PUBLIC POWER PARTNERS

OHIO MUNICIPAL ELECTRIC ASSOCIATION

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EPA Docket Center (EPA/DC)
U.S. Environmental Protection Agency
Mail Code: 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
Attn: DOCKET ID No. EPA-HQ-OAR-2013-0602

Re: Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014).

Dear Administrator McCarthy and Staff:

In response to the above-referenced docket, American Municipal Power, Inc. (AMP) and the Ohio Municipal Electric Association (OMEA) hereby offer the following comments for the record. Please note that incorporated by reference in this submittal are the comments submitted by AMP/OMEA on October 15, 2014 on the proposed Carbon Pollution Emission Guidelines for Modified and Reconstructed Electricity Generating Units (2060-AR88).

Background on AMP/OMEA

Ohio-based AMP is the non-profit wholesale power supplier and services provider for 129 locally regulated municipal electric entities located in Delaware, Kentucky, Michigan, Ohio, Pennsylvania, Virginia, and West Virginia. AMP's members collectively serve more than 625,000 residential, commercial, and industrial customers and have a system peak of more than 3,400 megawatts (MW). AMP's core mission is to be public power's leader in wholesale energy supply and value-added member services. AMP offers its member municipal electric systems the benefits of scale and expertise in providing and managing energy services.

AMP's diverse energy portfolio makes the organization a progressive leader in the deployment of renewable and advanced power assets that include a variety of base load, intermediate and distributed peaking generation using hydropower, wind, landfill gas, solar and fossil fuels, as well as a robust energy efficiency program. AMP has actively worked over the past decade to diversify our power supply portfolio, to the point that we are on track for our owned assets to be approximately 21% renewable by 2016. Our fossil fuel assets today consist of a 368 MW ownership share of the 1,600 MW coal-fired Prairie State Generating Co. (PSGC) located in Lively Grove, Illinois, as well as the 707 MW (fired) natural gas combined cycle (NGCC) AMP Fremont Energy Center (AFEC) in Fremont, Ohio. AMP's member and generation asset footprints do not match– in other words, we have generating assets in states where we have no members and members in states where we have no generating assets. The majority of AMP's members are located in the PJM Interconnection, LLC (PJM) regional transmission organization (RTO) footprint, while some members are located within the Midcontinent Independent System Operator, Inc. (MISO) footprint. The OMEA represents the state and federal legislative interests of AMP and 80 Ohio municipal electric systems.

Because of AMP's structure as a non-profit wholesale power provider, we closely follow regulatory initiatives that have the potential to impact the costs and reliability of our members' energy and capacity supply. Ultimately, the policies that impact our members impact their residential, commercial and industrial customers. To that end, AMP's/OMEA's comments on the design elements of limits on greenhouse gas (GHG) emissions from existing power plants reflect expected impacts of the upcoming standards on AMP and member units, as well as to other units in the region from which AMP/OMEA members expect to acquire varying proportions of their power supply through wholesale market purchases. The multi-state nature of AMP's/OMEA's membership and power supply portfolio, plus the various types of electricity markets within which we operate, all point to the need for careful consideration of all options, particularly those that acknowledge that "one size does not fit all" when it comes to carbon standards.

AMP/OMEA generally support and incorporate by reference the comments submitted to this rulemaking docket by the American Public Power Association (APPA) and the PSGC (the latter applicable to our members participating in the PSGC project). In addition, we offer the following comments. We also incorporate by reference comments filed by our member municipal electric systems of Hamilton, Ohio and Orrville, Ohio, as noted later in this document.

AMP/OMEA Comments

Timeframes for action are too compressed

Many state regulators and most of the regulated industry agree that the timelines expressed in the proposed rule are extremely aggressive, particularly when considering the unique and precedent-setting nature of the proposal. Even if state agencies are able to re-allocate necessary resources away from other environmental and energy programs, it may be impossible to meet U.S. EPA's proposed deadlines. In recognition of this fact, the U.S. EPA should eliminate the interim deadlines.

State administrative procedures can be lengthy and burdensome, even without the new legislative authority some states will need to satisfy the rule requirements. The time between the expected finalization of this rule in June 2015 and the deadline for states to submit plans in June 2016 is simply not enough time to make any necessary administrative and legislative changes, especially given the incompatibility between U.S. EPA's proposed timeline and some state legislative calendars.[1] This issue is particularly acute when considering administrations and legislatures will be grappling with policy issues and decisions related to implementing the proposal and the necessity of potentially reorganizing state utility and environmental regulatory structures.

Even if it was possible for a state agency to meet the timeframes contemplated in the rule, EGUs will have significant difficulty in developing the infrastructure and sustainability programs necessary to meet the interim goals. In order to maximize limited resources – thus maximizing

[1] The rules do provide states with additional time to submit complete plans if justified and supported: Individual plans would get a one year extension to June 30, 2017 and multi-state plans a two-year extension to June 30, 2018.

carbon reductions – EGUs need sufficient time to fully analyze potential reduction opportunities. The interim period glide path simply does not allow proper time for the development and implementation of carbon reduction projects.

