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EPA Docket Center
U.S. Environmental Protection Agency
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Mailcode 28221T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Peabody Energy Comments on EPA's Proposed Affordable Clean Energy Rule; Docket ID No. EPA-HQ-OAR-2017-0355

Peabody Energy Corporation (Peabody) submits to the U.S. Environmental Protection Agency (EPA or Agency) the following comments in support of EPA's proposed Affordable Clean Energy Rule (ACE or Proposal).

Introduction and Executive Summary

Peabody is the leading global pure-play coal company, serving power and steel customers in more than 25 countries on six continents. In the United States, Peabody owns interests in fourteen mining operations located in six different states. The principal business of Peabody's mining segments in the United States is the mining, preparation and sale of thermal coal, sold primarily to electric utilities in the United States under long-term contracts. Peabody produces approximately 20% of coal mined in the United States used for electricity generation. Peabody sells the coal it mines in the United States to approximately 65 electric utilities, which use that coal to fuel approximately 125 Electric Generating Units (EGUs) in the United States.

In ACE, EPA requests comment on numerous issues regarding its greenhouse gas (GHG) emissions guidelines for existing EGUs, including the roles of the states and federal government, systems of emissions reduction applicable to existing EGUs, compliance measures, and considerations regarding state planning requirements under the Clean Air Act (CAA or Act). In a separate notice, EPA also has proposed to repeal the final Clean Power Plan (CPP), 80 Fed. Reg. 64,662 (2015). Peabody submitted separate comments in support of the repeal proposal. EPA Docket ID No. EPA-HQ-OAR-2017-0355-21005.

ACE proposes three separate actions. First, it would set guidelines for GHG emissions from existing power plants based on "within the fenceline" measures only. Second, it revises CAA Section 111(d) regulations to give the states greater flexibility on the content and timing of their state plans. Third, it revises regulations under the New Source Review (NSR) program to ensure that efficiency improvements to existing plants do not trigger NSR requirements. Peabody supports each of these overall objectives of ACE.

Return to Inside the Fenceline Focus: Peabody supports ACE's return to EPA's historical interpretation that Section 111(d) only authorizes EPA to establish the best system of emission reduction (BSER) based on measures that can be employed within the fenceline of an existing source. In ACE, EPA properly determined that the best system for reducing GHG emission reductions from existing power plants is to improve the plants' efficiency. As EPA recognizes in its Proposal, performance standards—both for new sources under Section 111(b) and for existing sources under Section 111(d)—have always been based on technological or operational measures that can be implemented at individual sources. ACE also properly rejects carbon capture and sequestration (CCS) and co-firing with gas or biomass as BSER, and instead allows states the option of considering those measures in the development of their state plans.

Appropriate Flexibility for States: Peabody supports ACE's approach of providing states greater flexibility on the development of state plans. EPA properly identified a menu of heat rate improvement (HRI) measures to serve as the states' "checklist" of BSER technologies. ACE includes critical flexibility for how states apply BSER at a particular facility, including consideration of useful life and cost. Such flexibility is needed to address the diversity among existing EGUs, which makes nationally applicable and uniform standards infeasible. Under CAA Section 111(d), EPA's role is to establish BSER, but states have the primary responsibility for applying BSER to set performance standards for individual units. EPA's extensions of the deadline for state plans and for EPA action to approve those plans are also appropriate. The proposed 3-year timeline for the submission of state plans will give states needed time to work with EGUs on the BSER "menu" and to develop a plan that best accommodates the specific units in their state.

Proposed Hourly Emissions Test for NSR: EPA's proposed revisions to the NSR program appropriately give states the option to establish a new applicability test to prevent efficiency projects under ACE from triggering NSR permitting requirements. EPA's Proposal for an hourly emissions test under NSR is critical to ensure that HRI measures do not trigger NSR permitting requirements, is well within EPA's statutory authority, and will not undermine the important goals of the NSR program.

Response to Select Issues Raised by EPA in the Proposal

The following comments respond to some of the specific issues on which comment was sought in the Proposal. Given the overlap between many of the questions raised, in some instances we have provided a combined response.

I. Legal Authority for Determination of BSER (Comment C-2)

EPA solicits comment on the legal rationale to support its BSER determination. EPA explains that the BSER determination is based on, in the specific context of limiting GHG emissions from existing EGUs, reading CAA Section 111(a)(1) "as being limited to emission reduction measures that can be applied to or at an individual stationary source." 83 Fed. Reg. 44,746, 44,752 (2018). "That is, such measures must be based on a physical or operational change to a building, structure, facility or installation at that source rather than measures the source's owner or operator can implement at another location." *Id.*

EPA is correct that CAA Section 111(d) only authorizes EPA to establish BSER based on measures that can be employed within a source's fenceline. EPA properly determined that the best system for reducing GHG emission reductions from existing power plants is to improve the efficiency of those power plants. This interpretation is correct not only for the reasons stated by EPA in the Proposal—plain language, legislative history, prior agency practice and statutory context—but also because a broader interpretation allowing "outside the fence" regulations would create significant constitutional concerns that must be avoided. Peabody previously outlined the legal problems with the original CPP rulemaking's "outside the fenceline" approach in its comments on the CPP repeal proposal. Peabody hereby incorporates those prior comments set forth in EPA Docket ID No. EPA-HQ-OAR-2017-0355-21005.

