The National Rural Electric Cooperative Association

Comments on
Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations; Revisions to New Source Review Program

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I. SUMMARY

On behalf of America's Electric Cooperatives, the National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to submit these comments on the Environmental Protection Agency's (EPA's) proposed emission guidelines for greenhouse gas emissions from existing electric utility generating units, the ACE proposal. Although the electric cooperatives support and encourage renewable generation, they nonetheless have significant interests in coal-fired generation due in large part to earlier federally mandated requirements essentially forcing coal-fired generating facilities (EGUs) as new generation sources at a time when cooperatives faced the need to construct much needed new generation.

Generally, NRECA believes the ACE proposal is consistent with the statutory provisions in Section 111 of the Clean Air Act (CAA) including the limitations on EPA's authority to regulate existing coal-fired EGUs. Unlike the Clean Power Plan that would have required many of these units to significantly reduce generation or shut down, this proposal appropriately confines the requirements to what can be achieved "inside the fence line." This proposal also appropriately recognizes the important statutory role the states have in ultimately determining each individual EGU compliance obligation based on unit specific factors considering EPA general guidance and determination of the best system of emission reduction (BSER).

NRECA supports EPA's determination of BSER as heat rate improvements (HRI), or unit efficiency improvements. NRECA conferred with technical consultants Black & Veatch that have high expertise with coal-fired EGU technical designs and operations, and the results of this consultation support NRECA's belief that the list of candidate technologies for HRI that makeup BSER is reasonable. But as emphasized in these comments, both EPA in approving state plans and the states in the determination of unit performance standards must recognize that the application of BSER candidate technologies on a unit basis requires consideration of many unit specific factors by the state in making a unit specific performance standard determination.

The proposal's insistence on requiring a single metric for the performance standard in terms of mass CO_2 per MWh is not required by the statute and is otherwise ill advised. As detailed later, there are good reasons to allow an alternative metric in terms of mass CO_2 per unit of time including facilitating compliance demonstration and allowing unit operational flexibility. Further, unit compliance with either performance standard metric should be sufficient.

The proposed new source review (NSR) changes are long overdue and should be finalized even without Section 111 considerations. Specifically, alternative 2 that includes the achieved to achieved (pre-change emissions to post-change emissions) test is the best of the three proposed alternatives. However, a "causation" test needs to be added, so that an increase in post-change emissions must be "caused" by the "change" for an NSR violation to occur.

The proposal does not include regulation of natural gas-fired combustion turbine units and does not offer any supporting documentation to this end. If EPA should decide to propose a Section 111(d) regulation for these units, it would need to be done through a separate notice and comment rulemaking that includes technical data and rationale necessary to evaluate the proposal and issue a final decision.

The proposal correctly excludes natural gas co-firing at coal-fired EGUs as a BSER menu HRI candidate. Simply stated natural gas capabilities do not exist at many existing coal-fired EGU sites. Additionally, requiring natural gas co-firing would "redefine the source" and thus requiring it would not be not legally permissible as detailed later.

Lastly, we encourage EPA to consider several changes in the state guidelines in Subpart UUUUa that would clarify and facilitate the rule's implementation. As proposed the general guidelines require at least initial compliance in the form of legally enforceable increments of progress 24 months from plan submittal. Without a federally approved plan the utility may not have reasonable certainty regarding unit obligations. Accordingly, to address this uncertainty, the state guidelines should specify that time for compliance including requiring enforceable increments of progress should not begin until the state plan is approved by the Administrator or a federal plan is promulgated, whichever is later. Moreover the 24-month window is too short. Instead the state guidelines should allow 36 months from plan approval.

II. INTRODUCTION

The National Rural Electric Cooperative Association ("NRECA") appreciates the opportunity to comment on EPA's proposed Affordable Clean Energy rule (ACE), formally titled "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program," 83 Fed. Reg. 44746 (Aug. 31, 2018) ("the Proposed Rule").

NRECA is the national service organization for America's Electric Cooperatives. The nation's member-owned, not-for-profit electric cooperatives comprise a unique sector of the electric utility industry. Due to their size and structure, rural electric cooperatives face special challenges in adapting their operations to meet federal and state emissions restrictions. Those circumstances detailed herein present a unique and valuable perspective on the nature, scope and compliance challenges cooperatives face with any new guidelines EPA might adopt concerning greenhouse gas emissions from existing electric generating units ("EGUs").

NRECA represents the interests of the nation's nearly 900 rural electric utilities, that have the responsibility for "keeping the lights on" for more than 42 million people across 47 states and over 65% of the United States land mass in the lower 48 states. The electric cooperatives collectively serve all or part of 88% of the nation's counties and 13% of the nation's electric customers while distributing approximately 12% of all electricity sold in the United States.

NRECA's member cooperatives include 63 generation and transmission cooperatives ("G&Ts") and 833 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. G&Ts generate and transmit power to nearly 80% of the distribution cooperatives, which in turn provide power directly to end-of-the-line consumer-owners. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. NRECA members account for about 5% of national generation. On net, they generate approximately 50% of the electric energy they sell, purchasing the remaining 50% from non-NRECA members. All but three of NRECA's member cooperatives are "small business entities" as defined by the Small Business Administration. G&Ts and distribution cooperatives share responsibility for serving their members by providing safe, reliable, and affordable electric service.

Electric cooperatives power communities and empower their residents to improve their quality of life. Affordable electricity is the lifeblood of America's economy. For 75 years, electric cooperatives have proudly shouldered the responsibility of bringing electricity to rural parts of this country. Because of their critical role in providing affordable, reliable, and universally accessible electric service, electric cooperatives are vital to the economic health of the communities they serve.

Many consumers in rural communities are less affluent than those in other parts of the country. In 2015, the median household income for electric cooperative consumers was 11% below the national average. That figure is unsurprising, given that electric cooperatives serve 92% of persistent poverty counties (364 of 395) in the United States. Many of these economically disadvantaged customers live in areas with harsh winters and without access to natural gas. Most other heating alternatives, like propane and heating oil, are comparatively expensive. Many cooperative customers thus depend on cooperative-generated electricity for warmth during the coldest months of the year. Especially because many rural households lack viable heating alternatives, it is vitally important to these households that electric rates remain reasonable and affordable and that electric supplies remain reliable.

Compounding the challenges for NRECA's members is the fact that the parts of the country they serve are often primarily residential and sparsely-populated. Those characteristics make it comparatively more expensive per electric consumer and provide less revenue per consumer for rural electric cooperative electricity providers as compared to those in other utility sectors, which usually serve more compact, industrialized, and densely-populated areas. Data from the United States Energy Information Administration ("EIA") show that rural electric cooperatives serve an average of 8 consumers per mile of transmission line and collect annual revenue of approximately $19,000 per mile of line. In other utility sectors, the averages are 32 customers and $79,000 in annual revenue per mile of line. Due to those geographically-driven differences, 64% of rural electric cooperative members pay higher residential electric rates than do the customers of neighboring electric utilities. Higher rates impede the economic recovery of rural communities and can even challenge their viability. That makes it especially important for electric cooperatives to keep their electric rates affordable and avoid unnecessary rate increases.

Low population density affects not only the costs of providing electricity, but also the demand for it. In this respect, rural Americans are uniquely vulnerable to rising electricity costs. For instance, in America's rural expanses, people typically do not live in closely-confined houses or apartments, but in detached, single-unit homes that endure significant exposure to the elements. More than 14% of cooperative consumers live in manufactured housing, which is often energy-inefficient. The national figure, by comparison, is 6%. For those reasons, among others, the average household served by electric cooperatives uses 1,128 kWh of electricity each month, significantly more than the 825kWh monthly average for households served by investor-owned utilities ("IOUs"), or the 902 kWh monthly average for households served by municipal-owned utilities ("MOUs").

In sum, it is the special province of rural electric cooperatives to serve areas: (1) where it is especially costly to supply electricity mainly because the number of consumers per distribution line mile is extraordinarily low; (2) where aggregate demand for electricity per line mile is comparatively low; (3) where the average resident needs and consumes more electricity than nonrural residents making the need for affordable rates paramount; and (4) where many of the nation's poorest citizens live who can ill afford unaffordable electric rates . For decades, NRECA's member cooperatives have met those challenges head-on, with remarkable success. Today, cooperatives continue to play a vital role in life and development in rural communities across the country, despite the obstacles they face in keeping rates reasonable and electricity supply reliable.

NRECA's members are part of an American energy sector that, on its own, is already making substantial progress in reducing CO_2 emissions. According to EIA, energy-related CO_2 emissions decreased by 47 million metric tons ("MMmt") just in 2017, even as real gross domestic product increased by 2.3%.[1] The decline in carbon emissions is attributable to factors such as a 1.1% decline in the intensity of the energy supply (CO_2/Btu), a 2% decline in energy intensity (Btu/GDP) , and a 3.1% decline in the overall carbon intensity of the economy (CO_2/GDP).[2] The figures from last year are not anomalies. Emissions have declined in seven of the last ten years, so that energy-related CO_2 emissions in 2017 were 849 MMmt below 2005 levels — a 14% decrease.[3]

Many of NRECA's member cooperatives are at the forefront of the movement to reduce CO_2 emissions by, for example, investing in renewable energy sources and energy efficiency measures. More than 95% of electric cooperatives provide electricity

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[1] EIA, U.S. Energy-Related Carbon Dioxide Emissions, 2017, at 4 (Sept. 25, 2018), https://www.eia.gov/environment/emissions/carbon/pdf/2017_co2analysis.pdf .

