THE SCIENCE OF WATER CYCLE MANAGEMENT - Gare Henderson, Director, INDRA Institute

POINT OF USE WATER RECYCLING IN ELECTRIC UTILITY PLANTS - Azita Yazdani, P.E., Founder and CEO, Exergy Systems, Inc

I8. Water Supply & Security

REDUCING DISCHARGE FINES AND NEGATIVE PR THROUGH AUTOMATION OF DMRS - Paul Banfer, Vice President/Chief Technology Officer, EISC

FORWARD OSMOSIS BASED TREATMENT OF FGD WASTWATER - Mary Theresa Pendergast, Director, Oasys Water; Marek Nowosielski, Gordon Carter & John Tracy

DESIGN OF FGD ZLD SYSTEMS - INNOVATION, SIZING TOOLS & WASTE DISPOSAL - Dennis Fink, Water-for-Power Technology Leader, CH2M; Krystal Perez, Thomas Higgins

KLEENWATER FGD ZLD, 5GPM PILOT STUDY RESULTS - Mark Pastore, VP Technology, EES, Inc.; David Martin, ProChem, Inc.

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Sent by pdayal@euec.com

Message

From: Environment Missouri [action@environmentmissouri.org]
on behalf of LUISA DELGADO Ex. 6 Personal Privacy (PP)
Sent: 3/26/2014 6:15:07 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Thank you for protecting Missouri's rivers!

Mar 26, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

All our waterways should be clean enough to drink from, fish from and swim in without risk of pollution -- from our local rivers and streams, to iconic waters like the Meramec and the Missouri River. Unfortunately, loopholes in the Clean Water Act have left many of our smaller waters unprotected, including those that feed and filter the drinking water for 2.4 million Missourians.

Thank you for taking a major step forward to restore Clean Water Act protections to Missouri's streams and wetlands and for your commitment to protecting our waterways.

Please move forward as quickly as possible to finalize a strong rule that will restore Clean Water Act protections to all Missouri's waterways and protect our environment and health.

Sincerely,

Mrs. LUISA DELGADO

Ex. 6 Personal Privacy (PP)

Message

From: EUEC [pdayal@euec.ccsend.com]
on behalf of EUEC [info@euec.com]
Sent: 10/15/2015 2:15:58 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: ENERGYNews - BIOFUELS & ALTERNATIVE ENERGY

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H3.1 NHSM REGULATIONS - WHAT IS YOUR "COMFORT" STATUS? - Thomas Pritcher, Environmental Consulting & Technology

H3.2 RAPID, CONTINUOUS PRODUCTION OF SOLID BIOFUEL USING REACTIVE TWIN-SCREW EXTRUSION - Amber Broch, S. Kent Hoekman, Desert Research Institute; Larry Felix & Bill Farthing, Gas Technology Institute

H3.3 SHREDDED WASTE DOWNDRAFT GASIFIER FOR OVERSEAS CONTINGENCY OPERATIONS WASTE TO ENERGY CONVERSION - Matt Reed, Mike Cushman, Jim Belcher & Simeon Schlis, Infoscitex Corporation; Harris Gold, Consultant

H3.4 WHY POPULARIZING HOUSEHOLD BIOGAS DIGESTERS IN RURAL CHINA FAILED? - Wei Lin, Tsinghua-Rio Tinto, Liwei Hong, Global Environmental Institute

H3.5 FUEL DISPLACEMENT IN CALIFORNIA: A 2025 VIEW - Alejandro Zamorano, Bloomberg New Energy Finance

H3.6 BIODIESEL & BIOHEAT FUEL - Jessica Robinson, Director of Communications, National Biodiesel Board

H4.1 12 MW BIOMASS POWER PLANT AND DEDICATED ENERGY CROP PLANTATION IN NICARAGUA - Carl Kukkonen, CEO, VIASPACE

H4.2 ADVANCED BIOMASS PELLETS - A RENEWABLE, LOW EMISSIONS ALTERNATIVE FOR COAL FIRED GENERATING FACILITIES - Dammon Frecker, Thermogen Industries, LLC

H4.3 CONCEPT FOR SUSTAINABLE ENERGY, FORESTS, SOILS, WATER & COMMUNITIES - Timothy McDonald

H4.4 WOOD BIOENERGY & LAND USE: A CHALLENGE TO THE SEARCHINGER HYPOTHESIS - Roger Sedjo, Resources for the Future; Brent Sohngen, Ohio State University; Anne Riddle,

