The National Rural Electric Cooperative Association

Comments on Proposed Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed On or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations

80 Fed. Reg. 64,966 (Oct. 23, 2015)
[EPA-HQ-OAR-2015-0199; FRL 9930-67-OAR]

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On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units under Clean Air Act ("CAA") section 111(d) ("111(d) Rule," "Clean Power Plan," or "CPP") and proposed Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed On or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations implementing the 111(d) Rule ("Proposed Federal Plan (FP) /Model Trading Rules").[1] The 111(d) Rule and proposed FP/Model Trading Rules were published in the *Federal Register* on October 3, 2015. *See* 80 Fed. Reg. 64,662 (111(d) Rule); 80 Fed. Reg. 64,966 (Proposed FP /Model Trading Rules). Comments on the Proposed FP/Model Trading Rules are due on January 21, 2016, although the National Rural Electric Cooperative Association ("NRECA") has asked EPA to extend the comment period by sixty days to allow NRECA and its smaller utility member cooperatives additional time to analyze the complex proposal.

The National Rural Electric Cooperative Association ("NRECA") and thirty-seven of its member generation and transmission ("G&T) cooperatives have filed a petition for review of the 111(d) Rule in the D.C. Circuit challenging its legality.[2] The Proposed FP /Model Trading Rules suffer from the same legal defects as the 111(d) Rule, and NRECA therefore incorporates its comments on the 111(d) Rule by reference.[3] NRECA nonetheless submits these comments on the proposed FP/Model Trading Rules to ensure that they are effective and workable if implemented, and that States and the regulated industry have the flexibility they need to plan for compliance.[4]

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[1] EPA also issued final Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units under section 111(b).

[2] *See Nat'l Rural Electric Cooperative Ass'n v. EPA*, No. 15-1376, which has been consolidated with other challenges to the 111(d) Rule under the lead case of *State of West Virginia v. EPA*, 15-1363. In addition, NRECA member Tri-State Generation & Transmission Association, Inc. filed a petition challenging the 111(d) Rule, No. 15-1374, that has also been consolidated under the lead case.

[3] *See* Comment submitted by Rae E. Cronmiller, Environmental Counsel, National Rural Electric Cooperative Association (NRECA), EPA-HQ-OAR-013-0602-33118 ("NRECA Comments"). NRECA also incorporates by reference the legal arguments raised in the contemporaneously-filed comments on the Proposed FP/Model Trading Rules by the Utility Air Regulatory Group ("UARG"). Although EPA has made clear that it is not reopening its BSER determination or taking comment on the 111(d) Rule, the 111(d) Rule's legal infirmities are equally applicable here.

[4] Accordingly, nothing in these comments should be interpreted as consent to or approval of the 111(d) Rule and the FP/Model Trading Rules.

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I. Introduction to NRECA

The National Rural Electric Cooperative Association ("NRECA") is a national service organization representing the interests of cooperative electric utilities and the consumers they serve. Rural electric cooperatives labor to provide affordable electric power to their often-disadvantaged customers in an environment of ever-increasing environmental mandates, geographical constraints, and demographic challenges, making a workable federal plan and model trading rules critically important.

NRECA represents more than 900, mostly not-for-profit, member-owned rural electric cooperatives. NRECA members provide electricity to approximately 42 million member-consumers in 47 States, comprising 12 percent of U.S. electric customers. Cooperatives serve 19 million businesses, homes, schools, churches, farms, irrigation systems, and other entities in 2,500 of the 3,141 counties in the United States. They own and maintain 42 percent of the nation's electric distribution lines.

NRECA's members include 838 local distribution cooperatives that provide electricity directly to member-consumers and 65 generation and transmission ("G&T") cooperatives, which generate and transmit wholesale power to the majority of the distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve and all but three qualify as small businesses according to the U.S. Small Business Administration.[5]

Rural electric cooperatives serve large, primarily residential, low-density geographic regions where the costs of infrastructure and of providing service are high and revenues are low. According to the U.S. Energy Information Administration, rural electric cooperatives serve an average of only 7.4 consumers per mile of electric line and collect an annual revenue of $16,000 per mile of electric line. By comparison, investor-owned utilities serve an average of 34 customers per mile of line for the investor-owned electric utilities and collect $113,000 of revenue per mile of line. Fifty cooperatives have fewer than two consumers per mile of line (mostly in the Dakotas, Montana and Minnesota). Two with the lowest density areas are FEM Electric Association in South Dakota at less than one consumer per mile, and Cavalier REC in North Dakota at 1.02 consumers per mile of line. Electric cooperatives also have a significantly higher proportion of residential consumers than municipal and investor-owned utilities ("IOUs").[6]

Rural electric cooperatives are not-for-profit, but must impose relatively higher rates due to this geographically-determined disparity in distribution costs and revenues – the residential electric rates of 63 percent of rural electric cooperative members are higher than those charged to the customers of nearby IOUs. Those higher rates can impede the economic recovery of rural

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[5] *See, e.g.,* Brummett Decl. ¶ 4; Ledger Decl. ¶ 6. All cited declarations were filed as attachments to Motion of Utility and Allied Petitioners for Stay of Rule, *State of West Virginia*, No. 15-1363 (Doc. 1580014) (filed Oct. 23, 2015). Those declarations are also attached to these comments.

[6] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861.

communities and force disadvantaged rural customers to pay an even higher percentage of their income on electricity.

Low population density affects not only the cost of providing electricity, but also electricity demand, making rural Americans more vulnerable to rising electricity costs. Because population is more dispersed in rural areas, people tend to live in detached single unit homes that endure significant exposure to the elements, necessitating higher electricity use. For example, the average monthly electricity usage for households served by electric cooperatives is 1,128 kWh a month, significantly higher than the IOU monthly average of 829 kWh or the municipal monthly average of 971 kWh.[7] Moreover, because many rural residents do not have access to natural gas and depend on electricity and expensive propane and heating oil for warmth during cold months, electric cooperative members lack practical, affordable alternatives they can turn to when their electric rates rise.

The economic reality of higher heating costs falls particularly hard on low-income families living in rural America's manufactured and mobile housing. The percentage of mobile homes as a share of housing stock in electric cooperative service territory is more than double the U.S. average.[8] America's electric cooperatives also serve more than 90 percent of the persistent poverty counties across the country.[9] The customers of nine out of ten electric cooperatives have average household incomes lower than the national average. One in six consumers served by an electric cooperative lives at or below the poverty line. For example, the household income of Kentucky cooperative members is 7.4 percent below the state average household income and 22 percent below the national average.[10] Twenty of the eighty-two counties served by cooperatives in Kentucky are characterized as in "persistent poverty" by the U.S. Department of Agriculture.[11]

[7] These figures are 2012 weighted averages from EIA Form 861.

[8] The percentage of mobile homes as a proportion of housing stock is 14.7 percent in cooperative territories; the national average is 6.5 percent. For electric cooperatives that serve exclusively rural territories, that share goes up to 17.1 percent. These figures are based on U.S. Census data with calculations provided by EASY Analytic Software, Inc.

[9] USDA Economic Research Service (ERS) has defined counties as being persistently poor if 20 percent or more of their populations were living in poverty over the last 30 years (measured by the 1980, 1990 and 2000 decennial censuses and 2007-11 American Community Survey 5-year estimates). Using this definition, there are currently 353 persistently poor counties in the United States (comprising 11.2 percent of all U.S. counties). The large majority (301 or 85.3 percent) of the persistent-poverty counties are rural (*e.g.,* non-metro), accounting for 15.2 percent of all non-metro counties. Persistent poverty also demonstrates a strong regional pattern, with nearly 84 percent of persistent-poverty counties in the South, comprising of more than 20 percent of all counties in the region.

[10] Campbell Decl. ¶ 11.

[11] *Id.*; *see also, e.g.,* Lisa Johnson Decl. ¶ 8 ("Approximately one-third of Seminole's residential customers have household incomes below the poverty level."); Jura Decl. ¶ 11 ("The average income of Associated's residential member-consumers is between $25,000 and $50,000 a year. Sixteen percent of Associated's customers make less than $25,000 a year."); McInnes Decl. ¶ 4 (Continued...)

Rural electric cooperatives were formed specifically to provide reliable electric service to those member-consumers at the lowest reasonable cost.

The 111(d) Rule will have a disproportionately negative impact on rural electric cooperatives and the low income consumers they serve. To pay for capital expenditures necessary to comply with the coal- and gas-fired rates established in the 111(d) Rule, which existing units cannot meet through improvements at the affected unit alone, non-profit G&Ts will be forced to raise their rates significantly and unduly burden their rural, low-income consumers. Prematurely retired or "stranded" assets and high-cost financing also are likely to drive up cooperatives' rates.[12]

II. Summary of Comments

NRECA urges EPA to (1) adopt reliability review mechanisms and a dynamic reliability safety valve to ensure that the electric grid and the ability of generation on that grid to provide a reliable supply of electricity under all circumstances will not be disrupted by 111(d) Rule compliance and that EGUs are not penalized for their efforts to provide that reliable supply when faced with events beyond their control; (2) take all necessary steps to maximize robust and transparent trading markets for Emission Reduction Credits ("ERCs") and allowances; (3) provide notice and an opportunity for public comment (and to conduct a reliability review) before imposing a federal plan in any particular state; and (4) revise the alternative compliance pathway to minimize the risk of creating stranded assets and to satisfy EPA's statutory obligation to consider cost and avoid consumer rate shock.

III. Comments on the Proposed Federal Plan

A. EPA Should Finalize A General Federal Plan To Provide Guidance To States And Industry, But Cannot Impose A Plan In A Specific State Without An Opportunity For Notice And Comment.

EPA has invited comments on its staged approach to finalizing one or more model trading rules in the summer of 2016 while finalizing federal plans on a state-by-state basis only upon taking predicate action (such as a whole or partial disapproval of or a finding of failure to submit) on States' plans. 80 Fed. Reg. at 64,975. Under this iterative approach, States and industry will not have the benefit of knowing what type of federal plan would apply should the State fail to submit a state plan or EPA disapproves a state plan. For that reason, NRECA supports finalizing a general federal plan structure well before EPA proposes a specific federal

("Tri-State's power is sold to some of the most poverty-stricken counties in New Mexico and southern Colorado.").

[12] For a more complete discussion of the impacts of the 111(d) Rule on rural electric cooperatives, including rate increases, discussions of stranded assets, and other costs of compliance with the 111(d) Rule, *see* Attachments G, H, I, J, K, L, N, P, S to Motion of Utility and Allied Petitioners for Stay of Rule, *State of West Virginia*, No. 15-1363 (Doc. 1580014) (filed Oct. 23, 2015). Those declarations are also attached to these comments.

plan for any State, as this will facilitate the State planning process and enable States to make informed choices with a full understanding of consequences.

Importantly, although NRECA believes a general federal plan should be finalized to provide guidance for compliance planning by States and the regulated industry, EPA should not promulgate final federal plans for specific states without first providing notice and an opportunity for public comment on the state-specific elements of those plans. It appears that EPA may not intend to provide an opportunity to comment before imposing state-specific federal plans, *see* 80 Fed. Reg. at 64,975, but that omission would violate the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(b), (c). A FP imposes new duties, making it a legislative rule that requires notice and comment. *See General Motors Corp. v. Ruckelshaus*, 742 F.2d 1561, 1565 (D.C. Cir. 1984). The public would be denied any opportunity to comment on state-specific provisions, as the proposed federal plan does not contemplate any state-specific circumstances.[13]

Promulgating a federal plan in a state without an opportunity for public comment also would depart from EPA's past practices without a reasoned explanation for (or even acknowledgement of) the agency's change in position.[14] *See, e.g.*, 76 Fed. Reg. 38,748, 38,750 (July 1, 2011) (finalizing a Federal Plan under the Clean Air Act ("CAA") for Indian country after "an extensive outreach and consultation period . . . along with an extensive public comment period"); *Ober v. Whitman*, 243 F.2d 1190, (9th Cir. 2001) ("EPA proposed the FIP in April 1998, and after public comment adopted a final federal plan in August 1998."); *see also FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515-16 (2009) (holding that agencies that fail to supply a "reasoned explanation" for a change in position act arbitrarily and capriciously).

Denying the public an opportunity to comment would also deprive EPA of valuable state-specific information. In addition, in signaling that it does not plan to provide for public comment when a state receives a federal plan, EPA appears to assume that all federal plans will be identical, or at least substantially similar, and will not account for state-specific circumstances or needs. Such a cookie-cutter approach would be inflexible and unworkable and would almost certainly be found by a court to be arbitrary and capricious.

B. EPA Must Include An Initial Reliability Review Mechanism As Part Of Its Review Process For Approval Of State Plans Or Federal Plans Applicable To A State.

EPA should consider reliability at the time it proposes to issue a federal plan for a particular State or to approve a state plan. In the preamble to the Proposed FP/Model Trading Rules, EPA states that it is considering reliability in development of the federal plan. 80 Fed. Reg. at 64,981-82. However, it appears that EPA has confined its consideration of reliability to

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[13] Because no state-specific provisions are contemplated in the proposed federal plan, a state-specific FP could not be considered a logical outgrowth of the proposal.

[14] The CAA refers to "promulgation" of a federal plan, invoking the terminology of APA notice-and-comment rulemaking and providing further support for APA procedures here. *See* 42 U.S.C. §§ 7410(c)(1)(B), 7602(y).

its formulation of the model trading rules, which cannot account for state-specific reliability issues that may later arise. EPA also fails to propose a specific mechanism or provide any explanation of how EPA will evaluate reliability adequacy in imposing a federal plan or approving a state plan. EPA should establish such a process in the final federal plan rules to ensure that it considers reliability at the appropriate time to ensure that EPA conducts a meaningful, case-specific review of reliability requirements.

C. EPA Must Adopt A Dynamic Reliability Safety Valve To Ensure That Electric Reliability Will Be Maintained Under A Federal Plan.

Contrary to EPA's claim, the proposed federal plan has not "been designed to ensure that, to the greatest extent possible, implementation would not interfere with the power sector's ability to maintain electric reliability" because EPA has failed to include a dynamic reliability safety valve. 80 Fed. Reg. at 64,981-82. EPA has included robust reliability safety valve provisions in other rulemakings affecting the electric utility industry (*e.g.*, the Mercury and Air Toxics Rule) to ensure that individual sources can meet unexpected electricity needs, such as might occur during heat waves, extreme cold spells, or due to the unexpected retirement or failure of other units, such as nuclear units. EPA even nominally included a reliability safety valve in the 111(d) Rule, although that provision is much more limited than in other rulemakings.[15] Despite that inclusion, EPA has not included a reliability safety valve in the proposed federal plan.

EPA also asserts, vaguely, that it is considering reliability as part of developing the federal plan by consulting with planning authorities during the comment period. 80 Fed. Reg. at 64,981. EPA has not explained how it intends to meaningfully consider reliability or to address reliability in any final federal plan. In any event, consideration of or provision for reliability cannot truly be effective without an express dynamic reliability safety valve provision.

1. A Dynamic Reliability Safety Valve Is Critical To Ensure Uninterrupted Electric Grid Operation.

As NRECA explained in its comments on the proposed 111(d) Rule, "[t]he resources on the grid and their ability to serve consumers' energy needs change dynamically in response to intentional and unintentional changes in grid architecture, changes in market design and market conditions for the different participants, changes in technology, fires, floods, ice storms, and even economic growth and contractions." NRECA Comments at 166; *see also id.* at 166-68. Events that affect reliability – thereby affecting a particular EGU's need to generate more

[15] The 111(d) Rule provides a one-time, 90-day reprieve from emission standards, after which time the state plan must be amended to account for the increased emissions from a reliability-critical event. 80 Fed. Reg. at 64,877-78; 40 C.F.R. §§ 60.5785(e), 5870(g)(1). NRECA has submitted an administrative petition for reconsideration for the 111(d) Rule on the basis that (1) the public was not given an opportunity to comment on the limited safety valve provision EPA adopted in the final rule and (2) that the new safety valve provision in the final 111(d) Rule is unduly restrictive, allowing for only a single 90-day period in which the affected EGU is permitted to meet a standard other than the emission standard established for the EGU under the relevant State plan. *See* 80 Fed. Reg. at 64,877; *see also* 40 C.F.R. § 60.5785(e).

electricity than anticipated and resulting in increased CO_2 emissions – also include large changes in available electric generation or electric transmission capabilities, fuel shortages or costs that impair the ability to acquire fuel, including fuel transportation shortfalls, extreme weather events, natural disasters, acts of war, or changes in the laws, regulations, and rules affecting resource availability.[16]

To ensure that reliability is not jeopardized by unforeseen and unavoidable circumstances or systemic changes in the availability and operability of electric energy resources, EPA must put in place in any federal plan a sufficiently dynamic reliability safety valve (as detailed below) that allows affected EGUs to request and obtain meaningful relief for affected states, regions, and utility entities in an approved state or multi-state plan or in a federal plan.

Such a safety valve must apply to *all* affected units, including nuclear generating units. EPA should also consider a valve specific to nuclear units because of the risk of extended outages at nuclear plants. Under the existing plan, an extended outage could have devastating consequences for compliance. States operating both under state and federal plans are now faced with either maintaining excess capacity as a backup source of generation for their nuclear EGUs, or with the possibility that they will have to purchase large amounts of emission reduction credits ("ERCs") quickly, likely driving up the costs of those compliance instruments.

2. EPA Cannot Reply On the 111(d) Rule's Resource Adequacy and Reliability Analysis.

To the extent EPA is partially attempting to rely on the resource adequacy and reliability analysis performed for the 111(d) Rule to support a finding that its proposed FP/Model Trading Rules will not affect reliability, *see* 80 Fed. Reg. at 64,982, the Reliability TSD provides no such support. The Reliability TSD relied on the assumption that States would have the flexibility to design State plans to fit their unique circumstances and to take into account any resource adequacy or reliability constraints and on the limited reliability safety valve provision in the 111(d) Rule. Reliability TSD at 1-2. Those elements are absent from the proposed federal plan or model trading rules. As UARG contends in its comments on the proposed plan, EPA also must perform a resource adequacy and reliability analysis specifically for the proposal.

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[16] *See, e.g.,* ERCOT Analysis of the Impacts of the Clean Power Plan, *Final Rule Update* (Oct. 16, 2015), *available at* http://www.ercot.com/content/news/presentations/2015/ERCOT_Analysis_of_the_Impacts_of_the_Clean_Power_Plan-Final_.pdf (recognizing that unanticipated retirements could "pose challenges for maintaining grid reliability . . . . if multiple unit retirements occur within a short timeframe, there could be periods of reduced system-wide resource adequacy and localized transmission reliability issues"); Lanny Nickell, SPP Presentation to CenSARA, "Regional Implications of the Clean Power Plan" at 22 (Oct. 21, 2015) (reporting that there is "a risk of electric service interruptions and potential violations of NERC standards" if Clean Power Plan compliance begins and generator retirements occur before generation and transmission infrastructure is added or if replacement generation capacity is added before additional transmission infrastructure is built).

3. EPA Should Adopt A Robust Dynamic Reliability Safety Valve In Any Federal Plan.

Reliability concerns pose one of the major barriers to effective compliance with the 111(d) Rule, and NRECA therefore urges EPA to adopt the robust dynamic safety valve provision outlined below. A workable and dynamic mechanism to provide necessary grid and electric supply reliability would include, *inter alia*, the following elements:

- **Identification of triggering events**, including unforeseen and unavoidable circumstances or systemic changes in the availability and operability of electric energy resources. Triggering events should include (but not be limited to) large changes in available electric generation or transmission capabilities; fuel shortages or costs that impair the ability to acquire fuel, including fuel transportation shortfalls; extreme weather events; natural disasters; acts of war; or changes in the laws, regulations, and rules affecting the availability of electric generation, transmission capabilities, or fuel.

- **Clarification of who may apply for relief:** the owner and/or operator of an affected EGU should be permitted to petition EPA for relief, joined by an affected State or States, a RTO/ISO, and/or NERC-certified balancing authority (but such joinder should not be required).

- **Revised content for a petition for relief, including:**

    - A description of the circumstances relating to adequate and reliable electric service that petitioner(s) believe make full or timely compliance with a state or federal plan's emission reduction budget, target, or milestone impossible, impracticable, or unreasonable;

    - An accounting of the amount by which CO_2 emissions are likely to exceed the budget, target, or milestone in order to ensure adequate and reliable electric service and an estimation of the duration of the anticipated exceedance;

    - A description of actions that have been or may be undertaken to remedy or mitigate the exceedance while ensuring adequate and reliable electric service, or an explanation of why such actions are impossible, impracticable, or unreasonable;

    - If mitigating actions are identified, an explanation of which actions the State, region, or entity has implemented or proposes to implement, together with an implementation schedule and an estimate of annual CO_2 emissions deviations from the state or federal plan during and following implementation of the selected actions; and

    - A request for temporary or permanent adjustment in the State, region, or entity's emission budget, target, or milestone as the situation requires.

- **Expanded available relief and remedial actions:** Petitioners should be able to request prospective and/or retrospective relief from a CO_2 emissions budget, target, or milestone on an annual or multi-year basis to the extent required and based on the annual CO_2 emissions deviations estimated in the petition. EPA would have the right of annual review to ascertain that affected States, regions, and/or entities granted relief are taking the remedial actions specified in the petition to remedy the triggering circumstances (*i.e.*, the circumstances that necessitated the granted relief). Should such remedial actions become no longer viable, the affected parties should have the right to submit a revised petition identifying the factors causing the originally-identified remedial actions to be no longer viable and proposing different remedial actions or, if necessary, further relief from the state or federal plan's emission budget, target, or milestone.

- **Scope of relief:** EPA should not, as a condition of petition, approval or partial approval, require emissions offsets and should not impose noncompliance penalties for any actions or inactions that are the subject of an approved petition or partially approved petition. Such relief should include, but not be limited to, adjustments in the compliance obligations of the affected EGUs. The availability of relief should not be limited to any particular number of triggering events, but should be granted whenever warranted. EPA should allow the relevant state or federal plan to be amended to the extent required to reflect the relief granted.