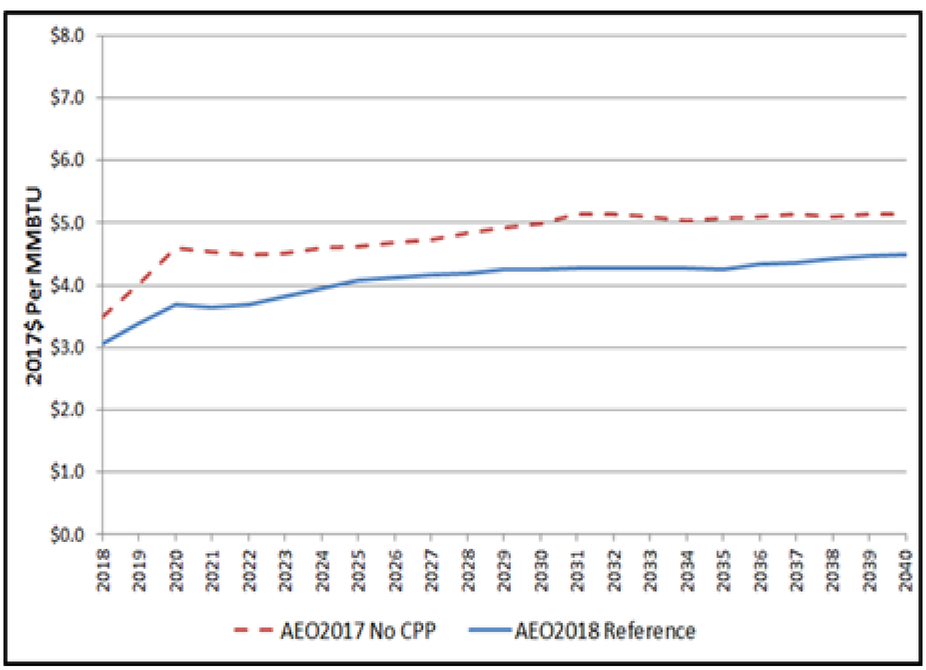
[2] *Id.*

[3] *Id.*

generated from renewable sources. And 82% of cooperatives offer their members some type of energy efficiency program, including rebates for efficient appliances and other incentives. Initiatives like those are among the reasons why, as EPA's proposal notes with respect to ***Comment C-1***, CO_2 emissions reductions are occurring at a consistent or faster rate than was projected even a few years ago. In fact, CO_2 emissions from the electricity sector have decreased 28% below 2005 levels.[4]

The price and supply of natural gas will play a significant role regarding whether this trend will continue. Figure 1 shows EIA Annual Energy Outlook for the years 2017 and 2018 for natural gas prices trending only slightly upward for the foreseeable future.

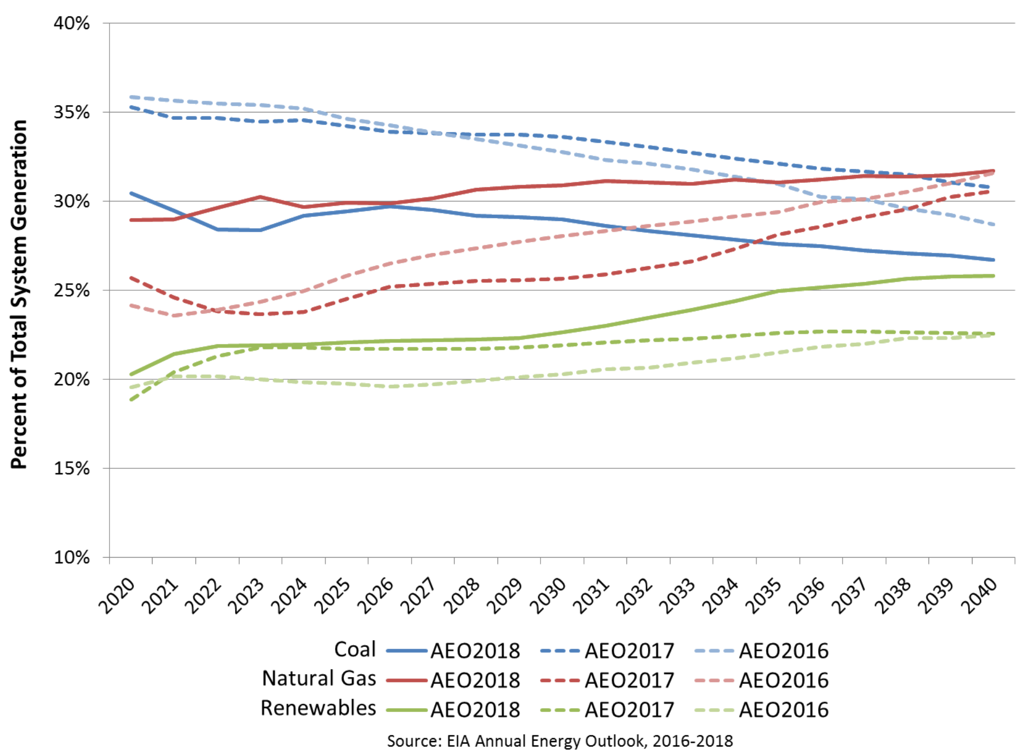
Figure 1. Long term projected natural gas prices from EIA Annual Energy Outlook for the years 2017 and 2018



[4] Id.

Figure 2 below shows that based on EIA Annual Energy Outlook for the years 2016, 2017 and 2018, the electricity sector projections for coal-fired generation for the next decade and beyond are trending consistently downward while renewables and lower carbon intensity natural gas generation are trending in the other direction. Assumptions of reasonably stable natural gas prices and supply play a vital role in these projections.

Figure 2: Long-Term Projected Share of U.S. Power Generation from Coal, Natural Gas, and Renewables from EIA Annual Energy Outlook Modeling



That stated, NRECA emphasizes that coal-fired generation remains both an essential and vital source of electric generation today. This is the case especially for cooperatives in large part because of the national circumstances at the time the need arose for significant cooperative self-generation in the mid 1970's. At that time of need, many existing non-cooperative generation sources could not or would not continue providing affordable and reliable electric generation to the cooperatives. Commensurate with the significant need for cooperative self-generation, the federal government passed the 1978 Powerplant and Industrial Fuel Use Act, 42 U.S.C. § 8301 et seq., which pushed the cooperative generators — the G&Ts — to build significant new baseload generation. That Act *mandated* that all such new generation be "coal capable," so as to preserve natural gas supplies for nonelectric and nonindustrial purposes. The coal capability requirement meant the new generating units bore significantly higher capital costs per megawatt of capacity than units constructed before Congress instituted the requirement. To produce electricity at competitive prices, therefore, the new units had to use coal, which was less expensive than natural gas.[5] The Fuel Use Act was repealed in 1987, but about two-thirds of today's cooperative coal-fired generation was built under the Act's "coal capable" mandate. Given the investments in coal capable generation mandated by the federal government, coal-fired electric generation remains the dominant source of electric generation for G&T cooperatives. Although self-coal-fired generation is down from 70% in 2014 to 61% in 2016, this percentage is notably significant when compared to a nationwide average of just over 30%, and this significance is a major reason why the CPP-mandated shift away from coal to other generation sources, if implemented,

[5] These units today cannot use natural gas as a primary fuel and provide competitively-priced electricity. Coal to gas converted units typically serve short term purposes or provide non-baseload generation, and are only available where adequate gas supply is available at the site.

would disproportionately harm electric cooperatives relative to the other utility sectors.

As discussed in these comments, NRECA supports EPA's efforts to craft carbon dioxide ("CO_2") emission standards for existing fossil fuel-fired electric generating units (EGUs) that are consistent with the limits on EPA's authority under Section 111 of the Clean Air Act, that are reasonable and achievable by existing EGUs, that recognize the cooperative federalism principles and division of authority between EPA and the States that are the foundations of the Act, and that provide States and EGUs appropriate flexibility in complying with the resulting standards of performance.

Additionally, NRECA also supports and appreciates EPA's long-overdue efforts to revise its New Source Review regulations so that they do not unfairly penalize those who comply with EPA's ACE rule or otherwise disincentivize precisely the sort of efficiency-improving projects and other environmentally beneficial projects that the ACE rule requires and that industry otherwise would undertake.

While the proposed rule reasonably seeks to further reduce CO_2 emissions at existing coal-fired steam electric boiler units, we agree with EPA about limits on its ability to regulate a broader array of stationary sources. For one thing — and as is pertinent for purposes of ***Comment C-3*** — we recognize that EPA is not currently positioned to promulgate a Section 111(d) rule for existing stationary gas combustion turbines. EPA has not proposed any specific language on which the public can comment, and it appears to lack the data necessary to develop the type of record required to support any such rule. In this context, if EPA is interested in developing Section 111(d) requirements for existing stationary gas combustion turbines, it would need to be done through a separate rulemaking process in which specific provisions could be proposed and commented on, and the necessary record to support any such proposals could be developed.

Lastly, we urge EPA to clarify early on that any final rule resulting from the Proposed Rule is limited to coal-fired steam electric boilers and specifically excludes gas-fired boilers. Gas-fired boilers are not regulated under Section 111(b). Consequently, there is no statutory basis for promulgating a Section 111(d) rule for them. EPA should make that clear up front in its final rule here.

