The Arizona Electric Power Cooperative ("AEPCO")

Comments on

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units, Proposed Rule, 79 Fed. Reg. 34,830 (June 18, 2014)

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INTRODUCTION

The Arizona Electric Power Cooperative, Inc. ("AEPCO"), which along with Southwest Transmission Cooperative and Sierra Southwest Cooperative Services, is one of three cooperatives making up Arizona's Generation and Transmission Cooperatives, is pleased to comment on the Environmental Protection Agency ("EPA") proposal for *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*, Proposed Rule, 79 Fed. Reg. 34,830 (June 18, 2014) (the "Proposed Rule"). AEPCO is highly concerned over EPA's broad overreach in its interpretation concerning its statutory and regulatory authority under Clean Air Act ("CAA") Section 111(d) to regulate States' energy generation, dispatch and demand under the guise of controlling CO_2 emissions. EPA's Proposed Rule is an unparalleled attempt to use its limited authority to regulate and control emissions from coal-fired sources to regulate the United States' electric energy markets and economy.

AEPCO is a rural, member-owned generation and transmission electric cooperative formed in 1961 to provide electric generation service to local rural, consumer-owned electric distribution cooperatives in Arizona. As a not-for-profit cooperative, AEPCO is fully owned by its members. AEPCO has six "Class A" members, who participate in and rely on AEPCO's electric generation services, and one "Class D" member that only participates in AEPCO's electric scheduling and trading services. Together, AEPCO's Class A members serve just under 150,000 meters, providing electricity primarily for residential use.

Because of the rural and residential nature of the cooperatives it serves and which comprise its membership, AEPCO is a relatively small entity with limited financial means. AEPCO operates only one power generation facility: the Apache Generating Station ("Apache" or "AGS"). Apache was first constructed with the installation of Steam Unit 1 ("ST1"), a 72 net MW steam unit in 1963, and Gas Turbine 1 ("GT1"), a 10 net MW simple cycle gas turbine in 1964. In 1978-1979, AEPCO added ST2 and ST3, almost identical Riley Stoker turbo-fired boiler units, each with a 175 net MW capacity. ST2 and ST3 are AEPCO's coal-fired units. Other simple cycle combustion turbines (GT2, GT3 and GT4) were added later. Collectively, Apache has approximately 555 MW of net installed capacity in its electric generating units ("EGUs").

The major units at Apache, coal-fired electric generating units ("EGUs") ST2 and ST3, were planned in the mid-1970s and installed by the late 1970s. At this time, the United States was undergoing multiple energy shocks due to the Oil Embargo and relatively limited supplies of domestically produced natural gas. In line with evolving United States energy policy favoring use of coal as a secure domestic energy source, AEPCO commissioned both ST2 and ST3 as coal-fired units, even though from a size perspective the units would have more typically been built as natural gas-fired units. AEPCO's decision to build coal-fired units was consistent with the Fuel Use Act, which forbid at that time the use of natural gas for electric generation in new units to conserve natural gas availability for residential and commercial use. Since that time, AEPCO's base load growth has not been sufficiently great to justify the installation of new, more efficient coal- or gas-fired load-following units. AEPCO thus remains heavily dependent upon its two coal-fired load-following units, ST2 and ST3. The history of AEPCO's resource decisions, including its conformance to United States' energy policy then favoring coal, should merit special consideration on behalf of AEPCO and entities like it.

Due to AEPCO's status as an electric power utility it will be subject to any requirements established under the Proposed Rule governing CO_2 emissions from fossil fuel-fired EGUs when it is finalized.

SUMMARY OF CONCERNS

- The Proposed Rule suffers from numerous technical defects in its construction and understanding of how the electric market works in the United States and particularly in Arizona. These defects include:
    - An overestimation of the amount of heat rate improvement that can be achieved on modern coal-fired EGUs typical of the Arizona coal-fired EGU fleet. In AEPCO's specific case, an improvement of from 1 to 1.5% is likely all that is economically appropriate;
    - An overestimation of how rapidly power can be redispatched from existing utility base-load coal-fired EGUs to merchant natural gas combined cycle ("NGCC")

EGUs considering constraints on ownership, available and useful capacity, transmission and natural gas supply.

- A need for greater clarity that renewable resources should be determined at the point of use, not generation, consistent with current market practices.
- An overestimation of the amount of energy efficiency that can be obtained year over year, resulting in a substantial overestimation of total energy efficiency savings in Arizona. As a Generation & Transmission Cooperative ("G&T"), AEPCO has no opportunities for energy efficiency savings at the retail load level.
- An unwarranted assumption that outside energy production can meet Arizona's energy needs during peak consumption periods.

- As a result of these technical defects, the Proposed Rule creates substantial risks to the reliability of Arizona's electric grid. These risks come from:
  - Closure of AEPCO's load-following coal-fired EGUs ST2 and ST3 that provide substantial capacity (350 MW out of 555 MW) and economic energy reliability to the southeast Arizona system.
  - Dislocation of the current electric transmission model, which is based on moving energy from the northern, eastern and southern periphery of the state toward Phoenix, Arizona. AEPCO is concerned that with the loss of ST2 and ST3, as may be required under the Proposed Rule, it will be unable to maintain voltage in the Southeast Arizona quadrant (the "southern bubble") that is currently anchored by Apache.
  - Inadequate time to provide for needed electric generation, transmission and natural gas transmission infrastructure upgrades.
  - AEPCO shares the Arizona Utilities Group ("AUG") concern that the Proposed Rule will drive Arizona's reserves into the negative by 2020.
- The Proposed Rule will result in severe economic stress on Arizona utilities, their customers and members, and ultimately the State's economy.

- The premature retirement of AEPCO's ST2 and ST3 will cost AEPCO upwards of $400 million to replace. The $400 million more than triples AEPCO's existing debt, thereby forcing rural and financially limited customers to pay for unused electric service.
- ST2 and ST3 currently represent approximately 75% of AEPCO's $185 million debt made up of both federal Rural Utilities Service ("RUS") guaranteed Federal Financing Bank ("FFB") loans and National Rural Utilities Cooperative Finance Corporation ("CFC") debt, of which $156 million is FFB debt.
- The Pace Study, completed on the behalf of AUG and submitted to EPA with their comments on the Proposed Rule, estimates that the Proposed Rule will leave Arizona customers paying for approximately over $3.8 billion (2020 dollars) in stranded costs from all utilities expected to face forced closure and diminished generation.
- The premature retirement of Arizona coal-fired EGU fleet and the disruption of the existing transmission models will entail additional costs, not yet estimated, but likely of significant magnitude, in additional electric transmission and natural gas distribution infrastructure. In particular, additional sources of generation would be required for AEPCO's transmission network in the "southern bubble".

- The Proposed Rule violates the Rural Electrification Act ("REA") and the 80-year federal mandate that the electric cooperative system provide reliable, low-cost electricity to rural America. AEPCO will be forced to violate its obligations under the REA mandate, as well as other state, Federal Energy Regulatory Commission ("FERC"), North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") requirements to serve its members with low-cost, reliable electric service.
- AEPCO understands that the Proposed Rule was motivated, at least in part, by EPA's desire to reduce the total cost of reducing carbon-intensive emissions from the United State's EGU fleet. EPA accordingly chose Building Blocks, primarily Building Block 2,

to use existing resources to reduce the cost of the transition. In some cases, however, this decision to reduce the total cost by focusing on enhanced utilization of existing resources, has imposed disproportionate costs on a few states, such as Arizona, and a few utilities, such as AEPCO. It is therefore appropriate that EPA consider a few generally applicable measures that may reduce the disproportionate costs on those most affected entities so that the burdens of the Proposed Rule may be more equitably shared. AEPCO proposes two such solutions in these comments: the "small public and cooperative utility" subcategory and the proposed AUG "solution" discussed in the following section of these comments.

- The Proposed Rule departs from the requirements of the CAA in many respects and should be withdrawn and reproposed as outlined herein.

PROPOSED SOLUTION

As stated above, AEPCO appreciates EPA's efforts to craft an approach to reducing carbon intensity of the United States' EGU fleet at a lower overall cost. However, aspects of EPA's solution have resulted in disproportionate costs being borne by a small subset of states and utilities, such as Arizona and AEPCO. AEPCO thus proposes two approaches that EPA should consider in reducing the disproportionate cost borne by a few, making the Proposed Rule more equitable, while still achieving the bulk of the carbon reduction.

Small Public and Cooperative Utility Subcategory Proposal

As outlined in AEPCO's comments submitted on September 29, 2014, AEPCO believes that EPA should create a subcategory for small public and cooperative utilities that are disproportionately affected by the Proposed Rule. Based on feedback from other members of the cooperative family, AEPCO has refined its proposal, which now reads as follows:

Proposed 40 C.F.R. § 60.5765(b)

(b) In lieu of meeting the state-wide goal established in 40 C.F.R. § 60.5765(a) and Table 1, a small public or cooperative utility may request a State to establish an alternative rate-based or mass-based emission performance goal for affected EGUs owned by a small public or cooperative utility on January 8, 2014, in accordance with this subsection.

(1) For purposes of this subsection, a "small public or cooperative utility" is a governmentally- or cooperatively-owned non-profit entity primarily engaged in the generation, transmission, and/or distribution of electric energy for sale with total electric output (including affiliates) of 4 million megawatt hours (MWh) or less during the baseline period.

(2) A small public or cooperative utility qualifies for the alternative limit in this subsection if, after implementing all reasonably cost effective affected unit heat rate improvements ("HRI"), dispatching all existing NGCC affected units owned and operated by the entity at 70% annual net capacity or, in the case of units owned but not operated, offering for dispatch all existing NGCC affected units at the entity's proportionate share of 70% annual net capacity, and accounting for any renewable resources (other than hydropower or existing nuclear generation) owned by the entity, the following are true:

(i) one or more affected EGUs (the "non-achieving unit(s)") owned by the small public or cooperative utility cannot achieve the interim goal on a rate basis using only the small public or cooperative utility's affected units and renewable resources and any existing state-mandated energy efficiency requirements;

(ii) the non-achieving unit(s), individually or collectively, make up 20% or more of the small public or cooperative utility's net generation in the baseline period;

(iii) shutting the non-achieving unit(s) down will occur prior to the end of the remaining useful life as determined by the utility regulatory commission having jurisdiction, if any, or the permitting authority, if none; and

(iv) the cost of building an equivalent sized NGCC, New Source Performance Standard ("NSPS")-compliant, unit or units to replace the non-achieving unit(s) plus servicing existing debt for the non-achieving units would, in the judgment of the state, be excessive.

(3) For each small public or cooperative utility that owned an affected EGU on June 18, 2014, and continues to own that non-achieving unit satisfying the criteria in paragraph (b)(2) of this section, the State may exclude such non-achieving unit(s) from calculating its state-wide goal in Table 1 of this subpart and establish an alternative goal under its state plan as follows:

(i) During the interim goal period:

(A) Each non-achieving unit owned by the qualifying small public or cooperative utility must implement all reasonably cost effective measures to improve heat rate, which must include enforceable increments of progress, not to exceed five years from plan approval;

(B) The qualifying small public or cooperative utility shall increase dispatch of all existing NGCC units it owns and operates to the maximum extent feasible, up to a 70% utilization rate and, for units it owns but does not operate, shall offer such unit for operation up to the utility's pro rata share of 70% annual utilization; provided, however, that if the increased dispatch of NGCC units results in the non-achieving unit being reduced below its reliability limit, the state plan may provide for either periodic curtailment or earlier retirement of the non-achieving unit so long as total carbon mass is not increased over what would be achieved by

70% utilization of NGCC units owned by the small public or cooperative utility during the interim goal period or appropriate pro rata share of units owned only in part by the small public or cooperative utility.

(C) The qualifying small public or cooperative utility shall install renewable energy ("RE") capacity or obtain renewable energy credits (in a state plan recognizing such credits) equal to at least 10% of non-achieving unit(s) capacity within five years of plan approval or 2025, whichever is later.

(D) The qualifying small public or cooperative utility, if it has local distribution, shall achieve at least one-half of any applicable state energy efficiency requirements set forth in the state plan.

(E) The qualifying small public or cooperative utility shall achieve a net reduction of its carbon intensity through the measures specified in paragraph (b)(3)(i)(A) through (D), plus additional increments of process specified in the state plan for such small public or cooperative utility, equal to the lesser of the following (excluding nuclear and hydropower):

(I) an amount that achieves for the small public or cooperative utility an emission rate equal to the state Final Goal established in Table 1 of Subpart UUUU by 2030; or

(II) an amount that achieves a 15% reduction from the baseline carbon intensity of the small public or cooperative utility.

(III) for units that the small public or cooperative utility owns only in part, the calculations of this paragraph (b)(3)(E) shall be made based on its ownership share in the units.

(F) The qualifying small public or cooperative utility must achieve at least 33% of the reduction required in subsection (b)(3)(i)(E) by 2020 or three years after plan approval, whichever is later.

