The National Rural Electric Cooperative Association

Comments on

Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

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The Environmental Protection Agency
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I. Summary of Comments

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 rule, Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (EGUs). The electric cooperatives support and encourage renewable generation and have significant interests in existing coal-fired generation due in large part to earlier federally mandated requirements essentially forcing coal-fired EGUs as the only option for new fossil-fuel generation sources when cooperatives faced the need to construct much needed new generation. Although no cooperative is actively planning to construct a new coal-fired EGU that NRECA is aware of, NRECA believes it is important that this rule addressing the Section 111(b) regulation for Greenhouse Gas New Source Performance Standards (NSPS) for new, reconstructed and modified Coal-Fired EGUs be workable and legally sound.

This regulation should incorporate solid principles in its formulation that can also be carried forward in future Section 111 rulemakings. To this end, EPA should conduct an "endangerment finding" for CO_2 emissions regulated under this proposal.

NRECA is **not** taking a position regarding the outcome of an endangerment finding; rather, incorporating the need for this undertaking here would establish the legal and regulatory precedent that EPA must conduct such findings for emissions from all sources that are likewise listed under Section 111. Indeed, it would be a Clean Air Act anomaly to allow regulation of a source emission without an agency showing need, as arguably would be the case without an endangerment finding to accompany this rulemaking.

The proposal correctly surmises that partial or full carbon capture and storage (CCS) is not a "Best System of Emission Reduction" (BSER) under which NSPS for CO_2 emissions can be established. As detailed in these comments, CCS is not commercially proven, broadly geographically available and cost reasonable, thus it cannot be considered BSER. Also, natural gas co-firing cannot constitute BSER as it is not available in needed quantities to ensure continued operation in many geographic areas, and in some cases gas co-firing would impressively "redefine the source."

In further consideration of what can constitute BSER, these comments challenge aspects of the proposal that adopt assumptions and legal interpretations incorporated in the 2015 rule. For example, cost reasonableness should not be based on "what the industry can bare," rather unit level costs are the cost reasonableness consideration.

NRECA believes that the existing provision that exempts EGUs that increase CO_2 hourly emissions less than 10% from modified NSPS should be retained. As pointed out below, even minor physical or operational changes including routine maintenance can result in inadvertent CO_2 hourly emission increases less than 10%. Such physical changes are certainly not intended to be EGU modifications within the NSPS context.

The proposal correctly defines BSER for coal-fired EGUs as most efficient demonstrated steam cycle of supercritical or subcritical depending on EGU size. NRECA believes, however, that EPA needs to reevaluate the proposed supercritical and subcritical NSPS and develop subcategories for EGUs utilizing lignite coal, for EGUs utilizing other coals based on specific coal properties including moister content, and for low duty cycle EGU operation. Further, EPA should abandon its present methodology used to develop the proposed performance standards that is based on "normalizing" best operated EGU emissions data by applying engineering equations and other assumptions to produce an NSPS. This process lacks real world considerations as well as demonstrations of viability. EPA should return to the previous methodology that identifies best performing existing EGUs and statistically sets the NSPS based on their abilities to achieve a given performance standard.

Lastly, this proposal does not address simple cycle combustion turbine NSPS, and any such effort to do so should be the topic of a subsequent rulemaking.

II. Introduction

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 or regulations EPA might adopt concerning greenhouse gas emissions from new, modified, and reconstructed 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 62 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 2017, 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. Rural electric cooperatives serve an average of 8 consumers per mile of distribution 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 these 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 just over 6%. For those reasons, among others, the average household served by electric cooperatives uses 1085 kWh of electricity each month, significantly more than the 794 kWh monthly average for households served by investor-owned utilities ("IOUs"), or the 871 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 an 1.1% decline in the carbon 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

[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.*

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 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 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 projections from the years 2017 and 2018 for natural gas prices trending only slightly upward for the foreseeable future.

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[3] *Id.*

[4] *Id.*

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

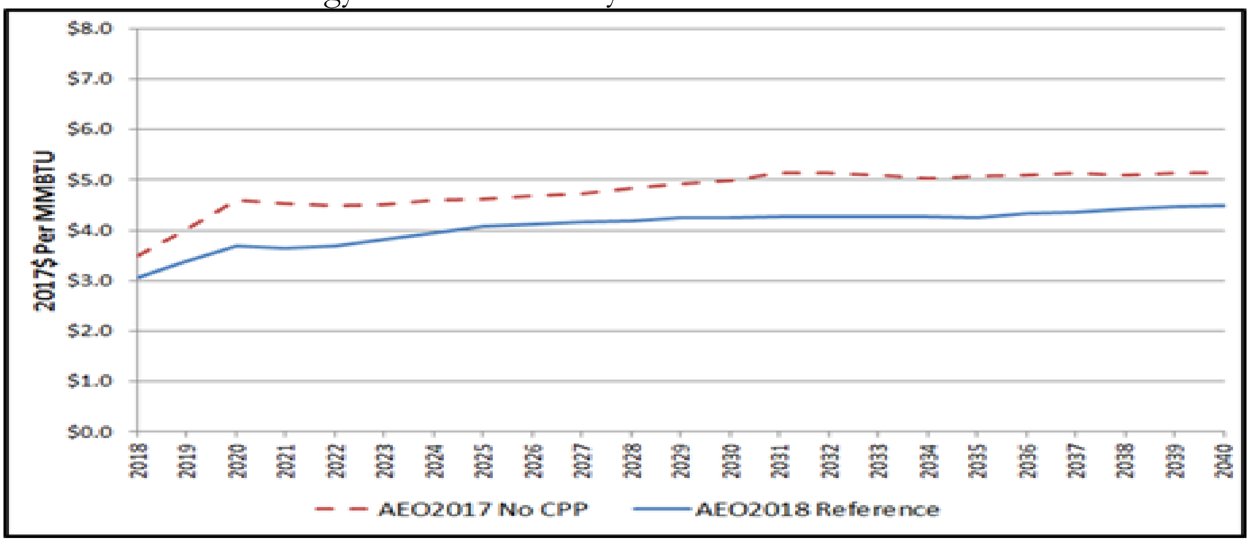
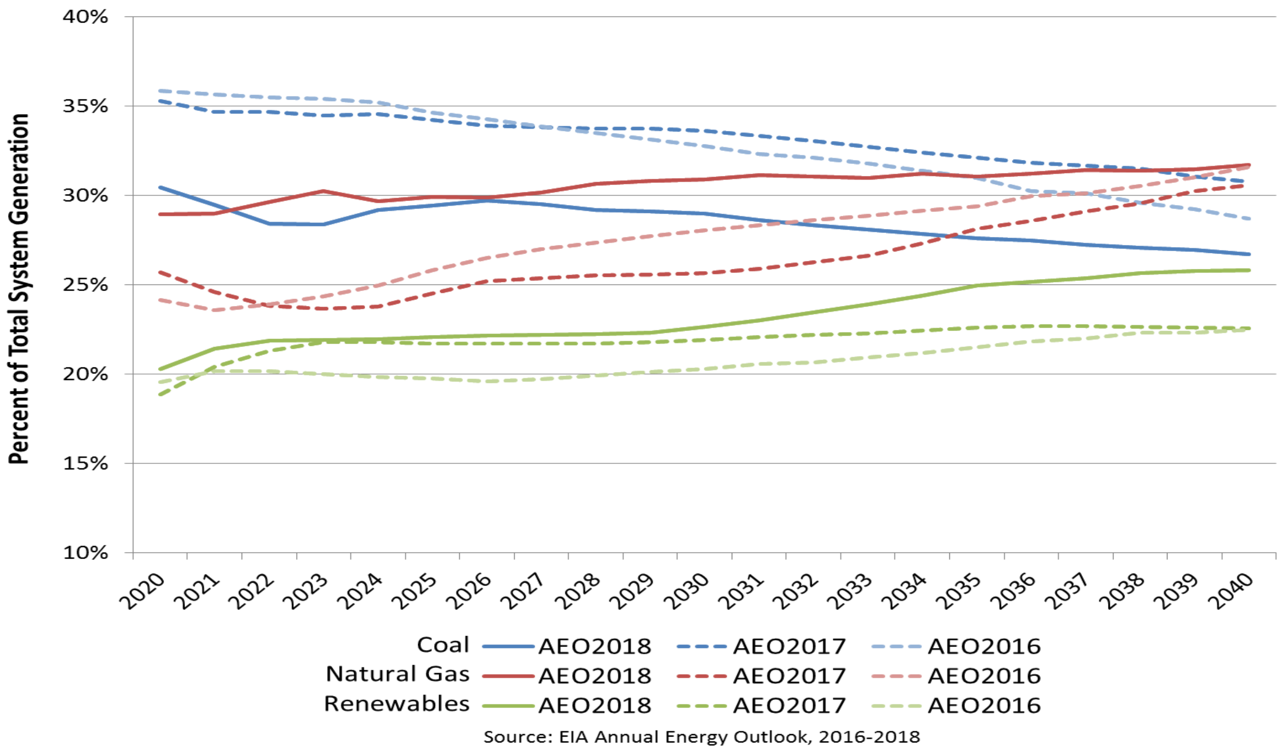