CAA Section 111(d) mandates a source-specific approach. Section 111 defines "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]." 42 U.S.C. § 7411(a)(1). Section 111(d) requires EPA to develop "procedure[s]" for states to promulgate these standards "for . . . existing source[s]." *Id*. § 7411(d)(1) (emphasis added). Section 111 further defines a "stationary source" as "any building, structure, facility, or installation." *Id*. § 7411(a)(3). The statutory text makes clear that the standards of performance must be established at an individual building or facility and, therefore, must be limited to the types of actions that can be implemented directly by an existing source. Indeed, Section 111(d)'s requirement that EPA allow states to adjust compliance obligations in order to consider the remaining useful life of an existing source is a clear indication that Congress intended compliance *at the source*. Thus, Section 111(d)'s unambiguous text authorizes regulation only at the source level.

This approach is echoed by EPA regulations. EPA's regulations implementing Section 111(d) confirm this "inside the fence" focus, defining an "emission guideline" as reflecting the BSER "for designated facilities." 40 C.F.R. § 60.21(e). A "designated facility" is "an existing facility" which would be subject to New Source Performance Standards (NSPS) if it were a new source. *Id*. § 60.21(b).

EPA's past practice further confirms that the BSER analysis and emissions guidelines established under Section 111(d) must be source-based and rely solely on actions that can be undertaken on site by the affected facility. In every instance when EPA established emissions guidelines under Section 111(d) prior to the CPP, it defined the BSER standard as systems for emission reduction that can be implemented onsite.[1] ACE will reinstate the long-standing

[1] *See* Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, 61 Fed. Reg. 9,905, 9,914 (1996) (guideline based on "[p]roperly operated gas collection and control systems achieving 98 percent emission reduction"); Notice, Primary Aluminum Plants; Availability of Final Guideline Document, 45 Fed. Reg. 26,294, 26,294 (1980) (control technologies); Notice, Kraft Pulp Mills; Final Guideline Document; Availability, 44 Fed. Reg. 29,828, 29,829 (1979) (control technologies); Emission Guideline for Sulfuric Acid Mist, 42 Fed. Reg. 55,796, 55,797 (1977) (control technologies); Final

understanding that the "best system of emission reduction" for a source can be based only on measures that can be applied to or at that source.

Accordingly, EPA's definition of BSER as HRI measures is fully supported by the law and by historical Agency practice prior to the CPP, and EPA must adhere to these limitations in the final rule. Peabody agrees with the analysis and justification for this revised BSER approach as set forth in the proposed rule. The BSER identified in ACE is consistent with EPA's authority under Section 111(d) and properly limits BSER to measures that are technically feasible and appropriate for coal-fired power plants. The HRI measures identified as BSER can be a cost-effective, achievable, practical way of reducing emissions that will minimize disruptions to electricity generation.

II. Carbon Capture and Storage (Comment C-12)

Peabody agrees with EPA's proposal not to include CCS as BSER for existing coal-fired EGUs because CCS is significantly more expensive than alternative options for reducing emissions and may not be a viable option for many facilities. 83 Fed. Reg. at 44,761. While the passage of the FUTURE Act has resulted in renewed momentum for CCS in the United States, the remaining financial and regulatory hurdles underscore that CCS is not adequately demonstrated at this time and should not be designated as BSER. However, EPA should allow CCS as a compliance option that states may consider for their state plans.

Peabody actively supports the development of CCS technology and improving the applicable regulatory frameworks. In 2015, Peabody's President and Chief Executive Officer Glenn Kellow chaired a National Coal Council report that called for enabling carbon capture to achieve policy parity with other low-carbon options, such as solar and wind. National Coal Council, *Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies* (Nov. 2015).[2] The report outlined what is needed to propel progress for CCS technologies. Key recommendations included a first-of-its-kind regulatory blueprint to remove barriers to construction and development of CCS projects, as well as a call for communication and collaboration among global policymakers.

Peabody also is a proud member of the broad coalition that worked to advance the FUTURE Act, which reformed the existing 45Q tax credit that was created to incentivize CCS deployment. As part of the Bipartisan Budget Act of 2018, Congress significantly increased and extended the Section 45Q tax credit for carbon sequestration. The bipartisan support to enhance the 45Q credit underscores the importance of CCS as a tool for cost efficient carbon emission reductions.

While tax credits have been a successful approach to incentivizing energy technologies in the United States, including for wind and solar energy, they are not a complete fix to the

Guideline Document Availability, Phosphate Fertilizer Plants, 42 Fed. Reg. 12,022, 12,022 (1977) (using spray-crossflow packed bed scrubbers as the "principal control device" for phosphate fertilizer plants).

[2] *Available at* http://www.nationalcoalcouncil.org/studies/2015/Leveling-the-Playing-Field-for-Low-Carbon-Coal-Fall-2015.pdf.

obstacles that CCS development faces. First, not all power companies pay enough in taxes to directly utilize the tax credits that would be generated. Second, the tax credits from the reformed 45Q are not available upfront—they are generated over time as the CO_2 is stored. This means that financing will likely be required for CCS projects' capital costs. In addition, uncertainty remains around storage rules. For these reasons, 45Q reform will likely not trigger a surge of CCS projects in the power sector.