III. THE ACE PROPOSAL IS WELL WITHIN EPA'S ADMINISTRATIVE DISCRETION.

The definition of BSER advanced in the proposed rule reflects a reasonable interpretation of Section 111. It comports with the statutory text, longstanding judicial and EPA interpretations, as well as common sense. Even if some alternative interpretation of Section 111 is available, EPA can and should support the interpretation suggested in the Proposed Rule based on practical and policy considerations.

A. The Proposed Rule's Definition of BSER Comports with the Text of Section 111.

Section 111 is clear that performance standards apply *to sources*. That means that, contrary to EPA's prior assertion in the Clean Power Plan ("CPP"), they do not apply separately to the owners and operators of sources. Section 111(d), for instance, provides that a State may set a standard of performance for an existing source that would be regulated under Section 111(b) "if such existing *source* were a new *source*."[6] State plans must "apply[] a standard of performance to any *particular source*."[7] And EPA's role is to establish a "procedure" for States to submit plans "establish[ing] standards of performance *for any existing source*."[8]

Section 111 also expressly contemplates adjusting standards of performance as they apply to individual sources in varying conditions. States must be permitted to consider "the remaining useful life of the existing *source*" when "applying a standard of performance" to "any particular *source*."[9] If EPA promulgates a federal plan in lieu of an unsatisfactory state plan, the statute requires EPA to "take into consideration … [the] remaining useful lives of the *sources* in the category of *sources* to which [the] standard applies."[10]

EPA cannot regulate existing sources under Section 111(d) unless it first regulates new sources under Section 111(b), another part of the law that focuses on individual "sources." To commence Section 111(b) regulation, EPA must first list

[6] 42 U.S.C. § 7411(d)(1) (emphasis added).
[7] *Id.* (emphasis added).
[8] *Id.* (emphasis added).
[9] *Id.* (emphasis added).
[10] *Id.* § 7411(d)(2) (emphasis added).

(Continued...)

categories of "stationary *sources*" to be regulated.[11] EPA then sets federal standards for new "*sources* within such [listed] category."[12]

For all of these Section 111 provisions, "source" is defined as an individual, physical "building, structure, facility, or installation."[13] Those are the things to be regulated under Section 111. "Source" is *not* defined to include the "owner or operator" of the "building, structure, facility, or installation." Indeed, Section 111 makes that distinction explicit. Congress differentiated the term "owner or operator" from the term "source" by giving the former a distinct definition: "any person who owns, leases, operates, controls, or supervises a stationary source."[14] Had Congress intended to include a facility's "owner or operator" within the term "source," there would have been no need to separately define those terms. Section 111 further states that it is unlawful "for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source."[15] That provision would make no sense if the term "source" extended beyond the facilities that actually emit air pollutants, so as to encompass owners and operators of those facilities.

B. The Decision in the *ASARCO* Case Supports EPA's Proposed Definition of BSER.

[11] *Id.* § 7411(b)(1)(A) (emphasis added).

[12] *Id.* § 7411(b)(1)(B) (emphasis added); *see also id.* § 7411(a)(2) (defining "new source" and discussing standards of performance "which will be applicable to such source").

[13] *Id.* § 7411(a)(3).

[14] *Id.* § 7411(a)(5).

[15] *Id.* § 7411(e).

(Continued...)

The holding in *ASARCO Inc. v. EPA*[16] also supports the validity of EPA's proposed definition of BSER. In *ASARCO*, the United States Court of Appeals for the District of Columbia Circuit held that EPA may not "embellish[]" the statutory definition of "stationary source" by rewriting it.[17] According to the Court, the statute "limit[s] the definition of 'stationary source' to one 'facility,'" not a "'combination of' facilities."[18] Thus, the Court explained, EPA may not "change the basic unit to which the [standards] apply from a *single* building, structure, facility, or installation — the unit prescribed in the statute — to a *combination* of such units."[19] The Court's focus on discrete generating units is consistent with the proposed rule's focus on measures that can be taken at individual units themselves, to the exclusion of measures requiring actions "beyond the fenceline" of those units.

C. EPA's Proposed Definition of BSER Comports with the Agency's Traditional Interpretations of Section 111.

The proposed rule comports with 45 years of consistent agency practice prior to the anomalous (and now stayed) Clean Power Plan (CPP). Prior to promulgating the CPP, each of the approximately 100 new source performance standards that EPA has set in more than 60 source categories has been based on technological or operational measures that the regulated source itself can implement.[20] In promulgating

[16] 578 F.2d 319 (D.C. Cir. 1978).
[17] *Id.* at 324, 326 n.24.
[18] *Id.* at 324.
[19] *Id.* at 327.
[20] *See generally* 40 C.F.R. pt. 60, subpts. Cb-OOOO.
(Continued...)

standards of performance for refineries, for example, EPA reiterated its longstanding view that "[t]he standard that the EPA develops [is] based on the BSER *achievable at that source*."[21] EPA took the same settled approach in promulgating its CO_2 standards of performance for *new* coal and gas under Section 111(b). EPA based those standards on its examination of the level of emissions performance those plants could achieve by using control technologies and operating practices at the plants themselves, not on the level that could be achieved on some combined basis including load shifting if their owners also built or paid for new lower- or zero-emitting resources.[22]

The same focus on setting standards applicable to the source itself — as opposed to standards focused on the source's owner or operator — is central to EPA's 40-year-old Subpart B regulations establishing the Section 111(d) "procedure."[23] In those regulations, EPA determined that Section 111(d) "emissions guideline[s]" must "reflect[] … the application of the best system of emission reduction … [that] has been adequately demonstrated *for designated facilities*,"[24] defined as the facility within the regulated source category for which the standard is developed.[25] Thus, every other Section 111(d) guideline EPA has promulgated has

[21] 79 Fed. Reg. 36880, 36885 (June 30, 2014) (emphasis added).
[22] 80 Fed. Reg. at 64512–13, Tbl. 1.
[23] *See* 40 C.F.R. pt. 60, subpt. B (promulgated by 40 Fed. Reg. 53340 (Nov. 17, 1975)).
[24] *Id.* § 60.21(e) (emphasis added).
[25] *Id.* § 60.21(b); *see also id.* § 60.22(b)(3) (guideline document to include "[i]nformation on the … costs and environmental effects of *applying each system to designated facilities*") (emphasis added); *id.* § 60.24(b)(3) ("Emissions standards shall apply *to all designated facilities* within the State") (emphasis added).
(Continued...)

defined the "designated facility"[26] and is based on systems that the "designated facility" can implement.[27] As EPA stated in one of its earliest guidelines, "[t]he emission guidelines will reflect the degrees of emission attainable with the best adequately demonstrated systems of emission reduction, considering costs[,] *as applied to existing facilities*."[28]

In all of the above instances, regulation was expressly confined to measures at the facility itself. We commend EPA for adhering to that established practice in the Proposed Rule.

D. Practical Reasons Also Counsel in Favor of Limiting the BSER to Measures That May Be Implemented at the Source Itself.

Doctrinal reasons are not the only ones that support EPA's proposal to define BSER in a way that precludes measures that require action beyond the source itself. To the extent there is ambiguity about what can and cannot count as BSER under Section 111, there are practical and policy reasons for limiting BSER to measures that can be taken "inside the fenceline." Foremost among them is that many alternative

[26] *E.g.*, *id.* §60.32c(a) (defining "designated facility to which the guidelines apply" as "each [municipal solid waste] landfill"); 44 Fed. Reg. 29828, 29829 (May 22, 1979) ("[T]he guideline document for kraft pulp mills is written in terms of standards of performance for each designated facility.").

[27] *E.g.*, 61 Fed. Reg. at 9914 (landfill guideline based on "[p]roperly operated gas collection and control systems achieving 98 percent emission reduction"); 45 Fed. Reg. 26294, 26294 (Apr. 17, 1980) (aluminum plant guideline based on "effective collection of emissions, followed by efficient fluoride removal by dry scrubbers or by wet scrubbers"); 44 Fed. Reg. at 29829 (pulp mill guideline based on digester systems, multiple-effect evaporator systems, and straight kraft recovery furnace systems); 41 Fed. Reg. 48706, 48706 (Nov. 4, 1976) (proposed guideline for sulfuric acid production units based on "fiber mist eliminators"); 41 Fed. Reg. 19585, 19585 (May 12, 1976) (draft guideline for fertilizer plants based on "spray cross-flow packed scrubbers").

[28] EPA, *Primary Aluminum: Guidelines for Control of Fluoride Emissions From Existing Primary Aluminum Plants* 1–2 (Dec. 1979), http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000M9HS.pdf (emphasis added).

measures are unattainable or unavailable to rural electric cooperatives around the country.

The practical problems with treating so-called "beyond-the-fenceline" measures as BSER were among the reasons NRECA objected to the second and third "building blocks" in the CPP. The second CPP building block called for electric providers to reduce generation from higher-emitting, coal-fired power plants and replace it with generation from natural gas plants. But that sort of fuel switching is simply not an option for many of NRECA's members because those members do not own or have access to natural gas plants from which to obtain the replacement energy. To take just one example, San Miguel Electric Cooperative operates a mine-mouth EGU in Christine, Texas. Like most mine-mouth EGUs, the San Miguel's unit is entirely coal-fired and not even connected to a natural gas supply. Switching to electricity generated from natural gas is thus not even a possibility for San Miguel, absent a massive investment in infrastructure of the sort that San Miguel cannot possibly afford.

Other rural electric cooperatives, like East Kentucky Power Cooperative ("EKPC"), have access to some electricity from gas-fired EGUs, but not nearly enough of it to allow any substantial reductions in coal generation. The gas-fired units that might serve EKPC are ill-equipped to operate at a capacity factor necessary to compensate for any curtailment in EKPC's coal-fired unit. Moreover, the region served by EKPC lacks the infrastructure necessary to transmit the necessary gas-fired power to EKPC.