Figure 2 below shows that based on EIA Annual Energy Outlook from the years 2016, 2017 and 2018, the electricity sector projections for coal-fired generation for the next decade and beyond are trending consistently downward while renewables and lower carbon intense natural gas generation are trending 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," 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 prior Administration's shift away from coal to other generation sources, if implemented, would have disproportionately harmed electric cooperatives relative to the other utility sectors.

[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.

NRECA supports efforts to ensure a broad range of future electric generating options including those from wind, solar, natural gas, nuclear and coal. To support future options for coal generation NRECA and the electric cooperatives are engaged in various research efforts with the aim to develop practical and cost-effective means to capture and ultimately sequester or utilize CO_2 from fossil fuel combustion flue gas, termed Carbon Capture Utilization Sequestration (CCUS). These efforts are described in the attached Appendix A.

As discussed in these comments that follow, the best system of emission reduction (BSER) under Section 111 does not comprehend any means that involves carbon capture. The status of that technology remains in development stages and is not proven ultimately workable, and certainly not commercialized or cost-effective. Thus, NRECA supports EPA's efforts to revise EPA's October 2015 final CO_2 emission standards for new, modified, and reconstructed fossil fuel-fired EGUs in a manner that is consistent with the limits on EPA's authority under Section 111(b) of the Clean Air Act, and to promulgate standards that are reasonable and achievable by new, modified, and reconstructed EGUs no matter where in the nation they may be located.

III. NRECA Response to Specific Requests for Comments

A. EPA Should Require Pollutant Specific Endangerment Findings

EPA has previously interpreted Section 111 to require only a single "endangerment finding," for a single pollutant emitted by sources in a source category to trigger EPA's full authority under Section 111. According to these prior interpretations, once such a finding has been made, EPA has authority to regulate *any* pollutant emitted by sources in that category, whether or not the source category's emissions of that particular pollutant pose any endangerment to the human health or welfare.

That interpretation is wrong, and EPA should reconsider and abandon it in favor of an interpretation that requires a pollutant-specific finding of endangerment to trigger EPA's regulatory authority with respect to that pollutant. EPA's existing interpretation contravenes the "major questions" canon, which reflects the law's expectation that Congress will "speak clearly if it wishes to assign an agency decisions of vast economic and political significance."[6] Regulating *all* emissions from a source category when only one or a limited number of pollutants has been found to pose an endangerment is precisely the kind of "transformative expansion in EPA's regulatory authority" based on a "long-extant statute" that requires "clear congressional authorization."[7] But the CAA does not clearly authorize EPA to regulate all emissions

[6] *Utility Air Regulatory Grp. v. EPA*, 573 U.S. 302 (2014)
[7] *Id.* at 324.

from a source category based on an endangerment finding that names only one or a group of pollutants. In authorizing EPA to list and regulate categories of stationary sources, Section 111(b) speaks only of "air pollution *which may reasonably be anticipated to endanger public health or welfare*." 42 U.S.C. § 7411(b)(1)(A). Consistent with the major questions canon, EPA should not interpret that very narrow, targeted language — by its terms, aimed only at pollutants that actually threaten health or welfare — as authorizing it to regulate emissions of pollutants that have not been found to pose any endangerment to health or welfare. To lawfully assert such sweeping authority over *all* emissions from an entire source category, even absent a finding that those emissions present an endangerment, EPA needs a clear and express grant of power from Congress. The language in Section 111(b) does not meet that high bar.

EPA should therefore disavow its prior interpretation allowing EPA to regulate all pollutants emitted by sources in a source category once EPA has made any endangerment finding related to that source category. Instead, EPA should adopt an interpretation that allows EPA to regulate a pollutant emitted by sources in a source category only after the Agency has determined that *that* pollutant causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

B. BSER For New Units Must be Immediately Achievable

Independent of the need to narrow the legal effect of an endangerment finding, NRECA generally supports EPA's effort to revise the Section 111(b) standards to ensure that they reflect the best system of emission reduction that can be implemented immediately by *all* new, modified, or reconstructed sources in the category, no matter where they are located, and that does not impermissibly redefine any source by, for instance, requiring it to switch a fuel other than that which it was designed to use.

In revising those standards, EPA should make several improvements to the existing BSER analysis. First, in response to **Request for Comment C-3**, the BSER must be one that sources *everywhere* can implement *immediately*, at a reasonable cost. Because the BSER applies to any source the construction of which commences after the date of *proposal* of a new source performance standard, 42 U.S.C. § 7411(a)(2), the BSER must be an emission standard that can be implemented immediately upon proposal. Otherwise, the NSPS could pose an unlawful obstacle to the construction of new (and much-needed) sources of electricity. BSER is a "system which must be adequately demonstrated, and the standard must be achievable."[8]

As the U.S. Court of Appeals for the District of Columbia Circuit has explained, the achievability of a BSER technology is "partially dependent on 'lead

[8] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433–34.

time,' the time in which the technology will have to be available. Since the standards here put into effect will control plants immediately, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed."[9] Thus, the D.C. Circuit has held that a system is not BSER when that determination is based solely on pilot-scale data; the question is whether it is immediately achievable by covered sources.[10] EPA should keep this immediacy principle firmly in mind when determining what technologies and methods constitute BSER.

C. BSER Must Be Broadly Achievable

i. BSER Must be Achievable by Individual Sources

BSER must also be an emission standard reflecting a technology or method of operation that can be implemented by all sources nationwide. If EPA cannot identify such a standard, then the alternative available under Section 111 is for EPA to adopt a work practice standard or other alternative approach to controlling emissions.[11] It is not, as EPA inquires about in **Request for Comment C-15**, to engage in geographic subcategorization. As explained below, NRECA believes EPA lacks authority for geographic subcategorization; EPA does not have the ability to define BSER other than in terms of what is achievable for all individual sources.

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[9] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.3d 375, 391–92 (D.C. Cir. 2011).
[10] *Id.*
[11] Where it is "not feasible to prescribe or enforce a standard of performance, [EPA] may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction ...." CAA § 111(h).

The reasons why this is so are two-fold. First, while EPA "may distinguish among classes, types, and sizes within categories of new sources to establish [an NSPS]"[12] it lacks explicit authority with respect to the location of a source. Geography is simply not a class, type, or size of source within a source category.

Second, even if EPA has discretion to subcategorize among sources in different geographical locations, resulting standards would be arbitrary and capricious. Specifically, geographic subcategorization would allow units in some areas to have an inappropriate economic advantage over units in other areas. For example, units situated in geographic regions where natural gas may be available as a fuel could be forced to spend vast sums of money and encounter significant (and potentially insurmountable) delay to build out the infrastructure to deliver that natural gas to a unit, while a similar unit located in an area with no readily available natural gas supply would be exempted from such requirements. The cost and timing differentials thus could materially advantage units located in the latter type of geographic area over units located in the former type of area especially in areas where "market" systems are employed to govern the dispatch of electricity. EPA's goal in crafting an NSPS should not be to economically advantage or disadvantage units based on the location in which they are needed and built.

[12] CAA §111(b)(2).

ii. BSER Cannot be Justified on Basis of Levelized Cost of Electricity

In the 2015 final rule, EPA used an analysis of the levelized cost of electricity ("LCOE") to compare the cost of newly constructed coal-fired power plants with nuclear units. EPA uses LCOE in this proposed rule to reach conclusions on the cost impacts of a range of potential new generation technologies.[13] While LCOE may be a useful analytical metric, it is not a sufficient basis on which to determine BSER since it does not measure the cost of imposing BSER on any one facility.