Thus, while new economic incentives for carbon capture projects at coal-fueled power plants are in place, we are still in the early stage of the technology deployment for CCS. There are only two large-scale coal-fueled power plants (*i.e.*, over 100 MW_e) operating with CCS technology in the world. Further, design constraints, site-specific limitations, and a lack of proximity to potential geologic storage sites make retrofitting existing sources with CCS technology difficult. EPA therefore properly found that CCS is not adequately demonstrated at this time and should not be designated as BSER. *See* 42 U.S.C. § 7411 (a)(1)(EPA must take cost into account to find that BSER has been "adequately demonstrated"); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973) ("[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly").

EPA should nonetheless be clear in the final rule that CCS is a non-BSER compliance option for states and EGUs. CCS constitutes an "at the source" compliance option because the capture of CO_2 occurs at the facility. CCS technologies are under development and EGU operators should be allowed to receive credit under ACE for the CO_2 reductions that might be achieved by the application of these CCS technologies on existing affected EGUs. Allowing states to permit companies to use CCS for compliance under CAA Section 111(d) could help encourage efforts to adequately demonstrate CCS in the future. Peabody encourages EPA to reaffirm that CCS could be included in an approvable state compliance plan as a potential compliance tool even though it cannot be considered part of BSER.

NSR could also potentially act as a barrier to the implementation of CCS projects that might be undertaken at existing EGUs, if the addition of CO_2 capture equipment and the integration of that equipment with the existing plant were deemed to trigger NSR. EPA should make clear that NSR will not be triggered in such circumstances. As discussed more fully below, the triggering of NSR would subject the source to onerous permitting requirements and lengthy permit procedures. Ensuring that CCS projects do not trigger NSR due to changes in the power plant or potentially small collateral increases of other air pollutants will remove one potentially important regulatory barrier to the implementation of these advanced CO_2 emission control projects. For this reason, Peabody supports EPA's proposal that the NSR hourly test will be applicable for all modifications at EGUs, not just HRI. The adoption of an hourly test will provide greater certainty that the application of CCS and other non-BSER compliance options at a power plant can be pursued without triggering NSR.

III. Source-Specific Compliance Schedules (Comment C-13)

Peabody supports ACE's proposed approach of allowing the states to develop source-specific compliance schedules in their plans. However, the compliance period should start from when the state plan is approved by EPA. Affected sources should not be required to begin implementing the compliance measures in a state plan until the plan is approved and is therefore final. EGUs will need to make investments to implement the HRI upgrades contemplated by ACE, and should not be required to undertake those investments until it is certain that the state plan is final. Therefore, the timeframe for EGU compliance should begin once a state plan is *approved* by EPA, not when it is *submitted* to EPA.

IV. Merits of Differentiating between Gross and Net Heat Rate (Comment C-16)

Peabody supports the use of gross energy output in the CO_2 emission rate calculations as gross output provides the most direct and consistent measurement of CO_2 emissions. Using net energy output would be inconsistent with other rulemakings and challenging for facilities to measure accurately.

The use of gross energy output allows the plant operator to account for electrical, mechanical, and thermal energy use by the plant, giving operators the needed flexibility to design overall systems in the most efficient and economic manner. Gross MWh output is straightforward, simple, consistent, directly measured, and already reported to EPA for other purposes as required by 40 C.F.R. Part 75. Gross generation relies on direct measurements sources currently use, as opposed to indirectly measuring net generation in new ways for many sources. Furthermore, market drivers will continue to ensure that power producers operate efficiently because utilities have a strong incentive to ensure the gap between gross and net output is as small as possible.

By allowing for the incorporation of waste heat and steam as a compliance option (increased gross MWh output with no additional CO_2 emissions), a gross energy output-based standard, which recognizes electrical, mechanical, and thermal energy uses, would allow operators to respond to market drivers and to make choices with respect to the quality of the waste heat and steam they produce, and, thus, likely increase the overall utilization of the energy.

Additionally, many utilities have made significant investments in environmental controls to comply with other regulatory requirements, which has a negative effect on net heat rate due to the parasitic load required for the controls. Net heat rate includes the impact of all emissions control equipment, including potentially CCS. Thus, EPA and states should focus on gross heat rate so as not to punish those plants that have implemented such upgrades and retrofits.

In sum, Peabody supports the use of gross heat rate over net because it is consistent with existing EPA reporting requirements and addresses the parasitic load impacts of air quality control systems.

V. Flexibility for States and Sources on Non-BSER Measures (Comment C-18)

EPA's proposal properly recognizes the leading role of the states in designing compliance plans and provides the flexibility states need. States need flexibility to address the variations in the existing fleet of EGUs, and to create and modify state plans that achieve compliance in an efficient and cost-effective manner. Flexibility in applying the standards to affected units and in defining how compliance is demonstrated also helps owners and operators of affected EGUs to achieve the most cost-effective reductions to help ensure that electricity remains affordable and reliable for all customers.

One of the most important tools for states will be the ability to utilize measures beyond those specifically identified in the Agency's BSER determination. ACE properly affirms states' ability to submit compliance plans that include measures not specifically identified in the BSER determination. The use of these non-BSER options is an important flexibility mechanism that allows states to design compliance plans that reflect the emission reduction opportunities available in each state. The CAA clearly permits sources to use a range of compliance options to achieve emissions standards, even if those options do not represent an element of BSER that is applicable to the entire source category. The final ACE rulemaking should continue to recognize that states have authority to use non-BSER measures in their compliance plans, and should ensure states have maximum flexibility to consider non-BSER compliance options, including CCS.