- **Necessary due process and procedural protections, including:** A petition for relief that is submitted prior to an emissions compliance or true-up date should toll that date until EPA approves or denies the petition. EPA should be required to evaluate the petition for completeness within a reasonable time, not to exceed 60 days after submittal. EPA also should be required to request additional information within that 60-day period if additional information is needed to complete the petition. Within 30 days after the initial 60-day period has run, or if additional information is submitted in response to a request by EPA, within 30 days after such information is submitted, EPA should propose to either grant or deny the petition, or to grant the petition in part and deny the petition in part, and should submit that proposal to the *Federal Register* for publication. EPA should take comment on its proposed action for a period of 30 days. After considering any comments submitted, EPA should take final action within 30 days of the close of the comment period in accordance with 42 U.S.C. § 7607.

- **Mandatory consultation with FERC on reliability:** FERC should be the lead agency on matters related to the reliability of the bulk electric system, consistent with FERC's authorities under the Federal Power Act and in light of FERC's extensive expertise. Accordingly, EPA should request consultation with and guidance from FERC in matters relating to reliability of the bulk electric system as contained in a petition for relief and shall give deference to FERC's response. EPA should not be permitted to deny a petition in whole or in part without requesting such consultation from FERC. As part of its responsibilities under the Federal Power Act, FERC as appropriate should address whether the triggering event described in the petition will affect the bulk electric system in such a way that is detrimental to adequate and reliable electric service. FERC should be required to provide its findings to EPA within 30 days for use in evaluating the petition for relief. EPA could depart from FERC's recommendations relating to reliability of the bulk electric system only if EPA adequately explains its reasons for doing so and does not act arbitrarily and capriciously.

- **Provision for final agency action and judicial review:** EPA's action granting or denying a petition for relief in full or in part should be considered a final agency action. EPA's failure to act on a petition within the time periods provided under the dynamic reliability safety valve provision should also be considered final agency action, reviewable in the United States Court of Appeals for the appropriate circuit in accordance with 42 U.S.C. § 7607(b).

These provisions will more effectively ensure reliability than the limited provision in the 111(d) Rule. A one-time, 90-day reprieve from emission standards – never to be repeated regardless of what exigencies may arise in the future – simply is not sufficient to ensure the reliability of the nation's electric supply. EPA should adopt those elements in any final federal plan and provide for such a provision in the model trading rules.

4. Trading Cannot Replace a Dynamic Reliability Safety Valve.

EPA contends that a trading program provides all the flexibility necessary to ensure reliability through the purchase of Emission Reduction Credits ("ERCs") or allowances, 80 Fed. Reg. at 64,982, but a trading program is simply *not* a sufficient substitute for a robust reliability safety valve provision. If affected Electric Generating Units ("EGUs") are, for any reason, not able to purchase sufficient ERCs or allowances to make up for increased generation resulting from an emergency event,[17] the individual EGU and/or the state as a whole would be unfairly penalized because the allowances would then be taken from the state's overall goal.

5. Without a Reliability Safety Valve Provision, the Federal Plan is Impermissibly More Stringent than the 111(d) Rule.

EPA's failure to include a reliability safety valve provision in the proposed federal plan, while at the same time including a safety valve in the 111(d) Rule (albeit a limited one), renders the proposed federal plan *more stringent* than EPA's emission guidelines for existing sources, in direct contravention of 40 C.F.R. § 60.27(e)(1), which bars a federal plan from being more stringent than the corresponding emission guideline it implements. The 111(d) Rule provides a one-time, 90-day reprieve from emission standards, after which time the state plan must be amended to account for the increased emissions from a reliability-critical event; there is no corresponding provision in the federal plan.

EGUs operating under a federal plan would also be disadvantaged in relationship to EGUs operating under state plans because units operating under a federal plan would not be granted even the initial 90-day period during which a reliability-critical affected EGU is excused from meeting the applicable emission standard under the 111(d) Rule. Any excess emissions would count against the state's overall emission goal or rate for affected EGUs immediately.

D. EPA Should Finalize Both Rate-Based and Mass-Based Federal Plan Approaches And Provide To The States The Clear Discretion To Choose A Rate-Based Or Mass-Based Plan

[17] The allowances or credits could be too expensive or simply unavailable, for example.

EPA has invited comment on whether it should finalize a single approach – either a rate-based or mass-based approach – for every state in which it promulgates a federal plan. 80 Fed. Reg. at 64,968-70. The agency has expressed a preference for finalizing only a single approach, however, and clearly favors a mass-based trading approach as "more straightforward to implement compared to the rate-based trading approach, both for the industry and for the implementing agency." 80 Fed. Reg. at 64,970. NRECA urges EPA to finalize *both* approaches to provide the maximum amount of flexibility to address state-specific circumstances. EPA, the states, and industry do have more experience with mass-based programs, but there may also be advantages to rate-based programs like avoidance of the leakage issue or characteristics that makes a rate-based program more appropriate for a particular state. There is no compelling reason to foreclose such flexibility.

In addition, if only one type of federal plan is available (*e.g.*, a mass-based approach), States that have adopted different approaches (*e.g.*, a rate-based approach) may be at a disadvantage and may be effectively coerced into adopting EPA's preferred approach. Moreover, if a state has developed a rate-based plan and energy producers within the State have relied on that plan in any respect in planning their generating resources, the switch to a mass-based federal plan following full or partial disapproval of the state's plan could lead to massive disruptions. These outcomes would be flatly inconsistent with EPA's stated intent to provide the states with maximum flexibility to meet the goals of the final rule.[18] *See, e.g.*, 80 Fed. Reg. at 65,968.

E. EPA Should Allow Trading Between Mass- and Rate-Based States

Under the Proposed Rule, EGUs in states subject to the Federal Plan or Model Trading Rules would be allowed to trade compliance instruments – either allowances or ERCs – with EGUs in states that use compliance instruments denominated in the same "currency" – that is, ERCs for rate-based plans and allowances for mass-based plans.[19] EPA proposes not to allow EGUs subject to a mass-based plan to use ERCs for compliance.[20] Likewise, EGUs subject to a rate-based plan would not be allowed to use allowances to demonstrate compliance.[21] Although we understand that allowing trading among EGUs subject to different types of plans might pose some technical difficulties, these barriers should not prevent EPA from allowing trading between mass- and rate-based states, including states subject to mass- or rate-based Federal Plans. As we explain below, EPA should allow EGUs in *both* mass- and rate-based states to demonstrate compliance using compliance instruments issued by *either* mass-based or rate-based states so long as they employ a conversion mechanism like that described below.

1. Rationale for Allowing Trading Between Mass- and Rate-Based States.

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[18] For similar reasons, NRECA recommends that EPA finalize both rate- and mass-based model trading rules. *See* Part IV.A below.

[19] 80 Fed. Reg. at 64,976.

[20] *Id.*

[21] *Id.*

As EPA recognizes, allowing EGUs to trade compliance instruments has the potential to reduce dramatically compliance costs and risks and improve EGUs' abilities to maintain reliability even in cases of unforeseen circumstances.[22] However, these benefits can only be realized if the market for compliance instruments is both large and efficient. The possibility that some states would choose to implement the 111(d) Rule using a mass-based approach while others select a rate-based approach, when combined with EPA's proposed prohibition on trading between mass- and rate-based states, could unnecessarily limit the size of the market for compliance instruments and therefore be a significant regulatory barrier for realizing these benefits of emissions trading.

In effect, unless EPA authorizes trading between mass- and rate-based states, the U.S. power grid could become "balkanized" – divided between states (including those subject to Federal Plans) employing a rate-based approach and those employing a mass-based approach. On the other hand, allowing EGUs in rate-based states to utilize compliance instruments issued in mass-based states and *vice versa*, would facilitate each state's (and EPA's) ability to adopt the compliance approach that works best for the EGUs in its jurisdiction, while also allowing EGUs and their customers to realize the benefits of trading with the greatest possible number of counterparties. This flexibility may be particularly important for electric utilities with generating assets that may spread across states with different regulatory approaches. Allowing EGUs to convert between ERCs and allowances would facilitate these utilities' ability to optimize their compliance approach across their entire fleet, which could reduce the overall cost of achieving the required emission reductions.

Furthermore, allowing such trading is not prohibited by statute; nor has EPA adequately explained its rationale for limiting compliance instrument trading only to states that employ the same type of compliance approach. Additionally, as we demonstrate in the next section, EPA can easily design a system that allows for such trading without adversely impacting the overall CO_2 emission reduction goals of the Clean Power Plan.[23]

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[22] *See, e.g.,* Proposed Rule, 80 Fed. Reg. at 64,977 ("The EPA believes that a broad trading region provides greater opportunities for cost-effective implementation of reductions compared to trading limited to a smaller region.").

[23] Some have argued that allowing trading between mass-based programs and rate-based programs will increase overall emissions by creating gains from trade that result in higher operation of units in rate-based systems than would otherwise occur. *See* Carolyn Fischer & Clayton Munnings, *Comments on Allowance Trading between States with Mass- and Rate-Based Policies*, in Comments by RFF Experts on EPA's Clean Power Plan 26, 26-28 (Dec. 6, 2014) *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-23042. This critique should not limit trading between rate-based and mass-based instruments under the Clean Power Plan for three reasons. First, EPA has set up a program that relies primarily on emission *rates*. Increasing the operations of units in rate-based states – including due to reduced costs of compliance facilitated by trading *between rate-based states* – is already permitted and expected under the Clean Power Plan, with or without compliance trading. Adopting a policy that limits this incentive effect in the context of rate-to-mass trading but not other kinds of trading would be arbitrary. Second, it is not clear that there will be an (Continued...)

2. Mechanism for Converting Between ERCs and Allowances.

The principal technical challenge to the trading of compliance instruments between rate- and mass-based states is the fact that these instruments are denominated in different units: MWh for ERCs, and short tons for emission allowances. Another key technical issue is that ERCs represent "the emissions-reducing effects of specific activities,"[24] whereas allowances represent the authorization to emit a specific amount of CO_2.[25]

To be useful for EGUs complying with mass-based limits, ERCs would have to be converted to a mass-based equivalent (*i.e.*, shorts tons). As we explain below, EPA could allow ERCs to be denominated or converted to a defined number of short tons based on a specified conversion factor. Upon conversion, the ERC would be removed from the compliance tracking system in the rate-based state (to ensure that no EGU could use it for compliance in a rate-based state), and a new emission allowance would be created in the tracking system for the mass-based state. Once converted to short tons, the resulting compliance instrument would be interchangeable with other emission allowances issued by the states (or EPA) under a mass-based plan. EGUs that wish to use these converted emission allowances for compliance would be required to follow the same rules that apply to the use of other emission allowances.

No such conversion between allowances and ERCs would be required for EGUs subject to a rate-based limit, because allowances can be used directly to reduce EGUs' adjusted emission

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incentive to shift generation under the Clean Power Plan because, unlike in a typical rate-based trading system, virtually all compliance units will be required to purchase credits from third parties. Any shift of generation from mass-based to rate-based states will require the purchase of additional ERCs, limiting this incentive. Third, there is some reason to believe that in circumstances such as this, where the regulated commodities under the rate-based and mass-based programs (*i.e.*, electricity) act as substitutes, trading can reduce overall emissions by reducing the costs of compliance in the mass-based state, thereby *reducing* the incentives created by the Clean Power Plan to shift generation from capped mass-based states to uncapped rate-based states. This emissions decrease may very well outweigh any emissions increase caused by the incentive effect to generate more from EGUs in a rate-based state due to lower compliance costs in that state. *See* Carolyn Fischer, Resources for the Future Discussion Paper 03–[32], *Combining Rate-Based and Cap-and Trade Emissions Policies* 10-12 (May 2003), *available at* http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-DP-03-32.pdf. This is particularly true where, as is expected, the trade of credits is likely to be from rate-based states to mass-based states – thereby driving *down* the demand for (and therefore the price of) emission allowances while driving *up* the demand for, and therefore price of rate-based credits. We would be happy to provide further analysis of this issue to the extent it is of interest to EPA.

[24] 80 Fed. Reg. at 64,724 (111(d) Rule); *id.* at 64,746 ("Increases in generation by NGCC units over baseline levels can also serve as the basis for creation of CO_2 ERCs—that is, instruments representing the ability of incremental electricity generated by NGCC units to cause emission reductions at affected steam EGUs.").

[25] *Id*. at 64,835 n.794.

rates under a rate-based program. To enable the use of allowances in rate-based systems, the tons represented by the allowances could simply be subtracted from the numerator of the rate-based compliance calculation to reflect the fact that the EGU holds an authorization to emit an equivalent number of tons of CO_2. As we explain below, this method maintains the stringency of the 111(d) Rule and avoids double-counting emission reductions.

Calculating the conversion factor for ERCs. States (and EPA, in its role as the administrator of a Federal Plan or Plans) could allow EGUs to convert ERCs (denominated in MWh) to allowances (denominated in tons) by using a conversion factor based on the number of additional tons that each additional ERC would allow an affected EGU to emit if the ERC were used for compliance under a rate-based system. The discussion below provides an explanation for calculating the conversion factor for determining this number of tons.

In a rate-based compliance system, EGUs in the state must meet the applicable emission rate by surrendering a sufficient number of ERCs and/or reducing their emissions such that each EGU's adjusted emission rate (after accounting for the unit's generation and ERCs) remains at or below the applicable rate-based limit. As long as the ratio of emissions to generation (including ERCs) is equal to or less than the applicable rate-based limit, the unit would be considered in compliance.

In a rate-based system that is already in compliance with the rate-based limit, the availability of *extra* ERCs beyond the number of ERCs needed for compliance can allow EGUs to increase their CO_2 emissions by a specific, known amount. As we demonstrate in Appendix A, the amount of additional tons of CO_2 that EGUs in a rate-based state could emit for every extra ERC is directly related to the rate-based limit for the state. *Specifically, for every additional MWh of ERCs available in a rate-based system, EGUs in the rate-based system can increase their emissions by at least the number of pounds in the numerator of the applicable rate limit*.[26]

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[26] Note that in practice, EGUs could increase their emissions by more than this amount. For example, if an EGU increased its emissions but also produced additional MWh of generation at the same time, it could increase total emissions by an even greater amount than the calculation shown in Appendix A. *See* EPA's CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule [Dkt. EPA-HQ-OAR-2013-0602] (Aug. 2015) ("Goal Computation TSD"), *available at* http://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents. In the Goal Computation TSD, EPA assumes that each extra "zero-carbon" MWh – i.e., each extra ERC – enables EGUs to increase their emissions by *twice* the applicable rate limit. *See* Goal Computation TSD at 24 ("every zero-emitting MWh added to the denominator of an EGU's effective emission rate would enable that EGU to add another MWh of generation with twice the emissions intensity of the applicable rate-based standard, because the average intensity of that emitting MWh combined with the zero-emitting MWh would then equal the applicable rate-based standard and thus maintain that EGU's compliance."). This assumption is correct if each additional MWh produced by EGUs in response to the availability of extra ERCs leads to an additional output of emissions at exactly twice the emission rate as the state-wide goal. Note, however, that the availability of extra ERCs does not always allow EGUs to emit at exactly twice the applicable rate limit. For example, if an EGU's (Continued...)

(Another way to think about this is that for every MWh of ERCs removed from a rate-based state, EGUs in the state must *reduce* their total allowable emissions by the number of pounds in the numerator of the rate-based state.)

The minimum amount of additional emissions allowed by an additional ERC in a state that does not need the ERC for compliance is always the same, and it is always equal to or greater than the numerator of the applicable rate-based limit for the EGU or the state. Note that the numerator of the rate-based limit is the *minimum*, because if the EGU were to increase its *generation* (in MWh) at the same time that it increased its emissions (*e.g.*, by increasing its net electric output), it would be able to add additional MWh to the denominator at the same time that it added emissions to the numerator, thus facilitating an even *greater* increase in total emissions than if it had only increased its emissions but not its generation.[27] (*See* Appendix A for additional numerical examples).

Because each ERC allows EGUs to produce at least this amount of additional emissions, if an ERC is removed from the rate-based state such that it can no longer be used for compliance, EGUs in the state would be unable to emit this additional number of pounds. *Thus, the removal of an ERC from a rate-based state for conversion to a tradable emission allowance prevents or avoids the emission of a known quantity of CO_2.* As long as the rate-based state or EGU must remain in compliance with its rate-based goal (after subtracting out the ERC), this quantity of CO_2 could be offset by an equivalent increase in allowable emissions in a mass-based state without affecting the total number of tons of CO_2 emitted allowed under the 111(d) program. This is because any increase in emissions in the mass-based state allowed by the converted ERC would be offset by an equivalent decrease in emissions in the rate-based state, leading to no net increase in overall system-wide emissions under the 111(d) program. In this sense, trading between rate- and mass-based states would be similar to trading between mass-based states, in

actual emission rate were higher than the applicable emission rate, the availability of an extra ERC would enable the EGU to generate less than one extra MWh and therefore it would be able to increase its emissions by somewhat less than twice the applicable emission rate. Similarly, if the EGU increased its emissions without increasing generation (*e.g.*, by operating at a lower efficiency than normal or by turning on pollution control equipment that required electricity to operate), it would only be able to increase emissions by one times the applicable rate-based limit. Other outcomes – including the ability to emit at more than twice the emission rate – are also possible, depending on the actual emission rate of the EGU. Appendix A provides further examples to demonstrate these points.

[27] It is theoretically possible for an EGU to increase its emissions but not its net generation. For example, if the EGU installed or operated new pollution control equipment that required extra electricity to operate (*i.e.*, imposed a parasitic load), it could see somewhat higher emissions without increasing its net generation (relative to a situation in which it operated without the pollution control equipment). Likewise, if the EGU needed to operate at a lower efficiency than normal – for example, as a result of partial loading – this could also lead to greater emissions per MWh.

which the increase in emissions in the "importing" state is directly offset by the decrease in emissions in the "exporting" state, ensuring no change in overall emissions.[28]

Selection of the Appropriate Rate-Mass Conversion Value. Because the amount of extra emissions is directly related to the applicable rate-based limit, the other key question involved in converting ERCs to allowances is what rate limit is the correct limit to use for conversion. The most appropriate approach would be to establish a single uniform national conversion rate for all surplus ERCs generated in any state that would apply regardless of the form of rate-based plan to which the state is subject.

Under this approach, EPA could require that EGUs converting ERCs to allowances use as the "conversion rate" the *blended nationwide emission rate limit* for the interim and final compliance periods. This limit could be obtained by weighting the nationwide subcategorized rate-based limits by the 2012 nationwide share of generation from affected fossil steam and gas turbine units to derive a single nationwide rate (similar to EPA's approach for calculating blended state-wide rates). For the interim period, this "reference rate" limit would be 1,257 lbs./MWh; for the final period, the reference rate would be 1,095 lbs./MWh.[29] This approach is justified because if EPA authorizes rate-to-mass trading, all states would effectively be able to join a single trading program, and so the combination of their state-wide rates would be an appropriate, common yardstick (or "reference rate") against which to measure the emissions impact of an ERC, regardless of where it is issued or used for compliance.

This approach is also preferable because, by relying on a single nationwide reference rate, EPA would ensure that all ERCs would have a common, constant tonnage equivalent value, regardless of the state that issued them. This approach would facilitate trading better than any alternative because it would establish a simple, nationally uniform, and transparent reference rate for ERC conversation that all stakeholders would be familiar with in advance.

Application of the conversion factor to ERCs. States employing rate-based trading systems could calculate the associated tonnage reduction value at the same time that they issue the ERC, and this value could be included among the "attributes" of each ERC along with its

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[28] *See* 80 Fed. Reg. at 64,893, n.928 (explaining that the stringency of the CPP emission limits is assured even when allowing for allowance trading between linked states "because under such linked programs, CO_2 emissions from affected EGUs in one state that exceed a state's mass CO_2 goal (or mass-based CO_2 goal plus new source CO_2 emission complement) would be accompanied by CO_2 emissions from affected EGUs in another linked state that are below that state's mass CO_2 goal (or mass-based CO_2 emission complement).").

[29] These figures are calculated using the figures and formulas in Appendix 1-5 to the Goal Computation TSD, *available at* http://www2.epa.gov/sites/production/files/2015-11/tsd-cpp-emission-performance-rate-goal-computation-appendix-1-5.xlsx. According to EPA's figures, generation from fossil steam units constituted 61 percent of affected EGU generation in 2012, while gas turbine generation accounted for 39 percent.

MWh value, its serial number, and any other information the state or EPA requires to allow transparent ERC tracking and retirement. Thus, ERCs issued during the interim compliance period would be assigned an allowance value of 1,257 lbs., even if they were ultimately banked and surrendered for compliance during the final compliance period. ERCs issued during the final compliance period would have a value of 1,095 lbs., reflecting the reference rate for that period. This approach is justified because each such converted ERC could be traded and used for compliance by an EGU immediately upon issuance, which means that the most appropriate "avoided emissions" value for the ERC is related to the rate-based limit that applies when the ERC is first issued.

Furthermore, this approach is greatly preferable to the alternative of calculating the avoided-emissions value after the fact, at the time that an EGU in a mass-based state requests that an ERC be converted from MWh to tons for use in a mass-based program. The up-front conversion approach greatly simplifies the administrative process by avoiding a second step in the process of having to quantify the avoided-emission value of the ERC at the time the credit is used for meeting its compliance obligation under the 111(d) program.

Using emission allowances for compliance in rate-based systems. No conversion would be needed to allow EGUs in rate-based systems to use emission allowances for compliance. Because each emission allowance represents a right to emit a short ton (2,000 lbs.) of CO_2, these allowances can be used directly to reduce the adjusted emission rate of EGUs subject to a rate-based limit. EGUs subject to a rate-based limit would simply subtract 2,000 lbs. from their reported emissions for each allowance surrendered for compliance, resulting in a lower overall emission rate. The surrender and retirement of each allowance by the EGU in the rate-based state would allow an EGU in the rate-based state to emit 2,000 lbs. more than it could without the allowance, while *preventing* an EGU in a mass-based state from emitting the same amount. Thus, the integrity of the program would be maintained and overall emissions across the system would be equivalent to a more restrictive system in which the allowances could only be used for compliance by EGUs subject to mass-based limits.