Given that litigation associated with the rulemaking is inevitable, states and the regulated industry are at risk in moving forward with developing and enacting Section 111(d) plans prior to the resolution of litigation. For that reason, we advocate for the amendment of the plan submittal deadlines contained in the Subpart B regulations (the Section 111(d) procedural regulations). The amendment could either be a basic extension of the submittal deadlines or implementation of a "legal trigger" approach.

Utilizing a "legal trigger" approach would require each state to submit a Section 111(d) plan within three years following the expiration of the litigation on the rule. Using the GHG New Source Review (NSR) tailoring rule situation as an example of what all parties should seek to avoid[2], this approach would ensure that states do not expend limited resources attempting to satisfy a rule that ultimately is vacated or remanded.[3]

In addition, beyond the practical considerations of being able to develop and submit a plan within the proposed time frames, the time allowed for the rule review and the development of comments by the revised December 1, 2014, deadline is very tight, particularly when the schedule dictated that comments on the modified/reconstructed rule proposal be submitted by October 16, 2014. As such, we do not believe there has been sufficient opportunity for adequate review of the background documents, assumptions, and support used in drafting the rule. This concern is highlighted by the fact that it was not until November 6, 2014, that U.S. EPA released the Technical Support Document (TSD) outlining two possible methods for performing a rate-to-mass translation which included mass-based equivalents for each state.[4] Less than a month was provided to review this new TSD and develop comments by the submission deadline. Likewise, while U.S. EPA's issuance of the Notice of Data Availability (NODA) in October is appreciated, its issuance barely a month before comments are due limits its usefulness.[5]

For instance, a limited review has already identified errors regarding NGCC facilities, including AMP's AFEC. U.S. EPA's TSD contains certain assumptions U.S. EPA made in developing potential output from NGCC when increasing the capacity factor to 70%. While USEPA assumes nameplate capacity when developing state goals, it is typical for nameplate capacities to be higher than actual production capability (especially at peak time), and real world values for net output are much lower and often only achieved at a less efficient heat rate. Using nameplate capacity causes a severe overestimation in the potential for CO2 emission reductions from re-dispatch. As such, U.S. EPA should revise projected natural gas utilization to reflect actual plant availability and existing regulatory and physical limitations.

Not having adequate time to review the rule provisions and how they relate to the multiple assumptions on which it is based raises the specter of each state developing a Section 111(d) regime based on faulty assumptions or data inputs on U.S. EPA's part. This concern is exacerbated by the

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[2] In *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014), the Supreme Court rejected a key aspect of EPA's legal justification for the Tailoring Rule. The Supreme Court's decision came more than three years after the rule's effective date, and forced states to needlessly invest significant resources to implement the rule.

[3] U.S. EPA can either amend the subpart B rules or provide a different deadline in the applicable subpart. (40 CFR 60.23(a) and 60.27(a)).

[4] Notice; Additional Information Regarding the Translation of Emission Rate-Based CO2 Goals to Mass-based Equivalents. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. EPA-HQ-OAR-2013-0602, RIN 2060-AR33

[5] Carbon Pollution Emission Guidelines for Existing Stationary Sources; Electric Utility Generating Units; Notice of Data Availability. 77 Federal Register 64543; October 30, 2014.

fact U.S. EPA has stated that the comment period is the <u>only</u> time the agency will accept comments on the calculated standards.

<u>Credit for all renewable and energy efficiency investments, including hydropower, critical</u>

It is extremely important to AMP/OMEA that our hydroelectric and other renewable energy (RE) and energy efficiency (EE) investments receive appropriate credit under state plans in Building Blocks 3 and 4.

AMP has new run-of-the-river hydropower assets under construction on the Ohio River in Kentucky and West Virginia that are slated to come online over the next two years and will provide approximately 300 MW of new clean energy and capacity to participating AMP members in multiple states. Additionally, AMP and its member community of Wadsworth, Ohio, have received a preliminary license and are pursuing the license and permits for a new facility at the RC Byrd Locks and Dam on the Ohio side of the Ohio River. These projects all advance the goal of reducing CO2 emissions. The stringency of the proposed emission reduction goals makes it essential that all impacted parties, be they states, utilities, municipalities or others are able to receive credit for the full array of emission reductions from their investments in these measures.

These hydropower investments, as well as those in wind, solar, landfill gas and carbon offset projects, were initiated in anticipation of carbon regulations and the need to reduce GHG emissions and, as such, they should not be denied credit under any state plans simply because they are pre-existing projects. While U.S. EPA excluded hydropower generation from the existing 2012 generation baseline for purposes of quantifying BSER-related renewable energy generation potential, according to the proposal nothing prevents states from considering incremental hydropower generation from existing and new facilities in complying with the GHG reduction targets. In fact, U.S. EPA specifically requests comment on whether and how to include hydropower generation in state plans.[6]

In relation to hydropower assets, AMP/OMEA is requesting that U.S. EPA clarify the line between new and existing resources. We believe that any hydropower assets coming on line after the 2012 baseline year in the proposal should be defined as new and be available to receive credit for use by states in their compliance plans. In particular, AMP and our members have hydropower assets that will be coming online in 2015-2016 that should be available for state compliance planning. These zero-emission projects involve a long development time for initial design, permitting and construction and substantial upfront costs. In addition to the long development time, these projects have a long lifespan and are financed for 35 years with an expected operational period of greater than 60 years. This long term carbon benefit should receive appropriate accounting within the Section 111(d) structure.