In many cases, generation-shifting or repowering with natural gas would require constructing new natural gas combined cycle ("NGCC") assets, along with the necessary infrastructure. EIA estimates that the cost of a new NGCC facility is just under $1,000/kW.[29] NRECA notes that some estimates for new NGCC units have exceeded that cost. For cooperatives that could afford to construct new capacity at that price, still more would be required, given that sufficient infrastructure is often not currently available to accommodate the potentially massive amount of new generating resources that could be required to meet almost any substantial generation-shifting requirement. And in all such cases, EPA would not be requiring the improvement of the existing generating resources that Section 111(d) regulates, but instead would effectively be requiring their replacement with new, alternatively-fired generation. Section 111(d) was never meant to operate in that manner.[30]

Similar problems inhered in the third CPP building block, which called for shifting generation away from coal-fired units and into lower CO_2 intensive and renewable sources. That was not — and is not — a viable alternative for many rural electric cooperatives, particularly those operating in parts of the country where wind and solar power are not realistic options. Even if EPA allowed these cooperatives to purchase credits from EGUs in other parts of the country, that would not necessarily solve the problem because it is not clear that growth levels in the renewable energy

[29] *See* EIA, *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018* (Feb. 2018), https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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[30] *See* Part IV, *infra*, and its discussion of "redefining the source."

sector could keep pace with demand. The renewable targets established under the CPP, for example, were attainable only assuming that the maximum historical rate of growth in renewable generation would continue every year, year after year, into the future, notwithstanding the law of diminishing returns and the fact that much of that maximum historical growth was fueled by anticipated expiration of favorable tax treatment for such resources — a factor that, by definition, would not occur year after year. If the necessary renewable energy failed to materialize, the results would have been disastrous for electric cooperatives and the public. Operators would have been forced to choose between either shutting down units — thus leaving demand unmet — or running in violation of the law in order to provide critical electric services to residences, hospitals, schools, and other vital facilities.

Even where it is feasible to shift generation away from coal, the cost of doing so is itself a serious impediment to including generation-shifting as an element of BSER. The costs of constructing new facilities and new transmission would ultimately have to be borne by the cooperatives' members, many of whom are among the least able in the country to bear additional costs. By way of illustration, Basin Electric Cooperative owns and operates multiple coal-based units with useful lives extending beyond 2040. In 2015, when it analyzed what it would need to do to comply with the generation-shifting mandates in the CPP, Basin determined that, *even if* it developed approximately 1,350 MW of new wind *and* 1,740 MW of new natural gas resources, it would *still* have to shutter operations at four of its existing coal-fired steam generating units — representing roughly 43% of its existing coal-fired generation capacity.

Perhaps the most dramatic illustration of the practical problems inherent in any approach mandating generation-shifting is the scenario facing San Miguel, which owns just the single, coal-fired power plant that it began operating in 1982. Because of the plant's age, emissions from it are considerably higher than would be required under practically any standard requiring generation-shifting. That means the only way for San Miguel to continue operating the plant — its only EGU — under such a standard would be to substantially curtail its use or purchase vast quantities of emissions credits, or try some combination of those two. Confronted with the CPP, for example, San Miguel studied its options and projected that it would have to shutter its lone EGU in 2022, on the day of the CPP's compliance deadline and a full 15 years before the end of the unit's expected useful life. The alternative would have been to dispatch the unit at well below its historic capacity factor, which would have led to greater operating costs per megawatt of generated electricity, which in turn would have made the plant more and more uneconomical to operate until it ultimately had to close (along with the mine that supplies it).

Practical difficulties like those are the inevitable results of almost any definition of BSER that extends "beyond the fenceline" of the individual units that are properly the subjects of regulation under Section 111(d). Those (and other) practical difficulties are themselves strong reasons for rejecting any such definition. EPA should make sure to note that, even if there is some ambiguity about the proper scope of BSER for purposes of Section 111, EPA would, in the exercise of its policy discretion, resolve that ambiguity in favor of an inside-the-fenceline definition of BSER in order to avoid the practical problems inherent in a more expansive, beyond-the-fenceline approach.

IV. THE PROPOSED DEFINITION OF BSER AVOIDS OTHER POTENTIAL PITFALLS.

NRECA supports EPA's proposal to confine BSER to technologies and operational practices that can be applied at the emissions unit itself. For the reasons just given, such a definition comports with the text of Section 111 and avoids the practical and statutory problems that would arise with definitions requiring beyond-the-fenceline measures.

It is also important that the candidate technologies are not of the sort that would redefine the sources to which they apply. The principle that, in prescribing environmental controls for a source, EPA should stop short of redefining that source comes from Best Available Control Technology ("BACT") review under the CAA's Prevention of Significant Deterioration ("PSD") program. As part of BACT review, agencies responsible for permitting new projects must identify all "available" control options for those projects. In deciding what options are "available," however, permitting agencies need not consider technologies and processes "that would fundamentally redefine the nature of the source proposed by the permit applicant."[31] So, for example, a permitting agency could not rely on BACT to insist that a project proponent construct an integrated gasification combined cycle ("IGCC") plant instead of a conventional coal-fired plant. That is so because "IGCC would fundamentally change the nature of the proposed major source as it would change the basic design of the equipment" being proposed.[32]

There are good reasons to apply something like the "no redefining the source" principle in the BSER context. For one thing, statutory and regulatory text expressly link BSER and BACT.[33] Given that relationship, it makes sense to treat BSER and BACT as subject to similar interpretive principles. In fact, NRECA agrees with EPA that it makes even more sense to avoid interpreting Section 111(d) to authorize measures redefining the source, since the sources subject to Section 111(d) are already constructed and operating.[34] Requiring measures that fundamentally redefine them is thus more likely to be seriously disruptive — not just to the sources themselves, but to the people and businesses that rely on them for electricity.

Other means of reducing or eliminating CO_2 emissions from flue gas have not been adequately demonstrated for use on existing facilities. Carbon capture and

[31] EPA, EPA-457/B-11 -001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 26 (Mar. 2011) (citing *In re Prairie State Generating Co.*, 13 E.A.D. 1, 23 (EAB 2006), *aff'd sub. nom Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007)).

[32] *In re Desert Rock Energy Co. LLC*, PSD Appeals Nos. 08-03, *et seq.* (EAB Setp. 2, 2009).

[33] *See* 40 C.F.R. 52.21(b)(12) (defining BACT with reference to regulations in 40 C.F.R. pt. 60, which covers standards of performance for new — and, by extension, existing — stationary sources); *see also* 42 U.S.C. § 7479(3) ("In no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 … of this title.").

[34] *See* 83 Fed. Reg. at 44753.

sequestration ("CCS"), for example, has never been successfully implemented at an existing plant without significant financial support from government entities.

The EPA should clarify in the final rule that carbon capture and storage technology is not BSER for existing coal-fired EGUs, although NRECA supports research and development of "clean coal" technologies, including carbon capture and storage (CCS) for the goal of future commercialization. At present, however, CCS has not been "adequately demonstrated" within the meaning of § 111(a)(1), such that it could serve as BSER for existing coal-fired EGUs under § 111(d).

This issue was extensively briefed in the currently pending lawsuit over the NSPS for EGUs. The arguments raised in that briefing continue to be valid. Among other things, facilities that received funding or tax credits under the Energy Policy Act of 2005 ("EPAct05") may not be consider by the EPA in determining BSER. Section 402(i) of EPAct05 provides:

[1] No technology, or [2] level of emission reduction, solely by reason of the use of the technology, or [3] the achievement of the emission reduction, by 1 or more facilities receiving assistance under this act, shall be considered to be adequately demonstrated for purposes of [Section 111 of the Clean Air Act].[35]

As numbered above, there are three separate prohibitions included in EPAct05. EPA cannot consider: 1) technology that received funding under EPAct05, 2) a level

[35] See 42 U.S.C. § 15962(i) (annotated to add heading numbers before subparts).

of emissions reduction achieved "solely" by reason of a technology funded through Clean Coal Power Initiative ("CCPI"); or (3) the performance of CCPI funded facilities in achieving certain emissions limits. The use of "solely" is limited to the second clause of the prohibition and does not apply to either the first or third provision. A similar interpretation applies to the §48A Internal Revenue Code ("IRC") limitation preventing the use of facilities receiving tax credits under §48A from being used to establish BSER.

The plain, unambiguous meaning of the EPAct05 limitations prohibits the EPA from considering EPAct05-supported technologies in determining BSER. This reading is further supported by the Congressional intent behind the passage of EPAct05, which stated that "the use of a certain technology by any facility assisted under this subtitle or the achievement of certain emissions reduction levels by any such facility will not result in that technology or emission reduction level being considered ... achievable, achievable in practice, or 'adequately demonstrated' for purposes of [section] 111 [of the CAA]."

There are currently only two operating power plants with CCS in the world, and only one in the United States.[36] Those two projects are NRG's Petra Nova faculty near Houston, Texas and SaskPower's Boundary Dam demonstration project in Saskatchewan, Canada.

[36] See United States Energy Information Administration, "Today in Energy," https://www.eia.gov/todayinenergy/detail.php?id=33552 (last visited Oct. 24, 2018).