No double-counting would occur. Allowing states to convert between ERCs and allowances as described above would avoid double-counting emission reductions while ensuring that EGUs comply with the applicable emission limits. When ERCs are converted from MWh to tons and used by an EGU to comply with a mass-based limit, the additional emissions that the converted ERCs would allow in the mass-based state would be offset by a corresponding emission reduction (or avoided emissions) that would result from the conversion and retirement of those ERCs in the rate-based state. Likewise, where emission allowances are used in a rate-based state to allow an EGU to emit more CO_2 than it would have been allowed to emit without surrendering the emission allowances, the removal of those emission allowances from the pool of allowances available in the mass-based state would ensure that an emission increase in the rate-based state would be offset by an equivalent reduction in the overall emissions allowed in the mass-based state. In fact, as the examples in Appendix A demonstrate, the conservative approach that we suggest here would significantly *underestimate* the actual amount of avoided emissions that could result from converting an ERC to an allowance in many cases. Thus, if EPA authorizes rate-to-mass trading as we suggest here, it is possible that power sector emissions would be even lower than under EPA's current approach.

In sum, allowing EGUs to trade compliance instruments between mass- and rate-based states (including states subject to the Federal Plan) is technically feasible and could be relatively simple to administer. Moreover, it is not prohibited by statute and would result in emissions reductions that are at least equivalent to – and potentially more stringent than – a system in which such trading was not allowed. Finally, and most importantly, allowing such trading between mass- and rate-based programs would enable the creation of the largest possible market for compliance instruments, thereby reducing costs and enhancing compliance flexibility as well as electric reliability for all states and EGUs. For these reasons, EPA should allow such trading to occur between mass- and rate-based plans – both between states that submit their own implementation plans and between such states and states subject to the Federal Plan.[30]

F. EPA Has Not Fulfilled Its Statutory Duties to Consider Remaining Useful Life and to Allow States to Consider Remaining Useful Life And Other Relevant Factors.

As the Supreme Court recently held in its consideration of the Mercury and Air Toxics Standards (MATS) rule, an "agency action is lawful only if it rests 'on a consideration of the relevant factors.'" *Michigan v. EPA*, 576 U.S. ___ (Slip Opinion p. 5) (2015) (citing *Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 43 (1983)). Section 111(d) expressly instructs EPA to permit the State in applying a standard of performance to any particular source under a plan to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies. EPA, however, has not provided for such consideration in the proposed Model Trading Rules. Section 111(d) also *directs* EPA, if imposing a federal plan itself, to "take into consideration, among other factors, remaining useful lives of the sources to which such standard applies." EPA has not satisfied those requirements. 42 U.S.C. § 7411(d)(1), (2). NRECA therefore proposes that EPA incorporate a variance provision into the general federal plan and amend the model trading rules to expressly permit States to factor the remaining useful life of each facility into state plans that incorporate trading.

1. EPA Should Modify The Model Rules To Allow States To Consider The Section 111 Factors When Setting Performance Standards, Including Remaining Useful Life.

The plain language of CAA section 111(d)(1) setting forth each State's authority to establish "standards of performance" for existing sources, as well as the definition of "standard of performance" in section 111(a)(1), allows States to set each source's standard of performance based upon consideration of: 1) each source's "remaining useful life," 2) "the cost of achieving such reduction" at each source, and 3) "energy requirements" "among other factors" in setting

[30] Allowing trading between mass- and rate-based states would also diminish the importance of selecting a single type of compliance approach (rate or mass) for the Federal Plan. As we explain above, where a state declines to submit its own implementation plan, EPA should allow the state to choose between either approach.

source-specific "standards of performance" for each existing source. CAA section 111(a)(1), (d)(1), 42 U.S.C. § 7411(a)(1), (d)(1). Section 111(d)(1) states that

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. *Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.*

42 U.S.C. § 7411(d)(1) (emphasis added). The second sentence of section 111(d)(1) unambiguously requires that the "[r]egulations of the Administrator under this paragraph" allow the State "to take into consideration, among other factors, the remaining useful life of the existing source." The "shall" in the second sentence, in fact, makes it a nondiscretionary duty that the "regulations of the Administrator" (i.e., the 111(d) Rule and these model rules) "under this paragraph" (section 111(d)(1)) "shall permit" "the State . . . to take into consideration, among other factors, the remaining useful life of the existing source."[31]

The 1977 amendments to § 111(d)(1) added the provision of the current statute that requires the Administrator to allow States to consider "in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, *among other factors, the remaining useful life* of the existing source to which such standard applies." 42 U.S.C. § 7411(d)(1) (emphasis added). The legislative history for that provision explained that "[t]he section also makes clear that standards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (not necessarily technological) *and must, unless the State decides to be more stringent, take into account the remaining useful life of the existing sources*."[32] That decision is for the State to make, not EPA.[33]

[31] The "among other factors" language refers back to the earlier language in the sentence addressing the State "applying a standard of performance to any particular source under a plan submitted under this paragraph." The definition of "standard of performance" in section 111(a)(1) lists the following as "other factors" that may be taken into consideration under the definition of standard of performance": "taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1).

[32] 1977 U.S.C.C.A.N. 1077 1088, H.R. Rep. 95-294 at 11 (May 12, 1977) (emphasis added).

Both the language of § 111(d)(1) and the legislative history also demonstrate that the "other factors" referred to are the factors listed for states to consider in the special definition of "standard of performance" added to the 1977 Act that applied specifically to § 111(d)(1): "taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements."[34] Moreover, EPA has further defined these "other factors" by regulation, to include: "Unreasonable cost of control resulting from plant age, location, or basic process design;…Physical impossibility of installing necessary control equipment; or…Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable." 40 C.F.R. 60.24(f). States must be allowed to consider all of these statutory and regulatory factors under § 111(d)(1), and EPA should change the proposed model rules to incorporate these statutorily-mandated and present regulatory factors into the final rules.

By failing to include those factors, including remaining useful life, in the proposed model trading rules, EPA has failed to comply with section 111(d) and with its own binding regulations. EPA must incorporate those factors into the final trading rules.

2. EPA Also Has Not Sufficiently Considered Remaining Useful Life In Formulating The Proposed Federal Plan.

EPA has declared that variances from the state goals need not be available to affected EGUs under a federal plan to account for remaining useful life. 80 Fed. Reg. 64,982. Although EPA acknowledges that it must consider remaining useful life in designing a federal plan pursuant to section 111(d)(1), *id.* at 64,982-83; *see* 42 U.S.C. § 7411(d)(2), EPA is "confident the proposed federal plan will not force costly pollution control investments at older plants with short remaining useful lives" because the CEIP will reward over-performance of some affected EGUs and allow others to purchase credits or allowances in lieu of installing pollution controls, 80 Fed. Reg. at 64,983. EPA also claims that it has accounted for remaining useful life because the proposed federal plan allows for long compliance times, early action credit, multi-year compliance periods, and the ability to link to other federal or State plans to create larger trading markets.[35] *Id.* at 64,983-84.

[33] "The committee purposely chose not to dictate a Federal response to balancing sometimes conflicting goals. [It] purposely chose not to dictate what State and local decisions on air quality deterioration must be. Maximum flexibility and State discretion are the bases of the committee's approach. The committee carefully balanced State and national interests by providing for a fair and open process in which State and local governments and the people they represent will be free to carry out the reasoned weighing of environmental and economic goals and needs." 1977 U.S.C.C.A.N. at 1225-26, H.R. Rep. 95-294 at 146-47.

[34] Pub. L. 95-95, Title I, § 109(a)-(d)(1), 91 Stat. 697 to 703 (Aug. 7, 1977).

[35] EPA proposes that affected EGUs in any state covered by a federal plan could trade compliance instruments with affected EGUs in any other state covered by a federal plan or a state plan meeting the conditions for linkage to the federal plan. 80 Fed. Reg. at 64,976.

None of those features truly considers a facility's remaining useful life for a number of reasons. First and foremost, EPA's refusal to allow for variances under a federal plan impermissibly reads out of section 111(d)(1) the requirement that remaining useful life may be expressly considered at the state's option. Second, outside-the-fenceline measures that an EGU owner or operator may take such as trading or investment cannot truly provide an alternative to "costly pollution control investments at older plants" because older plants do not even enjoy the option to install pollution controls (costly or not). EPA has admitted that no pollution controls would achieve the emission standards in the 111(d) Rule to allow existing units to meet the subcategory-specific emission rates. *See, e.g.*, 80 Fed. Reg. at 64,709, 64,717-78, 64,745-46. In fact, expensive pollutant controls that utilities have installed to comply with previous EPA regulations have actually diminished cooperatives' ability to comply with the 111(d) Rule due to the need to use extensive auxiliary electricity to power that equipment.

To comply, units will be forced to engage in trading, curtail generation, or close. Trading may also be an illusory option; affected EGUs will not able to adequately plan for continued operation without knowing what kind of federal trading plan will be imposed or whether the trading system will be affordable. If the relevant trading instruments (credits or allowances) are not affordable, units will be forced to curtail generation or close – naturally choosing closure once generation is reduced to the point where continued operation is no longer economically feasible.

Third, EPA's analysis of this issue also does not comport with statements in the preamble that remaining useful life is properly considered by assessing the time period associated with amortizable costs of compliance: "[t]he key consideration is whether the time period associated with amortizable costs of compliance will exceed the remaining useful lives of the sources in question." *Id.* at 64,983. EPA does not appear to have conducted that assessment, failing to meet even its own standard. If EPA intends to rely on that analysis, it should conduct that assessment and make it available for public comment.

Fourth, EPA cannot rely on potential linkage to a future federal trading program to satisfy its statutory duty to consider an individual unit's remaining useful life. States may adopt rate-based plans rather than EPA's clearly preferred mass-based approach. If an affected EGU is in a minority rate-based state, that unit will not be permitted to link to a mass-based multi-state or federal trading system. NRECA therefore urges EPA to include a variance provision in the final federal plan to fulfill its duty to consider remaining useful life under section 111(d).

3. EPA Must Also Consider Stranded Assets As Part Of The Remaining Useful Life Analysis.

As part of its remaining useful life analysis, EPA also must take into account the risk (and here, likelihood) of that the federal plan will result in the creation of stranded assets. In a footnote, EPA contends that concerns over stranded assets are somehow distinct from the remaining-useful-life factor in section 111(d)(1). 80 Fed. Reg. at 64,982 n.35. Nevertheless, EPA states that it undertook an analysis in the 111(d) Rule of whether and to what extent there may be a stranded asset concern. *Id.* EPA contends that this analysis demonstrates that stranded assets are not likely to be a widespread issue under the federal plan, *id.* but EPA's own IPM modeling contradicts that assertion by identifying units expected to close early under the 111(d) Rule (*i.e.*, stranded assets).

Indeed, many of NRECA's members will be left with stranded assets in attempting to comply with the 111(d) Rule, including Seminole Electric Cooperative in Florida. Seminole's coal-fired Seminole Generating Station ("SGS") has operated at an average capacity factor of 80 percent throughout the last 18 years, has a remaining useful life of at least another 30 years, and generates approximately 58 percent of the total energy that Seminole provided to its members in 2014.[36] In 2014, Seminole's Midulla Generating Station's ("MGS") natural gas combined cycle ("NGCC") unit provided approximately 17 percent of Seminole's total energy needs and, like SGS, has a remaining useful life of at least another 30 years.[37] Although both of those plants have a long remaining useful life, there is no viable, adequately demonstrated environmental control system that Seminole can install at either SGS or MGS to meet the 111(d) Rule's performance rates.[38] Seminole thus may be forced to close those baseload and intermediate load electricity generating facilities to comply with the 111(d) Rule.[39] If those units are forced to retire prematurely, Seminole will be required to obtain costly replacement generation assets or purchase power[40] and it will still be carrying approximately $836 million in outstanding debt associated with the prematurely-retired units.[41] Seminole will be forced to accelerate the depreciation schedules for those units to a significantly shorter useful life, forcing Seminole to raise its electricity rates to try to offset those costs.[42]

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[36] *Id.* ¶ 10.

[37] *Id.* ¶ 13.

[38] Declaration of Lisa Johnson, Seminole Electric Cooperative ¶¶ 7, 24.

[39] *Id.* ¶¶ 7, 24-25. The only other option available to Seminole is to purchase emission reduction credits or allowances through a trading program that *may* be established under the 111(d) Rule, but with the long times necessary to obtain or construct replacement generation, Seminole does not have the luxury of waiting to see if a trading program is adopted in Florida or if such a program (if adopted) will be affordable. *Id.* ¶¶ 25-28, 30-31. All cooperatives will be similarly constrained in their ability to depend on the establishment of an affordable trading program. *See* Jura Decl. ¶ 31; McInnes Decl. ¶ 18; *see also* Rasmussen Decl. ¶ 10 (noting that the Ute Tribe is opposed to cross-border or inter-jurisdictional trading).

[40] Seminole estimates that the total cost of replacing 1,800 MW of capacity generated by SGS and the MGS NGCC unit will be at least $1.8 billion. *Id.* ¶ 28. Seminole could alternatively attempt to purchase power, but regardless of whether Seminole constructs new generation or enters into purchased power contracts with others to achieve compliance, Seminole must also construct a new gas pipeline costing more than $80 million. *Id.* ¶ 30.

[41] *Id.*

[42] *Id.* In addition, Seminole has invested more than $530 million on state-of-the-art environmental control equipment as SGS since the plant came online in 1984 and more than $262.4 million since 2006 alone. *Id.* ¶ 23. If the plant is prematurely closed, that investment will be lost.

Similarly, to comply with the 111(d) Rule, Arizona Electric Power Cooperative, Inc. has determined that it will need to prematurely shutter coal operation of its ST3 coal-fired unit by 2029 and to retire substantial coal assets prior to the time the relevant contracts would have terminated in 2035.[43] San Miguel Electric Cooperative, Inc.'s 400 MW, mine-mouth power plant, which has 22 years of remaining operational life and no plans to retire, is also not expected to survive 111(d) Rule implementation because its average CO_2 emission rate is significantly higher than the 111(d) Rule's emission standard.[44] Associated Electric Cooperative, Inc. reports that the 111(d) Rule could force it "to commit to curtailing or even shuttering a significant percentage of its coal-fired base-load and intermediate electricity generating facilities, including New Madrid Unit 1 ("NM1") alone, or Thomas Hill Unit 1 ("TH1") either alone or in combination with Thomas Hill Unit 2 ("TH2"), by 2022."[45]

The costs of the assets stranded by the 111(d) Rule could be staggering, particularly for non-profit cooperatives. East Kentucky Power Cooperative Inc. estimates that $500 million of its assets will be stranded by the 111(d) Rule.[46] San Miguel Electric Cooperative, Inc. estimates that its debt, decommissioning costs, and mine closure costs resulting from premature closure of its unit will be between $362 and $489 million.[47] Associated Electric Cooperative, Inc. will be carrying approximately $550 million in outstanding debt associated with its prematurely retired unit(s).[48]

EPA should also acknowledge that the concept of stranded assets is broader than unit closures. Some existing units will be able to operate only if severely underutilized because of the reductions of capacity factor necessary to comply with the 111(d) Rule. For example, a facility like Hoosier Energy's Merom Generating Station in Sullivan County, Indiana, would normally run at a 70-80 percent capacity factor, but that capacity factor may need to be reduced to 40 percent to comply with the 111(d) Rule's emission standards. That level of reduced generation will hinder cooperatives' ability to pay down their capital debt or provide sufficient equity to keep the facility operating effectively. Underutilization thus will also leave utilities with stranded assets that EPA has not fully considered as part of this proposal.

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[43] Ledger Decl. ¶ 29.

[44] Brummett Decl. ¶¶ 14, 17-18.

[45] Jura Decl. ¶ 9; *see also id.* ¶¶ 23-25.

[46] Campbell Decl. ¶ 21.

[47] Brummett Decl. ¶ 19. Like other plants, San Miguel will lose the investments it has made in environmental controls, for which San Miguel has invested approximately $130 million. *Id.* ¶¶ 15, 42; *see also* McLennan Decl. ¶ 23 (discussing Minnkota Power Cooperative Inc.'s $425 million of debt incurred to "cover the cost of state-of-the-art environmental upgrades made by Minnkota to achieve compliance with other EPA rules between 2007 and 2011."). In addition, because San Miguel is a mine-mouth plant, it will lose the investments in the adjacent coal mine. Brummett Decl. ¶¶ 30-31.

[48] Jura Decl. ¶ 29.

4. The Federal Plan Should Include A Mechanism To Allow All Units To Qualify For Additional Time For Compliance.

EPA has requested comment on whether it would be possible to grant on a case-by-case basis certain affected EGUs additional time to come into compliance, especially for small entities. 80 Fed. Reg. at 64,981. We support case-by-case time extension for *all* units that qualify, regardless of size. The availability of such an extension is particularly important for single-unit operating entities that cannot trade allowances within their own companies' units and cannot transfer generation among commonly-owned units.

Such a mechanism is already contemplated by EPA's regulations. *See* 40 C.F.R. § 60.27(e)(2) ("Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24(f).").

The option to obtain additional time for compliance is especially critical because the construction, planning, development, coordination, siting, and permitting of energy resources to meet future demand is complex and involves tremendous costs and long lead times.[49] As East Kentucky Power Cooperative, Inc. has explained, "[l]ead times for siting, design, engineering, state and federal regulatory approvals, state and EPA environmental permitting, condemnation proceedings, procurement, construction and commission are a minimum of 6 years for plant modifications alone, and up to 10 years for transmission and natural gas infrastructure changes."[50] Similarly, Minnkota Power Cooperative, Inc. has determined in recent feasibility studies that "it will take as long as 7 years to create a site plan, complete permitting, finalize technology studies, conduct transmission and interconnection studies, complete regulatory filings, confirm fuel source, construct a pipeline, and more to have an operational [natural gas plant]."[51]

G. EPA Should Facilitate Linkage To The Federal Plan Whenever Possible.

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[49] Campbell Decl. ¶ 22.

[50] *Id.*

[51] McLennan Decl. ¶ 20; *see also* Lisa Johnson Decl. ¶¶ 26-28, 30-31 (planning and expenditures for compliance in 2022 must start in mid-2016); Jura Decl. ¶ 28 ("To replace NM1 or TH1 and/or TH2 by 2022, Associated will have to choose and evaluate potential sites and apply for the requisite environmental and local permits *by 2017* . . . ."); McLennan Decl. ¶¶ 14-15 ("A relatively simple project that will not traverse an environmentally sensitive area, require the exercise of eminent domain, or involve significant public opposition will take up to three years prior to construction. More complicated projects that will traverse federal lands, environmentally sensitive areas, or will generate public opposition may require 10 years or more to complete."); Rasmussen Decl. ¶ 12 ("Given the very long lead times involved in electric utility planning and resource acquisition, negotiations are already underway" on baseload power contracts set to expire during the years 2020-2025).

EPA proposes that affected EGUs in any state covered by a federal plan could trade compliance instruments with affected EGUs in any other state covered by a federal plan or by a state plan meeting the conditions for linkage to the federal plan. 80 Fed. Reg. at 64,976. Certain requirements must be met – the State plan must be of the same type (rate or mass) as the federal plan, the State plan must be approved by EPA as a ready-for-interstate-trading plan, and the state must use an EPA-administered tracking system. *Id.* at 64,976-77.

NRECA generally supports as much conformity as possible regarding trading rules and requirements to effectuate as fluid and as transparent a market as possible. We also support broad-based trading capabilities and believe that states with federal plans should be able to link to individual state plans or multi-state plans for trading, including with states that have adopted a state measures approach to include non-affected emissions sources.

To promote those goals, NRECA submits the following responses on issues for which EPA has solicited comment:

1. Tracking systems

EPA has requested comment on expanding the linkage requirements to include a state plan that uses an EPA-designated tracking system that is interoperable with an EPA-administered system. *Id.* at 64,977. EPA should adopt a mechanism by which alternative tracking systems can be used at the state's option to promote flexibility and to lower the potential costs of compliance if a state is already familiar with, or otherwise prefers, an alternative tracking system. If those systems are interoperable, there should be no barriers to allowing states the option to choose a particular system.

EPA has also requested comment on whether states with EPA-designated tracking systems should be required to register with the EPA, which EPA believes would ensure that the tracking systems are functionally interoperable. 80 Fed. Reg. at 64,977. It is not clear how such a registration program would work, or how EPA plans to ensure that the tracking systems are functionally interoperable. More detail from EPA would facilitate meaningful comment on this issue.

2. Differences in measurement

EPA is accepting comment on whether to extend linkage to state plans that issue allowances in metric tons (rather than short tons). 80 Fed. Reg. at 64,977. NRECA supports that option; we believe that the more flexible the federal plan, the more likely it is to be workable, and we support linkage under these circumstances.

H. EPA Should Not Impose Compliance Penalties.

EPA proposes a 2-for-1 ERC administrative compliance penalty and a 2-for-1 allowance administrative compliance penalty when there has been an excess of emissions. 80 Fed. Reg. at 65,010, 65,031. Any EGU that fails to secure sufficient ERCs or allowances by the applicable deadline would be required, after receiving notice of the deficiency, to provide for immediate deduction by EPA of two ERCs or two allowances for every ERC or allowance that the EGU fails to obtain. Those penalty allowances would be in addition to any other ERCs or allowances required for the next compliance period and would be automatic, regardless of any explanation by the owner or operator. NRECA opposes penalty provisions of any kind, particularly if a unit's emissions non-compliance is caused by reliability needs that EPA has failed to account for in the absence of a dynamic reliability safety valve.[52] Units would be unfairly penalized for emergency events beyond their control. Such a penalty provision could also lead to a scarcity of compliance instruments available on the market, heightening reliability concerns in the absence of a dynamic reliability safety valve.

The penalty provisions are not only unfair, but they also are contrary to 40 C.F.R. § 60.27(e)(1), which provides that when promulgating a federal plan for a state, EPA "will prescribe emission standards *of the same stringency* as the corresponding emission guideline(s) specified in the final guideline document . . . ." (emphasis added). By forcing an EGU to obtain additional ERCs or allowances over and beyond the amount needed to make up for the shortfall and beyond those needed to achieve compliance for the next compliance period, EPA proposes to increase the stringency of its emission standards beyond that required under the 111(d) Rule. In particular, for a mass-based system, because the total number of allowances under a state's budget remains the same and is unaffected by the penalty, an EGU would be required to obtain additional allowances which would in turn force corresponding emissions reduction elsewhere on the grid. This is inconsistent with both the regulatory language and section 111(d). EPA should therefore not impose any penalty when there has been an excess of emissions caused by reliability needs or for any other reason.