Towards that end, Peabody supports the inclusion of forest-derived biomass and non-forest biomass (*e.g.*, agricultural, waste stream-derived) for energy production as a non-BSER compliance option for affected units to meet state plan standards under this rule. (**Comments C-20, C-21**). For example, the utilization of a small amount of waste could yield significant emission reductions at an EGU and offer co-benefits to the local community. This is another example of an opportunity to give states and EGUs the greatest number of options for compliance, which Peabody supports.

VI. Emissions Averaging and Trading (Comments C-28 – C-41)

EPA should expressly endorse state authority to grant sources the ability to meet individual standards in a variety of ways, including averaging among units at a facility. Some EGU owners or operators are likely to undertake sufficient HRI measures to provide a substantial compliance margin beyond the CO_2 emission standard itself. In addition to minimizing the risk of enforcement and penalties, exceeding the standard ensures that the EGU will not fall out of compliance due to natural degradation before the unit's next long-term outage opportunity to perform efficiency projects. Allowing states to adopt flexible mechanisms, such as emissions averaging at individual facilities, will aid EGUs in meeting their emission limitation. Such averaging may also provide incentives to improve CO_2 emission rates beyond the standard at certain units. Facilities will thus have an incentive to pursue further HRI upgrades even if they are not required for compliance at a particular unit.

However, Peabody agrees with EPA's proposal not to allow averaging or trading across multiple stationary sources. Inter-facility trading is inconsistent with ACE's source-by-source, "inside the fence" approach. As noted in the Proposal, such inter-facility trading may encourage generation-shifting or shutting down particular sources. EPA should avoid creating such incentives, and therefore should not allow states to include averaging and trading between sources.

VII. Timing Requirements for State Plan Submission (Comment C-52)

Peabody supports EPA's proposal to provide states three years after the publication of the final emission guidelines to submit their plans. This suggested timeframe is necessary for states to fully engage in public and stakeholder consultations, perform required technical and economic analyses, and to comply with state statutory requirements and administrative rulemaking processes. For example, states will need time to perform a plant-by-plant analysis of the BSER menu and to develop and submit a plan for HRI that is achievable for each EGU in their state. The states will also need time to develop appropriate compliance timelines for the EGUs.

VIII. New Source Review

ACE's objective of improving the efficiency of power plants cannot be fully realized without addressing the risks and costs associated with the NSR program. Uncertainty over NSR permitting has been and continues to be a significant deterrent to efficiency modifications to existing EGUs. While the legal theories advanced in these actions may be open to question, projects associated with power plant efficiency have previously been the subject of NSR enforcement actions.[3] If an HRI project triggers NSR, significant time and resources are required to obtain a permit and to implement the permit requirements. These permitting costs would need to be considered by states in reviewing HRI as BSER, and could lead to certain upgrades being deemed too costly for a particular unit. Even if an HRI upgrade ultimately is not found to increase emissions, the process of and uncertainty associated with determining if NSR is triggered can deter HRI implementation. As discussed in detail below, EPA's proposed revisions to the NSR program are critical to ensure that HRI measures, including those proposed as BSER under ACE, do not trigger NSR permitting requirements.

A. NSR permitting is an obstacle to HRI updates at existing EGUs, and ACE heightens the concern (Comments C-65 – C-67).

NSR permitting is required for "any physical change in, or change in the method of operation of, a stationary source which *increases the amount of any air pollutant emitted by such source* or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4) (emphasis added). But the CAA does not specify by how much a physical or

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[3] For example, UARG identified over 400 projects (equipment upgrades) that can improve efficiency that, since 1999, EPA and citizen plaintiffs have targeted for NSR enforcement. Comments of UARG on the EPA Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: Proposed Rule, Dock. ID No. EPA-HQ-OAR-2013-0602-22768 at Att. A (Dec. 1, 2014). In addition, UARG identified over 600 *other* types of projects, such as like-kind replacement of worn equipment, that were also targeted for NSR enforcement. *Id.* at Att. B.

operational change must increase emissions to constitute a permit-requiring "modification." *See Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2435 (2014) (*UARG*). Instead, EPA is given discretion to determine whether a modification triggers NSR through implementing regulations.

Under current regulations, a major stationary source triggers NSR permitting requirements when it undertakes a physical or operational change that would result in (1) a significant emission increase at the emissions unit, and (2) a significant net emissions increase at the source (*i.e.*, a source-wide "netting" analysis that considers emission increases and decreases occurring at the source during a contemporaneous period). *See* 40 C.F.R. § 52.21(b)(2)(i). EPA regulations define what emissions rate constitutes "significant" for NSR pollutants on an *annual* tonnage basis. *See* 40 C.F.R. § 52.21(b)(23).