TECHNICAL TRACKS (view abstracts)

BIOFUELS
111 (D), NSR, NAAQS
ENERGY POLICY
RE: SOLAR & PV
RENEWABLE ENERGY
316 (B) WATER
MERCURY CONTROL
Hg (DCI and ACI)
CCS & CCR
CEMS & HCL
PERMITS COMPLIANCE
OPERATIONS & MGMT
ALT FUEL EV FLEETS
BATTERY & STORAGE
FGD ZLD WASTEWATER
EHS EMIS RISK MGMT
SCR & CONTROL TECH
CLEAN POWER PLAN
SOx & NOx CONTROL

H4.5 REAL-TIME CORROSION MONITORING DURING CO-FIRING OF ACCORDANT ENERGY'S REENGINEERED FEEDSTOCK - Jacob Beutler, Reaction Engineering International; K. Davis, REI; W. Cox, Corrosion Management Ltd.; D. Bai & R. Jafari Accordant Energy

H4.6 ONLINE ELEMENTAL ANALYSIS POSSIBILITIES IN COAL AND BIOMASS APPLICATIONS - Nichelle Worthington, SABIA

H6.1 CONSIDERATION OF ALTERNATIVE ENERGY SOURCES IN LICENSING OF NUCLEAR REACTORS - Andrew Kugler, U.S. Nuclear Regulatory Commission

H6.2 THE ALGAE ALTERNATIVE - CARBON CAPTURE & REUSE - Tim Zenk, VP, Algenol Biofuels; Paul Woods

H6.3 ALGAE - WASTE REMEDIATION AND ENERGY PRODUCTION - Samuel Shepherd, CTO, Missing Link Technology, LLC; Samuel Shepherd

H6.4 LAND USE CHANGE, CARBON, & BIOENERGY RECONSIDERED - Roger Sedjo,Resources for the Future; Brent Sohngen, Ohio State University; Anne Riddle, RFF

D9.1 COMMERCIALIZED; INDUSTRIAL SCALE PLASMA GASIFICATION TECHNOLOGY - Allison Yeckel, Westinghouse Plasma Corp.; Bruce Leonard, Richard Fish & Walter Howard

D9.2 OPPORTUNITIES & CHALLENGES OF INDUSTRY-WIDE ADOPTION OF COGENERATION IN NEW & OPERATING OIL SANDS FACILITIES - Experience Nduagu, University of Calgary; Dr. Ian D. Gates

D9.3 TWENTY-FIVE YEARS OF FUEL IMPACT ANALYSES - WHAT HAVE WE LEARNED, & WHERE ARE WE GOING? - Una Nowling, Technology Lead - Fuels, Black & Veatch

D9.4 TRENDS IN ENERGY & CARBON MANAGEMENT AT SEA PORTS - Matthew Wartian, Regional Global Practice Manager, Burns & McDonnell; Eric Putnam & Lit Chan, ENVIRON

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DECOMMISSIONING of POWER PLANTS

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From: EUEC 2017 [pdayal@euec.ccsend.com]
on behalf of EUEC 2017 [pdayal@euec.com]
Sent: 11/21/2016 1:06:08 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Discounted Registration for EUEC 2017: Feb 8-10, San Diego, CA

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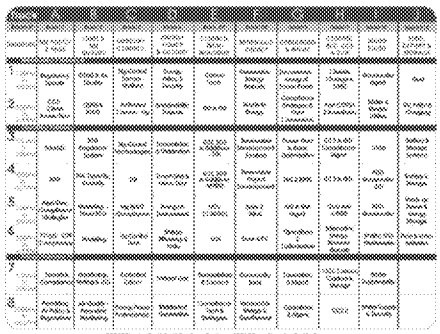

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A. Air Policy, CPP, Regs
B. CEMS, AQ, Modeling
C. Hg Control, DSI, MATs
D. Energy Policy, NG, T&D
E. SO2, NOx, SCR
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Message

From: Care2 [petitionquestions@care2team.com]
on behalf of Steven Barnholtz Ex. 6 Personal Privacy (PP)
Sent: 4/6/2014 6:42:50 AM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Save Bees

Apr 6, 2014

Ms. Regina McCarthy
William Jefferson Clinton Federal Building, Room 3000
1200 Pennsylvania Avenue, NW
Washington, DC 20460-0001

Dear Ms. McCarthy,

I am writing to ask that the EPA protect bees and other pollinators.