LCOE essentially looks at the cost of electricity from new generating units or plants by analyzing such costs over the lifetime of the generating resources. In this sense, LCOE does allow for comparison as between different electric generation technologies and may support broad conclusions (*e.g.*, that partial CCS is BSER for coal-fired EGUs). But in promulgating standards of performance, EPA must also consider costs in terms of the achievability of BSER for individual units. CAA section 111(b)(1) requires "considering the cost of achieving such [standard of performance]."

Costs are borne by electric generating sources and, by extension, by the individual electric consumer who purchases electricity from these sources. No electric consumer in the United States pays a national average cost for electricity, calculated with respect to a predicted lifetime of the generating sources involved. Thus, EPA

[13] *See, e.g.*, 83 Fed. Reg. 65,436, Table 4.

should not rely or not solely rely on LCOE to justify conclusions as to the appropriateness of a standard of performance. Rather, as outlined above, EPA needs to look towards costs experienced by individual regulated units.

D. BSER Cannot Include Requirement for Coal Units to Co-Fire with Natural Gas

The proposed rule also asks whether co-firing with natural gas should be considered as part of the BSER.[14] NRECA believes there are at least three reasons why co-firing with natural gas should not be part of BSER. First, natural gas is not available in all areas of the country; accordingly, and as explained above, treating co-firing with natural gas as BSER impermissibly penalizes sources depending on location. Second and relatedly, the infrastructure for delivering natural gas to coal-fired generating units generally does not currently exist in many locations and would take years to build out. Therefore, a BSER that includes co-firing is likely to be one that cannot be implemented immediately by new sources. Instead, construction of new units would likely be delayed by years as rights of way are sought, NEPA and other required reviews are conducted, and the pipeline and related infrastructure is built out. NRECA believes that this would render any BSER that includes co-firing arbitrary and capricious, given the statute's express requirement that a NSPS will apply to any source the construction of which commences after the date the NSPS is

[14] *See* 83 Fed. Reg. at 65445.

proposed (or, if the final rule differs from the proposed rule, from the date of finalization).

[EPA solicits comments on the specific costs of this at **Comment C-14**, if NRECA or its members have technical data to share, it could be included at this point.]

The third reason not to consider co-firing a coal-fired plant with natural gas as a component of BSER is that doing so would impermissibly "redefine the source." 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."[15] 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

[15] 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)).

"IGCC would fundamentally change the nature of the proposed major source as it would change the basic design of the equipment" being proposed.[16]

There are good reasons to apply the same principle in the BSER context. For one thing, statutory and regulatory text expressly link BSER and BACT.[17] Given that relationship, it makes sense to treat BSER and BACT as subject to similar interpretive principles. But in addition, since an NSPS standard serves as a "baseline" level of control for BACT, if NSPS standards allow for redefinition of sources, then standards which would otherwise be impermissible through BACT could be required. The NSPS would effectively serve as the means to impose redefinition of the source through the PSD program and BACT, no matter if this resulted in substantially increased costs, less operational flexibility or other impacts - mandatory through the NSPS program.

Requiring measures that fundamentally redefine a source is also more likely to be seriously disruptive — not just to the sources themselves, but to the people and businesses that rely on them for electricity. Transforming a coal plant into a partial natural gas plant may affect not only the cost of the resulting electricity, but other technical and economic considerations as well as the overall reliability of a facility.

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

[17] *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.").

Given that plants are often sited to be near, and then designed to use, a specific fuel source — such as a mine-mouth coal-fired plant that is sited and designed to burn the specific type of coal located adjacent to the plant — requiring co-firing would not only fundamentally require the redesign of the plant, but might in fact render various siting and design decisions impracticable or uneconomic.

E. EPA Cannot Require Carbon Capture and Sequestration

Among the other technologies mentioned in the proposed rule, NRECA emphatically believes that partial carbon capture and sequestration ("CCS") cannot be BSER. For one thing, CCS cannot be implemented in many areas of the country that either lack the geologic formations necessary to store CO_2 or lack the necessary pipeline capacity to transport captured CO_2. That includes large sections of the eastern and western United States, along with parts of the Upper Midwest, which lack the type of porous rock formations suitable for sequestration.[18] Even generating units located within a reasonable distance of areas geologically suited for storing carbon will still have to arrange to have CO_2 emissions transported to the storage facilities, something that is most efficiently accomplished by pipelines if on-site deep saline injection is not an option . We are only aware on one pipeline for CO_2 transport from an EGU, the pipeline connected to the Petra Nova project. All other EGUs would

[18] *See* https://19january2017snapshot.epa.gov/climatechange/carbon-dioxide-capture-and-sequestration-overview_.html#[2].

have to construct a connection to the storage facility, which would take a considerable amount of time and cost a prohibitive amount of money.[19]

Indeed, the costs associated with CCS are exorbitant, so requiring it as BSER will effectively end construction of new coal-fired EGUs. In probably the most noted example of the high costs associated with CCS, in February 2018, the Mississippi Public Service Commission approved an agreement concerning the Kemper County Power Plant, a facility originally designed and constructed as a coal gasification combined cycle plant incorporating CCS. The agreement, allowing the facility to operate as a natural gas plant, noted that Mississippi Power wrote off $6.4 billion in investments in the facility.[20] The total cost of the plant has been estimated at $7.5 billion. Those economics simply are not viable for ordinary electricity providers, especially small businesses like most of NRECA's membership. In formulating a Section 111(b) standard, EPA must consider whether "the adopted standard unduly precludes the supply" of electricity, "including whether it is unduly preclusive as to certain qualities, areas, or low-cost supplies."[21] A BSER that effectively ends construction of new coal-fired EGUs would be manifestly unreasonable considering EPA's duty to consider costs in formulating a BSER.

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[19] *See* https://cei.org/blog/questionable-economic-feasibility-carbon-capture-technology ("[T]he cost of producing and piping CO_2 from coal power plants still remains prohibitively high.").
[20] *See* http://www.psc.state.ms.us/mpsc/press%20releases/2018/PSC%20Joint%20Kemper%20Settlement.pdf
[21] *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).

There are other good reasons for EPA to consider the benefits of, and adopt, a more manageable BSER. Judicial precedents authorize EPA to adjust standards when existing ones would cause sources or consumers to experience unreasonably high costs on a regional and national basis.[22] EPA is also empowered to consider nonair quality health impacts, among other factors, when determining BSER.[23] Provision of a reliable electric supply is among the factors EPA may reasonably consider.[24] Those considerations counsel against treating CCS as BSER, given the expense and difficulty inherent in installing and operating CCS at coal-fired facilities.

Still another reason not to include CCS as part of BSER is that it has not been adequately demonstrated anywhere in the world. In the proposed rule, for example, EPA mentions SaskPower's Boundary Dam CCS project in Canada.[25] But that project "has been plagued by multiple shutdowns, has fallen way short of its emissions targets, and faces an unresolved problem with its core technology," while "costs … have soared, requiring tens of millions of dollars in new equipment and repairs."[26] It has reached the point that SaskPower has given up plans to continue retrofitting the

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[22] *See, e.g.*, *Sierra Club v. Costle*, 657 F.2d 298, 336–38 (D.C. Cir. 1981).
[23] 42 U.S.C. § 7411(a).
[24] *See id.* (authorizing EPA to consider "energy requirements).
[25] 83 Fed. Reg. at 65443.
[26] *See* https://www.nytimes.com/2016/03/30/business/energy-environment/technology-to-make-clean-energy-from-coal-is-stumbling-in-practice.html

rest of its plant for CCS.[27] All of this bears directly on EPA's **Request for Comment C-10**.

The same is true of NRG's Petra Nova CCS project in Texas, which EPA also mentions in the proposed rule.[28] Not long ago, the Competitive Enterprise Institute observed that Petra Nova was "still leaps and bounds away from economic sustainability without a carbon tax or high oil prices" — neither of which is on the horizon right now. To the extent Petra Nova is having any success, moreover, it is largely due to its being "perfectly located next to oil fields that can use the captured carbon" — meaning Petra Nova does not have to worry about high transport costs that many of NRECA's members would have to worry about with regard to CCS.[29] The consensus is that "conditions of the [Petra Nova] plant are not easily replicable," which is one reason why Petra Nova should not be treated as an adequate demonstration of CCS on a national level.[30] Another is that Petra Nova relies on significant government funding, showing that CCS is not yet capable of existing in ordinary market conditions.