I. EPA Should Make Clear That It Is Not Proposing To Regulate Modified/Reconstructed Sources As Existing Sources.

In the final 111(d) Rule, EPA declined to regulate modified and reconstructed sources as existing sources but stated that it would re-propose and accept comment on this issue. In the model rule/federal plan proposal, EPA re-raises the issue of whether, when an existing source modifies or reconstructs in such a way that it meets the definition of a new source, it becomes a new source under the statute and is no longer subject to the section 111(d) program. 80 Fed. Reg. at 65,039. In doing so, EPA appears to abandon its earlier proposal claiming authority to regulate modified and reconstructed sources as existing sources, instead taking the position that section 111(a)(2)'s definition of "new source" as including modified and reconstructed sources prevents new, modified, or reconstructed sources from simultaneously being subject to both a section 111(d) State plan and section 111(b) performance standard for the same pollutant.

NRECA agrees with EPA's conclusion that modified and reconstructed sources *cannot* simultaneously be subject to both a section 111(d) state plan and section 111(b) performance standards for CO_2 emissions. Those sources should be treated as modified or reconstructed sources subject to 111(b) regulation. EPA should further clarify that separation in the final rule to avoid misinterpretation.

[52] *See* Part III.C, *supra.*

J. EPA Should Deem Any State Renewable Portfolio Standards Evaluation, Measurement, And Verification Measures Appropriate For 111(d) Compliance

EPA proposes that evaluation, measurement, and verification measures ("EM&V") be required for resources that may generate ERCs or receive allowances under a federal plan and that will be presumptively approvable as part of the model trading rules. 80 Fed. Reg. at 65,002-08. States may also adopt EM&V measures that are "functionally equivalent" to EPA's proposal. *Id.* at 65,002 & n.78. But EPA does not have the authority to require functional equivalency for implementation provisions like EM&V measures *so long as the emission standards under a State plan are at least as stringent as the 111(d) Rule*. Under EPA's section 111(d) implementing regulations, *emission standards* must be as least as stringent as EPA's emission guidelines. 40 C.F.R. § 60.24(c). EPA cannot mandate that state plan provisions that are not directly tied to the stringency of the emission standards be as stringent as the provisions in EPA's model trading rule.

Electric cooperatives have developed a set of fundamental principles governing how the framework for EM&V should be applied. We believe that this framework is consistent with EPA's Draft EM&V Guidance and the requirements described in the model rule. NRECA urges EPA to support this existing framework per the statements in EPA's Draft EM&V Guidance, such as the following statement:

> "In June 2014, the EPA proposed carbon pollution emission guidelines for certain existing EGUs, as well as a 'State Plans Considerations' technical support document (TSD) that outlined a general approach to establishing EM&V requirements and guidance. The TSD proposed that the EPA's EM&V provisions could leverage the industry-standard practices, protocols, and methods currently utilized by the majority of states implementing demand-side EE and RE programs. The EPA further noted that many state PUCs, and other regulatory bodies and program management authorities, already have significant EM&V infrastructure in place, and some have been applying, refining, and enhancing their approaches for over 30 years."[53]

The approach NRECA outlines below incorporates decades of infrastructure. NRECA requests that EPA accept the NRECA framework as the industry best practice for the cooperatives and that EPA work to create certainty and confidence that these best practice approaches will continue to be accepted under EPA's program.[54]

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[53] EPA, Evaluation Measurement and Verification (EM&V) Guidance for Demand-Side Energy Efficiency (EE) (Draft) at 3 (Aug. 3, 2015), *available at* http://www.epa.gov/sites/production/files/2015-08/documents/cpp_emv_guidance_for_demand-side_ee_-_080315.pdf.

[54] *See* http://www.epa.gov/sites/production/files/201508/documents/cpp_emv_guidance_for_demand-side_ee_-_080315.pdf at page 3.

NRECA's framework is centered on using deemed savings where available and appropriate, and is updated periodically to incorporate changes in national or state standards for appliance and building codes, or to incorporate the results of new EM&V studies. The framework makes use of the full range of best practice EM&V protocols included in the Clean Power Plan EM&V guidance document. According to the "Model Energy Efficiency Program Impact Evaluation Guide" prepared by the NAPEE, deemed savings are based on stipulated values, which come from historical savings values of typical projects. Deemed savings are the per-unit energy savings values that can be claimed from installing specific measures under specific operating situations. Examples include agreed-upon savings per fixture for lighting retrofits in office buildings, with specific values for lights in private offices, common areas, hallways, etc. Many states and regions already have in place TRMs that provide deemed savings estimates for a comprehensive range of energy efficiency measures. Many states now rely upon the deemed savings numbers included in such TRMs as the basis for determining whether utilities have met annual kWh and kW savings targets, and to determine rewards or penalties in states where such incentive mechanisms exist. Thus, it is clear that deemed savings numbers are frequently relied upon in many jurisdictions by state regulatory agencies to determine compliance with legislative or regulatory requirements. NRECA also notes that the North American Energy Standards Board ("NAESB") established deemed savings business standards to determine savings for energy efficiency and demand response programs.

The NRECA EM&V framework for electric cooperatives is as follows.

(1) Cooperatives should be able to use "deemed' savings as the basis for tracking and reporting savings from energy efficiency programs. EM&V experience in several states indicates that regional energy efficiency organizations (such as the NEEP, the Midwest Energy Efficiency Alliance and the Northwest Energy Efficiency Alliance) and IOUs are already conducting regular EM&V studies with large budgets and sophisticated scopes. NRECA does not believe it is necessary for distribution cooperatives to "recreate the wheel" for EM&V studies. Rather, NRECA believes that such cooperatives use deemed savings based on the results of the detailed EM&V studies being performed by such entities in the same state or region, or EM&V studies from regional energy efficiency organizations or federal and state government agencies. EM&V studies from these other entities can serve as a basis for "deemed" savings for identical or similar energy efficiency programs or measures implemented through electric cooperative energy efficiency programs. For example, the average annual energy savings for installation of an ENERGY STAR refrigerator in the household of a cooperative member is likely the same as the energy savings for a customer of an investor-owned utility.

The use of deemed values in savings calculations and reporting is essentially an agreement between the parties to an evaluation to accept a *stipulated value*, or a set of assumptions, for use in determining energy and demand savings. If certain requirements are met (*e.g.*, verification of installation, satisfactory commissioning results, annual verification of equipment performance, and sufficient equipment or system maintenance), the project savings are considered to be confirmed. The stipulated savings for each verified installed project are then summed to generate a program savings value. Installation might be verified by physical inspection of a sample of projects or perhaps just an audit of receipts. Section 4.3 of the NAPEE Impact Evaluation Guide provides more detailed information on this approach.

(2) NRECA recommends that deemed savings values be updated periodically to incorporate changes in national or state standards for appliance and building codes, or to incorporate the results of new EM&V studies or studies done by national laboratories or similar research organizations. In addition, deemed savings values may need to be adjusted to allow for differences in the climate, geography, economic/demographic characteristics, building types and other factors for the service area of a small utility. Cooperatives would be able to use the best and latest available secondary data sources to update deemed savings values when appropriate.

NRECA also recommends that deemed savings values be reviewed and updated on a regular schedule (every few years) with oversight by a committee composed of a diverse group of regional and local energy efficiency stakeholders, structured similar to American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHRAE"), NAESB, or other similar organizations, so that deemed savings remain accurate and up-to-date. This regular review would also allow for the most recent impact evaluation results, results from building simulation modeling or pertinent data from other secondary sources to be reflected in deemed savings values.

(3) When deemed savings or Technical Reference Manuals are not available, cooperatives should be permitted to make use of the full range of the other best practice protocols included in the Clean Power Plan EM&V guidance document. The combination of existing TRMs and these other best practice protocols will provide sufficient flexibility to enable electric cooperatives to be able to follow the Clean Power Plan EM&V guidance document.

NRECA also recommends that EPA deem any EM&V process in place as part of or later adopted for state Renewable Portfolio Standards ("RPS") to be appropriate for use as part of a federal plan in a particular state or a state plan submitted for EPA approval. States must be given the flexibility to continue to determine their own EM&V approaches, as they have done under RPS programs, and to modify those EM&V measures as market conditions, technologies, data availability, or other circumstances change.

In addition, the EM&V process must not be so burdensome or complex that smaller utilities are disproportionately affected by compliance. Smaller entities like most rural electric cooperatives may find EM&V procedures, and particularly the requirements to measure and quantify reduced generation, onerous. EPA should consider whether to include special provisions to address the unique needs of cooperatives and other smaller utilities or to exempt utilities below a certain size from the EM&V process.

K. *UARG* Prohibits EPA From Requiring Title V Permit Revisions For Federal Plan Requirements

EPA believes that, for sources subject to Title V of the CAA, the applicable requirements under the federal plan will be "applicable requirements" under Title V and will need to be addressed in Title V permits (*e.g.*, provisions concerning designated representatives, monitoring, reporting, and recordkeeping, and the requirement to meet an emission rate through holding ERCs or allowances. 80 Fed. Reg. at 64,984 ("Under the proposed federal plan, title V permits for sources with affected EGUs will need to include any applicable requirements that the plan places on the affected EGUs."). An affected EGU thus may be required to modify an existing Title V permit or obtain a new permit if it does not already have one based on the newly applicable requirements. According to EPA, the Supreme Court's decision in *Utility Air*

Regulatory Grp. v. EPA (“UARG”), 134 S. Ct. 2427 (2014), holding that EPA may not treat greenhouse gases as an air pollutant in determining whether a source is a major source required to have a Title V permit, has no effect on that requirement. 80 Fed. Reg. at 64,984 (“[W]hile the emission of GHGs alone cannot trigger the need for a title V permit under *UARG*, the EPA believes a final federal plan under CAA section 111(d) will create new ‘applicable requirements’ in the form of an emissions standard (either an emission rate or an allowance system) and related requirements for GHGs (here, CO_2) on affected EGUs.”).

EPA’s attempt to distinguish *UARG* is unpersuasive – requiring Title V permit changes that arise solely because GHG emission standards are imposed through a federal plan is prohibited under *UARG*. “Title V defines a ‘major source’ by reference to the Act-wide definition of ‘major stationary source,’ which in turn means any stationary source with the potential to emit 100 tons per year of ‘any air pollutant.’” *UARG*, 134 S. Ct. at 2456 (quoting 42 U.S.C. §§ 7661(2)(B), 7602(j)). The Supreme Court made clear in *UARG*, however, that the phrase “any air pollutant” should be narrowly interpreted in the context of Title V’s permitting trigger “to encompass only pollutants emitted in quantities that enable them to be sensibly regulated at the statutory thresholds, and to exclude those atypical pollutants that, like greenhouse gases, are emitted in such vast quantities that their inclusion would radically transform those programs and render them unworkable as written.” *Id.* at 2442. “EPA itself has repeatedly acknowledged that applying the … Title V permitting requirements to greenhouse gases would be inconsistent with – in fact would overthrow – the Act’s structure and design.” *Id.* If EPA required Title V permitting changes or sources to acquire Title V permits based on the 111(d) Rule, the number of sources required to have or to modify existing Title V permits would skyrocket. EPA should make clear that no changes made to comply with a state or federal plan will trigger Title V compliance.

That approach is not only legally prohibited, but it is also untenable where units are forced to increase emissions for reliability reasons. Where, for example, reliability concerns force alternative unit operations that deviate from a state or federal plan, there must be a provision in the federal plan that allows such increased operation while avoiding possible Title V noncompliance.

L. EPA Should Not Require Monitoring And Reporting Prior To 2022.

EPA proposes to require monitoring and reporting of CO_2 mass and net generation for the year prior to the first interim compliance period beginning in 2022. 80 Fed. Reg. at 65,010-11. NRECA submits that such monitoring and reporting is unnecessarily onerous and irrelevant to the compliance period. EPA therefore should not require monitoring or reporting for periods prior to 2022.

M. EPA Should Consider Allowing States To Enter Or Exit The Federal Trading Program On A Case-By-Case Basis.

EPA seeks comment on whether there are reasons that a state should be allowed to transition from a federal plan to a state plan during a compliance period and, if so, what requirements should be in place to ensure the integrity of both plans while enabling the affected EGUs to understand and meet their compliance requirements. 80 Fed. Reg. at 65,011, 65,029.

NRECA generally encourages giving states the flexibility to enter or exit the federal trading program, but EPA should first determine whether marketplace disruption will result before allowing a state to enter or exit the federal program. That decision should be made on a case-specific basis rather than under a generally applicable rule.

Relatedly, NRECA supports EPA's proposal to allow for partial approval of a state plan and to give states the ability to seek delegation authority under a federal plan; those options should be available to (but not required for) states to promote flexibility.

N. Considerations For CEIP Formulation

EPA has not provided any details on the Clean Energy Incentive Program ("CEIP") in this proposal, indicating that it "will address implementation details of the CEIP in a subsequent action." 80 Fed. Reg. at 65,026. That subsequent action should provide an opportunity for public comment, in accordance with the APA.

In formulating those details, NRECA recommends that:

- EPA allow states to opt out of the CEIP under a federal plan or original state plan;
- EPA should allow credits to be generated earlier than proposed, and to allow credits for *all* projects that have commenced operation since the 111(d) Rule was proposed and for all investments in existing projects that were made after the 111(d) Rule was proposed;
- Unused allowances should be distributed back to a state's budget ; and
- Definition of "Low Income Community" –

  a. EPA should define low-income communities to expressly include all rural areas that meet the poverty criteria.

  b. The definition of "low income community" must be broad enough to include utility programs that broadly serve many of the nation's "low income communities" rather than requiring a case-by-case determination that the final recipient is "low income." This would mean cooperatives would not have to determine if one neighbor is eligible and another is not, which detracts from the overall objective to support and benefit communities as a whole.

  c. Utility programs that provide benefit to low-income communities should include not just residences, but EE projects at hospitals, schools, churches, and small commercial, industrial and agricultural businesses that serve these communities.

  d. Counties that serve a population that is on average "low income," including "non-metro counties with high incidence of poverty" and "persistent poverty counties" and "financially distressed, non-metro areas," should be eligible under the program. In addition, the program should provide the option to determine eligibility at a sub-county level because some utilities, especially in rural areas, serve counties that may

> not be considered low income as a whole but have significant low income areas that would benefit from clean energy incentives.[55]

NRECA believes that the CEIP can be an important tool to provide incentives to ramp up renewable energy and energy efficiency programs, particularly in the low-income communities (including rural areas) that NRECA members serve. In addition, NRECA submitted extensive comments on the CEIP to EPA docket EPA-HQ-OAR-2105-0734 that are hereby incorporated by reference and included as Appendix C.

O. Biomass Fuel Treatment Should Be Eligible To Generate ERCs or Allowances

EPA has proposed an option for biomass fuel treatment as an eligible resource to generate ERCs or as an eligible generator under a mass-based plan. 80 Fed. Reg. 64,995. EPA proposes a list of pre-approved qualified biomass fuels, which could be amended in the future as the science evolves, and seeks comment on the types of qualified biomass feedstocks that should be specified, if any. *Id.* at 64,995-96. EPA seeks comment on whether to include a provision that allows sources to seek approval for other types of biomass to be added to the pre-approved list and what that process would entail. *Id*. EPA also has requested comment on how EGUs would demonstrate that feedstocks meet the requirements to be accepted as pre-approved and on what EM&V measures should apply. *Id.* at 64,996.

Although EPA currently proposes biomass co-firing as a compliance mechanism for the model trading rules, biomass should also be a compliance option under a federal plan.[56] The 111(d) Rule already allows biomass as an approvable element for states that develop their own plans. *See, e.g.,* 80 Fed. Reg. at 64,756. There is no reason to treat biomass differently under a federal plan, and its exclusion as a compliance mechanism in the federal plan in fact makes the federal plan impermissibly more stringent than the 111(d) Rule. NRECA supports broad based recognition of eligible projects for generating ERCs under a rate-based program and for reducing the need for allowances and for the renewable energy set-aside under a mass-based program. Eligible projects should include those that utilize any and all organic plant or tree-based materials, whether those materials are a waste product or grown specifically for combustion.[57]

The viability of biomass has been demonstrated[58] such that co-firing with biomass should also be an eligible technology for the CEIP because it is quickly deployable like solar or wind, if

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[55] That definition should also apply to RE set-aside allowances for RE projects that specifically benefit low-income communities. 80 Fed. Reg. at 65,024.

[56] EPA proposes limiting the issuance of ERCs in a federal plan to affected EGUs, to RE resources (wind, solar, geothermal power, and hydropower), and to nuclear generation (new capacity and incremental capacity upgrades). 80 Fed. Reg. at 64,989-90.

[57] NRECA recommends that EPA expand its definition of eligible renewable resources to include resources considered renewable under individual state statutes.

[58] *See* Appendix E (Doug Boylan et al., "Co-Milling Green Wood Chips At Alabama Power Company's Plant Gadsden Unit 2").

not more so. In areas where co-firing is likely to occur, the feedstocks will be readily available and the combustion facilities already existing.

For biomass to be considered "qualified," we support a pre-approved list of qualified biomass fuels. This pre-approved list should include feedstocks recovered from land that fall under recognized land restoration practices, such as invasive brush removal in accordance with USDA Environmental Quality Incentive Program guidelines, and all biomass already eligible under state law as a renewable resource such as landfill gas and coal bed methane in Indiana. There also should be a process for adding feedstocks to the list over time that is efficient and not unduly burdensome. To make that process achievable in light of project development timelines, EPA should approve a new feedstock for the list of qualified biomass fuels no more than six months after an application for approval is submitted.

The EM&V process for qualified biomass should follow existing chain-of-custody protocols and minimize any additional burdens on EGUs.

New technologies should be added to the list of eligible measures under the federal plan pursuant to applications by States or other entities. NRECA supports including as wide of a range of eligible resources as possible (and as adequately demonstrated).

IV. General Comments On The Model Trading Rules

A. EPA Should Finalize Both Rate- and Mass-Based Model Trading Rules

EPA has drafted the model trading rules so that they can be adopted and incorporated by reference with a minimum amount of changes necessary to make the rule appropriate for use by states. 80 Fed. Reg. at 64,973. It is not clear from the preamble whether EPA intends to finalize both types of model trading rules. *Compare id.* at 64,966, 64,968 (EPA will finalize both model rules), *with id.* 64,970, 64,975 (EPA may finalize only one).

NRECA urges EPA to finalize both the rate- *and* mass-based rules to provide the maximum amount of guidance and flexibility to states. There is some tension between EPA's stated goal to promote flexibility on the one hand, and the agency's encouragement of states to adopt the presumptively approvable model rules. NRECA recognizes that reasonable model trading rules will, if workable and flexible, promote a more liquid market with relative ease of transaction. To balance those competing goals, NRECA believes it is important for EPA to finalize model trading rules for both rate- and mass-based approaches. Doing so will promote consistency for states that adopt each type of plan and will give states the option to choose the type of plan that best addresses its individual circumstances.

Such guidance may be instrumental because a state that incorporates one of the model trading rules into its state plan will present a presumptively approval plan. *See, e.g., id.* ("When the EPA finalizes one or both of its proposed approaches as a final model trading rule, and a state adopts a final model trading rule in its entirety as its state plan, it would be presumptively approvable."). If EPA declines to finalize the rate-based model trading rule, for example, states that intend to adopt a rate-based approach and to include credit trading as a compliance strategy would be at a disadvantage in their planning process, with no guidance as to whether their plans were likely to be EPA-approvable. That could effectively coerce states to adopt the mass-based trading approach, rendering the claimed "flexibility" with respect to states' ability to choose either a rate- or mass-based approach illusory. *See, e.g., id.* at 64,968-69.

B. EPA Should Clarify The Standard For Alternative Trading Provisions.

EPA intends that "States may submit means of meeting the [111(d) Rule's] requirements that differ from the model trading rule provisions, so long as the state demonstrates to EPA's satisfaction in the state plan submittal that such alternative means of addressing requirements are *at least as stringent as* the presumptively approvable approach described here." 80 Fed. Reg. at 64,969 (emphasis added); *see also id.* at 64,969 n.2. NRECA strongly supports states' ability to submit alternative trading programs to promote flexibility, but believes that EPA has not correctly stated the standard it will use in approving alternative trading provisions.

However, as explained above in Part III.J, under EPA's section 111(d) implementing regulations, only *emission standards* must be as least as stringent as EPA's emission guidelines. 40 C.F.R. § 60.24(c). Those regulations do not mandate that state plan provisions that are not directly tied to the stringency of the emission standards must be as stringent as the provisions in EPA's model trading rule. EPA should clarify in the final rules that alternative trading programs may be approved so long as they are designed to ensure that the emission standards will be at least as stringent as those in the final 111(d) Rule, regardless of any differences in administration or design of the trading program from the relevant federal model rule.

C. PMA Customers Should Receive The Benefit Of ERCs/Allowances Associated With New Or Incremental Hydropower Produced At Federal Dams

Under EPA's proposed FP/Model Trading Rules, new and incremental hydropower generation placed in service after 2012 will be eligible to generate ERCs under rate-based plans and renewable energy ("RE") set-aside allowances under mass-based plans. The proposed federal plan and two model rules do not, however, address the legal or beneficial ownership of ERCs and allowances when the hydro generation is owned by the United States Government – *e.g.*, the U.S. Army Corps of Engineers and/or the Bureau of Reclamation, – and is marketed by one of federal power marketing administrations ("PMAs"), such as the Southwestern, Southeastern, Western Area, and Bonneville Power Administrations (SWPA, SEPA, WAPA, BPA).

A significant percentage of the nation's existing hydropower resources is owned and marketed by the federal government. Under statutes governing the generation and sale of federal power, the state, municipal and cooperative "preference customers" that contract with the PMAs to purchase federal hydropower at wholesale are required to repay, with interest, all of the capital and operating costs associated with the government's investment in the power facilities. When replacements or upgrades to the power infrastructure are required, the federal power customers are also required to provide advance funding in lieu of congressional appropriations to ensure that the replacements and upgrades are accomplished in a timely fashion. Replacements and uprates to existing facilities typically results in increased generating capacity and energy production.