(ii) During the Final Goal period, the state plan shall provide that the qualifying small public or cooperative utility must take one of the following actions:

(A) Shutdown the non-achieving unit(s) at the start of the Final Goal period; or

(B) If any non-achieving unit(s) will remain in operation, then the qualifying small public or cooperative utility shall continue any measures imposed on the non-achieving unit(s) and the utility by the state plan and shall install additional RE or obtain RE credits (in a state plan recognizing such credits) beyond the quantity required in subparagraph (b)(3)(i)(C), equal to at least 10% of the non-achieving unit(s)' capacity prior to the start of the final goal period. Additional renewable energy offsets equal to 10% of the non-achieving unit(s)' capacity must be obtained prior to each fifth anniversary of the Final Goal plan effective date if the unit is to be kept in operation beyond the anniversary date. These offsets are in addition to any other RE requirements in the state plan that are applicable to all utilities.

(iii) Except as provided in paragraph (b)(3)(iv) of this section, a non-achieving unit may not operate pursuant to this subsection (b) beyond the end of its remaining useful life established by the utility regulatory commission having jurisdiction, if any, or the permitting authority, if none. The shutdown date for each non-achieving unit shall be included in the state plan.

(iv) A small public and cooperative utility that has non-achieving units that would be able to achieve the state final goal set forth in Table 1 of this subpart on or before December 31, 2039, may transition from this subcategory back to the State Plan by obtaining a revision to the state plan approved by EPA. A non-achieving unit that transitions back prior to December 31, 2039, shall not be subject to the mandatory shutdown provision of paragraph (b)(3)(iii), but shall comply with all requirements of the state plan applicable to that unit.

(4) A state may establish more stringent requirements for a qualifying small public or cooperative utility.

As indicated in AEPCO's comments filed on September 29, 2014, which are hereby incorporated by reference, this proposal would affect approximately 100 small public and cooperative entities if the 4 million MWh of sales definition is used. AEPCO's analysis determined that it is likely that the small public and cooperative utility subcategory would result in less than a 1% leakage rate from the carbon reduction that EPA is seeking.

Changes to the proposal from AEPCO's September 29, 2014, comments include the following:

- Clarification that small public or cooperative utility requests applicability of the subcategory (in paragraph (b) introductory language).
- Provided some clarification on how to handle units that are partially owned, or owned by not operated, which is a situation that applies to many cooperatives. Revised language addressing this issue is found in paragraphs (b)(2), (b)(3)(i)(B), and (b)(3)(i)(E)(III).
- Slightly loosened the language of paragraph (b)(3)(iii) to allow consideration of book life as suggested in EPA's Notice of Data Availability ("NODA"), while maintaining the requirement that the State Plan identify a date certain for shutdown.
- Added a new paragraph (b)(3)(iv) allowing a unit to avoid the mandatory shutdown requirement if the small public or cooperative utility system would come into compliance with the Final Goal by December 31, 2039.

At a meeting in September, 2014, and again in November, 2014, EPA inquired whether adequate flexibility exists under other provisions of the Proposed Rule to eliminate the need for the proposed small public and cooperative utility subcategory. Respectfully, AEPCO does not believe adequate flexibility exists. First, as detailed in the comments of the Arizona Department of Environmental Quality ("ADEQ") submitted on November 21, 2014, in Arizona there is no flexibility to alter the application of the Building Blocks and still achieve both the Interim and Final Goals. Thus, ADEQ does not have any practical ability to provide the relief needed to small public and cooperative utilities, at least under the current Proposed Rule. Second, even if the Interim Goal is relaxed, under the Proposed Rule's approach of defining a final, numeric target, any relief that is granted to a small public or cooperative utility will result in another entity having to reduce proportionally more. It is unclear whether, in such a zero sum situation, that a state agency such as ADEQ would find it politically possible to extend relief to deserving entities with limited financial capabilities. Third, it is not clear, given the Section 111's requirement that cost be considered in setting the standards of performance for each individual source, that it is appropriate to apply unreasonably costly controls to small public and cooperative entities or to reapportion costs beyond what a reasonable control costs on other entities. These problems are solved by creating a subcategory which meets its own criteria without reapportioning between the subcategory and the other sources no longer represented in the subcategory.

<u>The Arizona Utilities Group (AUG) Proposal</u>

AEPCO also urges EPA to adopt the comments filed by AUG, which has recommended a solution that reduces the costs of compliance while lessening the reliability problems and maintaining the bulk of the carbon reductions under the Proposed Rule. The AUG recommendation is as follows:

1. For purposes of goal setting under Building Block 2 ("BB2"):
    a. Redispatch from coal-fired EGUs to NGCC EGUs should occur upon the later of any of the following, if redispatch would occur prior to January 1, 2030:
        i. January 1, 2020;
        ii. January 1 of the year following 40 years after initial commencement of operation; or
        iii. January 1 of the year following 20 years after commencement of operation of major pollution control retrofit, such as selective catalytic reduction ("SCR"),

flue gas desulfurization ("FGD"), or baghouses at any EGU if installation occurred prior to issuance of the Final Section 111(d) rule, or after commencement of operation of selective non-catalytic reduction ("SNCR") or electrostatic precipitators ("ESPs") at an EGU owned by a small utility as defined by the Federal Energy Regulatory Commission ("FERC") if installation occurred prior to the first year of the compliance period (i.e., 2020).

b. For coal-fired EGUs that either shutdown or convert to natural gas-fired operation, redispatch would occur as specified in an applicable implementation plan or enforceable Title V permit, provided that such commitment is entered prior to the effective date of the final rule and the date of shutdown or natural gas conversion is prior to January 1, 2030.

c. Coal-fired EGUs that do not redispatch prior to January 1, 2030, under paragraphs 1.a or 1.b remain coal-fired EGUs for purposes of calculating the Interim and Final Goals.

2. For purposes of goal setting, when redispatching to NGCC, a rate of 1,000 lbs CO_2/MWh should be used, consistent with the most stringent standard in the EPA's proposed NSPS for EGUs.

3. The State should establish the Interim Goal in its State Plan based upon EPA's Building Block approach as modified by paragraphs 1 and 2 above.

AEPCO is a member of the AUG and agrees that this approach, which is more fully explained in the AUG comments, which AEPCO adopts and incorporates herein, addresses many of the issues that cause difficulty in Arizona. AEPCO recommends that EPA adopt both the proposed small and cooperative utility subcategory and the AUG proposal.

AEPCO's detailed comments and concerns follow.

BACKGROUND

Clean Air Act Section 111(d)

Section 111 of the CAA, 42 U.S.C. § 7411, requires that "standards of performance" be set for stationary sources of certain non-hazardous air pollutants and that these standards are to be based on the "best system of emission reduction" ("BSER") that EPA has determined is "adequately demonstrated." 42 U.S.C. § 7411(a)(1). For *new* sources EPA sets the actual standards of performance. *Id.* § 7411(b)(1)(B). For *existing* sources, EPA establishes procedures for the States to determine standards of performance. *Id.* § 7411(d). The States then use EPA's standards to 1) submit plans similar to state implementation plans under Section 110, which establish standards of performance for existing sources within the State; and 2) apply those standards of performance to specific sources. *Id.* When developing the standards of performance, States take into consideration several factors, including 1) the cost of achieving such reduction, any non-air quality health and environmental impact, energy requirements and, for existing sources, remaining useful life. 42 U.S.C. § 7411(a)(1) & (d)(1)(B). Standards must provide for "continuous emission reduction" and be demonstrated in practice. *Id.* § 7411(a)(1) & (7).

Proposed Rule

Under the Proposed Rule, EPA has determined Interim and Final CO_2 emission limitation goals for each individual state, including the State of Arizona, by establishing state-wide carbon intensity rates for each state's electric power sector and outlining its "proposal" of the BSER to achieve these goals. By establishing mandatory emission goals, EPA is effectively forcing states to reduce usage and reliance on carbon-based power generation from existing fossil fuel-fired EGUs and to "redispatch" this power generation to other electricity generation, such as NGCC generation and RE generation. The goal that EPA has set for each state must be "achievable" and "reasonable" based on the application of BSER. In this Proposed Rule, EPA has proposed that BSER for existing fossil fuel-fired power plants is the combination of four Building Blocks, or emission reduction strategies. The four building blocks were then used to develop an 1) Interim Goal for each states where the state must meet on average over the first ten (10) years of compliance (2020-2029); and 2) a Final Goal which states must meet on a three-year average starting in 2030. Under EPA's proposal, states have discretion to determine the policy measures and Building Blocks it will rely on to meet the goal.

As demonstrated in the following comments, EPA's Interim and Final goals deprive Arizona of any meaningful discretion in best determining the course of action for the State and will impose substantial costs on the State of Arizona, its utilities, their ratepayers, and Arizona's economy as a whole. The impact is even harsher on AEPCO, which faces the prospect of shutting down the 425 MW most efficient generation of its 555 MW capacity, unless EPA's Proposed Rule is substantially revised. EPA's mandated CO_2 emission limitation goals for states, without a specific and defined system of BSER, exceeds the Agency's authority and cannot be finalized as proposed.

<u>Rural Electrification, Rural Electric Cooperatives and AEPCO</u>

In 1935, President Franklin D. Roosevelt established the Rural Electrification Administration ("REA") by executive order and tasked it with bringing affordable electricity to rural communities across the country. *Establishment of the Rural Electrification Administration,* Exec. Order No. 7037, May 11, 1935. While acknowledging the difficulty and expense of extending service to less densely populated areas of the country, President Roosevelt also recognized the vital importance of rural communities and considered the REA's mission to bring modern electric service to rural families as "one of the most important projects" of the nation. Franklin D. Roosevelt, "Statement on Signing a Rural Electrification Bill" (Sept. 22, 1944), *available at* http://www.presidency.ucsb.edu/ws/?pid=16560. By passing the Rural Electrification Act ("RE Act") of 1936, Congress formally established the REA as a federal agency and made its mission to power America's rural communities and to improve access to electricity a matter of statutory mandate. 7 U.S.C. § 904(a).[1] The REA became a part of the Department of Agriculture in 1939. Since 1939, Congress has consistently acted to ensure that the REA, and its successor, the Rural Utilities Service ("RUS"), successfully provided electric service to the entire country.

Congress and the REA recognized that federal support was essential to the electrification of rural America because established utilities generally served high-density areas and did not

[1] *See also Arkansas Valley Cooperative Rural Electric Co. v. Elkins*, 200 Ark. 883, 141 S.W.2d 538 (1940) (The RE Act was designed to effect a "governmental policy" to make the benefits of electricity available to rural areas and "remedy a deficiency in the life and economy of the rural population of the nation."). "[T]he REA promotes and facilitates investment in electricity (and telephones, to a lesser extent) for rural areas in order to ensure that these regions receive power at reasonable prices." *Wabash Valley Power Ass'n, Inc. v. Rural Electrification Admin.*, 988 F.2d 1480, 1483 (1993) (citing to Congressional Budget Office, New Approaches to the Budgetary Treatment of Federal Credit Assistance (1984); M. Weidenbaum & R. Harnish, Government Credit Subsidies for Energy Development (1976)). "REA has a statutory duty to lend money and see that it is repaid; but more, it is a government agency created by Congress to further rural electrification." Norman L. Plotka, *Agricultural Credit: Electric and Telephone; Rural Electrification Act of 1936 and Related Statutory Provisions*, in Agricultural Law § 98.01[1] (2014) (citing *P.U.D. No. 1 of Pend Oreille County v. United States*, 417 F.2d 200 (9th Cir. 1969)).

serve farmers and other rural Americans. Particularly due to the lower population densities of rural areas, these utilities had no financial incentive to do so. Partnering with rural electric cooperatives was (and remains) fundamental to achieving the goals of the REA. *See generally* Rural Electrification Administration, "A Guide for Members of REA Cooperatives" (July 1940). Seeking to ensure that that maximum benefit was provided to rural communities, the government recognized that the cooperative model was the key to success. Where investor-owned utilities at the time were concerned that the high cost of extending service to under-populated and traditionally low-income areas conflicted with the duty to provide reasonable returns to shareholders, cooperatives had more flexibility as non-profit organizations to flow the benefits of the program directly to their rural membership. In this way, cooperatives became the predominant instrument through which the REA was able to comply with its statutory mandate. *Wabash Valley Power Ass'n., Inc. v. Rural Electrification Administration*, 988 F.2d 1480, 1490 (7th Cir.1993) ("Rural electrification, whether enabling electricity purchases by distribution cooperative customers or assisting the development of generation and transmission facilities, remains the fundamental goal of the RE Act.).