If a physical or operational change triggers NSR requirements, the source must obtain a permit prior to making the change and implement specific emission control requirements. The initial process to determine whether a change triggers NSR is costly and time intensive, even if the upgrade ultimately is found not to increase emissions. Obtaining a NSR permit is an even more costly and lengthy process that significantly delays, if not entirely deters, modifications to existing EGUs. In some cases, this has resulted in costly and protracted litigation, and expensive new emission control requirements, both of which result in substantial costs and delays. In addition, the need to obtain offsets in non-attainment NSR makes the permit process even more expensive, and sometimes impossible where the availability of offsets is limited. The burdens of NSR permitting are significant and often make implementing HRI and other efficiency measures cost prohibitive. *See UARG* at 2443 (describing the "numerous and costly requirements" imposed by PSD on those sources that are required to apply for permits).

Because the NSR program currently regulates annual emissions rather than emission rates, there is uncertainty whether and when efficiency improvements trigger NSR. By reducing the amount of fuel required per unit of electricity output, efficiency improvements lower emission rates. But increasing efficiency also lowers fuel costs, thereby reducing the unit's marginal cost of generating electricity. Efficiency improvements may therefore lead to higher annual emissions if units operate at a higher capacity factor after the modification. Inconsistent state and judicial interpretations of NSR have heightened the uncertainty concerning NSR's application to projects undertaken to maintain or improve reliability, availability, and efficiency.[4]

Further, under current interpretations, even if a facility undertakes a pre-construction emissions projection and determines they will be below significance levels for purposes of NSR, this determination does not protect the facility from enforcement if projections turn out to be

[4] "If an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *United States v. Duke Energy Corp.*, No. 1:00CV1262, 2010 WL 3023517, at *5 (M.D.N.C. 2010); *see also Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 577-78 (2007) (*Duke II*) (noting regulatory provision that requires assessing number of hours the unit is or probably will be running); *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir. 2006) (revitalizing a plant to operate more hours may trigger PSD obligations); *United States v. Ohio Edison Co.*, 276 F.Supp.2d 829, 834-35 (S.D. Ohio 2003) (finding PSD liability for projects that were "intended to result in increased hours of operation as a result of a reduction in . . . forced outages").

inaccurate. Moreover, even if a state or EPA decided not to pursue enforcement in such circumstances, the facility could still be subject to a potential citizen suit under the Act. Due to the significant penalties and injunctive relief available for NSR enforcement, utilities are often deterred from implementing efficiency upgrades at a facility even if they believe NSR should not be triggered.[5] Indeed, the National Coal Council reported that NSR is one of the largest barriers to heat rate improvement projects:

> The [NSR] permitting program unintentionally limits investments in efficiency. Some actions to improve efficiency at an existing power plant could lead to a designation of the change as a "major modification" subjecting the unit to NSR permitting requirements. These requirements usually entail additional environmental expenditures (that can reduce efficiency), as well as delays associated with processing the permit. In general, if a plant owner expects that an efficiency improvement would lead to such a designation, the efficiency project will not be pursued as the resulting permitting process would be extensive and the compliance requirements would be onerous and likely too stringent to be practicable.

National Coal Council, *Reliable & Resilient: The Value of Our Existing Coal Fleet* (May 2014).[6]

As discussed above, EPA identified HRI as the BSER for existing fossil-fueled steam generating EGUs and laid out the HRI measures to serve as the proposed technologies, equipment upgrades, and best operating and maintenance practices for limiting CO_2 emissions from affected EGUs. Under Section 111(d)(1), states may use the information provided by EPA on the "degree of emission limitation achievable through application of the [BSER]" to establish standards of performance for affected EGUs included in a state's plan. 42 U.S.C. § 7411(d)(1). In addition, ACE notes that states are "expected" to evaluate each of the listed HRI measures in establishing a standard of performance for any particular source. 83 Fed. Reg. at 44,756. States also will need to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies. While it is then within the state's discretion to take certain factors into consideration when determining how the standard of performance should be applied, EPA's identification of HRI as the BSER mandates the consideration of a range of HRI upgrades at existing EGUs.

HRI will lower a unit's emissions rate by reducing the fuel required per unit of electricity output. But, as explained above, increasing efficiency also lowers plants' total fuel costs, thereby reducing the unit's marginal cost of generating electricity. HRI may therefore lead to higher annual emissions because units could operate at a higher capacity factor after the modification. Because the NSR program currently regulates annual emissions rather than

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[5] The risk of triggering NSR is further heightened by market conditions that could cause units with lower marginal cost to run more and therefore lead to higher annual emissions. There is uncertainty with respect to future natural gas prices, especially with pending LNG export facilities coming online in the near future. Increased natural gas prices could increase the use of coal plants without the ability of utilities to fully predict that and without a way to recoup the cost of efficiency upgrades if NSR is triggered.

[6] *Available at* http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf.

emission rates, efficiency improvements, including HRI, can trigger NSR. Moreover, many EGUs have already implemented efficiency upgrades that clearly do not trigger NSR, but have refrained from making those improvements with a higher risk of triggering NSR. If EGUs are required under ACE to further reduce emissions through HRI, they will need to reach for upgrades that are more likely, or at least perceived to be more likely, to be deemed an NSR trigger. Thus, EPA is correct that ACE makes the case for NSR reform even more compelling.