Given the federal power customers' historical and ongoing role in underwriting the government's investment in hydropower infrastructure, it is fitting that *those customers* should, under a federal plan, receive the benefit of ERCs and/or allowances associated with new or incremental hydropower capacity brought on line at federal projects after 2012. PMAs could either (1) distribute a pro rata share of ERCs and/or allowances attributable to qualifying hydro generation to each of their customers that purchase such generation, or (2) sell the ERCs/allowances on the carbon trading markets and use the proceeds to reduce the rates paid by those customers. Allocations under a federal plan should not interfere with any existing arrangements between PMAs and customers.

We recognize that EPA may not have statutory authority to dictate how other federal agencies, such as the generating agencies and the PMAs, distribute ERCs and allowances attributable to qualifying federal hydropower. It would be appropriate and beneficial, however, for EPA to adopt a general policy in finalizing the two model rules and federal trading plans that the beneficial ownership of emissions credits and allowances *should* flow to the customers who have funded the federal generation infrastructure.

There is at least one precedent among the federal PMAs that recognizes this important principle. In WAPA's Sierra-Nevada marketing region in California, WAPA receives Renewable Energy Credits ("RECs") as a result of hydropower generation at several units of the federal Central Valley Project ("CVP") that qualify for such credits under the State's RPS program. In turn, WAPA offers a pro rata share of the RECs at no cost (other than nominal administrative costs) to interested WAPA customers who can use the credits to meet their RPS requirements. WAPA enters into annual contracts with interested customers to distribute the RECs. The same principle would support other PMAs' allocating ERCs and RE allowances under the 111(d) Rule to their customers.

Such a policy is also consistent with the default principle under most state renewable energy credit trading programs that, in the absence of contractual provisions to the contrary, the purchaser of renewable energy is entitled to any environmental attributes associated with the purchased product.

Accordingly, NRECA strongly encourages EPA – in finalizing the federal plan and model trading rules to include a general policy statement that, absent specific legislation or contractual provisions between the parties, recognizes the historical role of the PMAs and that the benefits of the ERCs/allowances from any uprates should flow to the PMA customers who paid for those uprates. Such a general policy statement will be a useful template for the various states and stakeholders as they work together to draft and submit state plans to EPA.

D. EPA Should Include A Dynamic Reliability Safety Valve Rather Than Rely On Set-Asides To Address Reliability

EPA has proposed including a set-aside under a mass-based approach to account for reliability. 80 Fed. Reg. at 64,982. EPA also requests comment on whether it should include an allowance set-aside or similar mechanism in a rate-based approach to address reliability. *Id*. As we have commented extensively in Part III.C, EPA should account for reliability concerns by including a dynamic safety valve in its federal plan and model trading rules. The elements that should be included in that reliability safety valve are laid out in that previous section of these comments.

V. Comments on EPA's Proposed Mass-Based Trading Rule

A. EPA Should Provide Maximum Flexibility To States In The Event The State Measures Federally Enforceable Backstop Is Triggered

EPA proposes that either a mass-based or rate-based model trading rule could provide the federally enforceable backstop in a state measures plan. 80 Fed. Reg. at 64,976. By contrast, the 111(d) Rule specified that only mass-based goals may be employed in a state measures approach, *see* 80 Fed. Reg. 64,662, 64,668, 64,827 (Oct. 243, 2015). NRECA supports the use of *either* rate- or mass-based programs as the federally enforceable backstop to give States maximum flexibility in the event such a backstop is triggered.

We note that the backstop raises a number of issues that EPA should clarify. First, the backstop will need to differ from the model trading rule because it must make up for the shortfall in emissions performance in a prior plan performance period (in other words, the emissions exceedances that triggered the backstop). 80 Fed. Reg. at 64,976. EPA should explain how it proposed to accommodate such exceedances in circumstances when a backstop is triggered. EPA also proposes that it will handle the administration of the trading program for states utilizing the model trading rule, but use of this backstop "does not mean that a federal plan has been put into effect. The state retains all of its rights and responsibilities with respect to the implementation and enforcement of the backstop as a component of its state measures plan." *Id.* It is not clear, however, precisely how a state will retain responsibility for implementation and enforcement of the backstop if EPA handles administration of the trading program. EPA should clarify those issues in the final rule.

B. EPA Does Not Have The Authority To Address Leakage.

Under mass-based approaches, EPA asserts that there is an incentive to shift generation from existing source generation (particularly existing NGCC sources) to new NGCC sources regulated under the less-stringent section 111(b) standards. *See* 80 Fed. Reg. at 64,977-78. To address this "leakage" under the mass-based approach under the federal plan and model rule, EPA proposes to establish an output-based allocation set-aside and a set-aside that encourages the installation of renewable energy sources. *Id.* at 64,978.

EPA lacks any legal authority to prohibit such shifts from existing to new sources. EPA's determination of BSER for existing sources is not legally implicated by generation shifts to new sources separately regulated under section 111(b). Emission reductions from existing sources should be equivalent under a rate- or mass-based approach *regardless* of any shift in the level of new source generation. EPA cannot prohibit sources from shutting down an old source in favor of a new (presumably lower-emitting) source.

In addition, to the extent that leakage is a problem, it is one of EPA's own making, because the agency set more stringent 111(d) emission standards for existing sources than for new, modified, or reconstructed sources under section 111(b). This incentivizes such shifts. If EPA wishes to dis-incentivize such shifts, then it should revisit its 111(d) standard and make it less stringent than the 111(b) standard. EPA contends, paradoxically, that the 111(b) standards are not less stringent than the standards for existing sources. 80 Fed. Reg. at 64,785-87. If that is the case, EPA loses any justification for addressing leakage.[59]

C. ERCs Should Be Transferrable Across State Lines, Whether They Are Generated In A Mass-Based State or Not.

To address concerns that emission reductions would be eroded if an affected EGU in a rate-based state counts the MWh from measures located in a mass-based state but the generation from that measure acts to serve the load in the mass-based state, EPA proposes to restrict ERC issuance for any emission reduction measures located in a mass-based state, except for renewable energy. 80 Fed. Reg. at 64,978. Renewable energy (RE) measures located in a state with a mass-based approach can be approved for ERC issuance under a rate-based plan if it is demonstrated that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet the load in a rate-based state. *Id.* However, if RE located in a mass-based state receives mass-based set-aside allowances for generation, that generation cannot be issued ERCs in a rate-based state. *Id.*

To promote flexibility, *any* ERC, regardless of how or where that ERC is created, should be transferrable so long as a demonstration is made that there would be no double-counting of credits. If double-counting is addressed, there is no reason to restrict ERCs from being transferred across state lines.

D. EPA Should Adopt A More Representative Baseline Allocation Approach.

EPA proposes to allocate the historical-generation-based portion of the allowances (the mass goal minus set-asides) to individual affected EGUs based on each affected EGU's share of the state's historical generation from 2010 through 2012.[60] 80 Fed. Reg. at 65,016-17. NRECA agrees that a historical approach is appropriate, but recommends that EPA take the highest year of the last five years of generation as the basis for allowance allocation, rather than the average of generation from 2010 to 2012. Alternatively, EPA should take the highest two of the last five years of generation or follow CSAPR methodology by taking the highest 3 of 5 years of operating data.

E. EPA Should Make The Alternative Compliance Pathway Available For All Units For Federal Or State Rate- or Mass-Based Plans

EPA has requested comment on an alternative compliance pathway for units under a mass-based approach as outlined in the Alternative Compliance Pathway for Units that Agree to

[59] Should the leakage provisions ultimately be upheld, NRECA supports the renewable energy set-aside, as explained further below.

[60] NRECA takes no position regarding whether allowances should be allocated based on MWh fossil fuel generation or based on a weighted method that would allocate more allowances per MWh to coal-fired EGUs.

Retire Before a Certain Date Technical Support Document.[61] *See* 80 Fed. Reg. at 64,980. As proposed, that pathway would apply to units that are willing to commit to retiring by December 31, 2029, and are willing to take an enforceable emission limitation that would assure that the overall state emission goal is met. NRECA appreciates the concept behind the proposed alternative compliance pathway, but the plan's requirement fall far short of providing meaningful assistance to utilities that will face stranded assets issues due to premature unit shutdown caused by 111(d) Rule implementation. Simply stated, requiring unit shut down by 2029 under restricted operating conditions would not provide sufficient time or operational flexibility to reasonably avoid unit closure without leaving significant stranded debt. While NRECA understands EPA's desire to offer an alternative compliance mechanism that demonstrates "emission neutrality," no requirement exists in the 111(d) Rule that "emission neutrality" must be demonstrated by 2030. In fact, the statutory mandate that BSER consider cost[62] clearly overrides the agency's desire to have an emissions-neutral accounting by 2030.

To overcome the deficiencies of the proposed federal plan and model rules and to partially alleviate the threat posed by the stranded asset issue, a broad, flexible, and improved Alternative Compliance Pathway ("Pathway" or "Alternative Pathway") should be finalized. NRECA appreciates efforts made by EPA to propose the Alternative Pathway and supports its finalization, but urges EPA to make various improvements, discussed below, to provide the relief needed.

1. Improvements requested

The following should be attributes of the final articulation of the Alternative Compliance Pathway:

- No 100 MW cutoff for eligibility. EPA has requested comment on expanding or limiting the availability of the Pathway, including a request as to whether the Pathway should be available to units greater than a 100 MW nameplate capacity. EPA has also requested comment on whether the Pathway should be available under both mass- and rate-based programs (and similarly if the 100 MW cutoff should apply). Stated simply: the Pathway should be available to all units who choose to avail themselves of the Pathway under either a mass- or rate-based program; there should not be an arbitrary limit based on the type of trading/compliance program or the size of the unit.

- Commitment. A unit must make an upfront commitment to participate in the alternative compliance program before the initial compliance deadline in 2022. Units may opt to make the commitment prior to that time in order to provide additional notice to their state and other market participants, but the commitment will become irrevocable only after the 2022 compliance deadline.

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[61] *See* http://www3.epa.gov/airquality/cpp/tsd-fp-alternative-compliance.pdf.

[62] Section 111(a)(1).

- Allowance Methodology. Participating units receive allowances without subtracting any set-asides following the state or federal plan allocation for the years up to and including the year 2035 plus allocations due to unit shutdown post 2029 (for two years as proposed). So long as there is an overall cap on allowances, this would do nothing to impact EPA's ultimate goals of the Clean Power Plan while providing additional flexibility to participating units.

- Flexibility to Use or Trade Allowances. A participating unit can operate the unit as desired during the operating period and can sell and buy allowances without additional restrictions because of participation in the alternative compliance program. This will provide a significant economic incentive to units to down-dispatch knowing that there will be a direct economic incentive to generate allowances that can be used at that date or in future dates.

- Date of retirement need not be pre-determined, need not be prior to 2030, but will not extend beyond 2036. The currently proposed alternative compliance pathway would require an affected unit to commit to retire on or before December 31, 2029. While NRECA believes that every unit should be able to operate to the end of its engineered life, whatever that individual plant's life may be, EPA should at a minimum extend the Alternative Pathway retirement date to at least December 31, 2036. These extra years of operational time would significantly reduce the impacts of stranding assets and remaining debt obligations. It provides additional time for units to operate into years closer to the end of their engineered life expectancy, provide more time to pay off debt, reduce the need to accelerate debt payments, and allow impacted entities to better distribute the accelerated debt payments that remain. Participating units must cease operation prior to the January 1, 2037 but the unit shutdown date does not have to be predetermined at the time of committing to the program. There are too many variables to commit to a certain retirement date or restrict operations during certain years (e.g. changing market conditions, fuels pricing, weather, etc.), to make any predictions or plan operations with certainty.

- True-up. Allowance true up must occur the year after shutdown following EGU requirements. At true up the unit must demonstrate "emissions neutrality" such that allowances in the unit account must be equal or greater than the sum total of unit emissions for the years' operating under the CPP.

- Allocations retired with the participating unit. The stream of allowance that would otherwise be allocated to the unit is subtracted from the state budget beginning in 2037 and continuing every year thereafter.

2. Legal rationale for these improvements

The Alternative Pathway is a step towards recognizing the remaining useful life of impacted units, as required under Section 111(d) of the Clean Air Act. While the Pathway does not fully address this requirement, and most importantly, the Clean Power Plan itself does not currently address the remaining useful life issue (as described in these and earlier comments), the Alternative Pathway would at least mitigate some of the harms recognized by Congress in putting in that provision in the Clean Air Act in the first place.

We believe the Alternative Compliance Pathway should be available to all units, but if EPA were to impose a limitation on the availability of the Pathway, we believe that universe should include electric cooperatives and, at a minimum, mine-mouth units given the additional capital and rate complexity faced by such operations.

EPA, as recently as the Mercury and Air Toxics Standards ("MATS") Rule, established a subcategory for lignite within the larger coal subcategory, stating that one of the bases for the subcategory is that lignite units are "universally constructed 'at or near' a mine containing" lignite with designated and narrowly limited conveyance mechanisms to transport lignite from the mine to the power plant. This limits compliance flexibility, compliance alternatives, and magnifies the impacts resulting from any difficulty to comply with the rule, as impacts will be borne by the plant *and* the mine. This same recognition of the unique characteristics of mine-mouth power plants should be recognized in the Federal Plan; the Alternative Compliance Pathway is one of those means to recognize this subcategory.

Creating a subcategory would also alleviate any concerns EPA may have about extending the Alternative Compliance Pathway past the 2022-2030 timeframe that was contemplated by EPA's BSER analysis. By definition, a subcategory need not strictly abide by the constraints of the BSER analysis that was the basis of the larger category of units governed by the Clean Power Plan.

3. San Miguel Electric Cooperative: An example of a plant where harm and rate impacts can be significantly mitigated by the alternative compliance pathway

There are numerous power plants in the United States, including electric cooperatives and members of NRECA, that would benefit from the Pathway. While there may be numerous examples, the need for the Pathway may be most clearly represented by the facts of the San Miguel Electric Cooperative, Inc. ("San Miguel") power plant ("San Miguel Power Plant"). San Miguel operates a single 400 mw, mine-mouth, lignite coal-fired EGU. It is located in Atascosa County, Texas, south of San Antonio, and serves approximately 200,000 South Texas homes. The San Miguel Power Plant began operating in 1982, four years after the passage of the Powerplant and Industrial Fuel Use Act of 1978 and with the economic support of the federal government. In fact, much of the financing secured to construct the plant came from the U.S. Department of Agriculture's Rural Utilities Service ("RUS"); $70 million dollars of its remaining debt is still secured by the RUS. The San Miguel Power Plant uses lignite mined from a co-owned and directly associated mine. The power plant has an engineered life for operations through 2037.

The San Miguel Power Plant is "fully-controlled," meaning it has a wet scrubber to control sulfur-dioxide emissions, an electro-state precipitator to control particulate matter emissions, a selective-non catalytic reduction system (as well as other low-NOx technologies) to control nitrogen oxide (NOx) emissions, and an activated carbon injection system to control mercury. It will be able to comply with the Cross-State Air Pollution Rule, Mercury and Air Toxics Standards Rule, and EPA's other recently finalized rule throughout its remaining engineered life. However, it will not be able to comply with the Clean Power Plan, as finalized, and the model federal plan, as proposed, without the availability of an Alternative Pathway.

San Miguel's associated mine also has a similarly projected lifespan – through 2037 – in order to provide the fuel for the plant; there are no other fuel sources or means to bring in fuel to the San Miguel Plant from another source besides the associated mine. Wholesale power contracts are structured under the assumption that San Miguel's remaining debt, the cost of decommission and retiring the plant ,and the costs of closing the mine can be recovered over the next 21-22 years, through 2037. The combined outstanding debt obligations range from $362 to $489 million, depending on numerous accounting and other factors. Further, San Miguel operates a single 400 MW power plant; there are no other means to mitigate the impacts of the Clean Power Plan internal to the company; the power plant and the mine are San Miguel's only primary assets.

The forced early retirement of the San Miguel plant – and associated accelerated retirement payments – will result in a dramatic increase in costs to San Miguel, its member cooperatives, and most importantly, the individual relying on the San Miguel Power Plant's power. For example, in Atascosa County, one-fifth of families live below the poverty line, including roughly one-quarter of those under the age of 18. In Christine, Texas – where San Miguel is located – one-third of the families live below the poverty line, including almost half of those under 18.[63] Under an accelerated retirement plan, San Miguel members would expect to see a rate increase of between 85 to 125% under a scenario where San Miguel waits to the end of the legal challenge process before beginning the retirement process and accelerating retirement. Even if San Miguel was to begin this accelerate retirement process today, members would expect to see a 51% increase in electricity rates.

Obviously, the Alternative Compliance Pathways could significantly mitigate the rate escalation issues noted above by affording the San Miguel unit the ability to live out more of its useful life during which its obligations can be addressed through modest rate escalation, as opposed to the dramatic escalation that would result otherwise due to the Clean Power Plan. We understand that San Miguel has provided additional detail about the potential rate mitigation to help illustrate the essential need for the improvements to the Alternative Compliance Pathway we are proposing.

F. Comments on the Mechanics of the Mass-Based Model Trading Rule

[63] San Miguel employs full-time 419 individuals from the area with salaries averaging far above the regional average, as well as employs hundreds of contractors part-time at the plant.

NRECA offers the following comments and recommendations on various mechanical aspects of the proposed mass-based model trading rule.

1. Banking

EPA requests comment on whether it should permit unlimited banking of allowances as proposed or whether they should be subject to a cap or expiration date. 80 Fed. Reg. at 65,014. EPA is not proposing to allow allowance borrowing across compliance periods but also requests comments on that issue. *Id.* For maximum flexibility, NRECA supports unlimited banking and borrowing to provide maximum flexibility for compliance, including banking and borrowing across interim compliance periods.

2. Compliance evaluation

EPA proposes to evaluate compliance on May 1 of the year after the last year in the compliance period, but requests comment on an earlier or later allowance transfer deadline. 80 Fed. Reg. at 65,014. Consistent with EPA's approach for a rate-based approach, true-up should be on November 1 of the subsequent year if trading across interim periods is not allowed. In either case, compliance evaluation or "true up" should occur by November 1 the year after the period ends.

3. Allocation methodologies

EPA has requested comment on several potential alternate allocation methodologies. 80 Fed. Reg. at 65,016-18. NRECA opposes auctions as a means of distributing allowances.

4. Set-asides to address leakage

EPA has proposed using two set-asides to address "leakage" concerns: one for NGCC units operating within a range of certain capacity factors and another for renewable energy. As previously noted in Part V.B, EPA lacks any legal authority to prohibit or restrict such "leakage."

Should EPA's ability to address "leakage" be upheld, however, EPA should:

- Allow coal-fired EGUs, in addition to NGCC units, to receive output-based set-aside allowances. If an output based set-aside is appropriate, it should not matter whether those allowances are allocated to coal-fired EGUs in addition to NGCC units so long as the total state emissions budget remains unchanged. In other words, allocating set-asides to coal-fired units would have no effect on the total level of emissions reductions achieved. Moreover, allocating set-asides to coal-fired units would equally serve the purpose of incentivizing increased existing source generation rather than shifting to new NGCC resources;

- Allow new nuclear units to generate set-aside allowances;

- Allow allowances to cross state borders to support broad-based trading rather than limiting the capacity for RE set-asides to within a particular state; and

- Distribute any remaining undistributed allowances from set-asides back to the State's budget.

VI. Comments on EPA's Proposed Rate-Based Trading Rule

A. All Rate-Based States Should Be Able To Trade With Each Other

As we discuss above, EPA should revise the Proposed Rule to enable EGUs to trade compliance instruments between mass- and rate-based states. Trading of compliance instruments is key to reducing the costs of complying with the CPP and improving EGUs' abilities to comply while maintaining a reliable, affordable supply of electricity. In addition to authorizing trading between mass- and rate-based states, EPA should revise the Proposed Rule to authorize trading of ERCs among all rate-based states, including among states that adopt blended rate-based limits and between states with subcategorized rate-based limits and blended limits.

1. EPA's Concerns with Rate-Based Trading Among States with Different Rate-Based Limits.

Under the Proposed Rule, only EGUs located in states that adopt the subcategorized emission limits in the CPP, and those that join a multi-state plan with a uniform blended rate limit, would be authorized to trade ERCs with EGUs in other states.[64] This limitation effectively prohibits EGUs in one state from trading ERCs with EGUs in other states that have adopted different rate-based standards. It also (inexplicably) prohibits EGUs in states with identical rate-based limits (for example, North Dakota and West Virginia) from trading ERCs even though EGUs in both states are ostensibly subject to the same emission limits.

EPA's concerns with allowing trading between rate-based states with different emission limits appears to be focused exclusively on trading of ERCs that are issued to affected fossil-fueled EGUs. For example, in the 111(d) Rule, EPA argues that this restriction is "necessary to ensure that each state that is allowing for the interstate transfer of ERCs is implementing rate-based emission standards for affected EGUs at the same lb [sic] CO_2/MWh level."[65] According to EPA, "[t]his assures that all the participating states are issuing ERCs to affected fossil steam and NGCC units that emit below their assigned emission standards on the same basis." *Id.* EPA's sole concern with this result appears to be that allowing trading between states with different rate-based limits would "provid[e] different incentives, in the form of issued ERCs, to affected steam generating units and NGCC units in different states that have comparable emission rates" and that "[p]roviding different incentives to similar affected EGUs could create distortionary effects that lead to shifts in generation among states based on the different CO_2 emission rate standards applied by states to similar types of affected EGUs."[66]

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[64] *See* Proposed Rule, 80 Fed. Reg. at 65,011; CPP Final Rule, 80 Fed. Reg. at 64,910.

[65] Final Rule, 80 Fed. Reg. at 64,910.

[66] *Id.*

According to EPA, "[p]roviding for the interstate trading of ERCs in this instance would exacerbate these distortionary effects by providing arbitrage opportunities."[67]

It is important to note at the outset that allowing ERC trading between states with different rate limits *only* poses a problem for ERCs that are issued to *affected fossil-fueled EGUs*. As we discuss in the next section, trading of ERCs issued to non-emitting resources does not lead to distortionary production incentives and does not require the type of "border adjustments" explained below. The following section discusses two options for converting ERCs between states with different rate-based limits that would eliminate any concerns about potential market "distortions" caused by issuing partial ERCs to affected fossil units that are subject to different state-wide rates.