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[27] *See* https://business.financialpost.com/pmn/business-pmn/no-more-retrofits-for-carbon-capture-and-storage-at-boundary-dam-saskpower; https://www.cbc.ca/news/canada/saskatoon/saskpower-abandons-carbon-capture-at-boundary-dam-4-and-5-1.4739107

[28] *See* 83 Fed. Reg. at 65444.

[29] *See* https://www.utilitydive.com/news/congress-doe-continue-carbon-capture-push-but-utilities-wary/524375/.

[30] *Id.*

The problems encountered by sources applying CCS give lie to EPA's prior conclusion, in its 2015 NSPS, that CCS has been adequately demonstrated. The same goes for the problems at facilities attempting to apply integrated gasification combined cycle ("IGCC") technology.

Regarding EPA's **Request for Comment C-12**, Duke Energy's Edwardsport plant in Indiana has been hit hard by "exorbitant [operation and maintenance] costs," to the point that Duke has had to enter into a settlement with a number of groups, including customer representatives, requiring Duke to give its customers a $30 million credit in the future in order to pay for project shortfalls now.[31] Far from improving, operation and maintenance costs are expected to increase at the IGCC facility before Duke's next ratemaking.[32]

Projects like Kemper and Boundary Dam are notable for another reason: they are the beneficiaries of significant government benefits, whether in the form of subsidies or tax credits. But in determining what technologies *should* be part of BSER, EPA is *prohibited by statute* from relying on energy projects that have received funding under programs like DOE's Clean Coal Technology Demonstration Program.[33] Drawing on the same underlying principle, and in response to **Request for**

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[31] *See* https://www.powermag.com/duke-hit-hard-by-exorbitant-om-costs-at-edwardsport-igcc-facility/.
[32] *Id.*
[33] *See* 42 U.S.C. §§ 15962(i), 13573(e), and 13574(d); *see also* NRECA comments filed with respect to the 2015 final rule, EPA-HQ-OAR-2013-0495-10952.

Comment C-11, EPA should also avoid relying on projects that are heavily funded by foreign governments, as such funding is a strong indication of unreasonable cost in normal market conditions.

F. Technologies Utilizing Tax Incentives needed to demonstrate Commercial Viability Cannot be BSER

NRECA fully supports federal financial assistance programs including tax incentives, such as 45Q, to assist in developing innovative technologies. However, BSER cannot include technologies where such incentives are needed to demonstrate commercial availability and cost reasonableness where such incentives cannot be applicable to electric cooperatives, which are generally nontaxable entities and thus ineligible to benefit from tax incentives or tax credits.

Moreover, the Energy Policy Act of 2005 ("EPAct05") was abundantly clear in prohibiting determination of BSER where financial assistance from the government was involved. EPAct05 provides that:

> [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].[34]

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

As numbered above, there are three separate prohibitions included in EPAct05. EPA cannot consider: (1) technology that received funding under the Energy Policy Act; (2) a level of emissions reduction achieved "solely" by reason of a technology funded through government-funded programs like the Clean Coal Power Initiative ("CCPI"); or (3) the performance of such government-assisted facilities in achieving emissions reductions. 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 in assessing BSER.

The plain meaning of these statutory limitations prohibits EPA from considering Energy Policy Act-supported (or section 48A credit-supported) technologies or emission reductions achieved through such technologies or credits in determining BSER. Congress made its intent clear by specifying 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]."[35]

G. NRECA Supports Gross Output Form of the Standard

[35] H.Rept. No. 109-215 at 240 (2005).

EPA has proposed to allow owners and operators of affected sources to comply by using either a gross-output-based standard or net-output-based standard.[36] NRECA supports this format for the new NSPS. In general, output-based standards can reward owners and operators that increase the efficiency of their electrical generation. As long as the level of the standard is achievable, an output-based standard can both help to ensure compliance as well as maintain source flexibility with respect to the type of emission control equipment that may need to be installed and configured. Allowing additional flexibility for a source to select a net-output based standard, as EPA also proposes, could additionally increase incentives for improved efficiency.

In promulgating any standard pursuant to CAA Section 111, EPA must be mindful that the Agency is not authorized to promulgate a standard which would require "any new or modified source to install and operate any particular technological system of continuous emission reduction."[37] Such prohibited requirements could occur not only with respect to standards which prescribe that specific emission control technology be utilized, but also with respect to forms of emission standards that have the same practical effect. By specifying various output-based standards depending on the type of generating and IGCC units involved and by further allowing

[36] 83 Fed. Reg. at 65,452, 65,462; proposed 40 C.F.R. §60.5520(c).
[37] CAA §111(b)(5)

for alternative standards, EPA helps reduce the possibility that a standard as applied to an affected unit would violate CAA Section 111(b)(5).[38]

H. EPA Should Allow Alternatives to Carbon Sequestration

In **Request for Comment C-48**, EPA inquires about allowing additional flexibility with respect to obtaining a waiver from the requirement that captured CO_2 be geologically sequestered. Current regulations allow a person to request a waiver from requirements that captured CO_2 be transferred to a facility reporting under 40 C.F.R. Part 96.[39] EPA proposes that a waiver be allowable where the captured CO_2 "will be used as an input to an industrial process where the life cycle emissions are reducing emissions as effective as geologic sequestration."[40] The proposed amendment does not change procedural requirements for a waiver or the requirement that the proposed technology "will not cause or contribute to an unreasonable risk to health."[41]

NRECA supports this additional alternative for the utilization of captured CO_2. There appears little reason for EPA to oppose additional source flexibility for sources that are incorporating carbon capture. It should be understood, however, that this support for alternatives to geological sequestration does not affect our views or

[38] NRECA reserves judgment with respect to whether EPA's final standards would violate this requirement.
[39] *See* 40 C.F.R. 60.5555(g).
[40] 83 Fed. Reg. at 65,460.
[41] Id; 40 C.F.R. 60.5555(g).

comments above with respect to the impermissibility of requiring sequestration as part of BSER.

I. Modifications resulting in less than 10% increase in CO_2 hourly rate emissions should continue to be excepted from NSPS

The existing new source NSPS that excludes existing sources that undertake modifications resulting in less than a 10% increase in hourly CO_2 emissions from modified NSPS standards should be retained. **(Comment C-21**) The proposal is correct in the supposition that many physical changes can result in inadvertent CO_2 hourly emission increases less than 10% **(Comment C-22).** For example, oftentimes when improving combustion efficiency at either a turbine or boiler, total emissions of CO may go down because of improved efficiency, but the CO will oxidize to CO_2. If the project is sufficiently successful and the underlying efficiency gain significant, the unit could have an hourly increase in CO_2 emissions solely because of oxidation of CO to CO_2.

As another example, many coal-fired units with feedwater heaters equipped with copper alloy tubes experience copper deposition in the high-pressure turbine that can reduce capacity by up to 10 MW on a 600 MW capacity range generator. With chemical cleaning of the turbine, most of that lost capacity is restored, potentially allowing the unit to increase CO_2 hourly emissions. Again, this is another situation where the CO_2 hourly emissions increase when the unit undergoes physical changes for maintenance to restore lost efficiency.

IV. EPA Must Avoid Misinterpreting Its Section 111(b) Authority

EPA previously discussed its authority to establish standards of performance for new, modified and reconstructed sources within the context of its proposed 2012 and 2014 rules for electric generating units.[42] In the current proposed rule, EPA references this prior discussion with respect to whether there is a need for an endangerment finding.[43] EPA also discusses previous court decisions and how they impact EPA's interpretation of a "standard of performance" and the factors that EPA must take into account in determining BSER.[44] Our comments regarding the need for an endangerment finding are included above. In this section, we provide our analysis of EPA's legal authority to set standards for new, modified and reconstructed sources pursuant to CAA Section 111 and our objection to the Agency's characterization of case law affecting the promulgation of such standards.[45]

A. EPA may not assume that pre-1990 case law controls its interpretation of BSER

[42] *See* 79 Fed. Reg. 1430 (Jan. 8, 2014); 77 Fed. Reg. 22392 (Apr. 13, 2012).
[43] 83 Fed. Reg. 65,432
[44] *Id.* at 65,432-4.
[45] With reference to its statutory interpretations, EPA has indicated that it will consider comments on "the correctness of the EPA's interpretations and determinations and whether there are alternative interpretations that may be permissible." 83 Fed. Reg. at 65,432, nt. 25. Additionally, the Agency has requested comment on all aspects of the proposed rulemaking. *Id.* at 65,456 (**Comment C-28**).