The language of the proposal regarding how these assets might be incorporated into a state plan is ambiguous, vague and uncertain. Specifically, the language states *"The exclusion of pre-existing hydropower generation from the baseline of this target-setting framework does not prevent states from considering incremental hydropower generation from existing facilities (or later-built facilities) as an option for compliance with state goals."*[7] U.S. EPA must clarify in the final rule this ambiguity in a manner that allows the states to utilize hydropower assets in realizing the assigned targets. In addition, it is unclear what re-licensing might mean for the existing versus new categorization.

Later in the preamble is a section titled *"Proposed Approach for Treatment of Existing State Programs and Measures in an Approvable State Plan"*.[8] This section states *"Specifically, the EPA is proposing that, for an existing state requirement, program, or measure, a state may apply toward its required*

[6] 79 Federal Register 34869
[7] 79 FR 34867
[8] 79 FR 34918

emission performance level the emission reductions that existing state programs and measures achieve during a plan performance period as a result of actions taken after the date of this proposal."

However, the above statement is conditioned with the following, "*We are also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO2 goals as part of building block 3.*"[9]

This section infers that a state could incorporate AMP's new hydropower builds into a state plan. Section 4.2.1 of the GHG Abatement Measures TSD also has a related statement that "*The analysis informing regional RE targets does not explicitly account for the potential of building new hydroelectric facilities as a source under RPS policies; however, states may choose to encourage such development, and generation from such facilities would not be excluded from compliance with a state's goal under this rule.*" This leads back to the need for U.S. EPA confirmation in the final rule that AMP and similarly situated entities satisfy "new hydropower" and can account for the benefits of existing hydropower resources on par with other zero-emitting renewable sources. These issues cannot be left for chance or later interpretation, but need to be clearly established up front by U.S. EPA. Again, AMP/OMEA advocates a position that any asset coming on-line after the 2012 baseline be considered a new asset that is appropriate for inclusion in a state's Section 111(d) plan even if not mandated

Another related issue that needs clarification relates to which state is able to incorporate hydropower into their compliance plan. There is some question as to whether hydropower located in one state must be counted towards the state goal, or if it can be used to meet another state's goal. In the section titled "*Treatment of Interstate Effects*"[10] U.S. EPA proposes to allow a state to take into account <u>all</u> of the CO2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states. However, regarding EE, a state can take into account in its plan <u>only</u> those CO2 emission reductions occurring (or projected to occur) in the state that result from demand-side EE measures implemented in the state. As a result, the proposal is unclear on how hydropower would be treated, and U.S. EPA should confirm that out of state hydropower assets (or other RE assets for that matter) can be used toward compliance with a state plan.

AMP/OMEA reads the proposal such that the rule would allow hydropower credits to cross state lines as it more closely aligns with RE, though it has been left out of BSER for RE. Also, we are requesting clarification from U.S. EPA on how they would treat the situation where two states each want to count the same hydropower generation toward their goal. Relevant questions in this regard include whether the owner of the hydropower (or other renewable) asset or output gets to pick the highest bidder, or is it load (contract path) following? It is essential that the final rule be clear on how RE is used in demonstrating compliance.

Beyond hydropower, U.S. EPA fails to account for decreasing return on investment seen in EE programs. We feel that entities like AMP and our members who have undertaken responsible and proactive portfolio options in the past receive credit for those past good deeds in state plans, such as credit for early action before 2012, and recommend that U.S. EPA be very clear in concurring that states can make that a component of their Section 111(d) plans.

In addition, AMP and our members participating in AFEC and PSGC have made investments in verified carbon offsets in a number of states. The offsets cover periods from 2011 to the present and involve various technologies such as landfill gas and forestry management. It is extremely important that U.S. EPA provide guidance on how to incorporate these voluntary early actions into state plans.

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[9] 79 FR 34918

[10] 79 FR 34921

While falling outside the scope of the Section 111(d) proposal by U.S. EPA's own admission, AMP/OMEA questions the validity of the Building Block 3 target-setting methodology set forth in the NODA.[11] Under the NODA's proposed approach, a state's goal would be informed by the opportunity to develop out-of-state RE resources as part of its state plan. While AMP/OMEA agrees with the flexibility afforded to states in developing RE outside their respective borders, it is misguided to use this potential in developing a state's individual goal. Specifically, certain aspects of RE development are not within a state's control when sited outside the state. Establishing state goals on out-of-state potential does not account for the inherent hurdles and cooperation necessary for such development.

<u>Unique issues associated with municipal utilities</u>

U.S. EPA specifically requested comment on whether there are special considerations affecting rural cooperative or municipal utilities that merit adjustments to the rule proposal.[12] While AMP/OMEA is not in a position to comment on the universe of potential issues given the multitude of organizational and regulatory structures of various entities, we do feel that our concerns are likely shared by others who are similarly situated to AMP/OMEA.