Petra Nova

Petra Nova is a CCPI-funded facility: it received a nearly $190 million CCPI grant. Petra Nova also received a $250 million loan from the Japanese government. Finally, the State of Texas enacted several incentives supporting the economics of Petra Nova. These are Tex. Health & Safety Code §§ 382.003(1-a) (definition of "Advanced Clean Energy Project" making CCS projects eligible for various tax exemptions, abatements, and credits); Tex. Tax Code §§ 11.31 (pollution control property tax exemption), 151.334 & .338 (sales tax exemption), 171.601-.602 (franchise/margins tax credit), 182.022(c) (gross receipts tax exemption), 202.0545(a)-(d) (30 year, 75% severance tax credit for oil produced through enhanced oil recovery (EOR) projects utilizing anthropogenic CO2); 313.021-.033 (local property tax abatements/value caps); 386.051(b)(5), .052(b)(5), .057(b)(3), & 391.001-.304 (establishing and funding the "New Technology Implementation Program," which includes CCS projects); and Tex. Nat. Res. Code § 120.001 (definition of "Clean Energy Project" making CCS projects eligible for certain tax credits). Although some of these provisions were not ultimately utilized by Petra Nova, several of them were relied upon and contributed (and continue to contribute) materially to the economic viability of the project. Thus, even without the absolute prohibition in EPAct05, Petra Nova does not demonstrate that CCS technology is adequately demonstrated commercially such that it can serve as BSER because Petra Nova was extensively subsidized by public funding without which it never could have been built.

Boundary Dam

The only other power plant utilizing CCS technology in current operation is SaskPower's Boundary Dam demonstration project in Saskatchewan, Canada. Boundary Dam was heavily subsidized by the Canadian government. It is sited near existing CO_2 pipelines, and its business model relies on the sale of captured CO_2 for enhanced oil recovery. SaskPower was not able to deliver all the CO_2 it had contracted to sell, and it was ultimately forced to renegotiate its CO_2 supply contract to avoid paying a $91 million penalty. The renegotiation reportedly reduced annual revenues by about one third over the life of the project.

Moreover, at 110 MW, Boundary Dam is small—very small. By way of comparison, Vistra Energy's Oak Grove power plant, a lignite-fueled plant that began operation in 2010, consists of two units totaling 1600 MW of installed capacity. Standing alone, Boundary Dam is not sufficient to show that CCS is "adequately demonstrated" for significantly larger existing EGUs, even if it had not been economically subsidized.

Therefore, the EPA should clarify in the final ACE rule that CCS technology is not BSER for existing coal-fired EGUs. CCS technology simply has not been demonstrated to be commercially or economically viable.[37]

[37] *See, e.g.*, Katie Fehrenbacher, *Carbon Capture Suffers a Huge Setback as Kemper Plant Suspends Work*, GREENTECH MEDIA (June 29, 2017), https://www.greentechmedia.com/articles/read/carbon-capture-suffers-a-huge-setback-as-kemper-plant-suspends-work.

Given the serious problems that plague these experimental alternatives such as CCS, incorporation of HRI measures set standards of performance for CO_2 emissions at existing EGUs is a logical and rational choice. Of course, not all of the candidate HRI technologies identified by EPA will be feasible to install or operate at all existing facilities. For that reason, we urge EPA to further clarify, in its final Section 111(d) rule, that EGUs are not required to implement the candidate HRI technologies in order to achieve the performance standards established by States. Rather, States must use those candidate technologies to establish a numerical emissions limit — the standard of performance — that "reflects the degree of emission limitation achievable through the application of the [BSER]."[38] Once a State establishes that number, the CAA leaves it to the individual EGUs to figure out how they will meet it. In its final rule, EPA should remind States that their roles under Section 111(d) stop short of prescribing *how* EGUs may satisfy established standards of performance.

V. PROPOSED ACE SUBPART UUUUA STATE GREENHOUSE GAS GUIDELINES MENU AND CANDIDATES

EPA asks whether HRI measures other than the seven EPA lists in the proposal should also be included as part of the BSER and added to the candidate technologies (***Comment C–6***) and whether there is additional information of which EPA should be aware of and consider in determining the BSER and establishing the candidate technologies for HRI measures (***Comment C–7***).

[38] 42 U.S.C. § 7411(a)(1).

As discussed in more detail in the attached report from Black and Veatch, NRECA believes that the seven candidate technologies EPA proposes to include as part of the BSER are generally appropriate for consideration as components of BSER, though we note that return on investment for many of these menu items will be hard to achieve. For these, the States' authority to consider unreasonable cost in light of remaining useful life when establishing the unit-specific standard of performance will be particularly important. As the Black and Veatch report also notes:

> With rare exceptions, all the technologies found in Table 1 of the proposed rule could be applied at coal-fired EGUs over 50 MWe in net capacity, and at most coal-fired EGUs under that capacity. However, the appropriateness of any one menu item to any individual coal-fired EGU must be viewed in light of already applied heat rate improvements related each one of these 7 potential improvement areas, considering planned economic remaining useful life, anticipated utilization, and other unit relevant specific factors.[39]

In short, any final rule must recognize and require the States to consider, in setting unit-specific standards of performance, that many units will already have undertaken some or all of the measures identified in Table I of the proposed rule and that considerations such as remaining useful life, how the technologies interact with and affect the performance of one another,[40] anticipated utilization of the unit, and other factors are highly relevant in determining which, if any, of the measures listed in Table 1 should be included in setting the standard of performance for that unit.

[39] Black & Veatch Report § 1.2.2.
[40] *Id.* § 1.2.5.

NRECA anticipates that some commenters will suggest additional measures for the list of items in Table 1, such as co-firing with natural gas, as a means of further reducing CO_2 emissions from coal-fired units. NRECA does not believe that the addition of gas co-firing would be appropriate, for two reasons: First, gas co-firing may not be available in certain parts of the country, and NRECA does not believe that EPA may include as part of BSER measures that cannot be implemented in *all* parts of the country. Second, EPA has long declined in determining best available control technology (BACT) for a source to consider options that would fundamentally redefine the source. NRECA believes EPA should follow that longstanding practice here and decline to include in its BSER any options, such as gas co-firing, that would fundamentally redefine a coal-fired EGU. NRECA notes that many coal-fired EGUs were built as such specifically because of the availability of a co-located coal mine (*i.e.*, "mine mouth" EGUs). Requiring such sources to co-fire with natural gas would fundamentally redefine such units, upsetting the economic calculations upon which their siting and construction were based and potentially requiring the construction of gas pipelines that do not currently serve the area. As EPA is well aware, the construction of such pipelines can be both extraordinarily costly and take years to accomplish, due to the National Environmental Policy Act (NEPA) and other impediments to speedy approval of such construction.

NRECA does not believe that any of the measures listed in Table 1 should be removed from the list. Again, however, as Black and Veatch states in its study, the need for case by case assessments of applicability for each of these measures is paramount.[41] By way of example,

> the merits of intelligent sootblowing may not be proportional to their expense for some units. Many units in the United States have already developed comprehensive sootblowing and/or water cleaning programs which provide high performance with reasonable O&M costs. Still many other units do not suffer from significant deposition of slag on furnace water walls, or fouling or ash deposits on convective tube surfaces. For this reason, the inclusion of intelligent sootblowing may seem somewhat unusual when compared to the other HRI categories in the proposal.[42]

EPA also states that it seeks comment on whether and how studies conducted by, among others, engineering firms can inform the Agency's understanding of potential HRI opportunities (***Comment C–8***). NRECA agrees that such studies can be very useful in understanding the interplay between the various menu items included in Table 1 of the proposal. We note that, in response to EPA's proposed Clean Power Plan, Sargent & Lundy prepared a report for NRECA entitled "Coal Fired Power Plant Heat Rate Reduction" that evaluated precisely this issue. As Sargent & Lundy concluded in that study,

> Combinations of strategies to achieve heat rate improvements do not always provide heat rate improvement reductions equal to the sum of each individual strategy's heat rate improvement because many of the technologies affect, or are dependent upon, plant operating variables that are inter-related. Therefore, case-by-case analyses must be conducted to determine whether the incremental heat rate improvement through the application of multiple strategies is economically justified.[43]

[41] *Id.* § 1.2.3.
[42] *Id.* § 1.2.1.
[43] Sargent & Lundy Report C-1 and Section 4, page 14.

NRECA believes EPA should take the conclusions of such engineering studies into account in providing guidance to the States on how the States are to establish standards of performance for individual units, and that the States should be required to consider the interplay between multiple HRI strategies in establishing unit-specific standards of performance.

VI. PROPOSED STANDARD OF PERFORMANCE ESTABLISHMENT

Responses in this section are addressed to individual solicitations for comment in the Proposed Rule. Each response is labeled with the solicitation to which it responds.