EPA is proposing to address this concern by incorporating an hourly test into the current NSR approach to determine whether a "modification" "increases" the amount of air pollutant emitted by existing EGUs. Under the proposed test:

> For a major modification to occur, under Step 1, a physical change or change in the method of operation must occur. If there is a physical change or change in method of operation, under Step 2, that change must result in an hourly emissions increase at the existing EGU. If a post-change hourly emissions increase is projected, a source must then proceed to determine whether there is also a significant emissions increase and a significant net emissions increase. In such cases, under Step 3, the owner/operator would determine whether an emissions increase would occur using the actual-to-projected-actual annual emissions test as provided in the current regulations. There would be no conversion from annual to hourly emissions. Finally, in Step 4, as in the current regulations, if a significant emissions increase is projected to occur, the source would still not be subject to major NSR unless there was a determination that a significant net emissions increase would occur.

83 Fed. Reg. at 44,780-81.

Under the hourly test, it would be irrelevant whether an EGU modification would increase annual emissions (tons per year) if the modification did not also increase the plant's hourly emissions rate (pounds per hour) beyond the regulatory threshold. Plants would therefore be able to implement HRI to improve efficiency and reduce emissions, without facing the burden of NSR, and continue to operate economically even if market conditions change and the plant operates more. The adoption of this hourly test will reduce uncertainty regarding NSR permitting triggers, promote efficiency upgrades to power plants, and help reduce sector-wide emissions.

Peabody supports EPA's proposal to amend the NSR regulations to include an hourly emissions test for EGUs in order to reduce the potential for affected sources triggering NSR when implementing HRI projects to comply with state performance standards. The adoption of the hourly test is necessary so that EGUs that implement efficiency improvement projects, including HRI, are not penalized by having to undergo costly NSR. The proposal is also fully consistent with the CAA. "The purpose of the NSR program is to protect public health and welfare, as well as national parks and wilderness areas, as new sources of air pollution are built and when existing sources are modified in a way that significantly increases air pollutant emissions." EPA, *New Source Review Report to the President*, 3 (June 2002) (New Source

Review Report). Accordingly, the goal of NSR is not to deter efficiency projects and upgrades. The proposed hourly test is a specific and narrow fix—adding one step to the existing three part test that would not otherwise alter the NSR program. The adoption of the hourly test will help return the NSR program to its original intent, and remove uncertainty and unintended disincentives for operators to install upgrades that could improve efficiency and lower emissions output.

B. The case law supports EPA's authority to adopt the hourly test (Comment C-68).

As noted above, a source undertakes a "modification" triggering NSR when "any physical change . . . or change in the method of operation . . . increases the amount of any air pollutant emitted by such source" occurs. 42 U.S.C. § 7411(a)(4). ACE incorporates an hourly test into the current NSR approach to determine whether a "*modification*" "*increases*" the amount of air pollutant emitted by the source. The hourly emissions increase test in ACE is similar to the hourly rate test proposed by EPA in 2005 and then supplemented in 2007 but never finalized. The case law from the litigation that preceded and followed the EPA's 2005 proposal confirms that EPA has discretion to establish the method of calculating emissions increases, including by way of an hourly test.

In 2002, EPA reviewed the NSR program and issued a report that concluded that "[as] applied to existing power plants and refineries . . . the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution." *New Source Review Report* at 3.

EPA subsequently promulgated regulations that implemented several of the recommendations in the New Source Review Report. Among other things, EPA altered the method for measuring past (or baseline) emissions used to determine whether a change "increases" emissions. *New York v. EPA*, 413 F.3d 3, 17 (D.C. Cir. 2005) (*New York*). Numerous petitioners challenged EPA's 2002 rule in the D.C. Circuit. The court found that the CAA grants EPA discretion to establish the method of calculating emissions increases and concluded that the challenges failed "to overcome the presumption of validity afforded to EPA regulations under the CAA." *Id*. The court stated that "[w]hile the CAA defines a 'modification' as any physical or operational change that 'increases' emissions, it is silent on how to calculate such 'increases' in emissions." *Id*. (citing 42 U.S.C. § 7411(a)(4)). Further, the court found that:

> The Supreme Court recognized in *Chevron* that, in enacting the NSR program, 'Congress sought to accommodate the conflict between the economic interest in permitting capital improvements to continue and the environmental interest in improving air quality,' and delegated the responsibility of balancing those interests to EPA. Different interpretations of the term 'increases' may have different environmental and economic consequences, and *in administering the NSR program and filling in the gaps left by Congress, EPA has the authority to*

> *choose an interpretation that balances those consequences*. Furthermore, as there is no question that the NSR program is technical and complex, *EPA may properly rely on its extensive experience and expertise in administering the program*."

Id. at 23-24 (citing *Chevron U.S.A., Inc. v. Natural Res. Def. Council*, 467 U.S. 837 (1984)) (emphasis added). The court emphasized that "[i]n enacting the NSR program, Congress did not specify how to calculate 'increases' in emissions, leaving EPA to fill in that gap while balancing the economic and environmental goals of the statute." *Id.* at 27.

