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U.S. Environmental Protection Agency
Attn: Docket ID No. EPA-HQ-OAR-2015-0199

**Comments of Clean Air Task Force and Conservation Law Foundation** on "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; Proposed Rule," 80 Fed. Reg. 64,966 (October 23, 2015)

Clean Air Task Force ("CATF") and Conservation Law Foundation ("CLF") (collectively "Commenters") respectfully submits these comments on the proposed U.S. Environmental Protection Agency ("EPA" or "Agency") "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014," as well as the proposed "Model Trading Rules."

Founded in 1996, CATF seeks to help safeguard against the worst impacts of climate change by working to catalyze the rapid global development and deployment of low carbon energy and other climate-protecting technologies, through research and analysis and public advocacy leadership. Since 1966, CLF has used the law, science, policymaking, and the business market to find pragmatic, innovative solutions to New England's toughest environmental problems. Whether that means cleaning up Boston Harbor, protecting ocean fisheries to ensure continued supply, stopping unnecessary highway construction in scenic areas, or expanding access to public transportation, we are driven to make all of New England a better place to live, work, and play. What's more, we have the toughness to hold polluters accountable, and the tenacity to see complex challenges through to their conclusion. CLF is also nimble enough to adjust course as conditions change to achieve the best outcomes. Our goal is not to preserve what used to be, but to create an even better New England — a region that's truly thriving.

CATF previously submitted comments to the Agency on its proposals to reduce carbon pollution from new power plants, including the January 2014 proposed "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430 (Jan. 8, 2014) and its February 26, 2014 "Notice of Data

Availability" in support thereof, 79 Fed. Reg. 10,750 (Feb. 26, 2014);[1] EPA's proposed "Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,960 (June 18, 2014);[2] as well as comments on EPA's carbon reduction proposals for existing power plants: EPA's June 2014 proposed "Clean Power Plan," i.e., "Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,830 (June 18, 2014); *and* "Notice of Data Availability in Support" in thereof, 79 Fed. Reg. 64,543 (Oct. 30, 2014); *and* "Technical Support Document: Translation of the Clean Power Plan Emission Rate-Based $CO_2$ Goals to Mass-Based Equivalents," U.S. EPA, Office of Air and Radiation (availability noticed: 79 Fed. Reg. 67,406 (Nov. 13, 2014)).[3]

Promulgation of a final model trading rule ("MTR") and federal plan ("FP") text is critical to successful implementation of the underlying Clean Power Plan. For the reasons described further below, both the final MTR and any final FPs should employ a mass-based allowance trading approach, with robust provisions to minimize "leakage."

## I. Overview.

### a. The Model Trading Rule and the Federal Plan are integral and necessary components of a robust and readily implementable Clean Power Plan package.

On October 23, 2015, EPA finalized the Clean Power Plan (the "CPP"), establishing emission guidelines to reduce carbon dioxide ("$CO_2$") from existing fossil fuel-fired electric generating units ("EGUs") pursuant to section 111(d) of the Clean Air Act ("CAA" or the "Act").[4] On the same date, EPA proposed a Federal Plan and Model Trading Rule as part of the overall suite of tools available to help achieve successful implementation of the CPP, and asked for comprehensive comments on both. While we offer comments on the details of EPA's

[1] Comment submitted by Ann Brewster Weeks *et al*., Senior Counsel and Legal Director, Clean Air Task Force (CATF), Doc. ID: EPA-HQ-OAR-2013-0495-9664 (May 9, 2014) *and* Comment submitted by Andres Restrepo, *et al*., Sierra Club, Doc. ID: EPA-HQ-OAR-2013-0495-9514 (May 9, 2014); CATF and CLF also submitted extensive comments on the Agency's subsequently withdrawn 2012 New Source Performance Standards for this industry, Comments of Clean Air Task Force and Conservation Law Foundation, Doc. IDs: EPA-HQ-OAR-2011-0060-9662, EPA-HQ-OAR-2011-0060-9663 (June 25, 2012).

[2] Comment submitted by James P. Duffy, Legal Fellow and Ann Brewster Weeks, Senior Counsel and Legal Director, Clean Air Task Force (CATF), Doc. ID: EPA-HQ-OAR-2013-0603-0280 (Oct. 16, 2014).

[3] Comment submitted by Ann Brewster Weeks, Legal Director, *et al*., Clean Air Task Force (CATF), Doc. ID: EPA-HQ-OAR-2013-0602-22612 (Dec. 1, 2014) [hereinafter "CATF CPP Comments"].