Comment C-14: The CAA directs EPA to "permit the State in applying a standard of performance to any particular source under a [state implementation plan] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[44] The final rule should remind States of the importance of considering actual conditions at individual sources when formulating standards of performance for those sources. Among the relevant conditions are any past HRI undertaken at the facility, along with ongoing activities there that significantly affect contemporary unit efficiency. In considering those past HRI and ongoing activities, States should be cognizant of an important reality: Some HRI are not cumulative of one another, or some may even work against each other. To give just one example, economizer upgrades sometimes shift heat transfer in a

[44] 42 U.S.C. § 7411(d)(1).

boiler in ways that can interfere with hot reheat and main stream production, especially in split backpass units.[45] Economizer upgrades thus have the real risk of reducing boiler exit gas temperatures, which can negatively impact not only SCR performance downstream, but also coal mill performance when mill air temperatures are reduced to the point where operations problems occur.[46]

Another example of overlapping and offsetting effects involves combining condenser maintenance practices with state of the art boiler water chemistry.[47] Optimizing boiler water chemistry is one way to keep deposits from forming inside the boiler feed loop. However, as Sargent and Lundy LLC explained in a 2014 report, "If very balanced cooling water chemistry is maintained, then deposits are less likely to form, and the heat rate improvement realized by maintenance practices such as condenser cleaning would be lower."[48]

The upshot is that, where a facility has already installed certain HRI, it does not always make sense to assume that certain other HRI upgrades are feasible, let alone advisable. And it certainly does not make sense to assume that combining HRI upgrades will yield reductions equal to the sum of each upgrade's estimated heat rate reduction.[49] As the Sargent and Lundy report explains:

[45] Black & Veatch Report, 1.2.5.
[46] *Id.*
[47] *See* Sargent & Lundy Report 14.
[48] *Id.*
[49] *See id.*

(Continued...)

> Because of the interdependency of variables for many of these heat rate improvement technologies, combinations of technologies cannot be assumed to have an additive impact on heat rate. Combinations of technologies should be assessed on a case-by-case basis to determine the combined heat rate improvement.[50]

For this reason the final rule should remind States of that reality so that they remember to consider what HRI and practices a unit has already adopted when deciding on standards of performance for specific sources.

Comment C-15: NRECA strongly supports a final rule giving States the opportunity to use a mass emission rate (e.*g*., tons per year) as an alternative compliance metric to a pounds per MWh rate. The reason a mass emission rate makes sense is that plant emissions are highly variable. They can, for instance, be influenced by the operating state of the unit, the type of fuel being used at a given moment, and the capacity factor at which the unit is required to run at a given moment. Given that variability — which is often not entirely within the unit's control — it may not always be feasible for units to comply with rate standards within narrower windows of time. A mass-based standard gives units the flexibility to stay within the operative standard of performance while still meeting the CAA's emissions-reducing goals.

[50] *Id.*

Nothing in the text of the CAA requires that a standard of performance be expressed in pounds per MWh or that a single metric for compliance is required. The Act simply calls for States to promulgate standards that reflect "the degree of emission limitation achievable through the application of [BSER]."[51] An annualized mass-based standard does that just as well as a rate expressed in something like pounds per MWh. In fact, an annualized mass-based standard can be thought of as a pounds per MWH standard multiplied by the unit's estimated energy production in MWh for a whole year. Nothing about such a standard is inconsistent with the principles underlying the pounds per MWh standard.

Comment C-16: For similar reasons, NRECA supports use of CO_2 gross as the rate alternative. Compared to CO_2 net, CO_2 gross is markedly simpler. The simplicity makes it easier to monitor compliance, which makes it less likely that compliance will disrupt the nation's energy suppliers. With that said, EPA should afford States the flexibility to develop a SIP that it deems best in meeting the requirements of the guidelines by not foreclosing the opportunity for States to establish a standard of performance on a pound-per-net-MWh basis.

Comment C-17: An annualized mass standard meets what EPA has identified as an important requirement for any standard of performance. Specifically, it is one variable method easy to measure emissions and monitor compliance at the unit itself. Because a mass standard is source-specific, there is no need to monitor emissions

[51] 42 U.S.C. § 7411(a)(1).

from other sources in order for the regulated entity to determine whether the relevant source is in compliance with the ACE rule.

Comment C-43: In providing guidance on standards of performance, EPA must make sure to allow States to consider multi-year averaging times. The fact that units' emissions vary so greatly depending on things like capacity factor and fuel source means that EPA and the States should adopt standards of performance that take into account the broad range of circumstances that units might encounter that could affect emissions.[52]

VII. Proposed Standard of Performance Variance Considerations

Comment C-22: The proposal asks for comment about what "other factors" States ought to consider in establishing standards of performance under Section 111. NRECA believes that the following factors merit particular attention: (1) anticipations in reduced operation at the unit; (2) the reasonableness (or unreasonableness) of a particular cost, including the extent to which the cost will actually reduce emissions; (3) physical impossibility or serious constraints on installing or operating particular HRI; (4) unit size; (5) unit location; (6) status as a capacity unit; (7) coal fuel characteristics; and (8) ability of unit owner or operator to trade among units (e.g., number of units at the facility). The Sargent and Lundy report explains in detail why a

[52] Black & Veatch 1.2.10.

(Continued...)

few of these factors warrant consideration, and NRECA commends the report to EPA for consideration.[53]

Importantly, though, that list is non-exhaustive. EPA should make sure that, whatever guidance it issues on this subject, States are aware that they are not limited in deciding that a particular condition reasonably justifies a variance. The current regulations embody that principle by expressly authorizing States to consider "*Other factors* specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable."[54] That catch-all provision gives States the flexibility to accommodate new or unanticipated conditions that might otherwise imperil compliance with a standard of performance. EPA should take care to note that, in identifying certain criteria presumptively warranting a variance, it does not mean to foreclose the possibility that States may appropriately identify other such criteria.

***Comment C-23*:** One option that EPA should explore in crafting a final rule here is the desirability of establishing a metric for the presumptive reasonableness of an expenditure. One such metric could be a ratio reflecting the cost of a particular HRI compared to the emissions saved over the remaining useful life of the unit. NRECA does not wish to propose a specific number for such a metric. To the extent "reasonableness" is a function of costs and benefits, a metric like the ratio we propose

[53] *See, e.g.*, Sargent & Lundy Report 15–37 (analyzing impact of cycling on HRI strategies), 38 (discussing effects of heat rate degradation); *see also id.* at 9 (explaining why considerations like fuel type, facility age, and spatial constraints can play a role in HRI project options).

[54] 40 C.F.R. § 60.24.

(dollars spent per ton of carbon saved over the unit's remaining useful life) embodies that definition. Identifying such a ratio would give States confidence to consider the cost-effectiveness of certain measures when crafting standards of performance.

It is important that, in proposing such a metric, EPA recognizes that the reasonableness of a given expenditure is contingent in large part on conditions at the unit and the unit's expected longevity. That is why weighing the emissions saved over the unit's remaining useful life is so important: It takes into account the fact that all units are subject to different operating conditions and restrictions, so that a particularly expensive measure that might nevertheless be eminently appropriate at a relatively new unit is simply wasteful at a unit with just a couple years of remaining use.

Comment C-24: The proposal asks specifically about what a standard of performance for a unit with a short remaining useful life might look like. NRECA appreciates EPA's concern with that scenario, because it is one potentially affecting a number of rural electric cooperatives throughout the country. The overarching consideration in formulating standards of consideration for such units, NRECA believes, ought to be providing maximum compliance flexibility. Units with short remaining useful lives are, as a financial matter, constrained in the extent to which they can practicably implement new HRI. So standards of performance for such units can best ensure meaningful emissions reductions by relying on operation and maintenance practices, perhaps along with tonnage caps, rather than assuming the units can implement costly and time-consuming technological HRIs.

Comments C-25, C-26, and C-73: One common thread in the questions posed in connection with Comments C-25, C-26, and C-73 is emissions trading or averaging. In considering such options, EPA should be aware that many rural electric cooperatives are small businesses. Among other things, that means they have limited options when it comes to intra-utility trading or averaging, simply because they do not own or operate other units with which to trade or average. Indeed, for the rural electric cooperatives that operate only a single unit, trading or averaging are, by definition, impossible.

This is not to say that trading or averaging should be off the table. It is to say, however, that EPA and the States should not presume that trading or averaging are regularly available, and should further not treat trading or averaging as standard substitutes for unit-specific variances. Fundamentally, States should focus their standards of performance on what is achievable at the unit itself, without considering other compliance options as a means to make a unit standard of performance more stringent.

Comment C-27: In the Proposed Rule, EPA inquires about other factors that may play a role in a State setting a standard of performance with consideration to NSR. Part IX of these comments goes into detail on the subject, and NRECA urges EPA to consider the arguments made there when thinking about Comment C-27. For now, it suffices to say that any HRI menu candidate that would trigger NSR if implemented should be evaluated for unreasonable cost considerations due to NSR requirements, with a variance standard established accordingly, based on the reasonableness (or unreasonableness) of the resulting expenses.

VIII. PROPOSED GENERAL IMPLEMENTING GUIDELINES INCLUDING GENERAL VARIANCE PROVISIONS

EPA asks (***Comment C-51***) whether the implementing regulations it has proposed to promulgate should include a provision expressly allowing for any specific emission guideline to supersede the applicability of the implementing regulations as appropriate.

NRECA supports the inclusion of such a provision in the implementing regulations. While NRECA is generally supportive of EPA's proposed amendments to those implementing regulations, NRECA can foresee that circumstances could arise in the future that might make application of certain, or even all, of the provisions of those implementing regulations less appropriate for a specific emission guideline. For example, while NRECA supports EPA's proposal to modify the timelines for submission and review of state plans and implementation of standards of performance by sources to be consistent with the timelines generally applicable to SIPs submitted under CAA Section 110, NRECA can also foresee that there might be circumstances where even those timelines are not sufficient, such as where calculation of a standard of performance or implementation of the measures required to achieve that standard of performance are particularly difficult or time-consuming. In such cases, EPA should have the discretion to depart from the general implementing regulations and include in the specific emission guideline timelines that are appropriate to the category being regulated and the BSER that has been identified.