One of the primary issues we have struggled with is how our assets fit into a regulatory scheme that contemplates regulation by <u>both</u> state utility commissions and state environmental agencies. By way of example, in Ohio, AMP and its member's fall outside the purview of the Public Utility Commission of Ohio's (PUCO) regulatory authorities based on Home Rule provisions imbedded in the state constitution. Our member municipal electric systems fall under varying degrees of state regulation across our seven state footprint; however, the majority of our members are not subject to state utility commission oversight.

Using Ohio as an example, entities such as our members that own and/or operate generation assets are subject to Ohio EPA's air quality jurisdiction and regulation, but because of Ohio's Constitutional Home Rule provisions they are not subject to enforceable RE mandates, EE requirements or enforceable state-level resource planning processes.[13] In Ohio, similar treatment extends to the state's rural electric cooperatives via legislation. This effectively prohibits the ability of either the PUCO or Ohio EPA to regulate our members' activities as contemplated by much of the Section 111(d) proposal.

AMP is not alone in pointing out that the Best System of Emission reduction (BSER) as envisioned by the Section 111(d) proposal functions primarily as an energy policy rather than a rule under the Clean Air Act (CAA). As a result, in Ohio, the PUCO is the most appropriate entity to determine how requirements falling under Building Blocks 2-4, such as re-dispatch, are implemented. Yet PUCO has no authority under Ohio's Constitution and existing laws to reach entities such as our members.

State Home Rule constitutional and statutory provisions are well established and critical underpinnings to the effectiveness of municipal electric system operations. For instance, the local control and decision making authority for our member municipal electric systems is one of the key reasons cited for our strong bond ratings – bond ratings that support our efforts to diversify our portfolio. The concept of the Section 111(d) plan reconfiguring the energy sector so that cooperatives and municipal utilities become regulated by a public utility or service commission is difficult to comprehend, not to mention at complete odds with the core purposes of these entities. One of AMP's/OMEA's driving missions is to provide affordable and reliable power to our member municipal electric systems based on the principals of self-governance and local control.

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[11] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: Notice of Data Availability. 79 Federal Register 64543, at 64547 and 64551

[12] 79 Federal Register 34887

[13] Ohio Constitution, Article 18

Entities such as AMP and its members are "self-regulating" as a matter of state law and accordingly, states generally will lack regulatory jurisdiction for Building Blocks 2-4. State environmental regulatory agencies will in most cases only have legal authority for obligations under Building Block 1, which in our case would result in AMP's fossil-fuel fired generating assets bearing the entire burden of achieving the CO2 goal. Indeed, U.S. EPA implicitly suggests that states reference the burdensome results of a state plan based on just Building Block 1 to entice non-jurisdictional entities like our members to voluntarily submit to broader jurisdiction.

U.S. EPA's proposed "voluntary" submission by cooperatives and municipal utilities creates tension between long-standing and established legal rights in exchange for purported compliance "flexibility" with the energy policy changes dictated by the Section 111(d) proposal. If adopted as written, the proposed rule would fundamentally transform the landscape of the cooperative and municipal utility industry. Ultimately, states are left with three untenable options: (1) pass state legislation designed to create regulatory authority that allows the state to develop an enforceable state plan against *all* generators for actions under *all b*uilding blocks; (2) create enough incentives such that all non-regulated entities voluntarily submit to some level of jurisdiction under the state plan, or; (3) submit to a federal implementation plan, essentially handing over control of state energy policy.

Precedent-setting nature of the outside-the-fence building blocks

Like numerous other impacted parties, AMP is struggling with the concept of an outside-the-fence regulatory approach. Significant legal and practical issues would need to be resolved before any state could utilize the portfolio approach envisioned by the third and fourth Building Blocks outlined in the proposal.

U.S. EPA is already familiar with the extensive debate on how states might incorporate outside-the-fence strategies into a Section 111(d) plan, including whether they are even legally permissible, and whether they are necessarily central to a compliance strategy. We will not repeat those here.

What we see as a major challenge is linking these strategies to actual, quantifiable emission reductions. These requirements will need to be thoroughly subjected to Evaluation, Measurement, and Verification (EMV) on their own before a state would be able to count the reductions towards its plan. While AMP has experience in this area with our Efficiency Smart™ energy efficiency program, the concepts contained in Building Blocks 3 and 4 fall under a plethora of policies and programs overseen by various regulatory agencies, but in most cases not by state environmental agencies. Although these methods, protocols, and third-party groups are already within the current structure of EE portfolios in many states, there is concern about including these portfolios in the state plans for Section 111(d) due to a lack of coordination and consistency for quantifying energy savings and emissions reductions. In order for states to use measured EE as a compliance mechanism for Section 111(d), it will be essential for U.S EPA to provide guidance regarding consistent assumptions to accurately calculate these emissions reductions. The unique outside-the-fence approach necessitates the development of some level of national uniformity in EM&V plans and protocols for purposes of demonstrating EE in state compliance plans.

Section 111(d) requires EE projects to achieve emissions reductions, not just displacement of coal-fired generation. So while each state will have its own plan and compliance obligations, it is important that the Section 111(d) rules provide for a mechanism to compare emissions across state lines and to ensure that measurement protocols are consistent.

AMP/OMEA continues to look at ways to make these outside-the-fence approaches workable in practice – especially given our multi-state generation and member footprint. Even if developed as an opt-in program for affected EGU's, with contractual obligations outside state environmental or utility regulatory realms, identifying workable and legally defensible enforcement mechanisms is a huge barrier.