[4] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,662 (Oct. 23, 2015).

proposal, we appreciate that these actions are consistent with CATF's recommendations in comments on the proposed CPP and our preceding "Power Switch"[5] report. There, we recommended that EPA provide a defined FP and MTR as a guide for state implementation.

EPA is required by the Act to promulgate and implement a FP that will meet CPP requirements for any state that does not submit a timely and approvable plan to implement the CPP.[6] Commenters agree with EPA's decision to make public and take comment on substantive FP text. Furthermore, we endorse a single FP prototype, so that the Agency is clear about its own policy choices, and offers a consistent approach to implementation from state to state and region to region. This interstate consistency will promote the effectiveness of a multi-state trading plan operating in the context of interconnected regional electric power systems. EPA noted that some states "have indicated that they may prefer to rely on a federal plan, either temporarily or permanently, rather than develop a plan of their own."[7] By proposing a FP now that can be imposed promptly, EPA can make clear to states the ramifications of that choice.

Commenters also strongly support EPA's proposal to finalize the MTR by mid-2016, in time for it to inform state plan development efforts. Unlike a FP, a MTR is not required by law. Nonetheless, as we expressed in our comments on the proposed CPP, it is sound policy. Adoption of a MTR provides states with a pathway that will reduce the time and resource commitment to implementation plan development. Additionally, finalization of a MTR will promote transparency and consistency among state implementation efforts and will support the development of a robust emission trading system (especially, as we discuss below, if that trading system is mass-based). In light of these and other advantages, CATF and many states and other stakeholders have expressed strong interest in a MTR approach that states may voluntarily adopt.[8] Without such a rule, there is a real risk that states will develop inconsistent or even conflicting plans, increasing the risk of "leakage" (that is, generation shifting from affected to unaffected sources resulting in a "failure to achieve emission performance levels consistent with the [best system of emission reduction

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[5] Clean Air Task Force, *Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants* (Feb. 2014), *available at*: http://www.catf.us/resources/publications/files/Power_Switch.pdf.

[6] Section 111(d)(2) of the Act provides, in pertinent part: "The Administrator shall have the same authority—(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 111(c) of this title in the case of failure to submit an implementation plan, and (B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 113 and 114 of this title with respect to an implementation plan."

[7] 80 Fed. Reg. at 64,974.

[8] *See, generally, e.g.*, *id*. at 64,974. CATF, in its 2014 comments on the proposed CPP, specifically urged EPA to adopt a model mass-based trading rule similar to the successful 1998 $NO_x$ SIP Call. CATF CPP Comments at 181-184.

("BSER")])[9], as discussed *infra* at section IV. of these comments.[10] A system of inconsistent state plans also has the potential to make EPA's evaluation and review of those plans more difficult, and may reduce the likelihood that a robust trading market will develop.

**b. In view of the severe threats posed by power plant carbon pollution to human health and welfare, the Model Trading Rule and Federal Plan must include safeguards against any weakening of the standards embodied in the Clean Power Plan.**

While a MTR and a FP will provide the consistency needed to enable effective implementation of the CPP, the need for consistency must not serve to weaken the integrity of the CPP or the emission guidelines it established. Steep reductions in carbon emissions are urgently needed, and the CPP must deliver on all of its projected emission reductions.

Just yesterday scientists at the National Oceanic and Atmospheric Administration announced that 2015 was the Earth's warmest year by the widest margin on record.[11] It is difficult to overstate the threats climate change pose to human health and welfare, in this nation and the rest of the world. These include rising sea levels, drought, disease, increasingly severe weather events, worsened air quality, increases in food- and water-borne pathogens, increased frequency of heat waves and the harms that accompany these changes.[12] Man-made emissions of $CO_2$ and other greenhouse gases[13] are the central cause of climate change.[14] As nations around the world recently meeting in Paris recognized, "climate change represents an urgent and potentially irreversible threat to human societies and the planet and thus requires the widest possible cooperation by all countries, and their participation in an effective and appropriate

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[9] *Id.* at 64,821.

[10] As discussed in section IV, *infra*, there are several different situations in which a plan to implement the CPP can produce unintended incentives that increase emissions beyond those contemplated in the CPP. We use the term "leakage" here to refer to all potential forms of leakage. We also use terms "new source leakage" and "gas-on-gas" leakage; the former referring to situations resulting in a shift in generation from existing gas units and from other low- and zero-emitting units to new gas plants that are outside of the scope of the CPP, and the latter being a subset of new source leakage involving a shift in generation from existing gas units to new gas units.

[11] NOAA National Centers for Environmental Information, *State of the Climate: Global Analysis for December 2015*, (Jan. 2016), *available at*: http://www.ncdc.noaa.gov/sotc/global/201512.