As EPA indicates in the proposed rule, Congress first enacted CAA Section 111 in 1970, including a statutory definition for what constitutes a "standard of performance." This statutory language was subsequently amended by the Clean Air Act Amendments of 1977 and amended again by the Clean Air Act Amendments of 1990.[46] But, contrary to what EPA suggests, it is not clear that when Congress last addressed the statutory language of CAA Section 111, it meant to provide that "the explanation in the 1977 legislative history, and the interpretation in the case law, of those parts of the definition in the case law remain relevant to the definition as it reads currently."[47]

First, a simple comparison of statutory language in 1970 and today makes clear that EPA is to take additional considerations into account beyond the ones specified in the 1970 statutory language. Specifically, the current version of the statute requires EPA to consider "any nonair quality health and environmental impact and energy requirements" when determining a standard of performance. [48] A rule that did not consider such considerations or a judicial opinion based on the pre-1990 statutory language cannot be parsed as to those parts of the definition which remain in

[46] *Id.* at 65,432, nt. 30.
[47] *Id.*
[48] CAA § 111(a)(1). Compare the current text with the 1970 definition, which stated that: "The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." Pub.L. 91-604, 84 Stat. 1683 (Dec. 31,1970).

existence and those that were added by later enactment. To do so improperly and groundlessly assumes that the additional statutory language had no bearing on either the rule or the opinion.

Second, even while some statutory terms are the same in the 1970 CAA as compared with the 1990 Clean Air Act Amendments, it is not necessarily true that 1977 legislative history is dispositive of, or even relevant to the interpretation of congressional action 13 years later. Each Congress is a separate body which is born anew after intervening elections. An earlier Congress cannot bind the actions of a later one.[49] What Congress intended in 1977 does not directly bear on what Congress intended in 1990, especially given that the statutory language change in 1990 took place in the context of a massive rewrite and expansion of the CAA.

Third, to the extent that it may be argued that Congress "returned" to the major part of the 1970 definition of a standard of performance in 1990 after substantially altering the language in 1977, this argument fails for want of contemporaneous expressions of intent. There is no language in the conference committee report for the 1990 Clean Air Act Amendments which EPA cites (or which could be cited for this proposition). Instead, what evidence of legislative intent exists shows that by amending the 1977 statutory language concerning "standard of

[49] *United States v. Winstar Corp. et al*, 518 U.S. 839 (1996).

performance" Congress was taking aim at the requirement for a system of "continuous emission control" which had been interpreted to mandate scrubbers on all new utility power plants.[50] In other words, Congress intended to remove language it considered problematic instead of ratifying prior judicial interpretations of the 1970 CAA.[51]

Therefore, to the extent EPA grounds its interpretation of various statutory factors on prior case law — particularly cases from the 1970s interpreting the allowable level of cost that a standard may impose as being anything less than what "the industry could bear and survive"[52] this reliance is misplaced even while the Agency claims that such may be interpreted to impose a test of "reasonableness."[53] Case law based on the 1970 CAA cannot be assumed to describe the boundaries of EPA's discretion, or to authorize the Agency to impose, at its discretion costs that occur at any point along a continuum of "substantial" costs to those just short of a level that would bankrupt an industry or facility.

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[50] S. Rept. 101-228 (December 20, 1989).,

[51] In the context of the 1990 Clean Air Act Amendments, this interpretation is reinforced by the observation that the newly enacted "acid rain" program in title IV of the CAA allowed use of low-sulfur coal as a compliance option for meeting new restrictions on sulfur dioxide emissions. The Senate noted that the 1977 statutory language "exacerbated a regional split over coal use and air pollution control that had existed for time. The original intent of the provision was to prevent western low sulfur coal from shutting eastern high sulfur coal out of the fuel market." *Id.* at 337-8.

[52] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) cited at 83 Fed. Reg. 65,433, nt. 39.

[53] EPA cites other case law: *Essex Chemical Corp. v. Ruck*leshaus, 486 F. 2d 417, 440 (D.C. Cir. 1973), cert denieid, 416 U.S. 969 (1974); *Portland Cement Association v. Ruckleshaus*, 486 F. 2d 375, 387-88 (D.C.Cir. 1973); *Sierra Club v. Costle*, 657 F. 2d 298, 313 (D.C.Cir. 1981). 83 Fed. Reg. at 65,433. But the Agency does not further analyze how this body of case law results in a test of "reasonableness" that is applicable in the current proposed rule, instead referencing that EPA has explained this "reasonableness" test in an unidentified, prior rulemaking. *Id.*

B. ***Sierra Club v. Costle*** does not allow EPA to ignore plant-level cost impacts

After determining that prior case law from the early 1970s, under different CAA Section 111 statutory criteria, applies directly to this proposed rulemaking, EPA suggests that the D.C. Circuit has allowed EPA "to consider the various factors it is required to consider on a national or regional level and over time, not only on a plant specific level or as of the time of the rulemaking."[54] The principle case cited for this proposition is *Sierra Club v. EPA*,[55] which concerned the legislative history of the 1970 CAA.[56]

As already discussed, relying on early versions of the CAA and selective parts of the legislative history of the CAA to justify current interpretations is a flawed approach. That holds true for the use of earlier interpretations to justify consideration of cost on a national or regional level in determining BSER. The problems are not solved by EPA's attempt to justify the interpretation under *Chevron* Step 1 or Step 2, as EPA tried to argue in its 2014 proposed NSPS for new, modified and reconstructed EGUs.[57] In the 2014 proposed NSPS, EPA claimed that the D.C. Circuit's decision in *Sierra Club* was "fully consistent with the Chevron framework"

[54] 83 Fed. Reg. at 65,434.
[55] 657 F. 2d at 327
[56] *Id.* at nt. 48.,49
[57] *Id.,* at nt. 48.

even while *Chevron* postdated Sierra Club by three years.[58] EPA there further suggested that even if the interpretation was not allowable under Chevron Step 1, the Agency would consider the interpretation "supportable under step 2 because it is reasonable and consistent with the purposes of the CAA."[59] EPA should disclaim such post hoc rationale, particularly where the object is to codify *Sierra Club's* interpretation of costs as being analyzed through "a nationwide lens."[60]

There are also several reasons why reviewing costs at the national versus source level is not the proper frame of reference. First, CAA Section 111(a) (2) indicates that standards are to "be applicable to such [new] source." Standards are to be promulgated for "new sources within [a source] category."[61] Nowhere does the statute indicate that EPA is to use nationwide levels or estimates of "acceptable" national costs when applying new standards to individual sources. On the contrary, the statute restricts EPA from requiring "any new or modified source to install and operate any particularized technological system of continuous emission control."[62] That language indicates Congress's intent that standards not be defined by particularized parameters, including those that may be defined in terms of cost.

[58] 79 Fed. Reg. at 1,466.
[59] *Id.*
[60] *Id.*
[61] CAA § 111(b)(1)(B).
[62] *Id.* § 111(b)(5).

EPA's narrow interpretation also ignores subsequent decisions of the D.C. Circuit, most prominently *National Lime Association v. EPA*.[63] In that case, the D.C. Circuit determined that EPA's Section 111 standards were unsupported because "the record d[id] not support the 'achievability' of the promulgated standards for the industry as a whole."[64] When assessing the achievability of a standard, the court explained, EPA must: "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the [ ] data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[65] The court noted that "EPA itself acknowledged in this case that 'standards of performance … must … [assure achievability of the standard as a whole] for all variations of operating conditions being considered anywhere in the country."[66]

This interpretation of Section 111 was followed in *Portland Cement Ass'n v. EPA*.[67] In that case, the D.C. Circuit noted that the standards at issue (for cement kilns) could be applied "to any kiln type and achieve the same control levels that would be expected with a new kiln at similar costs."[68]

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[63] 627 F. 2d 416 (D.C.Cir. 1980).
[64] *Id.* at 431.
[65] *Id.* at 434.
[66] *Id.* at 431.
[67] 665 F. 3d 177 (D.C.Cir. 2011).
[68] *Id.* at 190

To be clear, NRECA does not concede the applicability of pre-1990 case law to the promulgation of CAA Section 111 standards. If EPA nevertheless insists on relying on such case law, however, it should consider *all* of the precedent fully and fairly. It should not proceed with the selective reading and interpretation of the case law found in the part of the proposed rule dealing with need to consider plant-level effects when determining BSER.