The D.C. Circuit also upheld EPA's definition of "modification" for NSR purposes even though it differed from its definition for NSPS purposes. *Id*. at 19-20.[7] The court stated that "[g]iven the two quite differently worded regulatory definitions of 'modification' within the NSPS program at the time of the 1977 amendments, it would take a rather pointed indication from Congress to support the idea that it expressly adopted one of them for NSR. No such indication exists." *Id*. at 20. However, the court left open the question of "whether Congress intended to require that EPA use identical regulatory definitions of modification across the NSPS and NSR programs." *Id*. The D.C. Circuit's decision on this issue was contrary to the Fourth Circuit's decision in *United States v. Duke Energy Corp.*, 411 F.3d 539 (4th Cir. 2005) (*Duke I*), which held that the NSPS and PSD programs must have a uniform emissions test.[8]

Relying on the Fourth Circuit's decision in *Duke I*, EPA published a notice of proposed rulemaking in October 2005 that proposed to replace the NSR program's annual emissions test with an hourly test and thereby make uniform the emissions tests used for NSR and NSPS. 70 Fed. Reg. 61,081 (2005). But in 2007, the Supreme Court held that there was "no effectively irrebuttable presumption that the same defined term in different provisions of the same statute must be interpreted identically. Context counts." *Duke II* at 575-76 (citations omitted).

Based, at least in part, on *Duke II*, EPA decided it was unnecessary to pursue the proposed hourly test. However, it is important to recognize that the case law discussed above *preserved* EPA's authority to adopt such a test. First, the *New York* court found that the CAA grants EPA discretion to establish the method of calculating emissions increases. Second, the Supreme Court held that there was no statutory requirement that "modification" be defined the same for NSPS and NSR purposes, but preserved EPA's discretion to do so (*i.e.*, based on hourly emissions). As the D.C. Circuit's decision in *New York* made clear: "Congress did not specify how to calculate 'increases' in emissions, leaving EPA to fill in that gap while balancing the

[7] The PSD provisions require a permit before a "major emitting facility" can be "constructed," *id*. at § 7475(a), and define such "construction" to include a "modification (as defined in [NSPS])," *id*. at § 7479(2)(C). Despite the definitional parallels, EPA interpreted "modification" differently for PSD than for NSPS. The NSPS regulations required a source to use BACT when a modification increases the discharge of pollutants measured by an hourly test, but the PSD regulations required NSR for a modification only when it is a major one and only when it would increase the actual annual emissions of a pollutant.

[8] In 2006 the Seventh Circuit in a different enforcement case, *Cinergy*, followed the D.C. Circuit's lead in *New York*, stating that "[t]he same word can mean different things in the same statute" and, consequently, there can be different tests for emissions increases in NSPS and PSD. 458 F.3d at 710.

economic and environmental goals of the statute." *New York* at 27. Thus, the case law supports EPA's discretion to adopt an hourly test.

C. A maximum achieved hourly emission test is preferable over a maximum achievable hourly emissions test (Comments C-63, C-64).

As explained above, major stationary sources undertaking modifications must obtain *pre*-construction permits. Consequently, in order to determine whether a proposed change would cause a significant emissions increase triggering NSR, an operator must compare pre-change emissions of a project to projected post-change emissions. *See e.g.*, *Ohio Edison*, 276 F.Supp.2d at 865 ("[T]he [CAA] clearly requires that this calculation be made by the electric utility before the physical change is actually undertaken."). Peabody supports EPA's proposal to implement a test based on maximum achieved hourly emission because such a test would more accurately reflect the difference between actual modifications to the EGUs and changes that merely allow the EGU to run at its designed capacity, and would remove a major disincentive for operators to implement efficiency upgrades.

EPA is proposing the following three alternatives for assessing an hourly emissions increase under Step 2 of the NSR applicability analysis:

> Alternative 1 – Comparing the pre-change maximum *actual* hourly emissions rate in pounds per hour (lb/hr) to a projection of the post-change maximum *actual* hourly emissions rate in lb/hr, considering a period of 365 consecutive days within the 5 years preceding the start of construction;
>
> Alternative 2 – Comparing the pre-change maximum *actual* hourly emissions rate in lb/hr to a projection of the post-change maximum *actual* hourly emissions rate in lb/hr, considering the highest emission rate (lb/hr) actually achieved at any time within the 5 years preceding the start of construction; or
>
> Alternative 3 – Comparing the maximum *achievable* hourly emissions rate before the change to the maximum *achievable* hourly emissions rate after the change.

83 Fed. Reg. at 44,798-803.

Each of these alternatives would have important practical consequences. A unit's maximum design capacity is measured by the amount of emissions that a unit could emit if it was running at full design capacity all day every day. However, utilities do not usually run at full capacity all day every day. Under the current emissions analysis, if a plant that is not running at full capacity pre-change undergoes repairs or improvements that enable it to operate at closer to full capacity, and therefore potentially emit more pollution, the project could be subject to NSR, *even though the unit's maximum capacity might not have increased*. EPA's proposed alternatives would ensure that the test for triggering NSR reflects the differences in emissions based on actual modifications to the EGUs as opposed to changes that merely allow the EGU to run at its designed capacity. Such a test would therefore remove a major disincentive for operators to implement efficiency upgrades, such as HRI, because of the burden of potential NSR review.