In the decades following enactment of the RE Act, Congress has continued to support the REA by passing laws to secure funding and expand its mandate. *See generally* Norman L. Plotka, *Agricultural Credit: Electric and Telephone; Rural Electrification Act of 1936 and Related Statutory Provisions*, in Agricultural Law § 98.01[1] (2014) (citing *P.U.D. No. 1 of Pend Oreille County v. United States*, 417 F.2d 200, fn 11 (9th Cir. 1969)). Congress authorized the REA to borrow funds from the Reconstruction Finance Corporation in 1938. 52 Stat. 818 (1938). In 1944, Congress made loan funds under the RE Act permanently available and authorized the REA to refinance existing loans from the Tennessee Valley Authority. 58 Stat. 925 (1944). With the enactment of the Department of Agriculture Appropriation Act in 1947, the REA began borrowing funds from the Treasury. 61 Stat. 546 (1947). The Rural Electrification and Telephone Revolving Fund was established in 1973 to provide for insured and guaranteed loans under the RE Act. 87 Stat. 65 (1973). The REA's successor, the RUS, was formed in 1994 and continues to implement the statutory mandate of the RE Act through direct loans and loan guarantees, recognizing that "reliable, affordable electricity is essential to the economic well-being and quality of life for all of the nation's rural residents." USDA Rural Development–UEP Home, http://www.rurdev.usda.gov/UEP_HomePage.html (last visited Sept. 5, 2014).

Today, over 95% of all rural Americans have access to electricity. USDA, "When the Lights Came On," *available at* http://www.rurdev.usda.gov/rbs/pub/aug00/light.htm. The RUS Electric Programs have, either directly or indirectly, in some way funded all of the generating units owned and operated by G&Ts and almost half of all rural electric line construction in the nation. These programs continue to provide the capital needed to upgrade, expand, maintain and replace America's rural electric infrastructure including pollution controls for generating units. Through the Electric Programs and partnerships with over 900 rural cooperatives, the federal government is the majority note holder for approximately 700 electric systems borrowers in 46 states, with loan levels over $47 billion. Despite unquestionable success over the last 80 years, the statutory mandate to serve the rural community with reliable, low-cost power is as important as ever. As Secretary of Agriculture Tom Vilsack wrote in 2010, "Rural America is aging, and those living there earn less than their urban counterparts and are more likely to live in poverty." Tom Vilsack, *USDA: Committed to Co-ops*, Rural Cooperatives (May/June 2010), at 2.

AEPCO and its sister company, Southwest Transmission Cooperative, are G&T cooperatives.

DETAILED COMMENTS

I. EPA's Proposed Rule Violates the Rural Electrification Act ("REA") Mandate to Provide Affordable and Reliable Power to Rural America

The EPA's Proposed Rule violates the REA's federal mandate that rural America receive reliable, low cost electric services because it will result in the significant reduction in either the operation of or retirement of nearly all coal-fired EGUs, many of which are owned and operated by rural electric cooperatives such as AEPCO. EPA recognizes in the proposal that there is no technological option to reduce CO_2 emissions from power plants. Instead, EPA determines that the BSER for CO_2 emissions EGUs is primarily the reduction or elimination of coal generation. Without this coal generation, the reliability of this country's electric grid is severely threatened. Coal generation is essential to serving this country's electric load, ensuring that the owners and operators of coal generation remain viable and preventing dramatic increases in electricity rates. Due to their relatively small customer base, rural electric cooperatives are particularly vulnerable to the impacts of reduced coal generation ahead of the end of those EGUs useful life. In addition, without relief granted to small public and cooperative utilities, these disproportionate impacts will fall on the poorest electric consumers in the country. This is unacceptable. Because of the Proposed Rule, the CAA and the REA (and its progeny) can no longer be read and applied harmoniously. Consequently, the Proposed Rule must be withdrawn.

AEPCO, even more so than other G&Ts, will be forced to violate the mandate that it provide reliable, low-cost electricity to its members. AEPCO cannot achieve the Proposed Rule's Arizona emissions rate goals without shutting down the Apache coal-fired EGUs ST2 and ST3, which will leave AEPCO substantially short on generation. Without this reliable, high capacity generation, the Proposed Rule seeks to force AEPCO to natural gas combined-cycle resources and renewable energy to serve load that was met by coal generation. At this point AEPCO does not have (or have access to) sufficient natural gas combined-cycle and renewable energy generation to meet its load. Without adequate system generation AEPCO cannot reliably serve its load. Arizona reliability issues if the Proposed Rule were to be adopted were noted by both NERC and WECC.

Because the Proposed Rule will leave AEPCO without sufficient generation, it will be forced it into the spot energy market and other extremely costly capacity and energy options to serve its members. G&Ts like AEPCO are not-for-profits and do not have shareholder equity or any other means to deal with cost increases other than to pass them onto electricity rates. These increases in AEPCO's electricity costs, therefore, can only result in dramatic rate increases for its members. AEPCO's rates are paid by some of the poorest Americans. G&T ratepayers are not in a position to absorb significant rate increases and, to the extent possible, will choose to voluntarily reduce service and suffer from a lesser quality of life.

The Proposed Rule, therefore, will force AEPCO to violate the REA and the federal mandate to serve reliable, low-cost electricity to its members and must be withdrawn unless EPA adopts revisions such as those proposed in the small public and cooperative utility subcategory and the AUG proposal.

II. EPA’s Proposed Best System of Emission Reduction (“BSER”) and Associated Building Blocks Are Impermissible And Exceeds EPA’s Authority to Define Technological or Operational Emission Improvements at an Individual Source and Instead Seek to Regulate Energy Generation and Demand

EPA’s Proposed Rule and associated proposed best system of emission reduction (“BSER”) comprised of four “Building Blocks” is unreasonable, unfounded and arbitrary. EPA’s BSER proposes to redispatch power from coal-fired EGUs to lower-emitting natural gas-fired existing NGCC, redispatch from fossil fuel-fired EGUs to non-emitting renewable energy (“RE”) sources and nuclear power, and demand drastic end user reductions of electricity for the primary and sole purpose of reducing greenhouse gas (“GHG”) emissions from coal-fired EGUs. This attempt at lowering CO_2 emissions oversteps EPA’s regulatory and statutory authority because the proposed emission reduction system 1) requires emission reductions obtained from sources other than the “affected facility;” 2) requires emission reductions that are obtained through facilities and measures that are beyond the regulated source category (coal-fired EGUs) or that apply beyond this regulated source category; and 3) allows energy demand reduction and elimination (of coal-fired energy) to qualify as controlling emissions.

Instead of proposing a definite and specific system of BSER for states to apply to a designated existing source, EPA is proposing a vague list of items that States may utilize, at their discretion, which might conceivably lead to emission reductions. But EPA’s Building Blocks are not a proposed BSER sufficient to satisfy EPA’s duty to determine a system of means for obtaining emission reductions. Further, the Building Blocks far exceed EPA’s authority, propose overstated results and unachievable energy generation redispatches, and threaten the economic viability of AEPCO and its members.

A. EPA’s Building Block #1 is unsupported and unattainable as it mandates HRI of 6% that are overstated and unachievable.

EPA’s proposed Building Block #1 (“BB1”) is unreasonable because it seeks to require unachievable HRI from coal-fired EGUs of 4-6%. EPA’s assumption that 4-6% HRI levels are achievable is unfounded as the Agency assumes that 4% HRI can be achieved by the entire fleet of coal-fired EGUs through the adoption of heat rate variability best practices and an additional 2% HRI can be achieved by equipment upgrades. These HRI’s are not possible.

1. *EPA's assumptions are based on misinterpreted reports and the associated HRI targets are therefore not feasible*

EPA's assumptions of achievable HRI are based on its false interpretations of the Sargent & Lundy report, a 2009 study by the engineering firm Sargent & Lundy, and its uninformed assumptions of determining factors in its own sixteen unit study. Based on its faulty assumptions derived from these studies, EPA cannot adequately justify the feasibility of a 6% HRI for all coal-fired EGUs.

In its proposal, EPA stated that "… [b]y applying best practices to their operating and maintenance procedures owners and operators of EGUs could reduce heat rate variability relative to average heat rates and, because deviations generally result in performance worse than optimal heat rates, improve the EGUs' average heat rate." 79 Fed. Reg. at 34,860. EPA then justified this statement and its proposed 4% HRI by providing examples of 335 coal-fired EGUs that had heat rate variations of 8.5% or more each year. From this review, EPA concluded that "…other factors held equal, the range of variation indicates that significant potential for heat rate improvement is available through application of best practices." GHG Abatement Measures 2-30. EPA then determined through a regression analysis that 26% of heat rate variation is generally due to temperature and capacity factors. In order to determine the remaining portion of the 74% that could then be attributed to best practices, EPA constructed a 168-bin matrix, containing 14 temperature bins by 12 capacity factor bins. EPA then arbitrarily and capriciously assumed that for each EGU the same output can be produced by reducing the heat input by 30% of the difference between the reported value representing the top 10% in each bin—therefore arriving at a 4% HRI across the entire EGU fleet contributed to best practices. EPA does not provide any additional explanation or rational basis to support this matrix methodology and it is not supported by any technical explanation. Therefore, the 4% HRI assumption should not be afforded any weight. *Id*.

EPA also identified 16 EGUs from the study population to determine EGU year-to-year HRI. EPA's interpretation of HRI data from these units, where equipment upgrades resulted in 2-3% HRI, further demonstrates its faulty approach and interpretation of the data. EPA never contacted the owners of the units identified to determine what factors were responsible for the apparent heat rate reductions. While EPA attributed the HRI to equipment upgrades, preliminary discussion with the owners of these units reported that HRI were *not* the result of purposeful efforts to improve unit efficiency but were instead *almost exclusively* from changes in continuous emission monitoring system ("CEMS") reporting methodology. Therefore, it is clear that the reported HRI in this study did *not* reflect actual changes in unit efficiency or reductions in unit CO_2 emission rates. This is yet another example of EPA's unfounded determination that 4% HRI is achievable across the board for all coal-fired EGUs from best practices.

Further, to determine that additional 2% HRI could be achieved by all individual coal-fired EGUs, EPA relied on the Sargent & Lundy study. This study was based on a literature study, data provided by original equipment manufacturers, and the in-house database of Sargent & Lundy. In reality, the report estimates HRI ranges at a conceptual level only and were not based on detailed site-specific analysis. Conversely, several cases in the study actually demonstrate that it is not feasible to apply all of the HRI alternatives to every individual EGU; therefore, making the projected HRI improbable or even impossible. The cited case studies demonstrated that HRI alternatives were not available for every individual EGU because 1) individual generating units vary in plant design, previous equipment upgrades and operational approaches; 2) individual HRI technologies and strategies do not always combine in ways that equal the sum of the parts because many technologies are dependent on interrelated variables of plant operation; and 3) HRI depends on EGU load levels because a facility's average heat rate is lower when it is base-loaded than when it is load-cycled.

Lastly, EPA's assumption of an achievable HRI of 6% unrealistically assumes that coal-fired EGUs will be able to maintain a 6% HRI over the course of the ten-year performance period. This assumption is unfounded as HRI achieved through equipment upgrades actually *decline* over time due to many factors, such as natural degradation, installation of emission control technologies, and the coal-fired cycling. Therefore, due to EPA's faulty assumption that 6% HRI is consistent once achieved, coal-fired EGUs would in fact have to achieve a HRI *greater* than 6% and continue to implement *additional* HRI over time.

2. *Arizona will not be able to achieve 6% HRI as it has already implemented many of the heat rate variability best practices and*

equipment upgrades

In addition to the faulty assumptions by EPA, presented *supra*, concerning EGUs ability to achieve a 6% HRI, the State of Arizona cannot meet these improvement ranges because it has a relatively young coal-fired EGU fleet and has already implemented many heat rate improvement practices and equipment upgrades. The young nature of the fleet and all of the improvements that have already been made leave Arizona's utilities with little room for further HRI.

Arizona's coal fleet is the sixth youngest in the nation, which diminishes the ability to achieve further heat rate improvements. ADEQ, *State of Arizona Energy System: Examining the Current State of Arizona's Energy Mix in the Context of the Clean Power Plan*, at 15, Arizona's average coal unit has a rated capacity of about 330 MW, about ten (10%) percent less under actual operating conditions. Arizona's coal fleet has a rated capacity of about 3,900 MW for all units combined under normal operating conditions. *Id.*

In the last few decades, Arizona's ratepayers have made a significant investment into building Arizona's coal fleet and making it one of the more efficient coal fleets in the country. Arizona's younger fleet incorporates heat rate technologies and best practices not available to some older facilities; therefore, Arizona's atypically young coal fleet performs as well as, or better, than older units of comparable size and utilization in other states. Because of efficient performance of the young coal fleet, it is infeasible for Arizona utilities to improve coal unit heat rates of 6% under BB1. Due to the improvements that Arizona coal-fired units have already made, 1% improvements, at most, are realistic.

B. The current Interim target date of 2020 does not actually act as an interim date and in reality serves to effectively require the shutdown of coal facilities by 2020.

While EPA has provided the Final Goal for achievement of state-specific rate goals in 2030, in practice, the Proposed Rule's Interim Goal phase-in period of 2020-2029 actually requires implementation of BSER Building Block 2 ("BB2") and compliance with emission limitations far sooner. The Proposed Rule's timeline is unreasonable and unrealistic based on the time it will take states to submit approvable State Plans and implement adequate infrastructure improvements. The Interim Goal should be abolished and EPA should instead provide states with actual flexibility to establish appropriate increments of progress and emission reduction improvement.