C. EPA impermissibly ignores factors it must consider for BSER

In interpreting *Costle* to identify factors EPA must consider in determining BSER for a source category, the Agency misreads that decision. Specifically, EPA cites *Costle* for the proposition that EPA must consider whether BSER is "technically feasible, whether the costs of the system are reasonable, the amount of emissions reductions the system would generate, and whether the standard would effectively promote further deployment or development of advanced technology."[69] Although EPA then observes that there may be "other factors" to consider, the Agency fails to note that *Costle* specifies several of those factors that, so far, have not been considered in this rulemaking. EPA also stretches the decision beyond the breaking point in terms of defining "factors" which must necessarily apply to all determinations of BSER.

[69] 83 Fed. Reg. at 65,433; 65,444–45.

Contrary to what the proposed rule says,[70] the statutory criteria for a "standard of performance" do not include a requirement that a standard be set to "promote" the development of technology. Rather, the statute mandates that the standard be both adequately demonstrated and achievable.[71] On this point, it is relevant that Congress *deleted* "technological" from its definition of a 'standard of performance" as part of the 1990 Clean Air Act Amendments. So, the case law that EPA cites in support of the interpretative principle of promoting advanced technology was based on a different definition of a standard of performance than exists today, one which contained a specific reference to the "best technological system of continuous emission reduction."[72]

Second, to the extent EPA relies on *Costle* to support analysis of technological development, it must be noted that the court did not identify technological development as an independent factor to be *balanced* as against achievability, but rather, looked at this factor in connection with whether there was "substantial

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[70] *Id.* at 65,433

[71] CAA § 111(a)(1).

[72] While, overall, NRECA does not agree with EPA's characterization of the case law that is applicable to an NSPS promulgated today, it should be noted that elsewhere EPA argues that deleting "technological" means that statutory language in existence today should be interpreted in a similar manner as to the language that existed in 1970. Thus, at best, it would be inconsistent for EPA to argue that development of technology is an explicit part of setting a BSER standard today when the 1970 CAA did not include "technological" within the definition of a "standard of performance." Moreover, it can be observed that the judicial decision EPA relies on for the need to consider technological development in setting BSER is *Costle,* which involved a rulemaking that was promulgated under the 1977 CAA definition of "standard of performance" which EPA now views as inoperable.

evidence that such improvements are feasible."[73] In other words, where technological development is considered, it is only with respect to those new technologies that are currently feasible; it is not an independent factor to justify BSER as means of forcing the development of new technologies. *Costle* does not indicate that EPA must consider technological innovation or development; it merely stands for the proposition that EPA is not *precluded* from considering such factors in evaluating currently feasible technologies.[74]

Finally, EPA selectively picks what factors it must consider when determining BSER. In *Costle*, the court discussed the ability of EPA to promulgate a variable percentage reduction standard and referenced "the essential purposes of the Act."[75] Among the purposes cited were that "[t]he standards must not give a competitive advantage to one State over another in attracting industry," and that "[t]he standards must maximize the potential for long-term economic growth by reducing emissions as much as practicable."[76] Yet EPA makes no mention of such considerations, nor does it evaluate such factors in specific subsections of the proposed rule. Instead, EPA relies on an inaccurate and incomplete list of factors "for the EPA to consider in

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[73] 657 F.2d at 364.

[74] *Costle* described "technological innovation" as a "subfactor" stating that "[w]e have no reason to believe Congress meant to forclose in section 111(a) any consideration by EPA of the stimulation of technologies that promise significant cost, energy, nonair health and environmental benefits." *Id.* at 346.

[75] *Id.*at 324.

[76] *Id.*

making a BSER determination."[77] If EPA wishes to rely on *Costle* in this rulemaking, NRECA urges EPA to undertake a more comprehensive reading and application of that decision.

V. EPA Must Re-Evaluate the Proposed Standards of Performance for New And Modified Coal-fired EGUs

A. General Concerns with the Proposal and Recommendations

NRECA agrees with the proposed BSER for new coal-fired EGUs as the most efficient demonstrated steam cycle depending on unit size, i.e. supercritical steam conditions for large EGUs and subcritical steam conditions for small EGUs. However, NRECA believes EPA's methodology utilized to establish the proposed standards of performance is flawed.

As a threshold matter of concern for this rulemaking, EPA applies a methodology that "normalizes" the emission rate data from "the best operated and maintained EGUs" to derive a "single best EGU" based on this normalized emission rate. Specifically, EPA "normalizes" this emission rate data to account for "factors" that EPA "has information on and that engineering equations can be used to account for design efficiency differences between EGUs based on the factors." The proposal

[77] 83 Fed. Reg. 65,433, nt. 33. EPA specifically cites *Costle* as authority for the factors identified.

surmises that a new EGU owner can meet the normalized performance rate by applying the "best EGU designs parameters and O&M practices." [78]

This unorthodox and unproven method to derive the standards presents numerous problems. NRECA will not detail all our concerns in these comments. Instead, in the interest of expediency, the comments of the Utility Air Regulatory Group (UARG), of which NRECA is a member, addressing the proposed standards of performance and the standard setting methodology are incorporated herein. As a general matter UARG's comments recommend the following of particular interest to NRECA:

- A re-evaluation of the proposed standards of performance for both large and small new EGUs utilizing past standard setting methodology.
- Consider the creation of sub-categories to address EGU operation at lower capacity factors and lower duty cycles to recognize lower efficiencies as compared to more robust operation, or alternatively establish different standards of performance applicable at different operational levels.

  (Comment C-31)
- In addition to establishing a subcategory for lignite-fired EGUs as detailed below, consider establishing additional subcategories for other coal types as

[78] 83 Fed. Reg. 65450

a function of coal moister content and other coal specific characteristics. **(Comment C-30)**

B. EPA should Establish Subcategories based on Coal Characteristics

The EPA opted for three subcategories in the MATS Rule because it recognized that the "differences between given types of units can lead to corresponding differences in the nature of emissions and the technical feasibility of applying emission control techniques."[79] The EPA further explained that "[b]ecause the emissions of [mercury] are different between these two subcategories, we are proposing to establish different [mercury] emission limits for the two coal-fired subcategories."[80] The text of CAA Section 111(b) allows the EPA to create subcategories. Specifically, Section 111(b) provides that the EPA shall "list . . . categories of stationary sources" of air pollution for which the EPA shall establish new source performance standards. Section 111(b)(2) provides that the EPA "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." Thus, the Administrator has broad authority

[79] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.76 Fed. Reg. 85, 25037 (May 3, 2011) (codified at 40 C.F.R. Parts 60 and 63).
[80] Id.

to establish NSPS and is not limited to establishing standards based solely on coal rank.

The usual subcategories for coal of anthracite, bituminous, subbituminous, and lignite are too broad to capture the immense difference in coal properties that affect efficiency, therefore CO_2 emissions, based on BTU levels and moisture content within those subcategories of coal. In addition to a separate subcategory for lignite, EPA should consider other "classes" and/or "types" of coal for subcategorization under Section 111(b)(2), especially given the compelling data as discussed below that supports coal distinctions. The need for subcategorization is especially critical for modified units where new (modified) source standards apply (as proposed where the CO_2 hourly emission rate is increased by 10 percent or more) because these units will be operating with existing configurations without the potential advantage of incorporating newer designs that may be feasible for new EGUs.