In addition, we are reviewing the assumptions used in determining the associated reductions that could be derived from the outside-the-fence Building Blocks. For instance, U.S. EPA evaluated state renewable portfolio standards to assess the degree to which renewable energy options were available to each state and assumed that states could increase their energy efficiency by 1.5 percent annually. U.S. EPA's approach was to generate regional averages by grouping states.[14]

Finally, like others, we struggle with the concept that BSER for an existing EGU can be an enforceable action directed at a non-affected EGU. This approach extends regulatory programs far outside the bounds of their original intent. U.S. EPA appears to have a largely skirted the issue of how states would enforce such measures against non-EGU entities, and AMP/OMEA requests that U.S. EPA further elaborate on and address the practical and legal considerations associated with this critical issue.

Past Clean Air Act (CAA) actions impacting EGUs, as with other NSPS regulated industries, have been imposed inside-the-fence at the affected unit. These compliance strategies and tools are familiar to the state and regulated entities. Once the Section 111(d) plans step outside that fence line, the landscape becomes more difficult, particularly when moving beyond traditional state environmental and utility authorities. When factoring into the equation municipal electric systems and rural electric cooperatives that do not fall under state RE and EE standards because of local governance, U.S. EPA is essentially proposing a wholesale reworking of each state's individual enforcement authorities.

We are not repeating all the various legal issues raised by the proposal, but at the forefront are the problems associated with enforcing a standard that is directed at controlling emissions at an existing EGU against a non-affected facility, such as a manufacturing facility, commercial building, and the like. If a demand-side regulation was not met, and that was a contributing factor in a state's failure to meet its assigned CO2 goal, who would the state, or U.S. EPA, seek to sanction? It is difficult to imagine an enforcement action against a non-EGU based on an EGU NSPS from either a legal or practical standpoint, and difficult to imagine an enforcement action against an EGU for the actions of an entity accountable for improvements in EE.

As with other sections of the proposal, the approach of enforcing an EGU NSPS against a non-EGU puts the U.S. EPA in the position of establishing energy and economic policy, an action outside the realm of environmental policy and well beyond existing legal authorities.

<u>Inherent inconsistencies in the rule</u>

The proposal contains inconsistencies that bring into question the ability to meet state goals utilizing the various Building Blocks. For example, consider the relationship between the 6% efficiency improvement for coal-fired facilities called for by Building Block 1 and the re-dispatch to natural gas generation called for by Building Block 2.

Minimizing heat losses is the most significant factor affecting plant efficiency and, therefore, GHG emissions associated with energy production. However, there is considerable debate regarding the reality of U.S. EPA's estimates of a 6% improvement being achievable with the current coal fleet. We assume that some of these coal facilities have already made efficiency improvements in order to meet other state or federal standards. Any further improvements, whether from best practices or equipment upgrades, certainly will not equate to 6% "on average" and will not come without significant cost, if at all.

[14] 79 Federal Register 34867

So at the same time Building Block 2 envisions that utilities and grid operators would reduce GHG emissions by shifting generation from coal-fired units with higher emissions to lower NGCC emitting units, U.S. EPA's proposal is essentially seeking to squeeze additional efficiencies out of the existing coal fleet (often where little opportunity might exist to do so). Those coal-fired EGUs that are able to achieve additional heat rate improvement may then be positioned for more frequent dispatch.

U.S. EPA's proposal discusses the situation where EGU output increases due to the "rebound effect" from improvements in heat rate at individual EGUs. While U.S. EPA might assume that an EGU will spend money on a heat rate improvement project and then utilize the EGU less, that assumption is simply not realistic.

Unfortunately, it appears that U.S. EPA simply discounts this as a potential issue, concluding that the rebound effect would only be a concern if the rule were contemplating only heat rate improvements. The agency concludes that the rebound effect can simply be addressed by establishing BSER as a combination of approaches, such as demand side actions and an increase in renewable generation.[15] However, that view can only be supported by an assumption that a state utilizes <u>all</u> of the Building Blocks.

Again, this highlights the importance of adequate time to review the assumptions. As the State of Arizona has recently pointed out in specific detail, the failure of a single assumption by U.S. EPA on one Building Block impacts the validity of the assumptions and conclusions on all other Building Blocks, as they are all interrelated in achieving the state goal.[16]

<u>Concerns related to Hamilton, Ohio and Orrville, Ohio units</u>

In addition, and consistent with our comments of the modified and reconstructed rule proposal, as a regulated entity we struggle with certain inconsistencies in the rule that makes determining affected units difficult. One such inconsistency greatly impacts the designation of coal units for the AMP/OMEA member communities of Orrville, Ohio and Hamilton, Ohio. There appears to be a conflict between the language in the preamble to the Carbon Guidelines and the actual proposed rule text in the Carbon Guidelines with respect to what constitutes an "affected source." In accordance with the preamble, a source triggers the Carbon Guidelines based on *<u>the sale of</u>* greater than 219,000 MWh per year. However, under the proposed rule language, a source triggers the Carbon Guidelines based on whether or not the source was *<u>constructed for the purpose of</u>* supplying more than 219,000 MWh per year without regard to whether the source actually sells more than 219,000 MWh per year. As an example, Hamilton's Unit 9 (50.6MW) should not be considered an affected source subject to the rulemaking because it does not, and has not, sold more than 219,000 MWh in any year since and including USEPA's baseline year.