2. EPA's Concerns Do Not Apply to ERCs That Are Issued to Non-Emitting Resources.

EPA's concerns, discussed above, would not be relevant for trading of ERCs that are issued to zero-emitting resources such as RE, EE, and nuclear generators. Unlike affected EGUs (whose level of ERC issuance is directly tied to the rate-based limit to which they are subject), non-emitting resources receive one full ERC for every MWh produced or saved, *regardless of the rate limit in the state where they are located*.[68] Indeed, such resources can even generate ERCs if they are located in states or countries that are not subject to any rate-based limits under the 111(d) Rule.[69]

As EPA explains in the 111(d) Rule:

> we are adjusting rates using calculated MWhs, not based upon an emission reduction approximation as commenters outlined above. Not only does the method allow emission reductions to be accounted for as they occur across the grid, but it means the ERCs being traded across states represent one MWh of zero-emitting generation in whatever state it [sic] originated, and *its [sic] value is unaffected by any emission rate associated with its [sic] state of origin*. Thus, the finalized accounting and trading methods *minimize the relative incentives for*

[67] *Id.*

[68] *See, e.g.,* Final Rule, 80 Fed. Reg. at 64,914 ("ERCs being traded across states represent one MWh of zero-emitting generation in whatever state [they] originated, and [their] value is unaffected by any emission rate associated with [their] state of origin."); Proposed Rule, 80 Fed. Reg. at 65,990 ("An ERC is a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions.").

[69] *See* 40 C.F.R. § 60.5800(e) (authorizing issuance of ERCs to resources located in "States and areas of Indian country that do not have any affected EGUs, and other countries"); *see also* 40 C.F.R. § 60.5800(a)(3)(ii) (authorizing issuance of ERCs to certain resources in states with mass-based plans).

> *generating zero-emitting ERCs in a particular state based upon the rates that apply to that state*.[70]

Because of this, an ERC issued to a zero-emitting resource in any state with a rate-based limit – be it a subcategorized rate-based limit or a blended limits – would always have the same value as an ERC issued to the same non-emitting resource in another state with a rate-based limit. Furthermore, under the CPP, ERCs issued to zero-emitting resources in states or countries that do not have rate-based limits would also have the same value regardless of where the resource is located. Under both situations, the zero-emitting resource would receive a full MWh ERC for each MWh of zero-emitting power it produced (or avoided) – regardless of the rate limit (if any) that is applicable to EGUs in the jurisdiction where it is located. Thus, an ERC issued for 1 MWh of generation from a non-emitting resource in a state with a blended rate limit of 771 lbs./MWh would have the same value as an ERC issued for 1 MWh of generation from a non-emitting resource in a state with a blended rate limit of 1,305 lbs./MWh. The fact that the same number of ERCs would be issued to every non-emitting resource *regardless of the resource's location or the applicable rate-limit* (if any) in the jurisdiction should obviate any concerns EPA may have about potential distortionary effects that could occur if ERCs issued to non-emitting resources were traded between rate-based states with different emission limits. Consequently, there should be no barrier to trading ERCs that are issued to non-emitting resources across state lines, even in the absence of formal links between states.

As we note above, EPA's stated concerns are limited to issuance of ERCs to affected fossil-fuel EGUs. EPA has provided no reasonable explanation for why ERCs issued to *non-emitting* resources (including RE, nuclear, and EE) should not be tradable among all rate-based states, including among states that do not adopt the final rule's subcategorized emission limits. Prohibiting such trading is arbitrary and capricious because it is unexplained and because it would effectively raise the cost of the program without leading to any additional environmental benefit. Consequently, EGUs should be authorized to trade ERCs issued to non-emitting resources freely between all rate-based states that use compatible or interoperable tracking systems.

3. Addressing EPA's Concerns for ERCs Issued to Affected EGUs.

EPA takes the position that issuing ERCs on a differential basis to affected fossil-fuel EGUs could lead to distortions and opportunities for arbitrage among states with different rate-based limits. To the extent that trading between states with different rate-based limits poses significant arbitrage risks, these concerns can easily be avoided by implementing a conversion requirement for trading between rate-based states with different emission limits. This conversion requirement would be analogous to, but simpler than, the kinds of currency conversions that are required to facilitate trading between different countries. Specifically, EPA could require that states that wish to trade ERCs with other rate-based states with different rate-based limits use a conversion factor to convert ERCs from one state to the other. These rules would also apply to states subject to a rate-based Federal Plan and those adopting the rate-based Model Trading Rule.

[70] 80 Fed. Reg. at 64,914 (emphasis added).

As we explain below, this conversion factor could be designed to eliminate EPA's concerns over trading or arbitrage between states with different rate-based limits.

a. Option 1: Convert ERCs to Tons for Interstate Trading

The first option for converting ERCs between states with different rate-based limits is to convert ERCs to short tons using the approach discussed above in Section III.B. Section III, above, explains the rationale for this conversion. Once converted to short tons, the converted ERCs could be used to reduce the effective emission rates of EGUs in other rate-based states by deducting the tonnage-equivalent of each ERC from the numerator of the EGU that surrenders the converted EGU for compliance.[71]

b. Option 2: Use a "Lesser-of" Approach to Equalize Incentives Across States with Different Emission Rates.

A second approach would be to adjust any traded ERC to the lowest applicable emission rate as between the exporting and importing state.[72]

For partial ERCs[73] ("P-ERCs") issued to affected EGUs in states with <u>less stringent</u> (higher) emission rates than the states to which a P-ERC might be "imported," an adjustment would be necessary to avoid the incentive to shift generation to the exporting state.[74] As we explain, in this case, the ERC's value in the importing state would be discounted such that it is tied to the lesser of the two applicable rates. To ensure that incentives to increase generation at affected EGUs are equal as between the exporting and importing state, the value of the imported P-ERCs would be discounted based on the difference between the rate limits of the importing and exporting states. As explained in Appendix B, the discounted value of each partial ERC issued to an affected fossil EGU that is transferred to a state with a more stringent rate-based limit is shown by the following expression:

$$\text{P-ERC}_{\text{Converted}} = \text{P-ERC}_{\text{ExportState}}\ x\ \frac{\text{EGU emission standard}_{\text{ExportState}}\ x\ (\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate})}{\text{EGU emission standard}_{\text{ImportState}}\ x\ (\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate})}$$

In this formula, "$\text{P-ERC}_{\text{Converted}}$" represents the value of the imported P-ERCs in the importing state (i.e., the state where the P-ERCs are used for compliance). "EGU emission

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71 *See* Section III.B., above, for an explanation of why this approach is reasonable and would not result in a reduction in the stringency of the CPP.

72 Throughout this section, "exporting state" means the state where the ERC was initially issued to the affected EGU (based on emissions below the rate-based limit) and "importing state" means the state where another entity seeks to use the ERC from the exporting state for compliance.

73 Because affected EGUs will always have some emissions, they generate a fractional, or "partial" ERC for each MWh produced.

74 These comments are not proposing a process for trading of Gas Shift ERCs ("GS-ERCs") due to the potential added complexity of converting GS-ERCs into ERC equivalents in states that do not employ subcategorized rate-based limits.

standard$_{ExportState}$" is the emission rate limit applicable in the state where the P-ERC was issued (the "exporting" state). "EGU emission standard$_{ImportState}$" is the emission rate limit that applies in the importing state. "P-ERC$_{ExportState}$" is the value (in MWh) of the P-ERCs to be converted in the state where they were issued. "EGU emission rate" is the emission rate of the EGU to which the P-ERCs were originally issued.

As Appendix B explains, this conversion formula eliminates any incentive to increase production in the exporting state because it puts the affected EGU that wishes to export ERCs in precisely the same position as an identical EGU located in the importing state. By requiring a conversion when exporting ERCs, EGUs with identical emission rates would receive the same value for each MWh produced, regardless of whether they were located in the importing state or the exporting state. In other words, by adopting a "lesser-of" discounting approach, any marginal incentive to generate a P-ERC in the state with the higher rate for export to a state with a more stringent rate would be eliminated, because EGUs would receive the same value for the P-ERC regardless of whether it was generated in the importing state or imported. Thus, discounting P-ERCs in this manner would eliminate any ability to arbitrage the different rate-based limits in the two states.[75]

So, for example, using the formula for calculating P-ERCs found on page 65,093 of the Proposed Rule,[76] an NGCC unit with an actual emission rate of 950 lbs./MWh in West Virginia (final emission limit 1,305 lbs./MWh) and generation equal to 1,000 MWh during the applicable period would generate P-ERCs equal to 272 MWh.[77] If the P-ERC were exported to a state with a lower rate limit (e.g., Maryland), the P-ERC would have to be adjusted to reflect the lower emission limit in the importing state. Applying the formula from Appendix B shown above, the P-ERCs issued in West Virginia would have an adjusted value of 261.8 MWh.[78] Had the same EGU (or one with an identical emission rate) been located in Maryland instead of West Virginia,

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[75] The existence of different rate-based limits in neighboring states (and thus, different costs of compliance) combined with the ability to transmit electricity across state lines could lead to some generation shifts between states with different rate-based limits. Importantly, these generation shifts are the result of the interconnected nature of the electric grid and the design of the EPA program. They are not the result of interstate trading of ERCs, and would occur *whether or not EPA authorizes ERC trading* among states with different rates, as discussed herein. The suggestions in this section would not eliminate these incentives, but they would eliminate EPA's stated concern that allowing trading of ERCs issued to affected EGUs between states with different rate-based limit could result in opportunities for arbitrage or market distortions.

[76] Proposed Rule, 80 Fed. Reg. at 65,093.

[77] The value of P-ERCs issued to this EGU would equal [(1,305 lbs./MWh – 950 lbs./MWh) / 1,305 lbs./MWh] *x* 1,000 MWh = 272 MWh. *See* Proposed Rule, 80 Fed. Reg. at 65,093.

[78] Maryland's final blended emission limit is 1,287 lbs./MWh. Using the formula above (from Appendix B), the value of the converted P-ERCs issued by West Virginia and eligible for compliance in Maryland would be: $272 \text{ MWh } x \left\{\frac{1{,}305 \text{ lbs./MWh } x(1{,}287 \text{ lbs./MWh} - 950 \text{ lbs./MWh})}{1{,}287 \text{ lbs./MWh } x(1{,}305 \text{ lbs./MWh} - 950 \text{ lbs./MWh})}\right\} =$ *261.8 MWh.*

it would have received a quantity of P-ERCs of equal value,[79] indicating that the availability of interstate trading would not risk exacerbating shifts in generation between affected units.

Where the importing state's rate limit is lower than the measured CO_2 emission rate of the EGU receiving the P-ERC, this conversion formula would yield a *negative conversion value*, which would mean that conversion would be unattractive and would not be allowed. For example, if the same number of P-ERCs issued by West Virginia (valued at 272 MWh) were converted to P-ERCs in Virginia (whose final emission rate is 934 lbs./MWh), the resulting "conversion value" of the ERC would be:

$$\text{P-ERC}_{\text{Converted}} = 272\text{ MWh } x\ \frac{1{,}305\text{ lbs./MWh } x\ (934\text{ lbs./MWh} - 950\text{ lbs./MWh})}{934\text{ lbs./MWh } x\ (1{,}305\text{ lbs./MWh} - 950\text{ lbs./MWh})}$$

Or

$$\text{P-ERC}_{\text{Converted}} = \mathbf{-17.1\ MWh}$$

This makes intuitive sense, because an EGU emitting above the importing state's rate-based limit should not be able to receive the equivalent of a P-ERC in the importing state if it would not have received a P-ERC had the EGU actually been located in the importing state. Therefore, the lesser-of approach will prevent the export of P-ERCs issued to units that emit above the importing state's applicable rate-based limit.

Furthermore, *where the importing state has established separate subcategorized limits* for gas turbine and fossil steam units, the relevant "importing-state rate-based limit" could be set equal to *the lower of the applicable subcategorized limits*. In most cases,[80] this would result in use of the subcategorized emission rate limit for gas turbines (i.e., 832 lbs./MWh during the interim period and 771 lbs./MWh during the final period). If this rule is applied, the only ERCs generated in blended rate-based states that could be traded and used for compliance in subcategorized states would be ERCs issued to affected EGUs that emit below the lowest subcategorized rate limit (i.e., 832 lbs./MWh during the interim period and 771 lbs./MWh during the final period).

Finally, in cases *where the rate limit in the exporting state is more stringent (lower) than the limit in the importing state*, no adjustment would be necessary, because the affected EGU would receive a *lower* MWh value for each P-ERC in the exporting state than it would receive if

[79] This can be seen by calculating the P-ERC value for an EGU with emission rate equal to 950 lbs./MWh in Maryland. A *Maryland-based* EGU with an emission rate of 950 lbs./MWh and generation of 1,000 MWh would receive P-ERCs equal to [(1,287 lbs./MWh – 950 lbs./MWh) / 1,287 lbs./MWh] *x* 1,000 MWh, or *261.8 MWh*. This value is equivalent to the P-ERC value that results from converting the West Virginia-issued P-ERCs to Maryland P-ERCs under the formula above.

[80] Because states can, in theory, establish different subcategorized emission rate limits for gas and fossil steam units than those established in the CPP emission guidelines, it is possible that the applicable rate limit for conversion to some states could differ from the federal guidelines.

it had been located in the importing state, thus eliminating any distortionary incentive to increase generation in the exporting state rather than the importing state.[81] Therefore, the ability to use the P-ERC directly for compliance in the importing state would not distort the affected EGU's production incentive.

4. Implementing a Broader Rate-Based Trading Approach with Interstate Conversions.

To implement the second approach discussed above, EPA and states would need to incorporate three simple changes to the proposed rate-based Federal Plan and Model Trading Rule. First, the tracking system for ERCs would have to identify separately ERCs that are issued to *non-emitting resources* and P-ERCs issued to *affected EGUs*. EPA and states could continue to designate ERCs issued to non-emitting resources as "ERCs." The partial ERCs that would be issued to affected EGUs that emit below their emission rate could be designated "P-ERCs." This would be necessary because, as discussed above, ERCs issued to non-emitting resources would not need to be converted when traded between states, whereas P-ERCs issued to affected fossil EGUs would need to be converted before they could be used for compliance in an "importing" state with a different emission limit than the exporting state.

Second, EPA and states would specify that ERCs issued to *non-emitting resources* would be considered valid compliance instruments in every state that wishes to allow interstate ERC trading. EPA and states would also have to specify that P-ERCs issued by states to affected EGUs would be valid for compliance in other states if they are converted to compliance instruments in the "importing state" by using one of the two conversion approaches discussed above.

Third, if EPA opts for the "lesser-of" conversion approach described above, states that wish to allow P-ERCs to be exported would need to keep track of the emission rate of the EGU to which each P-ERC was issued. This emission rate would be known by the state (because it is required for the initial issuance of the P-ERC). Information on each eligible EGU's emission rate could be included in the "attributes" of any P-ERCs issued to affected EGUs in the state. Retention of the EGU emission rate information is necessary for accurate conversion of P-ERCs between states with different rate-based emission limits.

These changes are easily accomplished and implemented, and could significantly reduce costs and expand the flexibility of the CPP if EPA (through a Federal Plan) or the states opt for a rate-based implementation approach. Therefore, NRECA urges EPA to allow interstate trading of ERCs between all types of rate-based compliance programs by using one of the approaches discussed above.

[81] This implies that if the ERC had been issued to an affected EGU in the importing state, the same level of generation would have received more value (in terms of MWh) in the importing state than it received in the exporting state. Thus, there would be no incentive to shift generation from the importing state to the exporting state in this scenario.

B. ERC Banking Issues

EPA has proposed to allow unlimited ERC banking within and between the interim and final compliance periods, but requests comment on whether there should be a quantitative limit or cap on the number of ERCs that can be banked within and between the interim and final compliance periods. 80 Fed. Reg. at 65,010. EPA also requests comment on whether an ERC should be eligible to be banked, whether ERCs should have a shelf-life, and on a methodology that would allow ERC borrowing (that is, future ERC borrowing for purposes of compliance in a future compliance period) while maintaining the integrity of the compliance obligations. *Id.* NRECA supports unlimited banking and opposes the use of limits, caps, or a shelf-life to promote flexibility. The integrity of the compliance obligations can be easily maintained by requiring that borrowing be reported at the end of the interim compliance periods, with true-up falling on November 1 as EPA has proposed. 80 Fed. Reg. at 65,009.

With regards to other ERC issues, NRECA recommends that EPA make the first seller of an ERC responsible for its integrity and that EPA make out-of-state RE widely available for ERCs to support the broad-based trading so critical to the workability of any future federal plan or state trading programs.

VII. Comments On Proposed Amendments To Framework Regulations

EPA has proposed to amend the existing regulatory procedures for approval or disapproval of CAA section 111(d) state plans[82] "to reflect the enhancements Congress included in CAA section 110 for agency action on SIPs." 80 Fed. Reg. at 65,035. NRECA incorporates UARG's comments on these proposals by reference and comments separately here to highlight the following points:

First, EPA should clarify that it does not intend to attempt to alter the 111(d) Rule – such as by changing its BSER determinations or ratcheting down emission rates for affected EGUs – in a call for state plans under section 110(k)(5). EPA must make those kinds of changes to its 111(d) standards through notice-and-comment rulemaking, not through section 110, which provides no authority for making such changes.

Second, as discussed above in Part III.A, EPA must provide an opportunity for public notice and comment on a federal plan for a specific state before finalizing that plan.

Third, EPA should make its error correction authority clear, including limits on that authority. The plain language of Section 110 provides that EPA may only correct its *own* error in approving, disapproving or promulgating a plan. *See* 42 U.S.C. § 7410(k)(6) ("Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or part thereof), area designation, redesignation, classification, or reclassification was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any

[82] *See* 40 C.F.R. Part 60.

further submission from the State. Such determination and the basis thereof shall be provided to the State and public.”).

VIII. Even Though the Initial Regulatory Flexibility Analysis Conducted by EPA Finds That Affected Units Owned by Small Entity Electric Cooperatives Will Incur Significant Economic Impacts Under the Proposed Federal Plan and Model Trading Rules, NRECA’s Analysis Finds that the EPA Severely Underestimates the Compliance to Electric Cooperatives.

EPA’s analysis shows the proposed federal plan and model trading rules would have a significant economic impact on electric cooperatives. However, NRECA’s analysis shows that EPA has *substantially underestimated* the number of electric cooperatives that will be injured by the proposed rule. NRECA also estimates that year 2030 compliance costs for those affected units owned by electric cooperatives will be *substantially higher* than EPA’s projections – ranging from $2.5 to $3.6 billion. A gross undercounting of affected units owned by electric cooperatives appears to drive EPA’s projected compliance costs downward. When including the interim compliance period, NRECA estimates that total compliance costs to affected units owned by small entity electric cooperatives range from $11.7 billion to $20.3 billion over the 2022-2030 period.

A. EPA’s Analysis Shows the Proposed Federal Plan and Model Trading Rules Would Have a Significant Economic Impact on Electric Cooperatives.

The Regulatory Flexibility Act (“RFA”), 5 U.S.C. § 601, *et seq*., as amended by the Small Business Regulatory Enforcement Fairness Act, Public Law No. 104-121, requires that an agency prepare and make available an initial regulatory flexibility analysis (“IRFA”) if it proposes a rule which is expected to have significant economic impacts on a substantial number of small entities. Accordingly, EPA provides an IRFA of the impact of the proposed federal plan and model trading rules on 74 small entities, 17 of which are electric co-operatives (RIA at 2-18).

B. EPA Substantially Underestimates the Number of Electric Cooperatives Injured by the Proposed Rule.

EPA identifies 17 small entity electric cooperatives as owning affected units. NRECA’s analysis shows that currently 30 small entity electric cooperatives qualify as small entities based on the U.S. Small Business Administration’s size standard of 750 employees or less for fossil-fired electric generators.[83, 84] Small entity electric co-ops own a total of 230 affected units.

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[83] *See* Table 2-1 of the RIA.

[84] Those small entity electric co-ops are: Arizona Electric Power Co-op, Inc., Arkansas Electric Co-op Corp., Associated Electric Co-op, Inc., Big Rivers Electric Corporation, Brazos Electric Power Cooperative, Inc., Buckeye Power, Inc., Central Iowa Power Cooperative, Corn Belt Power Cooperative, Dairyland Power Cooperative, Deseret G&T East Kentucky Power Cooperative, Golden Spread Electric Cooperative, Inc., Hoosier Energy REC, Inc., Kansas Electric Power Co-op, Minnkota Power Cooperative, Inc., North Carolina EMC, Northeast Texas (Continued...)

Overall, 154 units are 100 percent owned by individual small entity electric co-ops. Seventy-six units are partially owned. All 30 small entities electric cooperatives are projected by NRECA to own shares of affected units that will be operating in the year 2030 under the proposed rule.

EPA's approach to identifying affected units owned by small entities is limited to majority owners of affected units that EPA projects will still be in operation in the year 2030 (RIA at 2-8). However, many electric cooperatives own partial, non-majority shares of affected units. EPA's stated methodology does not include the compliance cost impact of units for which co-ops own a minority share even though these co-ops are designated as small entities under the SBA size standards.

C. Year 2030 Compliance Costs to Electric Cooperatives Will be Substantially Higher than EPA's Projections – Ranging from $2.1 to $2.7 billion.

EPA estimates that the incremental costs in 2030 to affected units owned by small electric cooperatives under rate-based and mass-based federal plans and model rules to be $109 million and $133 million, respectively (RIA at 2-20, 2-21).[85]

NRECA has estimated the compliance cost to small entity electric cooperatives using the methodology outlined by EPA (RIA at 2-14). Using an electric market simulation model, scenarios representing rate-based and mass-based federal plans or model rules were simulated over the 2022-2030 period. In each respective scenario, all states of the contiguous United States are regulated under the same federal plan or model rule. *See* "The Compliance Costs of the EPA Clean Power Plan – Federal Plan and Model Rules: Affected Units Owned by Small Entity Electric Cooperatives" in Appendix D for the complete list of modeling assumptions.