The Proposed Rule sets state-specific CO_2 emission rate goals that EPA based on an assessment of the amount of emissions that can be reduced at existing fossil fuel-fired EGUs through the application of BSER required under Section 111(d). EPA has proposed that the state-specific goals be achieved no later than the year 2030. However, EPA has also proposed Interim Goals that states must meet beginning in 2020 and be phased in over the 2020-2029 phase-in period. This time period is unrealistic and unachievable for several reasons.

1. *More time is needed for State Plan development, approval and implementation*

First, EPA proposes to allow states only about one year from the finalization of the emission guidelines to submit their State Plans establishing and applying the standards of performance to affected facilities in the state. 79 Fed. Reg. 34,838. While EPA does propose to allow states up to one year for an extension or two years for proposals covering multiple states, these time periods are still unrealistic considering the complexity of implementation and the time necessary to adopt the adequate laws and regulations in each state to implement the State Plans. AEPCO believes that EPA should grant states at least three years to submit their emission guidelines to EPA, the same amount of time that Section 110 allows states after promulgation of a national ambient air quality standard ("NAAQS") to submit implementation plans, based on the expected complexity of regulatory implementation and infrastructure improvements. Additionally, EPA should grant more liberal extensions to states when a state can demonstrate that it is making a good faith effort to develop its State Plan. Lastly, the Proposed Rule does not offer states any flexibility to adjust their goals based on unanticipated circumstances, reduced hydroelectric power generation capacity, weather emergencies, environmental mandates, or energy emergencies, that would prevent a state or affected facility from complying with its emission reduction goals.

2. *EPA's Interim Goal must be abolished*

EPA's Interim Goals do not actually act as interim achievement goals and the "flexible implementation" claimed by EPA is largely illusory; therefore, EPA's Interim Goal must be abolished. EPA's proposal requires that states achieve its CO_2 emission performance levels on average over the ten-year period from 2020-2029. 79 Fed. Reg. at 34,838. In practice, this requires that states meet the performance levels as soon as 2020 in order to avoid having to make drastic reductions in later years to comply with the average. EPA even acknowledges this necessity by stating, "states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals." 79 Fed. Reg. at 34,839. Therefore, in order to meet these Interim Goals, states will be required to implement extremely aggressive emission reduction efforts starting in 2020; any shortfalls in reductions starting in 2020 will otherwise have to be made up by later-year emission reductions that will have to be substantially below EPA's projected average emission rates, resulting in significant over-compliance.

EPA's BB2 is another example of the illusory nature of EPA's proposed "flexible" implementation schedule between 2020-2029. Under BB2, EPA proposes redispatch from steam generators using coal, oil, or natural gas to existing NGCC units operating at up to a target 70% utilization effective in January 1, 2020. For some states, such as Arizona, this redispatch accounts for the most significant emissions reductions from the four possible Building Blocks. EPA has calculated the state emission reduction goals assuming that both BB1 and BB2 will be fully implemented by 2030. 79 Fed. Reg. at 34,905-6. In practice, this assumption requires states to implement the relevant infrastructure to comply with Building Block 2 by 2020, or soon after, because delaying complete implementation of BB2 will significantly increase state emission rates between 2020-2029, further forcing states to achieve more aggressive and drastic emission reductions in the latter years of the 2020-2029 timeframe. This result could even force states to exceed emission reductions required under the Final emission targets for 2030 and beyond.

This fast approaching aggressive interim deadline is clearly unattainable for states, especially Arizona, and must be removed from the Final Rule. The ADEQ has already put EPA on notice that it will face significant challenges in attempting to comply with the stringent Interim and Final Goal timeline. ADEQ has extensively documented that EPA's Interim Goal will remove any flexibility for Arizona to comply with EPA's guidelines.[2] Arizona faces unique challenges in making the necessary changes to comply with the goals. Arizona's proposed emission reduction of almost 52% is one of the most stringent under EPA's Proposed Rule. Additionally, EPA compounds the difficultly of this emission reduction by requiring over 95% of these reductions by the interim compliance goal of 2020. This requirement leaves Arizona utilities with no option but to shut down coal-fired capacity and redispatch to natural gas (BB2) in 2020 because the implementation or utilization of Building Blocks #3 or #4 will likely occur too late to aid compliance with the 2020 interim goal.

Instead of reliance on an interim goal, EPA should remove the Interim Goal and allow states the flexibility to actually determine reasonable progress goals. By maintaining the Final Goal of 2030, EPA can still ensure states will reach necessary emission reductions but the added flexibility will allow states to create State Plans and implement infrastructure improvements that will not threaten the economic viability or reliability of the state's electric power system, the utilities affected by this rule and the associated fossil fuel-fired unit improvements, and the customers relying on affordable and reliable power supply.

III. EPA's Building Block #2 Overestimates the Ability to Redispatch Coal-Fired Generation to Existing NGCC With A Utilization Target of 70%, Ignores the Difficulty or Impossibility of Shifting Energy Generation Based on Arizona's Current Infrastructure, and Inappropriately Excludes any Consideration of Hydroelectric Power.

EPA's proposed BB2 seeks to redispatch energy generation from coal-fired EGUs to less CO_2-intensive existing NGCC. In this proposal, EPA assumes that existing NGCC units can operate at 70% capacity factor but fails to demonstrate that this operation capacity is technically feasible. To complicate this assumption, EPA also fails to demonstrate or acknowledge the infrastructure and implementation problems associated with transferring such large energy production to existing NGCC.

A. *EPA fails to demonstrate that all NGCC units can operate at 70% capacity factor*

[2] ADEQ, Arizona Department of Environmental Quality Comments on Building Block 2 (November 20, 2014).

In BB2, EPA assumes that existing NGCC can operate at 70% annual capacity factor. This assumption is not based on an adequately demonstrated methodology. EPA based its assumption of this 70% annual capacity target on the general observation that 464 existing NGCC plants providing generation data in 2012, EPA's baseline year, had capacity factors of at least 70%. *GHG Abatement Measures TSD* at 3-7 to 3-9. EPA also reviewed different data that demonstrated that some units can *seasonally* operate at capacity factor greater than 70% with a 16% (winter) and 19% (summer) of units operating at or above that level in 2012. 79 Fed. Reg. at 34,863. Based on this demonstration, EPA "assumed that 70% was a reasonable fleet-wide ceiling for each state" on an annual basis. *GHG Abatement Measures TSD* 3-9. However, this 70% existing NGCC annual capacity factor target is grossly inflated and practically infeasible because of the small fraction of units that actually achieved operation at 70% capacity factor.

In addition to the small fraction of units that actually achieved 70% capacity factor operation in EPA's review, EPA's analysis is complicated by false assumptions and methodological flaws, including using ineligible EGUs in its calculation of state goals, including NGCC unit capacity that does not currently exist, accounting for NGCC capacity available for dispatch based on unit nameplate capacity instead of net summer capacity, and assuming that all existing NGCC units can achieve a 70% NGCC annual capacity factor target.

1. *In its calculation of state goals, EPA included capacity for existing NGCC units that do not currently exist*

In calculating state goals and the related existing NGCC capacity, EPA included NGCC units that do not currently exist, units that have not yet been fully developed, and units that may never be completed. EPA should revise their calculations to accurately demonstrate generation capacity that is *currently* available.

2. *EPA ignores that net summer capacity is a better indicator of the available NGCC capacity available for redispatch*

BB2 and its redispatch of coal-fired generation to NGCC also ignores problems associated with peak usage by failing to use net summer capacity in calculating NGCC capacity. EPA should have used net summer capacity because it reflects the maximum output that generating equipment can provide to the system at the time of peak summer demand, which is particularly critical in Arizona and other states with a wide divergence between peak and average demand. Net summer capacity is generally lower than the actual nameplate capacity because it reflects capacity reductions resulting from efficiency loss and electricity use for station service or auxiliary loads. Net summer capacity is a much better indicator of existing NGCC capacity available for redispatch because it reflects the amount of energy that EGUs will be able to supply to the power grid to replace lost generation from coal- and oil-fired sources. EPA's refusal to use net summer capacity creates a false impression about the availability of existing NGCC generation for redispatch.

EPA's refusal to account for net summer capacity further harms states with severe weather, such as Arizona. Arizona has a uniquely high summer peak demand. Most of central and southern Arizona, and specifically the cities of Phoenix and Tucson, have very high ambient temperatures during the summer months, resulting in an annual energy profile that peaks significantly during the long summer months. As a result, Arizona has the greatest change in capacity utilization of any state on a month-to-month basis.[3] Currently, the existing NGCC capacity in the state of Arizona is designed to act as an intermediate capacity resource with the ability to quickly and efficiently meet peak summer month demands; the State's current NGCC capacity is *not* sufficient to both redispatch coal generation and meet summer peak demand. If Arizona were to redispatch coal with the existing NGCC capacity, the State would need to build out significant additional NGCC capacity and infrastructure and renewable resources or make large and likely unsustainable market purchases. The Pace Study similarly found that existing NGCC EGUs are inadequate to replace the coal-fired EGUs. *See* Pace Study § 3.1, at 13.

3. *Even if the 70% NGCC annual capacity target was based on sound assumptions, it is infeasible that all NGCC units can achieve it*

Even if EPA's assumption of a 70% NGCC annual capacity was based on sound assumptions, the fact that NGCC facilities are capable of operating at 70% annual capacity does not mean they can actually do so in an integrated energy transmission system. EPA's current assumptions of the NGCC capacity are insufficient to demonstrate there is technical plant capability and infrastructure, available gas, gas transportation, gas storage, and electric

[3] *Id.* at 19.

transmission capacity available to sufficiently increase NGCC generators' historical performance. Currently, cooperatives across the nation own 12,000 MW NGCC capacity with NGCC plant capacity averaging 35% in 2012 and 27% in 2013. During the same time period, only 5 co-op NGCC facilities, representing 30% of the NGCC capacity, operated at 60% capacity when natural gas was priced historically low. EPA has not demonstrated that the NGCC fleet is capable of almost doubling its average performance in order to take on the demands of coal-fired re-dispatch.

B. EPA has effectively ignored drastic problems associated with the redistribution of power within the grid system based on Arizona's current infrastructure.

EPA's Proposed Rule does not evaluate or account for infrastructure and transportation capacity that must be implemented before existing NGCC can increase its capacity to the proposed 70% annual capacity target. EPA has failed to adequately evaluate the redirection of power given the current grid availability and resource location, consequences of such a significant increase in natural gas consumption, and the timeframe that necessary infrastructure improvements will require.

1. EPA failed to consider current NGCC capacity needs and increases, irrespective of its proposal to more than double the NGCC generation

In its Proposed Rule, EPA failed to account for increases in NGCC consumption *just from existing generation sources*. This additional gas transportation capacity needs to be established *before* NGCC can meet its current demands and future proposed 70% capacity target. Currently, the United State and Canada are already in need of additional natural gas pipelines to provide adequate transportation for existing generation sources. The Interstate Natural Gas Association of America ("INGAA") has estimated that the United States and Canada already need 28,900- 61,600 miles of additional natural gas pipelines through 2030—this is before considering any necessary increase in transportation needs from the Proposed Rule.[4] Additionally, increased transportation capacity also requires compression and pumping infrastructure and working gas storage capacity. With the Proposed Rule's projected increase in demand for natural gas from 25-32 states, the current infrastructure upgrades and increased

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[4] INGAA, North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, March 18, 2014 at http://www.ingaa.org/Foundation-Reports/2035Report.aspx.

capacity will only increase more. As the WECC in particular points out, the required natural gas buildout would occur in the same period. As a result, it is very likely that the United States suppliers would not be able to handle the numerous simultaneous projects. Consequently, building this volume of new natural gas is not feasible by the Interim Goal, possibly not even before the Final Goal.

2. *EPA has not addressed natural gas transport limits on redispatch.*

As noted by the Pace Study, the existing transmission network is designed for coal-fired EGUs located in the eastern and southern periphery of the State, while the NGCC EGUs are located in and around Phoenix and in the western periphery of the State. Significant modifications to the transmission network would be required to account for shutdown of the coal-fired EGUs and still provide reliable electricity. *See* Pace Study § 3.1, at 13-14. It does not appear that these issues were included in the proposed timing of BB2 implementation in 2020.

Similarly, Pace reviewed the natural gas pipeline capacity in Arizona and determined that there are two major systems: Transwestern and El Paso. The Transwestern system is essentially at 98-100% utilization even prior to the Proposed Rule. Increased utilization would thus fall almost wholly on the El Paso system, which is also reportedly near full capacity. Time is short to fully integrate pipeline system improvements prior to 2020, given lead times for such infrastructure projects. *See* Pace Study § 3.1, at 14.