Furthermore, USEPA's identification and inclusion of 25 MW nameplate capacity units as "affected sources" under the carbon guidelines is incorrect. A unit with a nameplate capacity of 25 MW could hypothetically produce 219,000 MWh per year only if the unit was capable of operating at its maximum rate for 8760 hours per year (i.e. 24 hours per day, seven days per week). No unit has the physical ability to operate non-stop at full nameplate capacity for an entire year. Therefore, USEPA has improperly included Hamilton (units 7 and 8) and Orrville (units 10 and 11) 25MW coal units in Ohio's baseline and goal computation as affected units.

Additional details regarding the above points are included in comments submitted separately by AMP/OMEA members Orrville and Hamilton, and have the full support of AMP/OMEA.

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[15] 79 Federal Register 34859

[16] Burr, S. Arizona Dept. of Environmental Quality to A-AND-R Docket ID No. EPA-HQ-OAR-2013-0602; Arizona Interim Goal Analysis, August 22, 2104

Natural gas plant utilization

The second Building Block consists of shifting energy generation away from higher- emitting coal-fired power plants to less-emitting natural gas plants. Based on U.S. EPA's assumption that natural gas plants are under-utilized, U.S. EPA projects that natural gas plants could run at 70% of their capacity, thus allowing each state to shift coal-fired generation to available natural gas plants currently operating at less than 70% capacity.[17] It does not appear from the proposal that U.S. EPA has given any consideration to the fact that some companies have built their natural gas capacity for specific purposes or taken limits to avoid New Source Review (NSR) or National Ambient Air Quality Standard (NAAQS) impacts. Instead, all these real world constraints are pushed aside as inconsequential.

Additionally, the proposal does not take into account how the organized markets of an RTO like PJM function. Specifically, states that have restructured their electric markets have effectively relinquished both jurisdiction over EGUs in their states and operational control over EGU dispatch and the transmission systems that deliver the energy from the EGUs to the RTOs. In the restructured states, the EGUs rely on RTO market signals sent by Federal Energy Regulatory Commission (FERC) jurisdictional wholesale markets to set the price at which they will offer their energy, capacity and other products into the market. Those federal, wholesale market signals also serve as indicators for whether the EGUs should continue to invest in ongoing operation and maintenance expenses. States no longer have the ability to intervene to direct which resources are operated, constructed, or maintained. Thus, while states that have retained or returned to traditional regulation have some control over EGUs and how they are dispatched, restructured states have little to none.

The same is true of the transmission systems that deliver the electricity from the EGUs. The RTOs have operational control over all federal-jurisdictional transmission facilities. For instance, if there are constraints on the transmission system controlled by PJM that would be exacerbated if AMP's AFEC NGCC were dispatched, PJM will not dispatch or will curtail the output of AFEC. In other words, whether EGUs run may not be limited to price signals, but rather, physical constraints on the transmission system and, of course, natural gas delivery constraints that are beyond either the EGU or the state's control. Given the myriad physical and market constraints that apply to EGUs, the 70% percent utilization rate for natural gas plants assumed in Building Block 2 is unrealistic within the timeframes envisioned by the rule proposal. While some of these constraints can be addressed over time, we request that U.S. EPA examine the impacts of these constraints and address how they impact the prospect of achieving 70% utilization within the time required.

U.S. EPA's underlying assumption for plant output capacity further aggravates the issue. As previously noted, in developing state targets U.S. EPA used generator nameplate capacity for goal computations, resulting in an overestimation of an EGU's potential. A more accurate assumption would be an EGU's summer rated maximum net output. This encompasses the peak demand season, as well an EGU's lowest net output capacity. As previously mentioned, AMP's AFEC NGCC has a maximum output rating registered with PJM that is significantly lower than the generator nameplate capacities used in the current computations. In addition, this capacity will continually decline due to plant degradation, a factor U.S. EPA also failed to consider.

U.S. EPA assumes that, because NGCC utilization rates are 60% or higher when constraints on natural gas or electricity transmission manifest themselves, a 70% NGCC utilization rate should be readily achievable.[18] However, this assumption is flawed. U.S. EPA uses a national average NGCC utilization rate as the basis for its conclusion that natural gas plants can meet the 70% utilization rate. Using a national average obviously ignores regional differences in both existing and potential new infrastructure. Not all states or regions have a 60% NGCC utilization rate during constraints or

[17] 79 Federal Register 34867-58

[18] 79 Federal Register 34863

otherwise. Thus, U.S. EPA's conclusion appears to incorrectly assume that in all instances the infrastructure exists to allow natural gas plants to meet the 70% utilization rate.