NRECA's analysis shows that compliance costs to electric cooperatives will be *19 to 33 times higher than the costs estimated by the EPA*. Under the rate-based approach, year 2030 compliance costs are estimated to be $3.6 billion. Under the mass-based approach, year 2030 costs are estimated to be $2.5 billion.

D. Mistaken Accounting of Affected Units Owned by Electric Cooperatives and Assumptions about Coal Plant Retirements Drive EPA's Projected Compliance Costs Downward.

The single most important cost driver leading to sharply lower and erroneous compliance cost estimates from EPA is believed to be the mistaken accounting of the affected units owned

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Elec. Co-op, NRECA Corporation, Old Dominion Electric Co-op, PowerSouth Energy Cooperative, Prairie Power, Inc., Seminole Electric Co-op, Inc., South Mississippi Electric Power, South Texas Electric Cooperative, Inc., Southern Illinois Power Cooperative, Sunflower Electric Power Corp., Wabash Valley Power Assn., Inc., Western Farmers Electric Co-op, Wolverine Power Supply Co-op, Inc., Northwest Iowa Power Cooperative, Sam Rayburn G&T, Inc.

[85] All compliance costs estimates from EPA and NRECA are reported in year 2011 dollars.

by electric cooperatives that qualify as small entities under the SBA criteria. Moreover, a review of the "parsed" files from the EPA's Integrated Planning Model (IPM) shows that it projects substantial retirements of approximately 3000 MW of co-op generating units under "business-as-usual" conditions without the 111(d) Rule. In effect, the EPA base case coal plant retirement assumptions implicitly assume zero compliance costs associated with these units. However, in the absence of the 111(d) Rule, electric cooperatives currently plan to keep the vast majority of their coal-fired generating capacity operating.[86] Thus, EPA substantially understates the cost associated with complying with the 111(d) Rule.

E. Total Compliance Cost for Electric Cooperatives Range from $11.7 Billion to $20.3 Billion over the 2022-2030 Period.

Although the EPA only provides cost estimates for the year 2030, compliance costs begin to escalate and rise steeply over the 2022-2029 interim period. NRECA has estimated the compliance costs to electric cooperatives over the interim period. Adding these projected costs to the year 2030 costs discussed above provides a total compliance cost of $11.7 billion under the mass-based federal plan and model rule scenario and $20.3 billion in the rate-based scenario.

IX. Comments On Market Liquidity

EPA solicits comment on approaches to ensure market liquidity while ensuring the stringency of the final 111(d) emissions guidelines. 80 Fed. Reg. at 64,981. Market liquidity is an important goal, as enhancing market liquidity could lead to reducing carbon compliance costs. With the ultimate goal of increasing carbon trading in all markets, liquidity and price transparency in the long and short term markets could allow for market participants to have clear pricing signals to support the determination of capital investments needed to comply with the final 111(d). Market participants located in illiquid markets are likely to have higher compliance costs, as the price disparity at which the commodity can be bought and sold can be inordinate in markets where trading is not transparent and/or where trading is infrequent.

NRECA suggests that EPA promote market liquidity in the following ways:

- Increasing the number of market participants in carbon markets, which will help enhance liquidity and transparency. In addition, a larger number of market participants will increase the number of products that are offered in the carbon markets to help compliance entities hedge effectively and enhance liquidity while supporting price transparency.

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[86] *See, e.g.,* Brummett Decl. ¶ 14 ("The engineered life of San Miguel's power plant . . . has recently been re-confirmed as 2037, 22 years from now. Despite repeated misconceptions by EPA in its modeling, San Miguel will not retire as a result of market conditions, the Cross-State Air Pollution Rule (CSAPR), or the Mercury and Air Toxics Standards (MATS). . . . San Miguel has heavily invested in environmental controls to ensure that the unit can comply with these and other pending rules and live out its engineered life through 2037 and only the 111(d) Rule would force the premature closure of San Miguel.").

- Applying high integrity standards to all market participants trading in the carbon markets to comply with the 111(d) Rule. The standards should include anti-market manipulation provisions to protect the integrity of the carbon markets.
- Distributing 100 percent of allowances in a state or federal mass-based program; the agencies should not withhold any allowances or be sellers in the market.

X. Comments on Market Oversight

The agency seeks comment on appropriate market monitoring activities, including tracking ownership of allowances or ERCs, oversight of the creation and verification of credits, and tracking market activity like transaction volumes and prices. 80 Fed. Reg. at 64,977. EPA should explicitly list entities that should are allowed to participate as buyers and sellers in any "market" (*i.e.,* effected EGUs and utilities that provide wholesale or retail electric service). If entities purchase allowances or ERCs for the purposes of withholding them from the market, emission reductions would be more stringent than necessary and could potentially cause reliability issues.

There should also be an independent market monitor to support the competitive performance of the carbon market. This independent market monitor would make recommendations if any changes need to be made to support the liquidity and transparency of the carbon markets. It will be imperative that there is market oversight reporting, but not from EPA. If there are integrity issues with the carbon markets, the issues should be reported at the State and Federal level. NRECA also supports the use of a third party tracking system that we expect to provide more functions, like the publishing of pricing to support market oversight and liquidity.

APPENDIX A:
DERIVATION OF THE ERC-TO-TONS CONVERSION FORMULA

This appendix explains the derivation of the ERCs-to-tons conversion formula discussed in Section III.B of these comments.

Under the CPP, EGUs in a state with a rate-based compliance system must meet the applicable emission rate by surrendering a sufficient number of ERCs and/or reducing their emissions such that each EGU's adjusted emission rate (after accounting for the unit's generation and ERCs) remains at or below the applicable rate-based limit. As long as the ratio of the EGU's emissions to its generation plus any ERCs it surrenders is equal to or less than the applicable rate-based limit in the state, the unit would be considered in compliance.

In a rate-based system that is in compliance with the rate-based limit, the availability of extra ERCs beyond the number of ERCs needed for compliance can allow EGUs to increase their CO_2 emissions by a known amount. (Similarly, the removal of ERCs would require EGUs to reduce their emissions by the same, known, amount.) As we demonstrate below, the amount of additional tons of CO_2 that EGUs in a rate-based state could emit for every extra ERC is related to the rate-based limit for the state and the emissions and generation of the EGU. If we assume that all EGUs comply with their rate-based limits—in other words, that each EGU's emissions divided by its generation plus ERCs surrendered must always equal the applicable rate-based limit—we can determine the number of additional emissions that an extra ERC can allow by solving for that term in the following formula:

Formula A-1:

$$\frac{\mathbf{Emissions_{EGU} + Emissions_{Extra}}}{\mathbf{Generation_{EGU} + 1\ MWh}} = \mathbf{RateLimit}$$

In this formula, "$\text{Emissions}_{\text{EGU}}$" means the EGU's CO_2 emissions without the extra ERCs. "$\text{Emissions}_{\text{Extra}}$" means the additional pounds of CO_2 the EGU could emit while remaining in compliance with the rate-based limit. "$\text{Generation}_{\text{EGU}}$" means the EGU's generation plus credit for generation associated with any ERCs that were required to bring the EGU into compliance with the rate limit. The 1 MWh represents the availability of 1 extra ERC equivalent to 1 MWh. "RateLimit" is the rate-based emission limit that applies to the EGU.

Solving for $\text{Emissions}_{\text{Extra}}$, we see that the amount of additional emissions allowed by the additional ERCs is equal to the Rate Limit of the state multiplied by the sum of EGU generation plus the 1 MWh represented by the ERC, minus the emissions of the EGU. In other words:

$$\text{Emissions}_{\text{EGU}} + \text{Emissions}_{\text{Extra}} = \text{RateLimit}\ x\ (\text{Generation}_{\text{EGU}} + 1\ \text{MWh})$$

Therefore,

$$\text{Emissions}_{\text{Extra}} = \text{RateLimit}\ x\ (\text{Generation}_{\text{EGU}} + 1\ \text{MWh}) - \text{Emissions}_{\text{EGU}}$$

Which is equivalent to

Formula A-2:

$$\mathbf{Emissions_{Extra} = (RateLimit\ \mathit{x}\ Generation_{EGU}) + (RateLimit\ \mathit{x}\ 1\ MWh) - (Emissions_{EGU})}$$

We next assume that the EGU would have been in compliance without the extra ERC. In other words, the ERC is "extra" and would lead to over-compliance if used by the EGU. If the EGU is exactly in compliance, the EGU's total emissions must, by definition, be less than or equal to the product of the rate limit and the level of EGU generation (plus any ERCs necessary for compliance). In other words, to be in compliance:

$$\frac{\mathrm{Emissions_{EGU}}}{\mathrm{Generation_{EGU}}} = \mathrm{RateLimit}$$

And therefore,

Formula A-3:

$$\mathbf{Emissions_{EGU} = RateLimit\ \mathit{x}\ Generation_{EGU}}$$

As above, "Generation$_{EGU}$" refers to the EGU's generation plus credit for generation associated with any ERCs that are required to bring the EGU into compliance with the rate limit, while "Emissions$_{EGU}$" refers to the EGU's emissions (without accounting for any extra emissions that an ERC would allow).

If we apply this assumption by substituting Formula A-3 into Formula A-2, above, we can make the following substitution:

$$\mathrm{Emissions\ _{Extra}} = (\mathrm{RateLimit}\ x\ \mathrm{Generation_{EGU}}) + (\mathrm{RateLimit}\ x\ 1\ \mathrm{MWh}) - (\mathbf{Emissions_{EGU}})$$

becomes:

$$\mathrm{Emissions\ _{Extra}} = (\mathrm{RateLimit}\ x\ \mathrm{Generation_{EGU}}) + (\mathrm{RateLimit\ x\ 1\ MWh}) - (\mathbf{RateLimit\ \mathit{x}\ Generation_{EGU}})$$

After making this substitution, we find that two terms cancel each other:

$$\mathrm{Emissions\ _{Extra}} = \cancel{(\mathrm{RateLimit}\ x\ \mathrm{Generation_{EGU}})} + (\mathrm{RateLimit}\ x\ 1\ \mathrm{MWh}) - \cancel{(\mathrm{RateLimit}\ x\ \mathrm{Generation_{EGU}})}$$

leaving:

Formula A-4:

$$\mathbf{Emissions\ _{Extra} = RateLimit\ \mathit{x}\ 1\ MWh}$$

Because rate limits are formulated in terms of X lbs./MWh, the expression above demonstrates that the extra emissions an EGU can emit by using one extra ERC is equal to the numerator (X lbs.) of the applicable rate limit:

$$\text{Emissions}_{\text{Extra}} = \text{RateLimit}\ x\ 1\ \text{MWh}$$

Becomes:

$$\text{Emissions}_{\text{Extra}} = \cancel{\text{RateLimit}}\ \mathbf{X\ lbs./MWh}\ x\ 1\ \text{MWh}$$

And therefore,

$$\text{Emissions}_{\text{Extra}} = \text{X lbs.}/\cancel{\text{MWh}}\ x\ 1\ \cancel{\text{MWh}}$$

Or

Formula A-5:

$$\boldsymbol{Emissions_{Extra} = X\ lbs.\ (where\ X\ is\ the\ numerator\ of\ the\ rate\text{-}based\ limit).}$$

That is, the amount of additional emissions each additional ERC enables an EGU to emit is at least equal to the numerator (X lbs.) in the applicable rate-based limit.

Formula A-5 represents the minimum amount of extra emissions. The reason that this is the minimum is that an extra ERC could theoretically allow an EGU to increase its emissions by more than this amount if the EGU also increased its own generation at the same time that it increased emissions.

Example 1: For example, suppose that an EGU with average emission rate of 2,000 lbs./MWh located in a rate-based state is subject to a rate-based limit of 1,305 lbs./MWh. Suppose that the EGU produces 1,000 MWh of electricity during the applicable compliance period. In this example, the EGU would have emissions equal to 1,000 MWh *x* 2,000 lbs./MWh, or 2,000,000 lbs. So, to remain in compliance with its 1,305 lbs./MWh emission limit, the EGU would need to have its generation plus ERCs (i.e., the denominator) equal to at least 1,532.57 MWh (if emissions equal 2,000,000 lbs. and generation plus ERCs equals 1,532.57 MWh, the EGU's <u>adjusted</u> emission rate for the period would be slightly less than 1,305 lbs./MWh and the EGU would be deemed in compliance). Because the EGU produced 1,000 MWh, this implies that the EGU would need to obtain at least 532.57 MWh of ERCs to be in compliance. However, if EPA maintains its proposal to denominate ERCs in <u>whole</u> MWh units, the EGU would, in practice, need to obtain <u>533</u> MWh of ERCs to allow it to produce 1,000 MWh at an emission rate of 2,000 lbs./MWh.

Note that this "whole-MWh" restriction means that in many cases, EGUs will slightly over-comply with their rate-based limits. In this case, even without any extra ERCs, the EGU could actually emit up to 2,000,565 lbs. (i.e., an extra 565 lbs.) while remaining in compliance with its rate-limit (2,000,565 lbs. / 1,533 MWh = 1,305 lbs./MWh).

Now suppose that an extra ERC equal to 1 MWh becomes available, such that the total ERCs available to the EGU now equal 534 MWh. If the EGU applied this ERC to adjust its generation <u>without increasing its generation</u>, the EGU would be able to emit an <u>additional 1,870 lbs</u>. more than it could emit when only 533 MWh of ERCs were available. This is because with generation plus ERCs (i.e., the denominator) equal to 1,534 MWh (1,000 MWh generated plus 534 MWh of ERCs), the EGU would still be in compliance even if it emitted 2,001,870 lbs. during the compliance period. This is because 2,001,870 lbs. / 1,534 MWh = 1,305 lbs./MWh, which is the EGU's emission limit. (An EGU that emits at 2,000 lbs./MWh on average could potentially increase its emissions by 1,870 lbs. over the course of the compliance period without increasing its net output by operating for some amount of time at a higher emission rate due to partial loading or the operation of pollution control equipment that imposes a parasitic load on the EGU.) Importantly, the amount of additional emissions allowed by the extra ERC in this example is greater than the result that would obtain if we used Formula A-5. Under Formula A-5, the amount of assumed extra emissions would be equal to the numerator of the applicable rate-based limit (1,305 lbs.)—a figure that is lower than the number of additional pounds the EGU in this example could actually emit (1,870 lbs.).[1] The reason that the EGU in this example can emit more than the rate-based limit even without increasing its generation is that the EGU was actually over-complying with its rate-based limit by 565 lbs. due to the "whole-MWh" restriction on ERCs and the need to round up to the next whole MWh.

Example 2: In the more typical case, the EGU in Example 1 could also increase its emissions while simultaneously increasing its generation. Doing so would allow the EGU to increase its emissions by more than it could have if its total generation remained unchanged. For example, suppose the EGU decided to produce an additional 1.5 MWh of generation to bring its total generation to 1,001.5 MWh for the period. In this case, the EGU's adjusted generation plus ERCs would be equal to 1,001.5 MWh of generation plus 533 MWh of ERCs that it had already procured, plus 1 MWh of additional ERCs that became available, for a total of 1,001.5 + 533 + 1 MWh, or 1,535.5 MWh in the denominator. In this scenario, the EGU could emit up to 2,003,827.5 lbs. of CO_2 while remaining in compliance with its rate-based limit. (To see this, divide 2,003,827.5 lbs. by 1,535.5 MWh; this is equal to 1,305 lbs./MWh, which is the EGU's rate-based limit in this example).

Thus, in this example, if the EGU increased its total generation by 1.5 MWh and obtained one extra MWh of ERCs, it could emit 3,827.5 lbs. of CO_2 more than it could have without the presence of the extra ERC (recall that without the extra ERC, the EGU in this example could only emit 2,000,000 lbs., whereas with the extra ERC plus its own increase in generation, the EGU can emit up to 2,003,827.5 lbs. without violating its emission limit). In other words, in this example and the previous example, the availability of one extra ERC allowed the EGU to increase its emissions by far more than two times the numerator of the applicable rate-based limit. This indicates that Formula A-5, above represents the minimum amount than an EGU in a rate-based state could increase its emissions due to the availability of an extra ERC.

Importantly, this increase would not be possible but for the existence of the extra ERC. For example, if the EGU in the previous example simply increased generation by 1.5 MWh at its average emission rate without obtaining additional ERCs, it would find itself out of compliance: its emissions would now total 2,003,000 lbs. (1,001.5 MWh of generation multiplied by the EGU's average emission rate of 2,000 lbs./MWh), whereas generation plus the 533 MWh of ERCs the EGU started with would equal 1,534.5 MWh. The EGU's calculated emission rate in this case would be 1,305.31 lbs./MWh—more than its rate-based emission limit. Thus, without

[1] In this example, the difference between the result of Formula 5 and the actual figure is due to the fact that ERCs are only issued in whole number increments, so the EGU was initially slightly over-complying.

the extra ERC, the EGU would not be able to increase its generation by this amount while remaining in compliance.

Example 3: Note further that other EGUs with different emission rates and generation could also increase their emissions by more than the applicable rate-based limit if they obtain an extra ERC and also increase their generation. For example, an EGU with an average emission rate of 1,500 lbs./MWh and subject to a 1,305 lbs./MWh rate limit that initially generated 1,000 MWh would emit 1,500,000 lbs. of CO_2 and would need 150 MWh of ERCs to be in compliance (1,500,000 lbs./1,150 MWh = 1,304.35 lbs./MWh). In fact, this EGU would be emitting 750 lbs. less than it could due to the need to round up the needed ERCs to the nearest whole number (with generation plus ERCs equal to 1,150 MWh, the EGU could emit up to 1,500,750 lbs. while remaining in compliance with its rate-based limit).

If the EGU in this third example were to obtain one additional ERC and also increase its generation by an additional 2 MWh (for a total of 3 extra MWh), the EGU would be able to emit up to 1,504,665 lbs. of CO_2, or an additional 4,665 lbs. more than it could without the extra ERC. (To see this, divide 1,504,665 lbs. by 1,153 MWh. The result is 1,305 lbs./MWh, meaning that the EGU would be in compliance even if it also increased its generation by 2 MWh.)

Even if the EGU in this example did not increase its generation, the availability of an extra ERC in addition to the 150 ERCs the EGU had already obtained would allow the EGU in this example to emit 2,055 extra lbs. of CO_2: [1,500,000 lbs. + 2,055 extra lbs.] / [1,000 MWh generation + 150 MWh ERCs + 1 MWh extra ERC] = 1,305 lbs./MWh.

Thus, these examples demonstrate that the formula shown in Formula A-5 represents the minimum amount of emissions that each EGU could emit if an additional ERC were to become available. In practice, due to the "whole-MWh" restriction, the role of rounding, and the ability to increase generation while increasing emissions, the availability of each extra ERC would actually allow EGUs to increase their generation by more than the amount in Formula A-5. For this reason, we view the approach discussed in these comments—which would limit the conversion value of an ERC to the numerator of the blended nation-wide rate-based limit—as an extremely conservative approach to quantifying the additional emissions that each extra ERC allows in a rate-based state.

APPENDIX B:
DERIVATION OF THE ERC CONVERSION FORMULA FOR ERCS ISSUED IN STATES WITH DIFFERENT RATE LIMITS

This Appendix explains how any distortionary effects that could be created by allowing partial ERCs ("P-ERCs") issued in one rate-based state to be used for compliance in another rate-based state with a different emission limit would be negated if the converted P-ERCs were calculated using the following formula:

$$\text{P-ERC}_{\text{Converted}} = \text{P-ERC}_{\text{ExportState}}\ x\ \frac{\text{EGU emission standard}_{\text{ExportState}}\ x\ (\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate})}{\text{EGU emission standard}_{\text{ImportState}}\ x\ (\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate})}$$

In this formula, "$\text{P-ERC}_{\text{Converted}}$" represents the value of the P-ERCs in the importing state (i.e., the state where the P-ERCs are used for compliance). "EGU emission $\text{standard}_{\text{ExportState}}$" is the emission rate limit applicable in the state where the P-ERCs were issued (the "exporting" state). "EGU emission $\text{standard}_{\text{ImportState}}$" is the emission rate limit that applies in the importing state, where the P-ERCs are to be used for compliance. "$\text{P-ERC}_{\text{ExportState}}$" is the value (in MWh) of the P-ERCs to be converted in the state where they were issued. "EGU emission rate" is the emission rate of the EGU to which the P-ERCs were issued.

The remainder of this Appendix explains the derivation of this formula, and demonstrates why this formula negates any distortionary effect that could be created by allowing rate-based trading among states with different emission rate limits.

Derivation of the P-ERC Conversion Formula:

Under the proposed rate-based Federal Plan and Model Trading Rule, ERCs can be issued to affected fossil-fueled EGUs according to the following formula:[1]

<u>**Formula B-1:**</u>

$$\text{ERCs} = \frac{\text{EGU emission standard} - \text{EGU emission rate}}{\text{EGU emission standard}}\ x\ \text{EGU generation}$$

Under this formula, the number of P-ERCs that each affected EGU receives is tied to the EGU's actual emission rate, the number of MWh produced, and the rate-based emission standard to which the EGU is subject. For units with identical emission rates, EGUs in states with higher (less stringent) emission rate limits will generate more P-ERCs for each incremental MWh of generation than EGUs in states with lower (more stringent) emission limits. Thus, if P-ERCs can be generated by an EGU in a state with a higher emission limit and "exported" to a state with a lower emission limit, EGUs in the state with the higher emission limit (the "exporting state") might receive a form of production incentive relative to EGUs in the state with a lower emission limit (the "importing state"). This incentive results from the fact that for every X MWh of

[1] This formula is taken directly from the Proposed Rule at 80 Fed. Reg. 65,093.

generation, the EGU in the exporting state would receive a slightly higher number of ERCs than would a similar EGU in the importing state.

To eliminate this arguably "distortionary" incentive, it is necessary to create a conversion process that counteracts the incremental incentive that would be created by the ability to trade P-ERCs between states with different emission rates. Specifically, if the number of P-ERCs obtained by converting imported out-of-state P-ERCs is equal to the number of P-ERCs that would be generated if the EGU had been located in and generated the P-ERC in the importing state, there should be no opportunity for arbitrage and no distortionary effect. This is because an EGU's incentive to generate an extra MWh so that it can receive an extra P-ERC for use in the importing state would be the same regardless of where the EGU is located and regardless of the emission rate to which the EGU is subject. (Another way to think about this is that the conversion formula should make an affected entity in the importing state indifferent as to whether it purchases an extra P-ERC from an EGU that is located in the importing state or imports a P-ERC generated by an identical EGU located in the exporting state.)