Native pollinators like bees play an essential role in the environment and are an indispensable part of our agricultural system. Many foods that we eat depend on crops pollinated by honeybees and 90% of all flowering plants require pollinators to reproduce. But in recent years, bees and other pollinators have been disappearing at alarming rates, causing widespread concern that these important species could be wiped out altogether.

Since insecticides like neonicotinoids first became widely used in the mid-2000s, roughly one-third of Americaâ'TMs honeybee colonies have collapsed each year. Allowing another of these insecticides to be used on millions of acres of farms and orchards will only make the situation worse.

Recently, your agency registered a new insecticide called sulfoxaflor even though the EPAâ'TMs own scientists considered the product to be similar to neonicotinoids and â'oevery highly toxicâ' to honeybees. We need to ensure that this insecticide, and others like it, does not get out into the environment. We cannot afford a collapse in pollinator species populations.

I urge you to refuse to register any insecticides unless scientists confirm they present no threat to bees and other pollinators.

Sincerely,

Mr. Steven Barnholtz
Meramec Ex. 6 Personal Privacy (PP)
Ex. 6 Personal Privacy (PP)

Message

From: NGI Special Reports [contact@naturalgasintel.com]
Sent: 10/12/2016 3:39:26 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: The Boomer Sooner: How the OK Liquids plays are changing the Midcontinent game

Please click here for web version or mobile version.

Learn what has producers buzzing about Oklahoma's stacked reservoirs. If well results and M&A activity offer any indication, the SCOOP and STACK are ready to take off in 2017 as commodity prices continue to recover.

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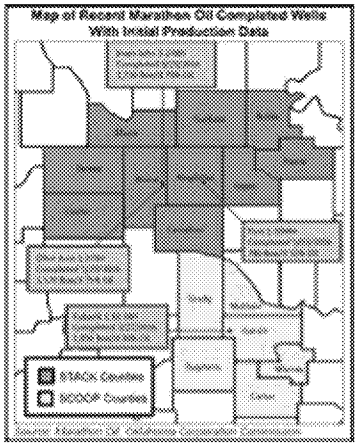

"We currently have 11 operated rigs drilling in the play, with 17 Meramec and nine Woodford wells completing or waiting on completion."
-- Continental Resources COO Jack Stark

"Results from our initial three Meramec spacing tests are outstanding, with flow rates exceeding type-curve expectations and minimal interference between wells. These positive results indicate the potential for tighter spacing and increased inventory in the core of the over-pressured oil window."
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on behalf of EUEC 2016 [info@euec.com]
Sent: 12/10/2015 2:07:26 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Hotels Selling out for EUEC 2016: Feb 3-5, San Diego, CA

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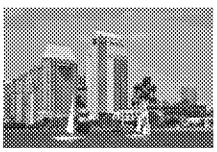

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David Mohler, Deputy Asst. Secretary, DOE

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Message

From: NRDC [nrdcinfo@nrdconline.org]
on behalf of Judith Medoff [medoffj@sbcglobal.net]
Sent: 1/15/2014 8:13:26 PM
To: Mccarthy, Gina [McCarthy.Gina@epa.gov]
Subject: Reopen investigations into polluted groundwater from fracking

Jan 15, 2014

Gina McCarthy, Administrator, U.S. Environmental Protection Agency

Dear McCarthy, Administrator, U.S. Environmental Protection Agency,

Please reopen the EPA's investigations into groundwater contamination linked to fracking activity in Parker County, TX, Dimock, PA and Pavilion, WY.

These EPA investigations initially showed potential groundwater contamination, making the water unsafe for residents. The contamination in all three cases was believed to be linked to nearby fracking activity.

In all three cases, the EPA abruptly pulled out, claiming the groundwater to be safe. But a recent report from your agency's own internal watchdog puts the groundwater safety in one of these locations in question. The December 24 Inspector General report into the Parker County, TX case shows the EPA has enough evidence to take on this case, the overall risk of contamination hasn't been determined, and the EPA need to take action to assess the risk to the public. The report also states that senior EPA officials and a senior attorney from the Justice Department agreed there was enough evidence to enforce the EPA order through the courts.

This watchdog report calls the EPA's decisions in all three locations into question. The EPA should end the confusion, frustration and fear and reopen all three investigations.

It's the duty of the EPA to protect our health and environment. Please reopen the investigations and commit to protecting Americans from any dangers associated with fracking activity.

Thank you.

Sincerely,

Dr. Judith Medoff
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