[12] *See, e.g., generally,* Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,497-99, 6,6524-36 (Dec. 15, 2009).

[13] Reductions of methane, another greenhouse gas, from oil and gas operations, are also important, as CATF stressed in its CPP Comments, at 75-76

[14] *See, e.g.,* 74 Fed. Reg. 66,496, at 66,517.

international response, with a view to accelerating the reduction of global greenhouse gas emissions…" and "that deep reductions in global emissions will be required…."[15] In furtherance of this international effort, the United States has pledged to reduce its greenhouse gas emissions by 26-28 percent (from 2005 levels) by 2025.[16] And, as EPA has recognized in the CPP, deep reductions in carbon dioxide emissions from this largest emitting source category are critical if we are to avoid the worst damages of climate change.[17] U.S. power plants are the largest industrial sources of $CO_2$, emitting over one-third of national energy-related $CO_2$, nearly three times as much as the total greenhouse gas emissions from the next ten largest industrial sectors *combined*.[18] Power sector carbon emissions must be reduced as much as possible,[19] and the CPP, supported by a robust FP and MTR, is an important and necessary step toward that goal.

### c. **Summary of CATF and CLF's comments and recommendations**.

We agree with EPA that the CPP must achieve $CO_2$ emissions reductions that are "quantifiable, non-duplicative, permanent, verifiable, and enforceable."[20] Here, Commenters stress that the FP and the MTR must not compromise the integrity of the CPP and must deliver the CPP's promised emission reductions through measures that meet EPA's criteria.[21]

In support of these principles, our primary comments on the proposed FP and MTR are summarized as follows:

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[15] United Nations Framework Convention on Climate Change, Conference of the Parties, 21st Session, Adoption of the Paris Agreement, FCCC/CP/2015/L.9/Rev.1, at 1 (Dec. 12, 2015), *available at*: http://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf.

[16] United States, *U.S. Cover Notice, Intended Nationally Determined Contribution and Accompanying Information*, (Mar. 31, 2015) *available at*: http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf.

[17] 80 Fed. Reg. at 64,688-89; *see also* CATF CPP Comments, at 2-3

[18] 80 Fed. Reg. at 64,979.

[19] A renowned group of climate scientists, focusing on the danger of climate-change induced global energy imbalance, ocean warming, ice sheet disintegration and large sea level rise, recently concluded that the "task of achieving a reduction at atmospheric $CO_2$ is formidable, but not impossible. Rapid transition to abundant affordable carbon-free electricity is the core requirement …." Hansen, J. *et al*., *Ice melt, sea level rise and superstorms: evidence from paleoclimate data, climate modeling and modern observations that 2°C global warming is highly dangerous*, 15 ATMOS. CHEM. PHYS. DISCUSS. 20,059 at 20,122 (July 23, 2015).

[20] *See. e.g.,* 79 Fed. Reg. 34,830, at 34,909-910; 80 Fed. Reg. at 64,833, 64.850.

[21] 40 C.F.R. § 60.5775.

1. EPA is well within its legal authority to propose a single prototype FP to be finalized for states that fail to submit a timely approvable CPP implementation plan and to propose and finalize a MTR that may be voluntarily adopted by states.

2. EPA should only finalize a mass-based FP and MTR. A mass-based allowance system that may be applied on an interstate and regional basis will promote rigorous CPP implementation in a manner that will more likely result in the required real reductions of carbon pollution.

3. EPA must maintain the integrity of the CPP in both the FP and the MTR by eliminating $CO_2$ *increases* due to "leakage," including unintended shifts of generation from existing natural gas combined cycle ("NGCC") plants to new NGCC plants ("gas-to-gas leakage") within a given state or between states in the same power market, as well as from existing nuclear and other low and zero carbon sources to new fossil-fueled generation (together, "new source leakage").

    a. Widespread adoption by states of allowance budget caps covering both new and existing sources is the simplest and most effective way to address new source leakage, and EPA should include it as the preferred option in the MTR.

    b. EPA should include an expanded and strengthened updating output-based allowance allocation approach (structured as an initial allocation to existing NGCC units and all low- and zero-emitting generation rather than a set-aside limited to existing NGCC units) in the FP and as a second leakage reduction option in the MTR for states not adopting the combined budget approach.

4. The proposed renewable energy ("RE") set-aside is not the most effective approach to address leakage, but must be repurposed to address unwarranted expansion of state mass allowance budgets through the addition of allowances that correspond to the *potential* incremental renewable generation permitted (as opposed to actually occurring) under a rate-based system.