Given U.S. EPA's suggestion in the October 2014 NODA that new gas development potentially can be part of BSER, U.S. EPA needs to account for the timeframes to develop and permit the necessary infrastructure for new NGCC.[19] While AMP is a strong supporter of NGCC and not a coal-heavy entity, we have concerns that the 70% utilization rate calls into question the costs and time associated with the upgrades and expansions of natural gas pipeline and transmission facilities that will be needed. It also ignores the regulatory and financial challenges of getting new gas infrastructure built. Accordingly, we request that U.S. EPA examine the actual current state of infrastructure and realistic projections of the time and cost to upgrade or construct natural gas pipeline and transmission facilities needed to eliminate or reduce specific state and regional constraints that impact the 70% assumption.

Concerns about the level of potential RTO involvement

While many portions of the United States operate in RTO regions, there are significant areas of the country where no RTOs exist. The existing RTOs have differing governance and operating structures. Some are stakeholder driven; others are not. And in many cases, states are divided between different RTOs – and in some cases between different RTOs and non-RTO areas.

The RTOs have assumed (with some initial and significant ongoing trepidation by load interests) the operation of energy, capacity, ancillary service and other markets. RTOs centrally dispatch EGUs within their footprint based on the marginal cost of operation of each individual unit as reflected in bids submitted to the RTO on a day ahead basis. In theory, dispatching EGUs across the RTO footprint based on the marginal cost to produce the next MW of electricity should maximize the economic efficiencies of the generation fleet for each hour of the operating day across the entire RTO footprint.

The RTOs already have extensive electric reliability responsibilities and AMP agrees that it is important for RTOs to continue that role through a reliability safety valve that enables the RTOs to assess, and, as necessary, to mitigate electric system reliability impacts resulting from related environmental compliance actions to maintain electric system reliability.

However, AMP/OMEA adamantly opposes RTOs running trading platforms or other new markets to achieve environmental compliance. AMP/OMEA has very serious concerns about the lack of consumer focus and transparency in the mandatory energy and capacity markets that some RTOs run today, as well as how the RTOs themselves are operated and governed, and we do not want to see those approaches broadened. It is also important to balance the reliability and environmental compliance with the ultimate costs on load (consumers and wholesale customers). The creation of new, mandatory markets or trading platforms run by the RTOs will significantly complicate the already overly complex competitive energy market and could very well add unnecessary costs. For these reasons, AMP/OMEA opposes giving the RTOs authority to create any new markets as a compliance vehicle.

Need for thorough review of reliability and cost impacts

The assumption underlying the Section 111(d) approach is that the electric utility industry will be able to implement a shift from economic dispatch to environmental dispatch while maintaining reliability. AMP/OMEA believes this assumption has not been thoroughly examined by U.S. EPA, in both legal and practical terms. The existing natural gas system infrastructure struggles at times to effectively handle current demand for natural gas during peak usage, let alone the increased

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[19] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: Notice of Data Availability. 79 Federal Register 64543

pressures that would result from demands for increased natural gas dispatch as envisioned by the proposal. AMP/OMEA does not feel that the multiple factors currently at work in the energy market that drive the dispatch of the existing generation fleet can effectively be transitioned to prioritize environmental dispatch within the proposed timeline.

The Section 111(d) proposal presents significant jurisdictional challenges between the Federal Energy Regulatory Commission (FERC) and U.S. EPA, and in fact has been referred to as a "jurisdictional train wreck."[20] AMP/OMEA recommends that prior to the approval of any state plan, that U.S. EPA and FERC jointly evaluate potential impacts of the proposal related to: (1) the supply and demand of natural gas; (2) natural gas prices; (3) current gas transmission pipelines; (4) the need and timing for construction within a state of new gas pipelines; and (5) the impacts on energy and capacity prices. The need for coordination between U.S. EPA and FERC regarding the feasibility of compliance with the proposed rule cannot be understated. We also believe U.S. EPA must proceed in a manner cognizant of the Tenth Amendment's limitations on federal encroachment of state authority.

New Source Review (NSR) considerations

U.S. EPA assumes that the heat rate of the existing coal fleet can be improved by 6%, with 2% of that coming from equipment upgrades. Yet a physical change or change in the method of operation relating to efficiency improvements at an affected EGU also has the potential to trigger NSR applicability determinations. If NSR is triggered, the facility may decide to opt out of such efficiency improvement projects, which is counter to the intent of the proposed emissions guidelines. Likewise, if the efficiency improvement is required by a state plan, U.S. EPA and the state are basically mandating a change that could trigger NSR. What makes the approach even more troublesome is that after mandating an efficiency improvement that triggers NSR review and a significant capital investment, the rule would then dictate decreased dispatch of the EGU in favor of less carbon intensive generation. Of course, just to add to the irony, decreased dispatch means decreased efficiency.

Many of the actions that the rule suggests to reduce carbon emissions - from fuel switches to boiler modifications that improve efficiency - have the potential to trigger NSR permitting requirements. Yet U.S. EPA gives little attention to Section 111(d)'s potential impact on NSR compliance. U.S. EPA appears to take the position that there will be few instances where a state plan would require sources to undertake physical or operational changes to improve unit efficiency which would result in increases in unit dispatch or unit annual emissions sufficient to trigger NSR permitting requirements.[21]

While U.S. EPA's position is based on a belief that efficiency projects required for compliance with Section 111(d) will largely cause a reduction in pollutants, this view ignores the fact that efficiency projects do not exist in a vacuum. A project to improve the heat rate of a unit, while reducing emissions of CO2, can simultaneously result in an emissions increase of other regulated pollutants. Given that the NSR regulations are pollutant specific, a project may trigger NSR requirements if there is a significant increase of any one regulated pollutant under the CAA. The mere fact that a project may not increase CO2 emissions does not ensure that the source is otherwise exempt from NSR permitting requirements.