Arizona does not currently have a sufficient natural gas pipeline system to support likely Proposed Rule demand and will not have time to upgrade the system to comply with the Interim and Final Goal timelines. NERC-CAISO has determined that Arizona's "existing pipeline capacity is not adequate to handle incremental gas needs of the state under the CPP." Pace Study § 3.6, at 26 (citing NERC-CAISO Joint Report, "Maintaining Bulk Power System Reliability while Integrating Variable Energy Resources"). EPA has not given adequate consideration of this issue and must revise the timing of BB2 and revision to the Interim Goal, at the very least, to accommodate the necessary infrastructure upgrades. Additionally, EPA assumed that states would be able to rely upon one another to comply. However, given that individual states have the theoretical ability to define their own future in terms of compliance with the goals of the

Proposed Rule, it is not guaranteed that Arizona will have sufficient capacity in its neighboring states to maintain reliable electric service. Consequently, Arizona must be afforded the relief requested to continue a reliable electric grid on its own as well as a sufficient MW peak reserve margin, as the Pace Study addressed.

3. *Arizona faces extensive and expensive evaluation, siting and permitting processes*

In addition to the expense related to increasing the infrastructure necessary to support the increased demand and use of NGCC, the process for infrastructure improvements is going to include time-consuming siting and permitting processes for pipeline, storage, and other midstream natural gas infrastructure. Modifying the electric transmission infrastructure is a complex, costly, time-consuming process that will require the cooperation of state and federal agencies, electric utilities, tribes, the general public, and private landowners. EPA has not provided guidance for grid updates and infrastructure support, necessary for states to begin such a daunting, timely, extensive, and expensive process.

Arizona faces an extensive planning and review process and will likely face NGCC resource allocation problems. Due to the inflexibility of the 2020 Interim Goal, the expected problems associated with ramping up energy efficiency, and the approval states will need to implement the State Plans, Arizona anticipates and expects that this will create complications regarding an uninterruptable supply of natural gas and pipelines and storage sufficient enough to allow available NGCC units to bridge the difference in the electric generating capacity. To further demonstrate this concern, the Salt River Project ("SRP") completed an analysis that demonstrates that this extra capacity does not exist during Arizona's peak summer months.[5] SRP additionally determined that Arizona has little to no control over how NGCC units are dispatched, as most of Arizona's merchant plant generators have contracts with in-state and out-of-state entities; therefore a combination of all merchant NGCC generation <u>and</u> the existing baseload coal-fired units will be necessary to meet electric demand in the state and ensure reliability. Arizona faces additional problems in a timeline for implementing new NGCC capacity, as siting and permitting requirements will likely average ten (10) years or more if

[5] Salt River Project, *Building Block #2 Impacts on the Emission Rate Goals for Arizona Under EPA's Clean Power Plan Proposal*, August 2014.

federal or tribal lands are involved. Further, given federal, state and tribal relations it may be infeasible or even impossible to acquire adequate private land for new projects.

Additionally, current infrastructure will not support AEPCO's need to re-dispatch its coal-fired units to NGCC. AEPCO's transmission is limited from Phoenix into the "southern bubble." AEPCO's development is centered around Apache and is not structured or designed to take energy redirection from the fringes of its transmission system and redistribute to the center of the system. AEPCO does not have the financial resources to replace its coal capacity with new NGCC. Currently, between 80-90% of energy supplied by AEPCO to its members is coal-generated. In addition to the higher fuel cost of NGCC, the added capital cost would place a severe burden on smaller entities. This results in the unequivocal necessity of Apache staying online.

4. *Arizona needs to protect the reliability of its energy grid*

It is unclear based on the current infrastructure, unknown timeline of NGCC infrastructure growth and reliability, and Arizona's unique peak summer loads, that Arizona could survive the loss of a natural gas pipeline and still support the grid demand without retaining backup coal-fired options to support the grid. Until the reliability and affordability of Arizonian electricity can be assured, EPA's Proposed Rule is infeasible and unreasonable for Arizona.

However, it is clear that the Proposed Rule will eliminate energy reserves and has timing issues that will significantly risk the reliability of the Arizona electric transmission network. In a study completed by Pace Global, Pace concluded that:

> The assumption that coal generation can be one-for-one diverted to existing NGCC units is inaccurate, and the magnitude and timing which Arizona specifically would need to switch generation would make the state's electric supply unreliable. The lead time for new transmission infrastructure is five to ten or more years. The recent North American Electric Reliability Corporation's (NERC) report 7 on the Clean Power Plan cites the need for a 10 to 15 year outlook for planning transmission development due to the time required for engineering, contracting, siting and permitting, as well as the various federal, state, provincial, and municipal approvals required. The CPP interim goals would

> allow for less than a 5 year outlook from state planning finalization until when the new transmission capacity would absolutely be needed.
>
> Since the CPP requirements will not be finalized until mid-2015 and state implementation plans will not be approved by EPA until mid-2017 or later, timing of the final state plan approval and the typical five-year timeframe to site and construct new power plants would result in real reserve margin declines, noting the sharp decrease in coal generation required under Pace Global's analysis of the CPP Building Block scenario. Given these real world constraints, Arizona will need to seek relief from the CPP's interim goals in order to maintain grid reliability and security. The EPA should include a reliability safety valve mechanism in the final rule. Even if the interim goals are delayed or state goals reduced, there is still a risk to reliability. Consistent with impacts, the EPA should include in its final rule circumstances under which compliance can be delayed to manage real time issues that will compromise electric reliability.

Pace Study § 3.5, at 20-22. AEPCO shares these concerns. Additionally, technical concerns surrounding the frequency and voltage support, as well as system stability, are necessary considerations in the applications of system-wide changes. This concept is illustrated in the following except from the Pace Study:

> Finally, the modeling does not take into account region-specific technical issues. In particular, given the remote location of Arizona's existing coal units, it is anticipated that shutdown of these units may result in issues surrounding voltage and system stability. In the absence of a detailed transmission analysis, given Arizona's demonstrated lack of flexibility, EPA would be unable to assess what units are necessary for the reliability of the electric grid.

Pace Study § 3.1, at 16. On the part of the AEPCO and Southwest Transmission Cooperative electric system, internal analyses indicate that Apache, due to its remote locations, is necessary for the continued reliability of the electric grid in the southeastern quadrant of Arizona, sometimes known as the "southern bubble".

IV. EPA should recognize existing hydropower for purposes of demonstrating compliance with the Proposed Rule.

EPA has excluded existing hydropower from consideration under the Proposed Rule, ostensibly because it would "distort" calculation of goals. 79 Fed. Reg. at 34,867. While AEPCO agrees that including existing hydropower in goal calculations would be distorting because hydropower may not have the same growth capacity as other renewables, EPA's concern about distortion does not justify eliminating consideration of existing hydropower for purposes of complying with the Interim and Final Goals. Just like other renewables, hydropower generates electricity with a considerably lower carbon intensity than coal, fuel oil, or even natural-gas. Thus, use of hydropower achieves EPA's objective of reduced carbon intensity. EPA should explicitly recognize that hydropower generation should be included in calculating a utility's or state's compliance with the Interim and Final Goals. Explicitly stating that existing hydropower can be used for the compliance demonstration creates an important incentive to keep such hydropower available for future use and to avoid replacing it with other, more carbon-intensive forms of power generation.

V. EPA's Building Block #3 Inappropriately Applies to Renewable Energy Outside of the Source Category and Incorrectly Evaluates Arizona's and AEPCO's Access and Ability to Utilize Low- or Zero-Carbon Generation.

A. EPA inappropriately attempts to apply its determination of BSER and Building Block #3 to sources outside of the regulated source category

EPA attempts to include both nuclear energy generation and RE generation in Building Block #3 ("BB3") as part of BSER. EPA cannot legally or technically include nuclear or RE in its proposal under this system because they are not a part of the target source category—coal-fired EGUs. Additionally, BSER must work to reduce emissions within the target regulated source category—replacing fossil fuel-fired EGUs with zero-emitting generation outside the target regulated source category cannot qualify as BSER. BSER also cannot be applied outside the target regulated source category—BSER must be used to reduce emissions at operating facilities *within* a source category.

B. EPA has miscalculated renewable energy availability

EPA miscalculates the availability of RE by the methodologies used to evaluate state and regional resources. In reviewing RE availability to determine 2030 RE regional targets, EPA makes several methodological flaws: excluding existing hydropower when included in existing state program goals, capping the maximum level of RE generation in any state at the regional average target, assuming that all States within a region will grow at the same rate to reach RE targets, recognizing only RE developed within state boarders, including existing and under-construction nuclear units, and applying its 5.8% nuclear "at risk" assumption to every state that has existing nuclear capacity. Additionally, most legislation accounts for RE at the point of use, rather than the point of generation. *See* Pace Study § 3.1, at 16. Unless EPA is seeking to substantially disrupt the market in RE, it should clarify that renewables are accounted at the point of use, not generation, consistent with state practice.

In order to determine state RE targets under BB3, EPA used 2012 state performance data demonstrating in-state generation from non-hydropower RE in each State. EPA then used this data to formulate state targets. In setting these targets, EPA did not consider the need for economic development for different business sectors, the cost of renewable resources and other options available within each State, availability of other fuels within the State, availability of transmission in the State, the costs, benefits and consequences of achieving environmental, economic and power goals through alternative means, and economic conditions of electric consumers and/or rural electric ratepayers.

EPA complicates its faulty methodologies by using blanket assumptions for all States, both for assuming that all states within a region will grow at the same rate to reach RE targets and in applying its 5.8% nuclear "at risk" assumption to every state that has existing nuclear capacity. These assumptions particularly harm Arizona and its associated RE target as Arizona's nuclear generation is not at risk of being retired due to market conditions; therefore, it is inappropriate to apply the 5.8% "at risk" assumption to Arizona and its target. EPA's failure to account for the fact that "at risk" facilities are not spread evenly throughout the nuclear fleet and for states that have much lower "at risk" units, substantially affects States', such as Arizona's, RE target.

C. EPA incorrectly evaluated the current system's reliability and mandated compliance with Interim and Final Goals sooner than the system can support.

EPA ignores the fact that another type of fuel must be available for when the grid and/or NGCC resources are not adequate to support demand. Coal generation was not designed to cycle with intermittent resources and does not possess the ramping capabilities to do so. Additionally, this kind of operation would place heavy wear-and-tear on these units, resulting in escalating costs of operations. *See* Pace Study § 5.5. EPA insufficiently estimated the availability and cost of renewable resources, as well as the cost of fossil fuel source backup. As discussed above, it is necessary for states, such as Arizona, to have reliable, available and cost-effective backup electricity in the case of unforeseen events or drastic weather events. EPA's Proposed Rule and Interim and Final Goals do not provide for this type of energy generation flexibility in times of peak demand or unreliable transmission, thereby endangering electric generation reliability for utilities and their customers.

VI. EPA's Building Block #4 Incorrectly Assumes That the Use of Demand-side Energy Efficiency Can Feasibly Reduce Generation For up to 1.5% Annual Incremental Savings

The Proposed Rule assumes that, for Arizona, demand-side energy efficiency increases 1.5% annually from 2017 to 2030, reducing carbon intensity by approximately 15%. Building Block #4 ("BB4") is the second largest component of the reduction for Arizona.

AEPCO and other third party evaluators have doubts about whether Arizona can consistently achieve 1.5% improvements in energy efficiency ("EE"). Pace found that only a single source, the American Council for an Energy Efficient Economy ("ACEE"), has produced an estimate this high. The next highest estimate, from the Electric Power Research Institute ("EPRI"), is 0.6%. Pace Study § 3.1, at 17. Pace also notes that only three states have ever achieved a 1.5% goal in a single year. *Id.* It is also unclear that this level of EE improvement can be kept up year-over-year as easier, more cost-effective, measures are adopted and subsequent measures become both less productive and most costly.

AEPCO believes that EPA has overestimated that amount of EE that can be achieved on a state-wide level, once EE mandates move beyond programs currently targeted at dense urban areas. The experience of utilities working in rural Arizona is that EE is difficult and expensive to obtain. Problems include: (1) utility difficulty in certifying or approving contractors for approved EE services or appliance installation; (2) customer difficulty in finding an approved contractor due to travel distances; (3) verification difficulty due to travel distance and expense in returning appliances or sending out verification personnel; (4) lower uptake due to poorer customer base diminishes the ability to handle the higher first costs, travel expenses, and similar issues; and (5) lower commercial and industrial customer base, with corresponding smaller opportunities for EE at any location, making much greater penetration required to achieve equivalent levels of EE compared to urban areas. These issues are in addition to other inherent challenges of rural electric cooperative or rural distribution company operation, such as higher transmission loss, fewer customers per line-mile, and higher cost per customer for distribution equipment. These challenges demand that rural cooperatives be treated differently in terms of what can reasonably be achieved in their service territories. Consequently, AEPCO has provided the proposed subcategory specifically addressing the unique needs and limitations of small public and cooperative utilities.

EE targets impose practical and legal hardships on generation and transmission cooperatives and merchant power facilities that do not have local distribution and hence do not have meaningful EE opportunities available to traditional utilities with local distribution. For entities without distribution, stringent EE requirements essentially require them to rely upon third parties to achieve EE improvements. This bifurcation in responsibility will, inevitably, lead to complications as the Clean Power Plan ("CPP") moves into its implementation phase.