EPA has flexibility under the CAA to implement any of the proposed alternatives. EPA regulations do not specify "an exact methodology to be used to determine future emissions," and "specifically allow the EPA to use a broad number of factors in determining what post-project emissions will be." *Duke Energy Corp.*, 2010 WL 3023517 at *5-6.[9]

While EPA has discretion to adopt any of the three proposed alternatives, Peabody recommends the adoption of an achieved emissions test like Alternative 1 or 2. An achieved emissions test compares a unit's pre-change achieved emissions to the unit's projected post-change achieved emissions and thus is more similar to the current actual-to-projected-actual test.[10] Peabody believes that an achieved emissions test is therefore preferable over an achievable emissions test. EPA should design an achieved emissions test to ensure that the measurement on which the hourly test is based is not an outlier that could be due to startup, shutdown, an emissions monitor malfunction or some other cause that is not indicative of the typical hourly rate at the EGU.

D. The hourly test should be applicable to all EGUs (Comments C-61, C-62).

EPA is proposing that the hourly test described above would apply to all physical and operational changes at an EGU. Peabody supports EPA's proposal to make the hourly test applicable to all modifications to existing EGUs, as this will help remove disincentives for existing units to upgrade based on uncertainty regarding NSR triggers. The hourly test should be applicable to all efficiency upgrades, and other modifications such as adding CCS, not just those required by state plans under ACE. Projects that improve heat rate are frequently undertaken by the utility industry as routine maintenance, and can also be required by some RTOs/ISOs and state PUCs as a means to keep fuel cost low. If plant X is adopting HRI because of ACE, and plant Y is adopting HRI voluntarily or due to a state PUC directive, they should be subject to the same test as to whether NSR is triggered.

E. NSR reform and ACE should be addressed concurrently (Comment C-71).

As previously discussed, NSR reform is critical to remove uncertainty and disincentives for EGU upgrades. Peabody agrees that NSR program flexibility "takes on added significance" with ACE due to the HRI projects that are expected to be undertaken. ACE heightens the need for NSR reform because EPA's identification of HRI as the BSER effectively guarantees that state plans will mandate HRI upgrades for some EGUs. As a result, the NSR revision is a critical element of ACE, and both should be finalized concurrently.

[9] EPA has previously adopted an "achievable" test to determine whether a modification is subject to NSPS. *See* 40 C.F.R. § 60.14(h) ("No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions *achievable* at that unit during the 5 years prior to the change.") (emphasis added).

[10] The current test, called the "actual-to-future-actual" or "actual-to-projected-actual" test, requires operators to project the source's actual, instead of potential, emissions after the change. *See* 57 Fed. Reg. 32,314 (1992).

Peabody also agrees that EPA should include a standard severability provision in ACE, so that if any provisions are struck down, it will not necessitate vacation of the entire ACE rule.

F. States should consider the cost of NSR compliance in the BSER analysis under Section 111(d) (Comment C-59).

If EPA is unable to finalize revisions to NSR that would prevent ACE implementation from triggering NSR, EPA should require that states include the costs of NSR compliance in assessing the feasibility of BSER. As previously discussed, under the current NSR regulations, there is a great deal of uncertainty as to whether and when EGUs will be able to implement the HRI identified as BSER by ACE without triggering NSR. To the extent any HRI project could trigger NSR, the need to install controls reflecting best available control technology or the lowest achievable emission rate under NSR would likely render the project exorbitantly costly. In addition, the delays involved with NSR permitting could prevent the HRI project from being available in time to meet the requirements adopted by the state under ACE. Accordingly, such projects would not be the basis for a Section 111(d) standard of performance. As a result, without the ability to factor in NSR permitting costs, more plants could be forced to close in states that set stricter standards of performance.

Therefore, states must consider NSR compliance costs to ensure the full costs of HRI are considered. The Section 111 procedures should authorize states to take into account the additional costs that would result from particular efficiency projects triggering NSR and therefore provide the technical basis for the disqualification of those projects in setting the performance standards for particular EGUs. Therefore, Peabody agrees with EPA's determination that "it is appropriate for states to consider the potential that the application of HRI may trigger NSR for some sources, and associated NSR requirements could ultimately impact the cost of HRI and the way the state applies standards to an affected EGU." 83 Fed. Reg. at 44,767.

Peabody also shares EPA's concerns that it would be difficult for states to predict the expected NSR permitting costs, as well as handle the significant increase in NSR permit applications, if the hourly test is not adopted. As EPA notes, "permitting requirements are case-by-case determinations and can therefore vary significantly due to a number of factors, including how well the source is already controlled, the emissions from nearby sources and their contribution to air quality concerns, whether the source is located in an attainment or nonattainment area, and the potential for the air permit to trigger other requirements (*e.g.*, Endangered Species Act, National Historic Preservation Act)." *Id.* "The case-by-case nature of the NSR program can lead to uncertainty for a state that is creating its 111(d) plan and wanting to ensure that the plan fully appreciates the projected compliance costs for its affected EGUs." *Id.*

Moreover, the implementation of HRI projects under ACE could lead to a great influx in NSR permit applications that states may not have the resources to handle. The significant burdens of NSR permitting for regulated units and the states would undermine the implementation of ACE by overwhelming state regulators and delaying, or rendering impracticable, many HRI upgrades. *See UARG* at 2443 (describing the "numerous and costly requirements" imposed on those sources that are required to apply for permits, and on states that "must grant or deny a permit within a year, during which time it must hold a public hearing on the application"). The difficulty of states being able to "factor-in" potential NSR cost and plan for the influx of NSR permit applications thus underscores the need for the adoption of the hourly emissions test.

Conclusion

Thank you for the opportunity to provide these comments.

Respectfully,

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