5. As stated above, EPA should not adopt a rate-based approach in the MTR or any subsequent FPs that are needed. If it nevertheless does so, biomass sources must not be eligible to earn emission reduction credits ("ERCs"), in either the FP or the MTR, as biomass-fueled sources do not produce immediate real, quantifiable, permanent, enforceable and verifiable carbon reductions, but require unlawful "borrowing" against future years.

## II. EPA's FP and MTR are well within EPA's authority – indeed, EPA has a mandatory duty to implement a FP where a state fails to produce an approved state plan.

### a. Federal plan.

Section 111(d)(2) of the Act provides in pertinent part:

> The Administrator shall have the same authority—
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> (A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under [section 110(c) of the Act] in case of failure to submit an implementation plan, and
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> (B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under [section 113 and 114 of the Act] with respect to an implementation plan.[22]

In turn, section 110(c)(1) of the Act provides:

> The Administrator *shall* promulgate a Federal Implementation Plan at any time within two years after the Administrator—
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> (A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section, or
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> (B) disapproves a State implementation plan in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.[23]

Read together, these provisions *require* EPA to promulgate a FP in the absence of an approvable state plan implementing the CPP. Thus, we strongly support EPA's declaration that "[i]f a state does not submit a final state plan or initial plan submittal, or if either a final state plan or an initial plan submittal does not meet the requirements of the EG, the agency will take the appropriate steps to finalize and implement a federal plan for that state's EGUs."[24]

Furthermore, these statutory provisions require EPA to promulgate such a FP *no later* than two years from EPA's negative finding, but nothing prevents EPA from promulgating a FP sooner than that.[25] Furthermore, while we note that EPA is not legally required to propose the

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[22] 42 U.S.C. § 7411(d)(2).

[23] 42 U.S.C. §7410(c)(1) (emphasis added).

[24] 80 Fed. Reg. 64,966, 64,974.

[25] As the U.S. Supreme Court stated: "EPA is not obligated to wait two years or postpone its action even a single day." *EPA v. EME Homer City Generation, L.P., et al,* __ U.S. __, 134 S.Ct. 1584, 1601 (2014). In the Cross State Air Pollution Rule (aka the "Transport Rule") at issue in *Homer City*, EPA finalized its primary rulemaking and a

text of a "prototype" FP now, prior to finding that any state has failed to submit an approvable state plan,[26] there are sound policy reasons for doing so, as we discuss in section III *infra*.

We also agree that EPA has clear authority to impose a FP that implements the CPP's performance standards through means of market-based techniques such as an interstate trading system of mass-based allowances as described in the CPP and in EPA's FP proposal.[27] Section 110(a)(2)(A) of the Act requires states to include in implementation plans "enforceable emission limitations and other control measures, means or techniques (including economic incentives such as fees, marketable permits and auctions of emission rights)…as may be necessary or appropriate to meet the applicable requirements…." EPA has the same authority when it issues a FP.[28] If there were any doubt on this issue, Congress explicitly provided the same authority to EPA by virtue of using nearly identical language in its definition of a FP.[29]

Of course, any FP promulgated by EPA must be no less rigorous than the CPP's performance standards, and must provide equivalent emission reductions.[30]

**b. Model trading rule.**

A state must submit a CPP implementation plan that EPA deems "satisfactory" and approves, in order to avoid the issuance of a FP. [31] In determining whether a state plan is

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FP implementing it *at the same time*. *Id*. at 1597; Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, at 48,271, 48,284-87 (Aug. 8, 2011).

[26] *Cf. EPA v. Homer City, supra*, 134 S.Ct. at 1600-02 (prior EPA guidance to states quantifying their specific obligations under the "Good Neighbor" provision of the Act (section 110(a)(2)(D)) is not a precondition to the issuance of a FP).

[27] *See, e.g.,* 80 Fed. Reg. at 64,987-89.

[28] *See, e.g., South Terminal Corp. v. EPA*, 504 F.2d 646, 668 (1st Cir 1974). "The statutory scheme would be unworkable were it read as giving EPA, when promulgating an implementation plan for a state, less than those necessary measures allowed by Congress to a state to accomplish federal clean air goals. Furthermore, EPA's longstanding regulations implementing section 111(d) explicitly authorize its emission guidelines to be implemented via allowances systems. 40 C.F.R. § 60.21(f) provides in pertinent part: "Emission standard means a legally enforceable regulation setting forth an allowance rate of emissions into the atmosphere, [or] establishing an allowance system…." Likewise, 40 C.F.R. § 60.24(b)(1) provides in pertinent part: "Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except where it is clearly impracticable."