VII. The Proposed Rule Should Provide a "Safety Valve" for EGUs Determined to be "Critical" for Grid Reliability.

AEPCO believes, as do others responsible for grid reliability, that the Proposed Rule should provide a "safety valve" to allow continued operation of EGUs that are determined to be "critical" for grid reliability. AEPCO believes that FERC, or the North American Energy Reliability Corporation ("NERC"), the reliability entity designated by FERC, or possibly state utility commissions, should be authorized to review the operation of the overall electric grid and identify any units that are "necessary for grid stability and reliability" as exempt from redispatch requirements under BB2 as well as state goal-setting. While FERC, NERC or state utility commissions are in the best position to determine what units are "necessary for grid stability and reliability," AEPCO believes such units may include EGUs that because of their location provide essential reliability services to portions of the grid that cannot be serviced by other units. Shutting such units down would jeopardize electric grid stability and reliability. Because of the nature of the grid, which tends to have multiple sources of generation for substantial urban areas, many of these grid stability and reliability situations may arise in more rural areas. AEPCO believes that jeopardizing grid reliability in these areas is inconsistent with the policy of the

United States expressed in the REA, as well as the mission of all utilities to provide reliable electric service.

VIII. Setting an Interim or Final Goal Below 1,000 lb/MWh Creates Substantial Equity Issues.

EPA has proposed to set the Interim and Final Goals below 1,000 lb/MWh for a number of States, including Arizona. Setting the rate below 1,000 lb/MWh creates substantial practical problems and equity issues. First, even modern NGCC units may not be able to consistently achieve a rate that is much below 1,000 lb/MWh. This means that modern NGCC units will, in States with low Interim and Final Goals, need to "blend" their emissions with renewables or energy efficiency steps to achieve a rate that is below their native emission rate.

Second, in states, such as Arizona, where the NGCC units are owned primarily by "merchant" facilities and the population is served by traditional utilities (whether IOU, public or cooperative), this disparity creates significant problems. In order to the NGCC units to run, they must reduce their emissions. However, the merchant NGCC operators likely have no renewables and no opportunity, as generation facilities only, to develop substantial energy efficiency improvements that would have the effect of reducing the NGCC EGU's carbon emission rate. In order for merchant NGCC units to run in states with Interim and Final Goals below the carbon emission rate achieved by an NGCC unit, the State must either require the merchant plants to install RE (which may or may not be within their financial means), purchase RE or energy efficiency credits from a traditional utility or other entity that has such credits (if any such EE credits exist or are allowed by the Proposed Rule, which is unclear), or else order the in-state utilities to achieve additional reductions to offset the "excess" emissions of the merchant NGCC units. If, as is the case in Arizona, a sizeable portion of the merchant NGCC power is directed to the export market, it is not clear that the State will be willing to impose additional costs upon its citizens and taxpayers for the sole benefit of a foreign state's citizens and taxpayers. The net effect may be that these units either shut down, resulting in an increase in the overall carbon intensity, or are forced out of the interstate market. In any event, the interconnected nature of the grid will suffer and EPA's IPM Modeling, which relies heavily upon such interstate movement of electricity to meet the Proposed Rule's Interim and Final Goals at reasonable costs, may prove illusory. The practical solution to this problem is to set the Proposed Rule's goal no lower than the eventual NSPS rate and allow use of the Building Blocks as an alternative to meeting the NSPS goal.

IX. The Proposed Rule Exceeds EPA's Statutory Authority Under the Clean Air Act ("CAA").

In its Proposed Rule, EPA has far exceeded its statutory authority granted by Congress in regulating existing source emissions under Section 111(d) of the CAA. EPA claims that Section 111(d) provides the necessary authority for it to promulgate the Proposed Rule, but this is plainly erroneous. Section 111(d)'s plain language does *not* provide EPA authority for the Proposed Rule and its accompanying interpretation of BSER and drastic effect on the nation's electric power generation system but instead Section 111(d) clearly *prohibits* EPA's proposal.

In its grant of authority, Congress has clearly and succinctly outlined EPA's authority to regulate emissions from existing sources. First, EPA must establish performance standards regulating CO_2 emissions from new units in the source category *before* it may establish performance standards regulating existing sources in the same source category under Section 111(d). Additionally, in this case, EPA may not regulate coal-fired EGUs under the Proposed Rule because EPA is prohibited by Section 111(d) from regulating source categories that are already regulated under Section 112.

When reviewing whether an agency's interpretation of a statute and its authority under the statute is valid, courts apply the framework from *Chevron, U.S.A. v. NRDC*, 467 U.S. 837, 842-43 (1984). The courts will apply Chevron's familiar framework to determine if Congress has spoken to the specific issue at hand or whether the statute is ambiguous or silent on the question at issue and if that is the product of an implicit delegation of interpretative authority to the agency. *United States v. Mead Corp.*, 553 U.S. 218, 226-27 (2001). Despite EPA's best effort, under *Chevron*, EPA's interpretation of Congressional language and EPA's self-proclaimed authority under Section 111(d) should not be granted deference.

A. CAA Section 111 prohibits simultaneous regulation of the same source under both "new source performance standards" promulgated under Section 111(b) and "existing source performance standards" promulgated under the procedure set forth in Section 111(d)

The CAA is clear that EPA's choice of regulations under Section 111 is binary: EPA may either (1) promulgate a federal standard of performance for *new sources* pursuant to CAA Section 111(b)(1)(B); or (2) prescribe regulations pursuant to Clean Air Act Section 111(d)(1)(A) requiring states to submit a plan "similar to Section 110" that adopts standards of performance for *existing sources*. A source can be a "new source" or an "existing source," but it cannot be both at the same time. The Act's binary division is then reemphasized in the definitions section of Section 111, which provides:

> **(2)** The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.
>
> **(6)** The term "existing source" means any stationary source other than a new source.

42 U.S.C. § 7411(a)(4) & (6). The definitions are clear that an "existing source" cannot be a "new source" and therefore, regulation of the same source under Section 111, subsections (b) and (d) at the same time cannot be squared with the express language of the CAA.

This means that the suggestion in the Proposed Rule that:

> The EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard being promulgated under CAA section 111(b) simultaneously with this rulemaking.

79 Fed. Reg. 34,903, col. 3, cannot be reconciled with the plain text of Section 111. "An agency has no power to 'tailor' legislation to bureaucratic policy goals by rewriting unambiguous statutory terms," regardless of how desirable the agency believes such an interpretation may be. *See UARG v. EPA*, 573 U.S. ---, slip op. at 21 (2014).

EPA's existing NSPS regulations also make this point. They state, flatly, that "an existing facility, upon reconstruction, becomes an affected facility," 40 C.F.R. § 60.15(a), and an "affected facility means, with reference to a stationary source, any apparatus to which [an NSPS] standard is applicable," 40 C.F.R. § 60.2 *Affected facility*. By contrast, the 111(d) implementing regulations in 40 C.F.R. Part 60, Subpart B provide that a "designated facility means any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant *if the existing facility were an affected facility* (see § 60.2(e))." 40 C.F.R. § 60.21(b) (emphasis added). It is thus clear that a designated facility cannot also be an affected facility at the same time. EPA has nowhere justified its sweeping change in interpretation that upends years of consistent application of Section 111 of the CAA.

Similarly, EPA has nowhere supported its novel contention that a "reconstructed facility" is still an existing facility. This interpretation flatly contradicts 40 C.F.R. § 60.15(a), which states that a facility that is reconstructed is an "affected facility" (i.e., one subject to the NSPS standards, and not a "designated facility"). EPA's interpretation requires disregard of its own regulations – regulations that the agency specifically stated are not open for comment and hence are not subject to change in this rulemaking.

B. EPA must first establish performance standards for new sources under Section 111(b) <u>before</u> it can establish emission guidelines for existing sources under Section 111(d).

In Section 111(d)(1)(A), the CAA clearly and plainly requires that EPA require states to establish standards of performance for "an existing source for any pollutant… to which a standard of performance would apply if such source were a *new* source." 42 U.S.C. §7411(d)(1)(A) (emphasis added). Based on the plain language, EPA must first establish standards of performance for new sources *before* promulgating regulations for existing sources under Section 111(d). Currently, there is no *valid* rule under Section 111(b) regulating CO_2 emissions from *new* coal- or gas-fired EGUs; therefore, EPA cannot promulgate the Proposed Rule attempting to regulate CO_2 emissions from *existing* coal- or gas-fired EGUs. EPA must finalize and publish their proposed rule *Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Generating Units*, 79 Fed. Reg. 1,430 (January 8, 2014), before finalizing any rule regulating CO_2 emissions from coal- and gas-fired EGUs.

C. CAA Section 111(d) prohibits EPA from establishing standards of performance "for any existing source for any air pollutant… emitted from a source category which is regulated under Section 112."

Under the plain language of Section 111(d), EPA cannot promulgate a final rule regulating CO_2 emissions from coal-fired EGUs because it has already regulated this source under the Mercury and Air Toxics Standard, 77 Fed. Reg. 9,304 (February 16, 2012). Section 111(d) prohibits "double regulations" of sources by prohibiting EPA from establishing standards of performance "for any existing source for any air pollutant… emitted from a source category that is regulated under Section 112." The plain language clearly demonstrates Congress's intent to avoid double regulation of sources.

1. The Mercury and Air Toxics Standard already regulates new and existing fossil fuel-fired EGUs under Section 112.

EPA cannot regulate existing coal-fired EGUs under the Proposed Rule because these sources have already been regulated under the Mercury and Air Toxics Standard. The Mercury and Air Toxics Standard, promulgated by EPA in 2012, regulates emissions of mercury and other hazardous pollutants from new and existing coal- and oil-fired EGUs under Section 112. Therefore, under the plain language of Section 111(d), EPA cannot further regulate existing coal-fired EGUs.

Section 111(d)'s plain language has recently been upheld by the Supreme Court, stating, "EPA may not employ § [111](d) if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§ [108-110], or the "hazardous air pollutants" program, § [112]." *American Power Co. v. Connecticut*, 131 S.Ct. 2527, 2537, 2537 n.7 (2011). The Supreme Court's dictum in this case should be definitive as under D.C. Circuit law, "dicta of the United States Supreme Court should be very persuasive." *Gabbs Exploration Co. v. Udall*, 315 F.2d 37, 39 (D.C. Cir. 1963).

2. EPA's Proposed Rule would result in the absurd result of finalizing more stringent emission reductions for existing fossil fuel-fired EGUs than new fossil fuel-fired EGUs regulated under Section 111(b).

EPA's Proposed Rule acts to impose more stringent emission reduction goals for older, less flexible, existing fossil fuel-fired sources than the proposed goals for modified/reconstructed sources and new sources in many states. This result is illogical as new sources can install the most current and state-of-the-art emissions control technology and make siting and design decisions necessary to best install and operate these technologies from the beginning of facility planning; generally, unlike existing sources, new sources can be designed and constructed in compliance with both Section 111 and Section 112 *in the first place*. It is largely impractical and unachievable to mandate the same technology for existing units after they have been built.

While the standards of performance under Section 111(b) and (d) must be related to each other, under no circumstances should Section 111(d) standards be more stringent than 111(b) requirements or apply more broadly. Generally, existing sources should not be held to a stricter standard or more stringent standard than new sources because it is be more difficult to retrofit existing facilities with new emission technology, existing sources may have limited remaining useful lives and additional regulatory burdens and multiple regulatory schemes governing an existing facility may likely endanger the facility's future viability.

EPA's past practice has generally conformed to the practice that NSPS under Section 111(b) would be at least as stringent as, if not more stringent, than existing source performance standards. However, despite EPA's past practice and general logic, the Proposed Rule imposes more stringent emission rates on existing sources than new sources. Twenty-five of the 48 states[6] for which interim emission limitation rates have been proposed, and 26 of the 48 states[7] for which final emission rates are proposed, the proposed rates are *more, or much more, stringent* than rates for NGCC units (1,000 lbs. CO_2/MWh) under the proposed NSPS. *See* Table 8. Proposed State Goals (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs), 79 Fed. Reg. at 34,895. For example, Arizona's proposed Interim goal rate is 735 lb. CO_2/MWh, significantly lower than the 1,000 lb. CO_2/MWh NSPS rate. Other states, such as Idaho, have rates proposed as low as 244 lb. CO_2/MWh. Like Idaho,

[6] Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Idaho, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, Nevada, New Hampshire, New Jersey, New York, Oklahoma, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Virginia, and Washington.
[7] 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.

many state emission targets are 40 to 50 percent *lower* than the emission rates required for new sources. This outcome is illogical and contrary to Congressional intent under Section 111.