EPA also asks whether the timelines it proposes for plan submission (3 years from promulgation of an emission guideline), EPA action on a submitted plan (1 year from submission), and time for EPA promulgation of a federal plan (2 years after failure to submit or submission of an incomplete state plan) are appropriate (***Comments C–52, C–53, C–54, & C–55***). NRECA generally supports these timelines. However, NRECA also believes, given the nature of the heat rate improvement measures contemplated by EPA for inclusion in the BSER and the need to implement those improvements during regularly-scheduled plant outages, which may not occur with sufficient frequency to allow implementation of those measures in the timeframes EPA presently contemplates,[55] that the final amendments to the implementing regulations and the final ACE rule should permit units a period of 36 months, rather than 24 months, from approval of a state plan or finalization of a federal plan, before increments of progress are required. Moreover, the final emission guidelines for the ACE rule should require States to allow sources to coordinate their individual heat rate improvement projects with the relevant unit outage schedules,

[55] *See* Black and Veatch § 1.3.1, explaining that in the case of some HRI projects, such as steam path upgrades, the typical outage time between turbine overhauls is six years, with some units attempting to achieve a 10-year outage schedule. For others, such as economizer upgrades, the relevant outage cycle is that applicable to major boiler projects, which is typically every three to five years.

even if that schedule extends more than 36 months from plan approval or promulgation.

NRECA further supports EPA's inclusion in any final amendment to the implementing regulations of language generally permitting a State to consider, in applying a standard of performance to any individual source, the remaining useful life of the source and the various other factors EPA proposes to include in 40 C.F.R. § 60.24a(e). State authority to consider such factors on a unit-by-unit basis is consistent with the text of Section 111(d), with EPA's longstanding regulations governing establishment by the States of standards of performance for existing sources, and with Congress's intent in Section 111(d) not to require of existing sources that they implement BSER measures that make no economic sense for an existing source, given its remaining useful life, or that cannot be implemented due to technological, siting, design, or other limitations.

NRECA also agrees with EPA's statement in footnote 37 of the proposal that, while the Clean Air Act allows States to adopt state laws and regulations that are more stringent than those required by the Clean Air Act, it is not within EPA's authority under the Clean Air Act to approve or disapprove of or otherwise pass upon the lawfulness of such state laws or regulations. Such laws and regulations are purely creatures of state law, and they should be assessed accordingly by state regulatory authorities and state judicial tribunals, and not by EPA or the federal judiciary. Accordingly, NRECA agrees that EPA should exclude from any approval it issues, and should refrain from including in any federal plan designed to replace a missing, not approvable, or incomplete state plan, any provision that exceeds the requirements of the federal Clean Air Act—that is, any provision of a plan or any standard of performance that EPA itself could not issue pursuant to the federal Clean Air Act.

IX. New Source Review Permitting of HRIs

NRECA has long supported reform of, and we support EPA's current efforts to reform, the existing New Source Review (NSR) rules. Our support for such reform is born out of concern that many common-sense heat rate improvements and other plant physical or operational changes that could increase EGU efficiency and therefore reduce emissions are foregone precisely because of the delay and prohibitive costs that attend NSR evaluation and potentially costly required controls. Given that a final ACE rule or a state-developed standard of performance might actually *require* a source to implement an HRI project, it is all the more important that such HRIs not be impeded by NSR requirements and that source owners and operators not be effectively penalized for doing precisely what the ACE rule requires.

NRECA therefore urges EPA to adopt the proposed reforms to the NSR rules for EGUs, and not merely for HRI projects required by a final ACE rule. More specifically, NRECA urges EPA to adopt Alternative 2 version of the "maximum-achieved hourly emission" tests — as Step 2 of the final major NSR applicability test for an existing EGU, as we believe that those tests are the simplest to apply, as well as being consistent with case law. We also believe that EPA ought to make clear that only those increases in emissions "caused" by implementation of an HRI (in contrast to, say, increases caused by demand growth) ought to be considered in determining whether NSR is triggered. Thus, EPA needs to incorporate a causation analysis into any new NSR rule that includes an achieved or achievable test. We further believe that EPA ought to provide for compliance flexibility in the final rule, such as by allowing sources to avoid NSR altogether by agreeing to "synthetic minor" permits under which a source agrees to limit its hours of operation or dispatch so that there will be no significant net emissions increase from the source.

A. EPA Should Recognize the HRIs and Other Environmentally Beneficial Projects Foregone as a Result of NSR.

The experience of NRECA's member cooperatives shows that one of the unintended consequences of the NSR program, particularly as applied to EGUs, has been to discourage owners and operators from undertaking the very heat rate improvements and other projects that would increase the energy efficiency of EGUs and thereby lower their hourly emissions of CO_2 and other pollutants. This is because more efficient units, which tend to operate at lower cost per kilowatt-hour of energy produced, are likely to be dispatched more under current least-cost dispatch criteria. Under current NSR regulations, then, even though an EGU's rate of emissions is likely to drop as a result of implementation of an HRI, the NSR applicability test, which focuses on projected actual annual emissions, *see, e.g.*, 40 CFR 52.21(b)(41), will be triggered. Once this happens, the additional delay and expense associated with the

NSR permitting process is often enough to persuade the owner or operator to forego the project.

To exemplify the concerns that plague the current NSR program, one G&T cooperative recently commented to NRECA that it

"…believes it has the potential to improve heat rate and reduce emissions by modifying its boiler surface area due to recent, substantive changes in its fuel quality; however, engineering staff at the plant have been reluctant to pursue further evaluating these changes due to the belief that such a project would trigger NSR permitting."

NRECA believes that Congress never intended NSR to serve as a barrier to undertaking such environmentally beneficial projects. *New York v. EPA*[56] is not to the contrary. There, the D.C. Circuit invalidated a 2002 rule that had entirely exempted from NSR "pollution control projects" — that is, projects intended to reduce emissions of a "primary" pollutant but that might increase emissions of a collateral pollutant. But the flaw in that rule, according to the court, was that EPA had simply exempted such projects from NSR on the ground that they were not the type of physical or operational "changes" Congress had intended would trigger NSR. As the statute defines a "modification" as "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

[56] 413 F.3d 3, 40–42 (D.C. Cir. 2005) (*New York I*).

(Continued...)

previously emitted,"[57] EPA could not by regulation exclude a physical or operational change that does result in an increase in the emission of a pollutant.

EPA attempts no such absolute exclusion here. A heat rate improvement project — *i.e.*, a physical or operational change that improves the efficiency of an EGU — that results in an increase in emissions of a pollutant (whether CO_2 or some "collateral" pollutant) *will trigger NSR*. But as both the Supreme Court and the D.C. Circuit have recognized, the statute does not define what an "increase" in emissions is.[58] EPA is therefore free to, and should, reasonably amend that definition to eliminate the perverse penalty that NSR currently imposes on those who implement HRIs. This will ensure that the energy system overall is calling upon the least-cost sources for electricity generation, without penalizing through the NSR program those who have implemented ACE-required heat rate improvements.

B. Synthetic Minor Permits as an NSR Compliance Alternative

As EPA notes in the preamble to the ACE rule,[59] EPA's regulations have long provided that sources may avoid NSR regulation by taking a permit restriction so that the source's potential to emit is less than the threshold amount for a major source of the regulated pollutant.[60] Such permit-limited sources are known as "synthetic minor" sources.

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[57] 42 U.S.C. § 7411(a)(4).

[58] *See*, *e.g.*, *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 581 & n.8 (2007); *New York v. EPA*, 443 F.3d 880, 888-89 (D.C. Cir. 2006) (statutory term "increase" "necessitated further definition regarding rate and measurement for the term to have any contextual meaning").

[59] *See* 83 Fed. Reg. 44,776.

[60] *See* 40 CFR 49.158.

NRECA recommends that the final ACE rule allow sources to apply for, and States to approve, synthetic minor permits as a means of avoiding any NSR triggering that might result from a source's implementation of a heat rate improvement or any other measure required of it pursuant to the ACE rule. This would be consistent with the existing program. EPA itself noted in the ANPRM that preceded the present proposed rule that synthetic minor permits are often used to avoid triggering NSR,[61] and even the Clean Power Plan that EPA now proposes to replace contemplated that sources can elect to take enforceable limits on hours of operation, in the form of a synthetic minor permit, to avoid triggering NSR requirements that would otherwise apply.[62]

NRECA urges EPA to include a synthetic minor compliance mechanism for those sources that wish at their election to adopt it for two reasons: first, for some sources it may prove simpler or desirable for other reasons to take an enforceable limit on hours of operation, or operate at a lower load with no limit on hours of operation, than to undertake the calculations necessary to determine whether NSR has been triggered as a result of a heat rate improvement or other project undertaken by an EGU as a consequence of the ACE rule; second, a synthetic minor provision may provide an option for avoiding triggering NSR in the event that EPA does not finalize or a court invalidates EPA's NSR reforms.

[61] *See* 82 Fed. Reg. 61,518.
[62] *See, e.g.,* 80 Fed. Reg. 64,781.

Ultimately, a synthetic minor permit works as an NSR avoidance mechanism only if a source and the permit issuer can agree on a tonnage limitation that reflects the post-change level of emissions that would not constitute a significant net emissions increase and thus that would not trigger NSR review. Stated differently a tonnage limitation should reflect what unit emissions would be if the changes triggering NSR were implemented that would have resulted in reduced emissions. This in turn may require sources and permit issuers to convert rate-based standards of performance into annual tonnage (*i.e.*, mass) measurements.