For example, coal moisture and BTU content that affects boiler efficiency can vary significantly even within a given coal rank. Coal subcategory moisture content and heat content per BTU/lb. varies for Colorado Plateau from 3-15% moisture and from 9,200-12,800 BTU/lb., for Powder River Basin from 24-31% moisture and from 7,800-9,700 BTU/lb., and for Gulf Coast lignite from 30-45 % moisture and from

5,200-7,200 BTU/lb. The effects of moisture in coal on the power block (boiler-turbine-generator unit) are decreased boiler efficiency, decreased overall unit efficiency (resulting in increased heat rate), and decrease in unit load.[81] The impact of a 1% increase in moisture on boiler efficiency is approximately 0.2% to 0.27%, which results in an approximate 10-11 kcal/kWh per 1% change in moisture.[82] Likewise, increasing levels of hydrogen and ash content in coal decreases boiler efficiency.[83]

"Coal properties determine both gross and net efficiency due to impacts on boiler performance and compatibility with environmental systems."[84] "It is important to emphasize fuel choice is dictated by numerous variables (e.g., price, availability, boiler design and environmental controls) so changing coal rank may not be practical at many units."[85] Differences in coal properties affect various factors, which in turn influence boiler performance in many ways, including the effects of mining and transportation of coal, effects of coal storage, the importance of boiler design that is optimized for particular coal properties (including moisture and BTU/lb.),

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[81] Siddhartha Bhatt M and Rajkumar N, *Effect of moisture in coal on station heat rate and fuel cost for Indian thermal power plants,* The Journal of CPRI, Vol. 11, No. 4, December 2015, pp. 773-786, at p. 777.
[82] *Id.* at p. 778.
[83] See, e.g., A Bhati, *Improving Energy Efficiency of Boiler Systems,* CED Engineering at https://www.cedengineering.com/userfiles/Energy%20Efficiency%20Boilers.pdf
[84] The National Coal Council, *Reliable & Resilient, the Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions,* lead authors: Doug Carter, J. Edward Cichanowicz, Stu Dalton & EPRI Team (May 2014) at p. 58. This study was conducted at the request of Secretary of Energy Ernest J. Moniz to John Eaves, Chairman of the National Coal Council (letter dated January 31, 2014) requesting that the National Coal Council "conduct a new study that assesses the existing U.S. coal fleet." This letter is included as an introductory page to the study completed by the National Coal Council and delivered to Secretary Moniz on May 14, 2014.
[85] *Id.* at p. 59.

combustion performance (as affected by coal properties, excess air, ambient air temperature and humidity, existing temperature, cooling and back pressure, and other normal boiler design and operational variabilities), mill performance (as affected by coal hardness and purity), boiler performance (including leakage and heat transfer losses), slagging, performance of ESP (electrostatic precipitator) or baghouse, SO_2 scrubber design and performance, life of boiler components, and other related maintenance and operational factors. The objective is to enable complete combustion of coal particles, to limit formulation of pollutants like NOx, and to maximize heat transfer to achieve optimum efficiency.

Boilers are designed to most efficiently burn a coal with certain properties, including BTU level and moisture content. Most coal switching since passage of the 1990 CAA Amendments has substituted subbituminous for bituminous coal, seeking least cost SO_2 and NOx compliance. In part because these existing boilers were not designed to burn subbituminous coal, reversing these changes – if enabled by environmental control system design – could elevate efficiency due to the lower moisture content of higher rank coal. For example, a large (500 MW) generating unit that fires a bituminous coal, that switched to Powder River Basin (PRB) subbituminous coal, would incur a boiler thermal efficiency penalty of 4.2 percentage points (e.g., a boiler thermal efficiency of 89.2% would decrease to 85.0%, due to higher fuel moisture content). The auxiliary power consumption of pulverizers, gas fans and sootblowers increase, in this example case, by 5.9%,[86] causing an overall efficiency decrease of about 5%, or about 500 BTU/kWh. But coal-switching is limited by overall coal and transportation costs and differences in capital costs for pollution controls and available and cost-effective retrofits, given the existing boiler and plant design.

In summary, the ranges of moisture content and BTU content within each of the traditional subcategories of coal (anthracite, bituminous, subbituminous and lignite) are too large to establish an achievable standard of performance for new or modified sources within that wide range. In addition to a lignite subcategory as discussed below, EPA should establish additional subcategories based on a certain moisture level, BTU level, hydrogen level, and ash content, and allow the standard to be adjusted up or down based upon how much the most cost-effective available coal varies from the baseline moisture, BTU, hydrogen, and ash content levels.

In adjusting the baseline standard, the permitting authority (whether State or Federal) should be required to consider boiler design and the most cost-effective coal available based on the source's location and the most cost-effective pollution control options that the Administrator has identified as adequately demonstrated, cost-

[86] The National Coal Council, supra, *Reliable & Resilient, the Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions,* at p. 58.

effective candidate technologies, including operational and maintenance practices. For new sources, the permitting authority may consider whether boiler design can be adjusted to most efficiently burn the most cost-effective coal available at that location, including transportation costs. For modified sources, boilers cannot usually be cost-effectively changed from original design, so the standard should be established based on the moisture, BTU, hydrogen, and ash content of the most cost-effective coal available at that location. To allow adjustment of the presumptive standard of performance based on design and coal properties, EPA could establish a list of factors for the permitting authority to consider similar to proposed subpart UUUUa, 40 CFR § 60.5740a, 83 Fed. Reg. 44746, 44808-09 (August 31, 2018), which list of factors for the permitting authority to consider under the 111(b) rule should include:

- Coal properties, including moisture levels, BTU levels, hydrogen levels, and ash content levels;
- Operational variability and emission rate variability, including an operational margin to account for such variability.
- Boiler design, and other physical, operational, and market conditions and restraints, including energy demand and reliability and cost factors that may affect efficiency, or cause cycling or low load operation; and

- For existing sources for which a standard has already been established under Section 111(d):
  - A review of the existing source standard of performance established under Section 111(d), including candidate BSER technologies and operational measures, in light of changed conditions since the standard was established;
  - Whether the installation of pollution control technologies under new source review for pollutants other than carbon dioxide may negatively impact the efficiency of the unit.

C. EPA Should Establish a Subcategory for Lignite-Fired EGUs

Lignite is the lowest rank of coal because it has the lowest heat content and the highest moisture content relative to other types of coal.[87] Lignite is not economical to transport long distances; thus, it is not traded on the world market like other ranks of coal. Lignite-burning EGUs are, therefore, often mine-mouth plants, i.e. power plants that are directly associated with the mines that supply their coal. Lignite coal mines

[87] See 40 C.F.R. § 60.5580.

provide coal for the mine-mouth EGUs and lack infrastructure to transport coal elsewhere.

The generation of electricity from lignite is technologically, chemically, physically, and functionally distinct from other, higher ranks of coal. As mentioned earlier, some of these distinctions are recognized by industry, regulators, and by EPA in MATS Rule. In particular, MATS sets three emission limits for each of its three subcategories: (1) existing non-lignite units, (2) existing lignite units, and (3) new units. The main emission limit distinction between existing non-lignite units and existing lignite units is for mercury, where the emission limit for non-lignite units is 1.2 lb./TBtu and 0.013 lb./Gwh and the emission limit for lignite units is 4.0 lb./TBtu and 0.040 lb./GWh.

NRECA believes the existing emissions data shows lignite-fired super-critical units have notably higher historic hourly emissions rates than the proposed hourly NSPS rate of 1900 lbs./MWh. EPA itself surmises that only **ultra**-supercritical lignite-fired units, could meet the proposed standard.[88] But **ultra**-supercritical steam condition is not the proposed BSER, nor has EPA offered any empirical data to

[88] 83 Fed. Reg. 65451

support the supposition that even ultra-supercritical lignite-fired EGU could meet the proposed standard.

The study of CO_2 emissions from the existing supercritical lignite-fired EGUs over the 2010-2018 operating period and data analysis prepared by Cichanowicz et al included as Attachment 1 to these comments demonstrate the need for higher NSPS limits for lignite-fired supercritical EGUs than the proposed 1900 lbs./MWh. Standard. **(Comment C-30**). The data analysis shows that these units operating over the multi-year periods and over varying unit operations consistently have significantly higher CO_2 lbs./MWh emissions that the proposed limit.