3. The clerical mistake in the 1990 CAA Amendments does not make Section 111(d)'s prohibition ambiguous.

Despite the clarity provided in a literal reading of Section 111(d), EPA argues that the statute's prohibition is ambiguous due to a clerical mistake in the 1990 CAA Amendments. In 1990, Congress amended Section 111(d), which previously prohibited EPA from regulating, "any air pollutant … included on a list published under … [Section] 112(b)(1)(A)." 42 U.S.C. §7411(d) (1987). In 1990, Congress decided to revise this provision and both the House and Senate proposed new language. The House draft replaced the cross-reference to "112(b)(1)(A)" with, "Section 112" ("any pollutant…from a source category which is regulated under Section 112"), the language that now appears in the U.S. Code. The Senate version replaced the cross-reference to "112(b)(1)(A)" with "in lieu thereof '[112](b)." Unfortunately, in the rush of passing the Amendments and signing them into law, both versions were included in the 1990 Amendments; however, the House version was published in the U.S. Code.

Despite EPA's claims, the House version controls over the Senate's because of longstanding and well-established rules for resolving legislative drafting inconsistencies and clerical errors in federal legislation. First, the House amendment is a substantive amendment, deliberately and significantly altering the scope of Section 111(d), while the Senate version is a conforming and clerical amendment that simply updated Section 111(d)'s language to reflect other changes made by the 1990 Amendments—acting alone, without a cross-reference to update, the Senate Amendment is superfluous. Therefore, the inclusion of the Senate amendment is clearly a mistake and even EPA has stated that the Senate amendment is "a drafting error" that "should not be considered." 70 Fed. Reg. 15,993, 16,031 (March 29, 2005).

Case precedent also clearly supports this plain reading of the U.S. Code. Circuit courts have largely held that where a mistake in correcting a cross-reference conflicts with the statute's substantive provisions, the mistake should be handled as, " the result of a scrivener's erro[r]" and not "creating an ambiguity." *Am. Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336-37 (D.C. Cir. 2013). In addition to circuit courts, the Supreme Court has held that "a failure to delete an inappropriate cross-reference" is "simply a drafting mistake" that does "not warrant rewriting the remained of the statute's language." *Chickasaw Nation v. United States*, 534 U.S. 84, 90-91 (2001). Therefore, it is clear that judicial and legislative drafting interpretation supports the substantive House version of Section 111(d).

Furthermore, the limitations in the House and Senate amendments are compatible with one another and neither restriction on EPA's authority under the section forecloses full enforcement of the other. Statutory construction requires courts and agencies to give effect, whenever possible, to all of the language in a statute. *Reiter v. Sonotone Corp*., 442 U.S. 330, 339 (1979). However, EPA's interpretation of Section 111(d) would not give effect to either versions of the amendment. In direct conflict with the House amendment version that bans *any* regulation under Section 111(d) of existing sources already regulated under Section 112, EPA's interpretation would permit regulation as long as the *pollutant* itself is not regulated under Section 112 because CO_2 was not itself regulated under the Mercury and Air Toxics Standard, only hazardous air pollutants ("HAPs") from coal- and oil-fired EGUs. Additionally, in direct conflict with the Senate's version, which prohibits regulation of any HAP under Section 111(d), EPA's interpretation would permit regulation of a HAP under Section 111(d) if Section 112 does not regulate the HAP and the emitting source. Despite EPA's erroneous attempt at claiming that the limitations in these amendments negate each other, it is possible, and therefore mandatory, to read the versions as prohibiting EPA from regulating emissions of any pollutant from sources in a category that is already regulated under Section 112 under its authority in Section 111(d).

D. EPA's interpretation of Section 111(d) is not entitled to Chevron deference.

Even if the court found that the multiple versions of Section 111(d) in the 1990 CAA amendments rendered the section ambiguous, EPA's erroneous departure from Section 111(d)'s plain text would not allow the Agency to receive *Chevron* deference from the court. The Supreme Court has clearly held that "agencies exercise discretion only in the spaces created by statutory silence or ambiguity; they must always 'give effect to the unambiguously expressed intent of Congress." *UARG v. EPA*, 134 S.Ct. 2427, 2445 (2014). Therefore, no *Chevron* deference is owed to an agency that is interpreting what laws Congress actually enacted.

1. *EPA does not automatically receive Chevron deference in statutory interpretation and it is inappropriate to grant it here.*

Chevron deference is not automatically provided to an agency when it is interpreting a statute, as not all statutory ambiguity deserves the deference provided by *Chevron*. In fact, Chief Justice Roberts recently spoke on this matter, holding that "Direct conflict is not ambiguity, and the resolution of such a conflict is not a statutory construction but legislative choice. *Chevron* is not a license for an agency to repair a statute that does not make sense." *Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2214 (2014) (Roberts, C.J., concurring). This statement goes to support the principle that *Chevron* deference should only be given to an agency's interpretation where there is Congressional intent to delegate to the agency the authority to interpret the statute. Therefore, the clear drafting error concerning the two versions of Section 111(d) should not amount to ambiguity sufficient to provide deference to EPA's unreasonable interpretation.

2. *Under Chevron's own framework, EPA's interpretation of Section 111(d) is not even entitled to Chevron deference because it is unreasonable.*

EPA's interpretation of Section 111(d) is unreasonable and therefore cannot be afforded *Chevron* deference. Under *Chevron's* framework, a court will only defer to an agency's interpretations "if they are reasonable and consistent with statutory purpose." *GTE Serv. Corp. v. F.C.C.*, 205 F.3d 416, 422 (D.C. Cir. 2000). EPA's interpretation of Section 111(d) fails this prong of *Chevron* because it contravenes Congressional intent behind the amendment. EPA even concedes that a primary purpose of the 1990 amendments and the revision of Section 111(d) was to preclude regulation of pollutants emitted from a specific source category that has already been regulated under Section 112 in order to avoid "duplicative or overlapping regulation." 70 Fed. Reg. 15,993, 16,031 (March 29, 2005). As demonstrated by EPA's regulatory requirements under the Mercury and Air Toxics Standards, multiple regulations governing the same source category presents duplicative and costly regulations and associated air pollution control technological or financial impossibility.

3. EPA's interpretation of Section 111(d) is in clear contrast with EPA's past practice.

EPA has never before issued standards of performance under Section 111(d) for a source category that is already regulated under Section 112. It is inappropriate for EPA to assume that courts would grant deference to EPA's interpretation concerning the Code ambiguity surrounding 111(d). EPA's interpretation cannot be more reasonable than the U.S. Code compiler, a neutral party.

E. CAA Section 111(d) Does Not Provide EPA Authority Beyond Defining the Best Source of Emission Reduction ("BSER") For the Regulated Source Category.

Assuming, *arguendo*, that Section 111(d) grants EPA the requisite authority to promulgate the Proposed Rule regulating CO_2 emissions from existing coal-fired EGUs, EPA has still overstepped this limited authority to define BSER only for the regulated source category—coal- and oil-fired EUGs. EPA's "laundry list" of emission reduction suggestions that states *may* use to *possibly* reduce CO_2 emissions is not a specific and definite BSER and grossly and unreasonably expands regulation beyond the affected source category. By attempting to expand BSER, and the associated Building Blocks, beyond the affected source category units, EPA illegally seeks to regulate the electric power transmission system as a whole.

F. EPA's BSER proposal must be limited to a "system of emission reduction"—technical and operational measures that may be achieved at the affected facility.

Under CAA authority, EPA may propose BSER for a "system of emission reduction." A "system of emission reduction" includes technological and operational improvements that can be made at a specific unit. States then apply EPA's BSER to determine "standards of performance." Section 111(d) defines a standard of performance as "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 the Administrator determines has been adequately demonstrated." BSER is a source-based standard and is limited to systems of emission reduction that can be implemented on-site by the facility.

Previously, EPA has limited BSER to technology-based emission controls that could be installed and implemented at the sources subject to regulation. (i.e. phosphate fertilizer plants, sulfuric acid plants, kraft paper mills, primary aluminum plants, municipal solid waste landfills.).

EPA's authority does not extend to "looking beyond the fence line" of a source to establish BSER or promulgate state-specific emission limitation goals.

G. EPA lacks authority to regulate emissions from sources beyond the regulated source category.

In the Proposed Rule, EPA far exceeds its grant of authority under Section 111(d) by proposing BSER under a laundry list of Building Blocks that seek to 1) mandate reductions from sources other than the "affected facility;" 2) mandate emission reductions achieved through facilities or by measures beyond the regulated source category; and 3) define emission reduction and elimination of demand for energy as an approvable method of controlling emissions. Each of these measures far exceeds EPA's authority to promulgate a definite and specific "system of emission reduction."

EPA's proposed system is not a definite or specific system but instead a listing of disparate items that largely do not even relate to the regulate source category—*coal-fired EGUs*. This attempt to regulate outside its authoritative grant of Section 111(d) is a clear attempt to regulate the electric generation, transmission and consumption market in the United States and has been plainly prohibited by the Supreme Court. *See UARG v. EPA*, 134 S.Ct. 2427, 2444 (2014) (quoting *FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 159 (2000)) ("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" and the Court will expect "Congress to speak clearly if it wishes to assign an agency decisions of vast economic and political significance.") Additionally, this concept is strengthened when an agency lays claim to authority to regulate subjects traditionally left to States because "[a]bsent a clear statement of that purpose, [the court] will not presume Congress to have authorized such a stark intrusion into traditional state authority." *Bond v. United States*, 134 S. Ct. 2077, 2083 (2014).

H. EPA's attempt to expand BSER "outside the fence" beyond the regulated source category serves to redefine "standards of performance" by limiting source operations and consumer demand instead of reducing CO_2 emission emitted from coal-fired EGUs.

Section 111(d) plainly requires EPA to establish procedures and emissions guidelines, and then allow States to develop "a plan which establishes standards of performance for any existing source for any air pollutant." EPA's Proposed Rule seeks to redefine both "performance" and "source" by attempting to substitute generation from coal-fired EGUs with generation from gas-fired units and renewable resources.

1. *EPA erroneously attempts to redefine "standards of performance" to equate to the total amount of emissions from a source category, even at the necessity of diminishing a specific unit's generation or ceasing operation altogether.*

Based on the plain language of "performance" in Section 111(d) and logical interpretation, "performance" should mean the amount of emissions that can be attributed to a given generation output from a specific source. EPA's interpretation of "performance" is clearly erroneous as it attempts to redefine "standard of performance" to equate to the total amount of emissions from an entire source category generally; EPA further degrades the plain and logical definition of "performance" by applying this definition even if it requires specific units to diminish generation or cease operation altogether.

Instead of a BSER in the form of emissions guidance to improve operations at coal-fired EGUs and, therefore, decrease CO_2 emissions from this regulated source category, EPA proposes to instead simply eliminate the underlying generation altogether. Through its Building Blocks, EPA proposes to decrease CO_2 emissions by mandating that coal-fired EGUs simply operate less by shifting the generation demands to NGCC and RE. This is not an appropriate interpretation of how a standard of performance should regulate the source category.

EPA also arbitrarily redefines "source" by applying emission controls under Section 111(d) to a combination of units. Based on definitions provided by the CAA and its regulations, EPA must limit its BSER to reductions that are attainable at each affected source, a single, individual, inside-the-fence unit. Section 111(d) regulates only existing sources which are "any stationary source" other than a new source. The CAA defines a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." 40 C.F.R. § 60.2. Further, Section 111(d), therefore, clearly provides that emission controls must apply directly to "a single building, structure, facility, or installation—the unit prescribed in the statute." This plain language prohibits applying emission controls under Section 111(d) to a combination of units or units "outside the fence" of the stationary source.

Despite the statute's clear definition of sources, EPA's BSER and Building Blocks create a "portfolio approach" (that States may largely pick and choose from at their discretion to in order to achieve specific state goals) that far exceeds plans and emissions guidelines that apply at individual, "inside-the-fence" units. By proscribing requirements for redispatch to gas-fired EGUs, RE resources, nuclear power plants, and end-user energy efficiency improvements, EPA's Proposed Rule's Building Blocks clearly mandate that multiple, "outside the fence" facilities operate in cooperation with each other.

EPA has never before promulgated such an expansive reading of "source," as demonstrated by its final promulgated regulations for specific source categories in 13 instances.[8] Additionally, it seems noteworthy that EPA has chosen to confine its NSPS and the modified/reconstructed source standards for coal- and oil-fired EGUs to source-specific and "inside-the-fence" measures. EPA has not reasonably justified its departure from plain language interpretation and to expand "source" to "beyond-the-fence" units is arbitrary and unreasonable.