To determine the appropriate conversion factor ("CF") to eliminate this distortionary incentive, we solve the following formula:

Formula B-2:

$$\textbf{P-ERC}_{\textbf{ExportState}}\ x\ \textbf{CF} = \textbf{P-ERC}_{\textbf{Converted}} = \textbf{P-ERC}_{\textbf{ImportState}}$$

In this formula, "$\text{P-ERC}_{\text{ExportState}}$" means the value of the exported P-ERC in the state in which it was issued (the "exporting" state). "$\text{P-ERC}_{\text{Converted}}$" is the converted, discounted value that the P-ERC is given when imported and used for compliance in the importing state. "$\text{P-ERC}_{\text{ImportState}}$" is the P-ERC value that an identical affected EGU would have received for the same amount of generation if the EGU had been located in the importing state, and subject to the emission limit in the importing state. "CF" is the conversion factor.

In the formula above, we are setting the value of the converted P-ERC equal to the value that the EGU would have received if it had been located in the importing state. This value is equal to the value of the P-ERC in the exporting state multiplied by a conversion factor ("CF"). If the value of the imported P-ERC in the importing state would be the same as if the affected EGU had been located in the importing state, there would be no additional, distortionary incentive to generate the P-ERC out of state and import it into the state.

The key issue, therefore, is how much the imported P-ERC needs to be discounted so that its value is equal to a P-ERC issued to an identical unit within the importing state. In other words, we need to solve for CF. To solve this equation for CF, we first set CF equal to the ratio of $\text{P-ERC}_{\text{ImportState}}$ to $\text{P-ERC}_{\text{ExportState}}$ by dividing both sides by $\text{P-ERC}_{\text{ExportState}}$:

$$\text{P-ERC}_{\text{ExportState}}\ x\ \text{CF} = \text{P-ERC}_{\text{ImportState}}$$

And therefore,

$$\text{CF} = \frac{\text{P-ERC}_{\text{ImportState}}}{\text{P-ERC}_{\text{ExportState}}}$$

If we substitute in Formula B-1, above for the two P-ERC terms in this formula, we get the following expression:

$$\text{CF} = \frac{\text{P-ERC}_{\text{ImportState}}}{\text{P-ERC}_{\text{ExportState}}}$$

becomes

$$CF = \frac{\frac{\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate}}{\text{EGU emission standard}_{\text{ImportState}}} \, x \text{ EGU generation}}{\frac{\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate}}{\text{EGU emission standard}_{\text{ExportState}}} \, x \text{ EGU generation}}$$

Or, simply,[2]

$$\text{CF} = \frac{\frac{\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate}}{\text{EGU emission standard}_{\text{ImportState}}}}{\frac{\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate}}{\text{EGU emission standard}_{\text{ExportState}}}}$$

This formula is equivalent to the somewhat simpler:

Formula B-3:

$$\text{CF} = \frac{\text{EGU emission standard}_{\text{ExportState}} \, x \, (\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate})}{\text{EGU emission standard}_{\text{ImportState}} \, x \, (\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate})}$$

So, for any given EGU emission rate and any two states, Formula B-3 can provide a conversion factor that will eliminate the incentive for an EGU with identical emissions in a high-emission rate state to produce more P-ERCs for export than it would if it were located in a lower-emission rate state.

Now that we have solved for CF, we can determine the discounted quantity of P-ERCs that the importing entity could use for compliance in the importing state. Recall that to eliminate distortionary effects, we set

$$\textbf{P-ERC}_{\textbf{ExportState}} \, x \, \textbf{CF} = \textbf{P-ERC}_{\textbf{Converted}} = \textbf{P-ERC}_{\textbf{ImportState}}$$

So

$$\text{P-ERC}_{\text{Converted}} = \text{P-ERC}_{\text{ExportState}} \, x \, \textbf{CF}$$

Therefore:

[2] The identical "EGU generation" variables in the numerator and denominator cancel each other.

Formula B-4:

$$\textbf{P-ERC}_{\textbf{Converted}} = \textbf{P-ERC}_{\textbf{ExportState}}\ x\ \frac{\textbf{EGU emission standard}_{\textbf{ExportState}}\ x\ (\textbf{EGU emission standard}_{\textbf{ImportState}} - \textbf{EGU emission rate})}{\textbf{EGU emission standard}_{\textbf{ImportState}}\ x\ (\textbf{EGU emission standard}_{\textbf{Export State}} - \textbf{EGU emission rate})}$$

Note that to conduct this conversion, we must know the quantity of P-ERCs we wish to convert ($\text{P-ERC}_{\text{ExportState}}$), the emission rate limits in the importing and exporting states, and the emission rate for the EGU that generated the P-ERCs. Therefore, to allow for interstate trading of P-ERCs among states with different rate-based limits, it would be necessary to include as one attribute of each P-ERC the emission rate of the EGU that generated the P-ERC.

Importantly, this formula provides a mechanism for converting the value of P-ERCs in the exporting state to a value that is equal to the value that the same EGU would have received if the P-ERCs had been generated in the importing state. We can see this by testing the formula with an actual example.

Assume an NGCC unit (emission rate 950 lbs./MWh) located in West Virginia (final emission rate 1,305 lbs./MWh) generates 1,000 MWh. Using Formula B-1, this NGCC would receive P-ERCs equal to:

$$\text{P-ERC}_{\text{ExportState}} = \frac{\text{EGU emission standard} - \text{EGU emission rate}}{\text{EGU emission standard}}\ x \text{ EGU generation}$$

So:

$$\text{P-ERC}_{\text{ExportState}} = \frac{1{,}305 \text{ lbs./MWh} - 950 \text{ lbs./MWh}}{1{,}305 \text{ lbs./MWh}}\ x\ 1{,}000 \text{ MWh} = 272 \text{ MWh}$$

When imported to a neighboring state (e.g., Maryland, final emission rate = 1,287 lbs./MWh) and converted using the Formula B-4, above, this quantity of P-ERCs would be converted to:

$$\text{P-ERC}_{\text{Converted}} = \text{P-ERC}_{\text{ExportState}}\ x\ \frac{\text{EGU emission standard}_{\text{ExportState}}\ x\ (\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate})}{\text{EGU emission standard}_{\text{ImportState}}\ x\ (\text{EGU emission standard}_{\text{Export State}} - \text{EGU emission rate})}$$

or

$$\text{P-ERC}_{\text{ Converted}} = 272 \text{ MWh}\ x\ \frac{1{,}305 \text{ lbs./MWh}\ x\ (1{,}287 \text{ lbs./MWh} - 950 \text{ lbs./MWh})}{1{,}287 \text{ lbs./MWh}\ x\ (1{,}305 \text{ lbs./MWh} - 950 \text{ lbs./MWh})} = \mathbf{261.8\ MWh}$$

To check whether this formula equalizes the playing field across the two states by ensuring that a similar EGU in Maryland (the importing state) would have received the same number of P-ERCs, we calculate the number of P-ERCs that an identical EGU with emission rate of 950 lbs./MWh and generation of 1,000 MWh would receive in Maryland:

$$\text{P-ERC}_{\text{ImportState}} = \frac{\text{EGU emission standard}_{\text{ImportState}} - \text{EGU emission rate}}{\text{EGU emission standard}_{\text{ImportState}}}\ x\ 1{,}000 \text{ MWh}$$

So, in this example,

$$\text{P-ERC}_{\text{ImportState}} = \frac{1{,}287\text{ lbs./MWh} - 950\text{ lbs./MWh}}{1{,}287\text{ lbs./MWh}}\ x\ 1{,}000\text{ MWh} = \mathbf{261.8\ MWh}$$

This value, 261.8 MWh, is the same value that the P-ERCs generated in West Virginia by an identical EGU and converted from West Virginia P-ERCs to Maryland P-ERCs using Formula B-4. Thus, the conversion formula removes any advantage that the NGCC unit had simply because it was located in a state with a higher emission rate. Consequently, conducting a conversion using this formula would remove any distortions and opportunities for arbitrage that interstate trading of P-ERCs could cause.

National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

January 21, 2016

Sent via email to: emvinput@epa.gov

Re: NRECA Comments to EPA on draft EM&V Guidance for the Clean Power Plan

Dear EPA,

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to submit comments to EPA on the draft Evaluation, Measurement and Verification (EM&V) guidance document (draft EM&V Guidance document) for the Clean Power Plan (CPP).[1] NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric energy to over 42 million people in 47 states. Electric cooperatives own and maintain 2.5 million miles or 42 percent of the nation's electric distribution lines, covering 75 percent of the U.S. landmass. NRECA and our members are therefore in a uniquely-informed position to provide comments on this issue and are significant stakeholders to the CPP, as well as EM&V processes, including the draft EM&V Guidance document.

Over the past several years, electric cooperatives have developed a framework and a set of fundamental principles for EM&V that are predicated on decades of experiences with energy efficiency programs and which should be applied to cooperative and other utility energy efficiency programs under the model rules (Model Rules) and state compliance plans (Compliance Plans). This framework is consistent with EPA's draft EM&V Guidance document and the requirements described in the Model Rules, and NRECA requests that EPA concludes that the framework meets the description noted in the following statement found in the draft EM&V Guidance document:

> "In June 2014, the EPA proposed carbon pollution emission guidelines for certain existing EGUs, as well as a 'State Plans Considerations' technical support document (TSD) that outlined a general approach to establishing EM&V requirements and guidance. The TSD proposed that the EPA's EM&V provisions could leverage the industry-standard practices, protocols, and methods currently utilized by the majority of states implementing demand-side EE and RE programs. The EPA further noted that many state PUCs, and other regulatory bodies and program management authorities, already have significant EM&V infrastructure in place, and some have been applying, refining, and enhancing their approaches for over 30 years."[2]

The approach NRECA outlines below is based on decades of cooperative experience with energy efficiency programs and associated EM&V infrastructure. NRECA requests that EPA accept the NRECA framework as an industry best practice for the cooperatives and other utilities, and that EPA recognize this best practice approach is consistent with the principles in the draft EM&V Guidance document and in the Model Rules.

[1] NRECA (EPA-HQ-OAR-2013-0602-33118) has filed extensive comments regarding EPA's CPP and will file comments on January 21, 2016 on the Final Rule. Our initial comments on this draft guidance do not amend or detract from the positions we have taken or will take before EPA, including our submittal on January 21, 2016 to the rulemaking docket.

[2] http://www.epa.gov/sites/production/files/2015-08/documents/cpp_emv_guidance_for_demand-side_ee_-_080315.pdf at page 3.

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This framework uses deemed savings where available and appropriate, and is updated periodically in order to incorporate changes in national or state standards for appliance and building codes, or to incorporate the results of new EM&V studies. The NRECA framework also makes use of the full range of best practice EM&V protocols included in the draft EM&V Guidance document. According to the "Model Energy Efficiency Program Impact Evaluation Guide" prepared by the EPA/Department of Energy National Action Plan on Energy Efficiency (NAPEE), deemed savings are based on stipulated values, which come from historical savings values of industry-typical projects. Deemed savings are the per-unit energy savings values that can be claimed from installing specific measures under specific operating situations. Examples include agreed-upon savings per fixture for lighting retrofits in office buildings, with specific values for lights in private offices, common areas, hallways, *etc*. Many states and regions already have in place Technical Resource Manuals (TRMs) that provide deemed savings estimates for a comprehensive range of energy efficiency measures. Many states now rely upon the deemed savings numbers included in such TRMs as the basis for (1) determining whether utilities have met annual kilowatt-hour (kWh) and kilowatt (kW) savings targets, and (2) assessing rewards or penalties in states where such incentive mechanisms exist. Deemed savings numbers are frequently relied upon in many jurisdictions by state regulatory agencies to determine compliance with legislative or regulatory requirements.[3] NRECA also notes that the North American Energy Standards Board (NAESB) established deemed savings business standards to determine savings for energy efficiency and demand response programs.

The NRECA EM&V framework approach for electric cooperatives is as follows.

1) The use of deemed values in savings calculations and reporting is essentially an agreement between the parties to an evaluation to accept a stipulated value, or a set of assumptions, for use in determining energy and demand savings. If certain requirements are met (e.g., verification of installation, satisfactory commissioning results, annual verification of equipment performance, and sufficient equipment or system maintenance), the project savings are considered to be confirmed. The stipulated savings for each verified installed project are then summed to generate a program savings value. Installation might be verified by physical inspection of a sample of projects or perhaps just an audit of receipts. Section 4.3 of the NAPEE Impact Evaluation Guide provides more detailed information on this approach.

2) Cooperatives should be able to use "deemed' savings from studies and TRMs as the basis for tracking and reporting savings from energy efficiency programs. EM&V experience in several states indicates that regional energy efficiency organizations (such as the Northeast Energy Efficiency Partnerships (NEEP), the Midwest Energy Efficiency Alliance and the Northwest Energy Efficiency Alliance) and investor-owned utilities (IOUs) are already conducting regular EM&V studies with large budgets and sophisticated scopes. It is not necessary for distribution cooperatives, many of which are smaller without similar budgets or economies of scale, to "recreate the wheel" for EM&V studies. Rather, NRECA believes that such cooperatives should be able to use deemed savings based on the results of the detailed EM&V studies being performed by such entities in the same state or region, or EM&V

[3] For example, in the Northwest there is the pre-existing congressionally created Power and Conservation Council of the Pacific Northwest and their Regional Technical Forum.

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studies from regional energy efficiency organizations or Federal and state government agencies. EM&V studies from these other entities can serve as a basis for "deemed" savings for identical or similar energy efficiency programs or measures implemented through electric cooperative energy efficiency programs. For example, the average annual energy savings for installation of an ENERGY STAR refrigerator in the household of a cooperative member is likely the same as the energy savings for a customer of an IOU.

3) NRECA recommends that deemed savings values be updated periodically in order to incorporate changes in national or state standards for appliance and building codes, or to incorporate the results of new EM&V studies or studies done by national laboratories or similar research organizations. In addition, deemed savings values may need to be adjusted to allow for differences in the climate, geography, economic/demographic characteristics, building types and other factors for the service area of a small utility. Cooperatives would be able to use the best and latest available secondary data sources to update deemed savings values when appropriate.

   NRECA also recommends that deemed savings values be reviewed and updated on a regular schedule (every few years) with oversight by a committee composed of a diverse group of regional and local energy efficiency stakeholders, structured similar to American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), NAESB, or other similar organizations, so that deemed savings remain accurate and up-to-date. This regular review would also allow for the most recent impact evaluation results, results from building simulation modeling or pertinent data from other secondary sources to be reflected in deemed savings values.

Additional Comments:

a. *Net vs gross* – The draft EM&V Guidance document does not address whether or not savings should be calculated on a net vs. a gross basis. Since the interest is carbon reductions, the savings should be gross, and should include all mechanisms for acquiring savings, including programs, codes, standards and market dynamics. Net savings is less important from a carbon perspective—the impact of the program itself should be a secondary consideration to ensuring that energy savings occurred, no matter the reason. In addition, conducting a net to gross estimation pulls evaluation and research budgets away from quantifying the gross energy savings as accurately as possible.

b. *Independence* – There are several references to "independent verification" in the draft EM&V Guidance document. The draft EM&V Guidance document should clarify that independent verification can be performed internally by utilities and program administrators. NRECA believes that independent and unbiased evaluation studies can be funded by and managed by a program administrator, especially when the evaluation activities have sufficient transparency and review and are functionally separated within an organization that exhibits a culture of evaluation.

c. *Verification* – Page 8 of the draft EM&V Guidance document states that[w]hen deemed savings are used to quantify MWh savings, a separate verification process is needed to confirm the quantity of units installed." This is so vague that the impact could range from incidental to onerous. NRECA is concerned that the EM&V requirements would be overly burdensome to cooperatives whose customers are spread over a sparsely populated area of hundreds or thousands of square miles. The draft EM&V Guidance document appears to suggest that significant EM&V will be required even when deemed savings numbers are used. Physical verification of even a small percentage of the installations could impose a burden that could hinder the ability of consumers to get efficiency incentives at all.

d. *Early replacement activities:* Early replacement activities, such as appliance recycling programs, are hugely successful tried and true efficiency programs implemented by cooperatives. (For more information on cooperative appliance recycling programs, see attachment 1). On page 12 of the draft EM&V Guidance document, EPA states "[f]or early replacement activities, with strong evidence that replacement of functioning equipment is due to program influence, a dual baseline is applicable: Use existing conditions for defining the CPB [(common practice baseline)] for the remaining useful lifetime (RUL) of the replaced equipment or system. Use the CPB that would apply to new construction or replacement on failure for the remainder of the new equipment EUL." These strict requirements would likely kill the program as the cost of compliance would exceed the value of the savings.

e. *Forward adjustment of savings* - On page 15 of the draft EM&V guidance document, EPA discusses the need to "Forward Adjust" energy efficiency savings based on changes in the calculated value of deemed savings that occur somewhere during the life of a measure. This process would be problematic as tracking measures over multiple years will be enough of a challenge without trying to adjust the values "on the fly."

f. *Use of TRMs across states* - Page 16 of the draft EM&V Guidance document mentions the fact that there are 20 or more TRMs in use across the country. Since some co-ops serve consumers in multiple states, some cooperatives employ a composite of state TRMs. It would be unfortunate and burdensome if cooperatives that span several states had to use different TRMs in each of the states that they serve. In these cases, optional adoption of regional TRMs (perhaps by climate zone) would be helpful.

g. *Avoiding double counting* - Section 2.9 on page 23 of the draft EM&V Guidance document discusses verification and suggests that third-party counting of installed light bulbs would be required. Implementing this in a sparsely populated area would likely cause most "small" measures to be eliminated as they would not be cost-effective given the cost of verification.

h. *Interactive effects of end-use fossil fuel use* - Section 2.11.2 on page 25 of the draft EM&V Guidance document states that "[i]t is not necessary to quantify the interactive effects of end-use fossil fuel use (i.e., non-electricity fuels such as natural gas) for the purpose of the EPA's emissions guidelines for affected electric utility generating units." This is problematic from an environmental perspective and should be revised. Take the example of replacing an electric water heater with a gas water heater. It would appear that an implementer could count the kWh savings (carbon dioxide reduction) from removing the water heater while assuming that the new gas water heater has ZERO environmental impact. At the same time, it is not clear if the stakeholder would be allowed to count the environmental impact of reduced fossil fuel use from measures such as insulation or weather sealing programs. This provision could create significant incentives for fuel switching from electric to ANY other source, such as fuel oil, propane or

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natural gas, at a time when emission intensity of the grid is decreasing. This is contrary to the goals of EPA and the CPP.

Thank you for your review and consideration of our comments. In conclusion, electric cooperatives are a unique and significant stakeholder group to the Clean Power Plan and the draft EM&V Guidance document. We appreciate your consideration of our comments and look forward to engaging in the process as the program details are further developed.

We would be happy to discuss any details of our comments and concerns as a follow-up.

Respectfully submitted,

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Attachment 1: Appliance Recycling Programs

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Attachment 1: Appliance Recycling Programs

Overview:

Appliance recycling programs are among the most effective programs to reduce energy consumption and demand on the electrical grid. Older model appliances are often much less efficient than newer models. In the case of refrigerators, for example:

- Every year, refrigerator efficiency improves. An average fridge purchased in 2008 consumes 3 percent less energy than one from 2007.
- Forty-four percent of fridges that could be recycled are used as second fridges, sold or given away.
- Only three out of 10 refrigerators sold are Energy Star-qualified.
- Twenty-seven million inefficient models made before 1993 are still in American homes.
- Surveys indicate that over 30% of members in some cooperative utility service areas own two or more refrigerators

Programs that remove these products from the electrical system constitute effective energy efficiency programs and should be accepted by EPA for us in EPA's CEIP.

Eligibility and Verification:

In order to be eligible for recycling programs, refrigerators and freezers must be in working condition, and must be between 10 and 30 cubic feet in size, using inside measurements. Utilities contract with third-party administrators, such as Appliance Recycling Centers of America, Inc. (ARCA), to pick up and recycle refrigerators and freezers that are in working condition. The appliance must be operating in order for the recycler to verify functionality. Once functionality is confirmed, the recycler will cut the cord and mark the exterior of the unit to ensure that it does not go back into operation before it reaches the recycling center. ARCA is just one program provider; other similar vendors should be considered acceptable under EPA's proposed rule as well.

ARCA, Inc. Background

"ARCA's 38 years of experience in the appliance recycling and replacement industry includes 25 years of providing service to electric utilities. Throughout our history, we have demonstrated the expertise to operate comprehensive energy efficiency programs in terms of design, scope and operation. Our development of equipment, processes and systems has lessened the negative impact of appliance disposal on the environment. Our philosophy has always been to provide unrivaled customer service, emphasize safety and environmental compliance, maximize recycling and minimize disposal in landfills.

The quantification of energy savings resulting from appliance recycling and replacement programs has been of long-standing interest to the sponsors of these programs from the time they were first conducted in the early 1990s. ARCA was an early advocate for ensuring the proper handling of R-12 and CFC-11 from old refrigerators and freezers, air conditioners and dehumidifiers due to the huge energy savings and environmental benefits available to electric utilities by retiring and/or changing out these old appliances. ARCA has consistently provided the highest levels of design and implementation proficiency in helping utilities achieve their energy savings goals."[4]

Utility Energy Savings

In this case study, the estimate savings for the particular products will vary depending on the particular program, the contribution of the product to the system demand peak, and the energy consumption of the recycled product. The savings calculations used for these programs and approved by coop board and public utility commissions are based on credible studies that are published in technical resource manuals and approved by public utility commissions in a process that aligns with EPA's discussion of acceptable practices in EPA's proposed regulation.[5] These types of successful programs have been an integral part of nationwide efforts to achieve energy efficiency gains in the past. Programs of the design described in this case study, if included in a State Plan should be accepted for use in the CEIP.

[4] http://www.arcarecyclinginc.com/arca-advantage

[5] State Plan Considerations: Section 5.A; "Quantification, Monitoring, and Verification for End Use Energy Efficiency", pg. 34