VI. Any Effort to consider Repealing or Revising Operational Limits for Simple Cycle Combustion Turbines should be addressed in a subsequent rulemaking

EPA's 2015 NSPS included, as part of its applicability criteria, the requirement that a unit have "net electric sales ≤ design efficiency (not to exceed 50 percent)."[89] While EPA recognized that simple cycle units often supported renewable generation, which can result in variable loads, EPA believed that simple cycle turbines would be excluded from regulation under the NSPS "as a practical matter" since the vast majority of simple cycle units had historically been used as peaking units, selling "less

[89] 80 Fed. Reg. 64,510, 64,603 (Oct. 23, 2015).

than five percent of their potential electric output on an annual basis, well below the proposed one-third electric sales threshold."[90]

EPA received numerous comments on these criteria, including recommendations that the Agency increase the percentage sales threshold. Commenters indicated that simple cycle and combined cycle turbines served different purposes and that simple cycle units should be categorically excluded from regulation.[91] But in the end, EPA believed that a percentage sales criterion was an appropriate way of balancing competing concerns.[92] Efforts to address these concerns should be addressed in a separate rulemaking.

[90] *Id.*
[91] *Id.* at 64,604.
[92] EPA cited data showing that simple cycle turbines operating in Texas generally sold about 10 percent of power to the grid with a high of 25 percent. Id. 64,610-11.

Appendix A

NRECA and cooperative participation in CCUS research initiatives

1. Wyoming Integrated Test Center for Carbon (Wyoming ITC-C)

NRECA is both a founding and funding participant in The Wyoming ITC-C, a public-private partnership, whose purpose is to provide an industrial-scale facility to test innovative methods to remove and capture carbon dioxide (CO_2) from combustion and utilize it to develop useful products. NRECA partially funded the construction of the facility, including engineering, construction and startup activities, and actively serves on the ITC Board along with Investor Owned Utility Black Hills Corporation, Basin Electric Cooperative, The Wyoming Governor's Office, The University of Wyoming and Tri-State Generation and Transmission Association. The Wyoming ITC-C allows researchers to test different processes and techniques.

Presently the $20 million COSIA NRG Carbon X PRIZE will be hosted at the Center. The "XPRIZE" is a global competition to develop breakthrough technologies that will convert CO_2 emissions from power plants and industrial facilities into valuable products like building materials, alternative fuels and other items that we use every day. Electric cooperatives will receive unique benefits of this initiative at the Center through a financial commitment to join this International Test Center Network and through the agreement with the XPRIZE Foundation that allows co-ops access to tests and results performed throughout the world to further carbon capture and utilization techniques including using CO_2 to produce useful products. The XPRIZE Foundation agreement brings this significant $20 million cash prize to the table for the purposes of inspiring and motivating scientists to find resourceful and beneficial uses for carbon from the fossil power plants and accelerating the traditional research cycle to this end.

Additionally, the Center will provide a venue for researchers to test CCUS technologies using 20 MW equivalent of actual flue gas from Basin Electric Power Cooperative's Dry Fork sub bituminous coal-fired power plant. Along with testing CO_2 capture technologies, additional research by the COSIA NRG Carbon X PRIZE will look at converting the CO_2 into marketable commodities. With advances in technology, CO_2 can be converted from a waste into useful fuels, chemicals, and other products. Market value for such products could potentially produce revenues exceeding the cost to capture and convert the CO_2, and thus, potentially reduce electricity costs from coal-fired power generation in the future.

Five finalists have been selected by the COSIA NRG Carbon X PRIZE to test technologies at the center to convert CO_2 from coal combustion flue gas into useful products. The selected technologies fall into the following categories: 1. Design promising catalysts and materials for the efficient and selective conversion of CO_2 into methanol, 2. Produce chemicals and bio-composite foamed plastics by making Wood–Plastic Composites (WPC) whose foam profiles are made with supercritical CO_2, 3. Produce solid carbonates with applications for building materials that will have commercial value in existing established and new markets, 4. Produce stronger, greener concrete using existing concrete production equipment and develop Portland cement chemistry to react with CO_2 emissions to produce in-situ nano sized mineral carbonate embedded within the concrete and 5. Produce building materials that absorb CO_2 during the production process to replace concrete.

2. The Enviro-Ambient Corporation (EAC) Carbon Capture Module

NRECA is working with Enviro-Ambient Corporation (EAC) and interested G&Ts in hosting and demonstrating a 25 MW Carbon Capture Module using multiple stages of injection of micronized water/foggers to capture CO_2 at potentially lower costs than other options. The EAC novel CO_2 capture solution has been previously demonstrated at a 2.5 MW scale in Louisville, Kentucky. Enviro Ambient develops and delivers a patented, turnkey energy recovery and emissions control technology that will remove up to 95% of sulphur dioxide [SO2], nitrogen oxides [NOx], mercury [Hg], and particulate matter {PM2] and reduces carbon dioxide [CO2] emissions by more than 60%.

In addition, our technology helps users address the challenges of rising fuel costs and the increased demand for more efficient, environmentally friendly power generation and industrial manufacturing. The flue gas energy recovery system converts waste heat from exhaust streams generated by equipment, such as small gas turbines and industrial processes into usable electricity, thereby reducing energy costs and providing a significant reduction in operating costs. The first fogging stage provides sensible cooling of the gases by latent heat of vaporization of water. Micronized water is also sprayed in the second fogging stage for the CO_2 capture process. The water droplets fall to the reactor floor where they drain into an air-tight waste water tank. Here the droplets coalesce and form bulk water. After capture of the CO_2, the CO_2 conversion and utilization solutions are as follows: 1. Selectively convert hydrogen and CO_2, or natural gas and CO_2, into carbon black or other nanoscale carbons in a relatively low power and heat environment using an inexpensive catalyst and 2. Convert water and CO_2 into oxygen and ethanol (alcohol), that is pure (200 proof undenatured) and suitable for food and industrial grade processes. Of course, the captured CO_2 can also be used for enhanced oil recovery.

3. Sustainable Energy Solutions (SES) Innovation Cryogenic Carbon Capture (CCC)

NRECA is participating actively participating through local, state and federal advocacy and detailed technology reviews and verification with and monitoring other potentially efficient and low-cost CO_2 capture options such as the CCC method. The CCC process (1) cools a dirty exhaust flue gas stream to the point that the CO_2 freezes using mostly the heat of recuperation of the recycled cold nitrogen gas, (2) separates solid CO_2 as it freezes from the clean gas, (3) melts the CO_2 through heat of recuperation and pressurizes it to form a pure liquid, and (4) warms up the clean, harmless gas releasing it to the atmosphere. This process can also effectively remove nearly all the remaining pollutants including mercury, sulfur dioxide and sulfur trioxide, nitrous oxides. In addition, the process can be designed to not only cryogenically remove the CO_2 during the off-peak evening hours, but it can also produce a slipstream of liquefied natural gas that can be stored and then used during the daytime peak periods to freeze the CO_2 without significant use of electric power and thus the fossil generation plant can produce nearly full output during the peak hours of the day. The CCC is a CO_2 capture process that can be configured into a very low-cost energy storage system.

4. The Linde Group and Southern Research (SC) processes

NRECA has identified the two processes as promising. Linde Group process is a promising option for chemical/catalytic conversion of CO_2 to useful chemicals and fuels. This process involves a dry reforming system with methane and CO_2 that uses proprietary catalysts to produce CO and H from either steam reformation or partial oxidation of methane to make a syngas in turn to make Dimethyl Ether (DME) for final use. Since the total process is exothermic it can be used to produce electricity and/or steam for sale. Linde has focused on DME for use in diesel engines, an advantage of DME is the high cetane number of 55, compared to that of diesel fuel from petroleum, which is 40–53. The Linde Group has also identified over 100 useful conversion of CO_2 into useful products such as methanol, gasoline, diesel, urea, and DME. Additionally, Southern Research is close to completing development of a low temperature process to convert ethane produced from shale gas (of low value) + CO_2 using Oxidative De-Hydrogenation (ODH) using a mixed oxide metallic catalyst converting ethane into 99% ethylene (of high-value) + CO which can be burned to produce heat or electricity.

5. The National Carbon Capture Center in Wilsonville, Alabama

NRECA is becoming a participating sponsor for the National Carbon Capture Center to further leverage our limited research dollars along with EPRI and several other entities including coal companies and investor owned utilities. The National Carbon Capture Center is a U.S. Department of Energy-sponsored research facility focused on finding breakthroughs in next-generation carbon capture technologies. Managed and operated by Southern Company, its world-class neutral test center works with technology developers from around the world to accelerate the development and commercialization of technologies to reduce greenhouse gas emissions from fossil fuel-based power plants.