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8 *See Regulation of CO_2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority*, R. Nordhaus and I. Gutherz, 44 ELR 10,366, 10,372 n. 57 (2014). According to the authors, the 13 are: Phosphate Fertilizer Plants; Final Guideline Document Availability, 42 Fed. Reg. 12,022 (Mar. 1, 1977); Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist, 42 Fed. Reg. 55,796 (Oct. 18, 1977); Kraft Pulp Mills, Notice of Availability of Final Guideline Document, 44 Fed. Reg. 29,828 (May 22, 1979); Primary Aluminum Plants, Notice of Availability of Final Guideline Document, 45 Fed. Reg. 26,294 (Apr. 17, 1980); Emission Guidelines; Municipal Waste Combustors, Final Emission Guidelines, 56 Fed. Reg. 5,514 (Feb. 11, 1991), withdrawn & superseded by 60 Fed. Reg. 65,387 (Dec. 19, 1995) (same source category); Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule, 61 Fed. Reg. 9,905 (Mar. 12, 1996); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, Final Rule, 62 Fed. Reg. 48,348 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, Final Standards and Guidelines, 65 Fed. Reg. 75,338 (Dec. 1, 2000); Emission Guidelines for Existing Small Municipal Waste Combustion Units, Final Rule, 65 Fed. Reg. 76,378 (Dec. 6, 2000); Clean Air Mercury Rule, 70 Fed. Reg. 28,606; Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Other Solid Waste Incineration Units, Final Rule, 70 Fed. Reg. 74,870 (Dec. 16, 2005); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule, 76 Fed. Reg. 15,372 (Mar. 21, 2011).

2. EPA's Proposed Rule Violates States' Statutory Authority Under Section 111(d), Thereby Violating Principles of Cooperative Federalism.

Section 111(d) succinctly and clearly grants States' the authority to "establish[] standards of performance for any existing source for any air pollutant. 42 C.F.R. §7411(d)(1). EPA's Proposed Rule unreasonably and arbitrarily disregards this grant of authority and encroaches on the States' right to set performance standards for their existing sources. Under Section 111(d), EPA's authority is limited to 1) promulgating regulations establishing procedures for States to use and by which to submit their State Plans and standards; and 2) establishing a definite and specific adequately-demonstrated BSER by which the States are to rely on in establishing their applicable standards of performance. In its Proposed Rule, EPA plainly violates this division of authority and the principle of cooperative federalism by proposing binding, inflexible and specific state emission targets without allowing States to provide for site-by-site unit analysis; and therefore demotes States to the ministerial role of implementing these substantive standards of performance and state emission targets.

3. The Proposed Rule violates State statutory authority to develop standards of performance based on a unit-by-unit analysis taking into account factors such as "remaining useful life" of the unit.

Section 111(d) clearly mandates that EPA only "prescribe regulations which shall establish a procedure similar to that provided by Section 7410 of this title" and that States will then "submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant." 42 U.S.C. §7411(d)(1). Further, in developing these standards of performance, States are permitted and required to take into consideration, "*among other factors, the remaining useful life* of the existing source to which such standard applies." 42 U.S.C. §7411(d) (emphasis added). In addition the "remaining useful life" of the unit, States are permitted, by EPA's own regulations, to:

> […] [P]rovide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required [under the paragraph setting emissions standards for designated pollutants the Administrator determines may cause or contribute to endangerment of public health], provided that the State demonstrates with respect to such facility (or class of facilities): (1) Unreasonable cost of control resulting from plant age, location, or basic process design; (2) Physical impossibility of installing necessary control equipment, or (3) Other

> factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

40 C.F.R. §60.24(f). This regulation allows states to take into account the individual unit's circumstances in adopting emission standards and compliance schedules based on factors such as age, location, design, and technological compatibility.

4. *States should retain the authority to consider factors such as "remaining useful life" to avoid forced closure of coal-fired EGUs.*

It is clear from the plain language of Section 111(d) that Congress anticipated that some units would not be capable of meeting the most aggressive goals of emission reductions and that it would then be appropriate for states to take into account factors, such as the remaining useful life of the existing source, in applying a standard of performance. Despite this clear and specific allowance, EPA's Proposed Rule's state-specific emission reduction targets are based on reductions from <u>all</u> units and fail to take into account any source-specific factors. This proposal invalidly removes States' statutory authority to develop standards of performance that take into account the remaining useful lives of specific existing facilities.

Without revising the inflexible and unreasonable state-specific emission reduction targets and Building Blocks to consider the remaining useful life of units, the Proposed Rule will force closure and drastic curtailment of operations from coal-fired EGUs—in direct contravention of Congress's intent in drafting Section 111(d). Based on EPA's own modeling, 21% of cooperative coal generation capacity must be retired under the proposal, including two of AEPCO's units, ST2 and ST3, totaling 350 MW. These units will be forced into retirement because the standards EPA has set in its Proposed Rule are so stringent that they cannot be met except by closing or drastically curtailing coal-fired EGU generation.

The forced early retirement or curtailment of coal-fired EGUs will potentially result in massive stranded costs of shutting down relatively new or recently upgraded EGUs prior to the end of the amortization period for initial construction or significant pollution control upgrades. Operating an EGU at a reduced capacity factor or ceasing to run an EGU that was expected to run for a period of at least the remaining useful life results in high unrecovered costs for a utility. If the EGU ceases operation, those costs that would have been recovered during the run life must still be absorbed by the utility's customers, in AEPCO's case its members. The earlier reduced utilization or cease of operations occurs within the life of an EGU, the higher the cost. Without revision, the Proposed Rule will result in stranded costs of approximately $3.8 billion (2020 dollars). *See* Pace Study, §5.4, at 34. Based on Section 111(d)'s plain language and the Proposed Rule's resulting significant risk for stranded assets, EPA must allow States to consider the remaining useful life of units on a unit-by-unit basis when establishing standards of performance.

Both the AEPCO and the AUG solutions outlined at the beginning of these comments will do much to redress this issue.

5. *The Proposed Rule fails to allow States the ability to consider factors unique to rural electric cooperatives in implementing and complying with standards of performance based on BSER.*

In addition to the challenges all facilities will have in complying with EPA's Building Blocks and inflexible and unreasonable state emission targets, rural electric cooperatives in particular, such as AEPCO, will face significant difficulty in complying with the state emission targets and Building Blocks. Rural electric cooperatives are a perfect example of the types of facilities for which Congress intended to allow States to consider additional factors in determining the application of standards of performance, as cooperatives generally have: 1) much more limited, coal-reliant generating assets with limited capacity for heat rate improvements; 2) limited gas-fired and renewable energy sources, reducing their ability to re-dispatch generation from coal-fired units; 3) extremely limited opportunity for demand-side energy efficiency measures; 4) unique financing constraints from lessor financing arrangements; and 5) very small fleets of generating assets that constrain flexibility to control dispatch due to operation in a competitive market.

The Proposed Rule and its curtailment or shutdown of units will have significant detrimental impacts on many electric customers. In reality, rates and electric bills will increase, some drastically. It is estimated that rates and electric bills could increase more than 25% and in some cases have been demonstrated to be as high as 40%+ for small utilities. *See* Pace Study, §§ 5.2 & 5.3. AEPCO, as a small rural electric cooperative expects to see rate increases even higher than this range. However, rate increases could be even higher if natural gas prices exceed beyond those assumed. Given the anticipated closure of many of Arizona's coal plants under the Proposed Rule, increased demand on natural gas may lead not only to higher market prices, but also no other source of controllable generation to use in times of high prices. Further, given the extremely volatile history of natural gas prices, consumer electric rates would also experience a high level of volatility, which would place undue strain on AEPCO members, many of whom are rural and financially limited.

EPA should account for these difficult constraints on rural electric cooperatives and substantially revise the Proposed Rule to reflect that 1) most rural electric cooperatives have extremely limited portfolios of generating assets and redispatch to gas-fired or renewable energy sources may not be available for many rural electric systems; 2) often rural electric cooperatives rely on coal-fired EGUs that may only be able to make minimal heat rate improvements to achieve lower CO_2 emissions; 3) existing lessor financing arrangements and concerns about creating stranded assets due to premature shutdown or curtailment will create adverse rate impacts; and 4) opportunities for additional demand-side energy measures in rural areas are extremely limited due to the rural and residential nature of cooperative customers.

X. The Proposed Rule Does Not Comply with the Regulatory Flexibility Act's Mandate that Regulatory Relief Be Provided to Small Entities such as AEPCO.

In its Proposed Rule, EPA substantively disregards AEPCO's status as a small entity under the Regulatory Flexibility Act ("RFA"), 5 U.S.C. § 601 et seq., and improperly denies AEPCO and other small rural utilities the protections afforded to it. The purpose of the RFA is "to fit regulatory and informational requirements to the scale of the businesses, organizations and governmental jurisdictions subject to the regulation." RFA, Pub. L. No. 96-354, § 2, 94 Stat 1164 (1980). This requires federal agencies to consider the impacts that regulations will have on smaller entities. See 5 U.S.C. § 603(a).

The RFA requires the Agency's initial analysis to include "a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply…" 5 U.S.C. § 603(b)(3) (emphasis added). Additionally, EPA has a duty to correctly estimate the proper number of entities to be included in the RFA analysis. *See North Carolina Fisheries Ass'n* *v. Daley*, 27 F.Supp.2d 650, 659 (E.D.Va. 1998); *N.W. Mining Ass'n v. Babbitt*, 5 F.Supp.2d 9, 15–16 (D.D.C. 1998). EPA failed to do this.

Additionally, EPA erroneously declines to provide AEPCO a full RFA analysis by certifying that "this action will not have a significant economic impact on a substantial number of small entities." 79 Fed. Reg. at 34946. The Administrator's decision certifying that the Proposed Rule will not impose any requirements on small entities is incorrect. EPA states that "[t]he proposed rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those state requirements that could potentially impact small entities." *Id*. This statement is incorrect as EPA's Proposed Rule and incorporated BSER mandate Interim and Final Goals that will force closure and diminished coal-fired generation from small rural utilities, leading to a disparate impact on these utilities and their customers.

Under the Proposed Rule, EPA's "acknowledgement" of an RFA analysis is not adequate. In enacting the RFA, Congress found that,

> [U]niform Federal regulatory and reporting requirements have in numerous instances imposed unnecessary and disproportionately burdensome demands…upon small [entities]…[T]he practice of treating all regulated [entities] as equivalent may lead to inefficient use of regulatory agency resources, enforcement problems and, in some cases, to actions inconsistent with the legislative intent of health, safety, environmental and economic welfare legislation."

RFA, Pub. L. No. 96-354, § 2. While failing to allow AEPCO RFA protections, EPA attempts to claim it conducted the RFA analysis in the preamble to the Rule. EPA attempts to brush off its RFA duty by stating it conducted stakeholder outreach. 79 Fed. Reg. at 34,946. However, there is no actual analysis as to why EPA's Proposed Rule and its BSER determination including Interim and Final Goals will not have a "significant economic impact on a substantial number of small entities." EPA provides "buzz" words to indicate an analysis was completed, but its statements lack any justifying substance. As demonstrated by AEPCO's comments, this Proposed Rule will have a significant economic effect on small entities, such as AEPCO, as it forces ceased operation and diminished generation.

The RFA requires the agency to produce a final regulatory flexibility analysis. 5 USC § 604. The Administrator sidestepped this requirement with an unreasonable certification that was arbitrary and capricious. A Court can review the substance of the agency's RFA analysis to determine if the final rule is reasonable. *See State of Mich. v. Thomas*, 805 F.2d 176, 188 (6th Cir. 1986); *Thompson v. Clark*, 741 F.2d 401, 405 (D.C.Cir. 1984). EPA's "decision may still be overturned because of an analysis so defective as to render its final decision unreasonable, or, in the absence of any analysis, because of a failure to respond to public comment concerning the rule's impact on small entities." *Thomas*, 805 F.2d at 188; *Thompson*, 741 F.2d at 408. AEPCO is entitled to a full analysis under the RFA. Because this did not occur, the Court must vacate and remand the Rule to EPA.

INCORPORATION OF ADDITIONAL COMMENTS

AEPCO seeks to incorporate by reference all comments previously submitted by AEPCO, including but not limited to the following comments: AEPCO comments dated September 29, 2014.

Additionally, AEPCO incorporates by reference all comments submitted on this Proposed Rule by associations of which AEPCO is a member of, including National Rural Electric Cooperative Association ("NRECA"), The Arizona Utilities Group ("AUG"), G&T Cooperative Fossil Group, and the Class of '85 Regulatory Response Group, and WEST Associates.

AEPCO also incorporates by reference the ADEQ November 21, 2014, comments on Building Block 2.

AEPCO supports and adopts the ADEQ December 1, 2014, comments and the Arizona Corporation Commission December 1, 2014, comments to the extent not inconsistent with these comments.

CONCLUSION

As currently drafted, the Proposed Rule places an unreasonable and inequitable burden on AEPCO to reduce its CO_2 emissions by imposing overly stringent Interim and Final emission rate goals on the State of Arizona that will impact electric system reliability, impose an unreasonable financial burden on Arizona's ratepayers, including AEPCO's members, and force early closure or reduced generation from coal-fired EGUs, in direct contravention of Section 111(d). EPA's Proposed Rule far exceeds its limited statutory authority under Section 111(d) to establish a system of emission guidelines and procedures for States to use in determining standards of performance for existing coal-fired EGUs and instead seeks to regulate the entire electric generation, transmission, and consumption market in the United States. AEPCO urges EPA to adopt the proposed solutions contained in the "small public and cooperative utility" subcategory and the approach to BB2 redispatch recommended by the AUG as the best way to ameliorate some of the very real costs and burdens of the proposed Clean Power Plan.

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