U.S. EPA must modify the proposal to ensure that NSR does not serve as a regulatory deterrent to effectuating the development of lower-emitting and more efficient power generation. However, given the history of the NSR program and U.S. EPA's enforcement initiatives, it is clear that that compliance with state plans developed pursuant to Section 111(d) have a strong potential to trigger NSR obligations. AMP/OMEA proposes that U.S. EPA include an explicit exemption to NSR

[20] Id.

[21] 79 Federal Register 34928

permitting requirements for projects or activities undertaken by affected entities to comply with Section 111(d). The importance of this issue is of such magnitude that it warrants consistent treatment, and should not, and in order to assume consistent enforcement perhaps cannot, be left to individual state implementation plans.

As a result, AMP/OMEA feel that the Section 111(d) rule should include explicit provisions that will allow an affected EGU to undergo a physical or operational change to meet a state's Section 111(d) plan without triggering NSR permitting requirements should an increase in utilization or emission of a regulated pollutant be expected from such change. This approach can be achieved by adding language that excludes projects undertaken pursuant to a state Section 111(d) plan from the definition of "major modification."

Another approach would be to handle physical or operational changes undertaken pursuant to Section 111(d) in a manner similar to GHG emissions under U.S. EPA's Tailoring Rule. U.S. EPA could find that physical or operational changes undertaken solely to comply with a state plan under Section 111(d) that result in an emissions increase of any regulated NSR pollutant would not trigger NSR permitting requirements. This approach could recognize that if the source undertakes a project that results in an improvement to heat rate, but was not done in furtherance of achieving a state goal under Section 111(d), the source may trigger NSR permitting requirements.

U.S. EPA should also note that while most NSR discussions are focused on Building Block 1, there are also natural gas units that have taken synthetic minor restrictions to avoid NSR. Increasing utilization may impact the status of these units and trigger NSR. As such, it should not be assumed that these units can meet or exceed a 70% utilization rate without the removal of certain permit restrictions.

AMP/OMEA strongly supports the concept that if a source is taking an action to comply with a state plan, any changes can be treated as non-NSR triggering events. EGUs should be able to increase capacity at efficient units without an NSR penalty, as this action ultimately is consistent with the goals of the rulemaking.

Use of 2012 as the baseline

It is surprising that U.S. EPA chose to use just one calendar year of data as the baseline, effectively ignoring variables such as weather, unplanned and planned outages, fuel price variability and other factors that result in shifts among generation sources. In 2012 natural gas prices were at historical lows and NG-fired EGUs ran at higher capacity factors than would otherwise have been the case. Using a year that is not representative of generation patterns results in compliance with emissions targets appear more achievable.

Because no single year can be representative of electricity generating patterns, AMP/OMEA recommends that U.S. EPA use at least the average of the last three years as the baseline period. This approach would allow use of the most current data while at the same time developing a baseline that recognizes annual variations in generation source and emissions, as well as aligning with the proposed rolling three year average compliance period in the proposal.

We appreciate the fact that U.S. EPA, while originally taking the position that any potential changes to state goals using a multi-year base year would be minimal, has noted the concerns of states and regulated entities and has requested comment on a multi-year approach in the recent NODA.[22] AMP/OMEA recognizes that each baseline approach presents its own advantages and disadvantages, but final state baselines should be representative and not penalize states or entities like AMP/OMEA and its members who have taken responsible early actions. If U.S. EPA maintains

[22] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: Notice of Data Availability. 79 Federal Register 64543, at 64548

its approach of using 2012 as the baseline, the rule should be drafted such that the baseline can be adjusted for individual states where it can be demonstrated that certain anomalies may have had an undue influence on the baseline.

Closing

Throughout the Section 111(d) process U.S. EPA has highlighted that the proposal provides states flexibility in their approach to reducing CO2 emissions, and that the proposed guidelines provide options for meeting the state specific goals in a manner that accommodates a diverse range of state approaches. However, AMP/OMEA is very cognizant of the fact that the flexibility U.S. EPA advocates is limited to choosing the methods of emission reduction and timeframe of plan development and implementation. No flexibility is given in determining the total emission reduction figure.

AMP/OMEA, like many others, sees Section 111(d)(1) as clearly prescribing authority for U.S. EPA to set up procedures, but states are given the authority and responsibility to set up the actual, substantive standards of performance. Despite the use by U.S. EPA throughout the proposal of terms such as "targets" and "goals", each state is mandated to achieve a specific reduction level that is federally enforceable. AMP/OMEA requests that U.S. EPA directly address how the proposed approach is not contrary to the language and intent of Section 111(d)(1) that states themselves set the actual standards.

While by no means exhaustive, the comments provided represent issues of most concern to AMP/OMEA relative to the proposed existing unit rules to limit CO2 emissions. We thank U.S. EPA for this opportunity to provide input to the agency on these important matters; please let us know if you need additional information.

Respectfully Submitted

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