NRECA advocated earlier in these comments in VI that the standard of performance need not be relegated to one metric, in this case the proposed lbs. CO_2/MWh. Our earlier comments advocated that other standards of performance metrics should be viable options, such as mass CO_2/hour or year. NRECA notes here that a mass CO_2/time advocated earlier fits well into the synthetic minor approach that includes a tonnage cap alternative and also provides an efficient and effective method of compliance with ACE for sources that *could* technically undertake HRIs or other measures required by the ACE rule, but that wish (for economic, practical, or other reasons) not to undertake those measures. For such sources, a permit that limits the source's annual hours of operation, or otherwise requires a source to control emissions to the annual tonnage limit through reduced load operation, such that its total annual emissions are no more than would have been emitted had the source undertaken the HRIs or other ACE-mandated measures would achieve the same emissions limitation as a rate per unit of energy. Alternatively, an EGU could de-rate and achieve the same emissions limitation as a rate per unit of energy. NRECA urges EPA to allow the use of such enforceable limitations as a means of ACE compliance.

C. Responses to Specific EPA Requests for Comment.

As we did in a previous section of these comments, NRECA here responds directly to enumerated comment solicitations from the Proposed Rule.

Comment C-59: *Whether it is appropriate to consider the costs of NSR compliance in the BSER analysis under section 111(d), assuming that triggering NSR cannot otherwise be avoided through actions by the source or through revisions to the NSR regulations that are proposed by EPA in this rule or if EPA does not finalize revisions to the NSR regulations.*

Section 111(a)(1) defines "standard of performance" to mean "a standard for emissions of air pollutants which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (*taking into account the cost of achieving such reduction*…) the Administrator determines has been adequately demonstrated."[63] NRECA believes that, in light of the highlighted statutory language, it is not only appropriate, but obligatory that States (or EPA, where it is implementing ACE) take into account *all* costs of achieving ACE compliance obligation of a standard of performance. This includes any and all costs associated with NSR that are triggered as an unavoidable consequence of ACE

[63] 42 U.S.C. § 7411(a)(1).

compliance. An ACE-mandated measure that, by itself, may seem cost-effective, may prove to be unreasonably costly under 40 C.F.R. § 60.24(f)(1) in light of plant age, location, or basic design process once unavoidable NSR costs are taken into account. Where that is the case, such measures should not be included in calculating the standard of performance applicable to an individual source.

Comment C-60: *How the potential for delays because of an influx of NSR permit applications may be accounted for in setting an implementation schedule for 111(d) plans.*

NRECA appreciates and urges EPA to adopt the revisions it proposes to the general regulations regarding the times for submittal of state plans implementing ACE, EPA review and approval of those plans considering NRECA's proposed timeline modifications to the state guidelines (section 60.5750a as discussed in X that follows) for states and EGUs to implement EPA-approved plans. That notwithstanding, once NSR is triggered for a source modification, the source may not begin construction of that modification until an NSR permit has been issued. The process of applying for and obtaining such a permit can take a year or more. NRECA believes that any final ACE rule must provide additional time for compliance by a source any time NSR has been triggered. The final ACE should provide that, in such cases, compliance by the source with the standard of performance set for it by the State (or by EPA, where it is implementing ACE) should be consistent with the time required for unit compliance after state plan submittal. Under the proposal, that time is two years from state plan submittal. We believe, however, following earlier comment herein, that the time at which increments of progress would be triggered should be three years from the latter of state plan or EPA approval.

Comment C-61*: Whether a narrower range of options for implementing an hourly emissions test for NSR for EGUs would both help promote energy efficiency and the effectiveness of implementing the ACE rule, while at the same time being consistent with the NSR provisions in CAA and past judicial decisions interpreting those provisions.*

As noted above, NRECA believes that a revision of the NSR regulations to conform the definition of the statutory term "modification" such that it is an hourly rate-based emission test for both NSR/PSD and NSPS is consistent with both the statute and the case law. In this regard, it is important that Congress chose not to define the term "modification" separately for the NSR/PSD programs, but instead to incorporate by reference the definition of modification that appears in Section 111(a)(4) – within the definitional section of the NSPS provision. While EPA has previously defined the term differently for the two programs – such that, for NSPS, regulation is triggered by an increase in the *hourly rate* of emissions, while NSR and PSD regulation is triggered by an increase in the *annual mass* of emissions – both the Supreme Court and the D.C. Circuit have acknowledged that the term "modification" is ambiguous and that nothing in the statute requires that the term be interpreted differently for the two programs.[64]

[64] *See*, *e.g.*, *Duke Energy*, 549 U.S. at 581 & n.8 (2007); *New York v. EPA*, 443 F.3d 880, 888-89 (D.C. Cir. 2006).

EPA, then, must provide a rational basis for its change in position. NRECA submits that the perverse "penalty" the rate-based NSR definition of "modification" imposes on EGUs that comply with the ACE rules HRI requirements is ample reason to revise its definition of "modification" precisely to avoid such absurd consequences.

Comment C-62: *Whether to confine the applicability of the hourly test to a smaller subset of the power sector, such as only the affected EGUs that are making modifications to comply with their state's standards of performance pursuant to these section 111(d) emissions guidelines.*

As discussed earlier in these comments,[65] many NRECA members have previously chosen not to undertake heat rate improvements and other environmentally beneficial plant improvement projects simply to avoid triggering NSR. Obviously, all of these foregone projects were before the advent of the ACE rule, and many were even before the advent of the Clean Power Plan. All of this suggests that EPA's proposed NSR reforms should be extended to all EGUs, whether or not subject to the ACE rule, and that these reforms should be adopted whether or not the ACE rule is finalized. This is the only way to ensure that NSR applicability does not continue to stand as a barrier to efficiency-improving and other environmentally beneficial projects that would otherwise be undertaken by EGUs.

Comments C-63 and C-64: *Whether EPA's 2007 argument – that an hourly achievable test is equivalent to a measure of actual emissions because "for most, if not all EGUs, the hourly rate at which the unit is actually able to emit is substantively equivalent to that unit's*

[65] *See supra* IX A.

historical maximum hourly emissions" – is still valid; and whether if, practically speaking, maximum achieved and maximum achievable hourly rates are equivalent for most if not all EGUs, EPA has the flexibility under the CAA to implement an hourly achievable emissions test for NSR.

NRECA continues to support the actual-to-projected actual test for whether there has been an emissions increase following a modification. NRECA also believes that, for purposes of the ACE rule, projected actual emissions should exclude any emissions increases that the emissions unit could have accommodated before the modification and that are unrelated to the modification, such as increases in emissions due to demand growth.

Comments C-66 and C-67: *The extent to which EPA should allow the adoption of an NSR hourly emissions test for EGUs in light of EPA's decision to issue these proposed emission guidelines for the power sector.*

The ACE rule, if finalized as proposed, would *require* sources to evaluate the HRI menu items and possibly other measures that, if considered together with the NSR costs they trigger, the EGU owner or operator would decline to undertake, as prohibitively costly. Given that these undertakings will be mandated, rather than voluntary, NRECA believes it is incumbent on EPA to provide relief to EGUs regulated by ACE, so that compliance with the rule does not result in the costly and burdensome "penalty" of triggering New Source Review. The promulgation of a final ACE rule without such reform of NSR would be profoundly unfair to NRECA's members and other regulated EGUs.

Comment C-68: *Other ways to minimize or eliminate any adverse impact that NSR may have on implementing section 111(d) plans for EGUs.*

As discussed above,[66] NRECA urges EPA to include a synthetic minor permitting option as a compliance methodology that sources and States may agree to implement to avoid triggering NSR.

X. PROPOSED PROVISIONS MORE APPROPRIATELY INCORPORATED INTO STATE THAN GENERAL GUIDELINES AND SUGGESTED AMENDMENTS TO THE STATE GUIDELINES

NRECA urges EPA to include in any final ACE rule any parts of the revised general guidelines that EPA believes are essential to the proper and efficient functioning and implementation of the final ACE rule. EPA itself states in the proposal that a Section 111(d) rule may include specific provisions intended to override, for purposes of that rule, the provisions of the general guidelines. One reason to do so is that future revisions to the general guidelines could otherwise upset the manner in which the ACE rule was intended to function. Thus, for instance, NRECA urges EPA to include in the ACE rule itself all revisions to the general guidelines that might be critical to the proper functioning and implementation of the ACE rule. These include:

[66] *See supra* IX B.

- The specific timeframes for submission of state plans, EPA review and approval of those plans, and implementation of standards of performance by regulated EGUs;
- Important definitions, such as EPA's revised definition of "standard of performance."
- The additional source specific factors detailed above in VII including (1) variable or anticipations in reduced operation at the unit; (2) the reasonableness (or unreasonableness) of a particular cost, including the extent to which the cost will actually reduce emissions; (3) physical impossibility or serious constraints on installing or operating particular HRI; (4) unit size; (5) unit location; (6) status as a capacity unit; (7) coal fuel characteristics; and (8) ability of unit owner or operator to trade among units (e.g., number of units at the facility as proposed or broader averaging if included in the final rule) into Section 60.5755a (2)(i).
- As proposed the general guidelines require at least initial compliance in the form of legally enforceable increments of progress 24 months from plan submittal (Section 6024a (d)(1)). Without a federally approved plan the utility may not have reasonable certainty regarding unit obligations. Accordingly, to address this uncertainty, the state guidelines (section 60.5750a) should specify that time for compliance including requiring enforceable increments of progress should not begin until the state plan is approved by the Administrator or a federal plan is promulgated, whichever is later. Moreover the 24-month

window is too short. Instead the state guidelines should allow 36 months from plan approval.