[29] Section 302(y) of the Act provides in pertinent part: "The term 'Federal implementation plan' means a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emission allowances)…."42 U.S.C. § 7602(y).

[30] *See, e.g.,* 40 C.F.R. § 60.27(e).

[31] 42 U.S.C. § 7411(d)(2)(A).

"satisfactory," EPA will determine whether it provides for emission reductions that are no less stringent than those required by the performance standards promulgated in the CPP (which reflect the BSER), and otherwise meets the requirements of the CPP.[32] EPA has provided states with substantial discretion in formulating their implementation plans in the CPP, provided that they will include emissions reductions at least equivalent to those in the CPP guidelines. EPA proposed that state adoption of the final MTR will render their its state implementation plan presumptively approvable, thereby sparing the state any regulatory uncertainty and minimizing state resource expenditure.[33]

## III. EPA can, and should, promulgate only a mass-based MTR, and FPs, should a final FP be required.

### a. Model Trading Rule.

EPA can and should finalize only a single approach in the MTR and in any needed final FPs. A single approach to the MTR provides states with the clearest statement of EPA's preferred policy for "satisfactory" state plans. That approach should be mass-based, in order to enhance trading program efficiency, conserve resources, promote ease and efficiency of program administration, and ease compliance burdens for regulated entities.

### b. Federal Plan.

Commenters agree with EPA's proposed two-stage process in imposing FPs on non-compliant states—that is, establishing regulatory text now for both the FPs and the MTR, but finalizing the FP subsequently only for those states that fail to produce an approvable plan.[34] The second stage would be largely ministerial, simply applying the "prototype" FP text to individual states and finalizing a new section in the state-specific subparts of 40 C.F.R. part 62.[35] Commenters agree with EPA that "it is reasonable to propose this federal plan now so that federal plans will be ready to be promulgated quickly in cases where states have failed to submit a plan or their plans are found unsatisfactory."[36] Commenters urge EPA to finalize the prototype FP text along with the MTR text as soon as practicable.

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[32] *See, e.g.,* 40 C.F.R. §§ 60.24(c), 60.27(c)(3). *See also* State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340, 53,342 (Nov. 17, 1975) (explaining that EPA interprets its duty to determine whether a state plan is "satisfactory" as requiring substantive criteria, including an appropriate BSER).

[33] *See, e.g.*, 80 Fed. Reg. at 64,969, 64,973 (discussing presumptive approvability for MTR based state plans).

[34] *See. e.g.,* 80 Fed. Reg. at 64,973, 64,974-75.

[35] *Id*. at 64,975.

[36] *Id*.

Additionally, Commenters support EPA's stated intention "to finalize a single approach in all promulgated FPs for particular states…."[37] That single approach should be the mass-based allowance trading approach.

The primary function of a section 111(d) FP is to implement the applicable performance standards and emission guidelines in the event of a state's failure to do so. A FP should reflect the most effective approach to implementing those standards, and EPA must choose that approach. Where, as here, the regulated industry involves a highly interconnected network of power generation and transmission, and generation and emissions can readily be shifted across state lines, no rational principle is available to support an EPA choice to finalize different FP approaches for different states. As EPA notes—and we agree—a single FP approach will "enhance the consistency of the federal trading program, achieve economies of scale through a single, broad trading program, ensure efficient administration of the program, and simplify compliance planning for affected EGUs."[38]

**c. The FPs and the MTR should both employ the mass-based trading approach.**

As the Agency itself has recognized in its proposal, a mass-based emission allowance trading program has many advantages over a rate-based approach.[39] Perhaps most importantly, achievement of the required emissions level is much more predictable and likely in a mass-based allowance system with a cap, than with a rate-based system, that provides no ultimate limit on emissions,[40] but is designed to reduce carbon intensity. From an environmental and climate standpoint, permanently reducing the overall level of $CO_2$ emissions is critical—it is much more important than simply reducing carbon intensity. As EPA stated years ago in the context of the 1998 $NO_x$ SIP Call,[41] in response to commenters arguing for a rate-based program:

> EPA recommends a cap-and-trade program for purposes of the $NO_x$ SIP call because, by limiting total $NO_x$ emissions to the level determined to address the interstate transport problem, a cap better ensures achievement and maintenance of

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[37] *Id*. at 64,970.

[38] *Id*.

[39] *Id*. at 64,970, 65,011.

[40] All mass-based trading plans must be designed and implemented so that they do not unintentionally produce "leakage," that is, shifts in generation and emissions from sources within the plan's emissions "cap" to higher emitting sources outside of that cap and thus not covered by the plan. Such leakage must be minimized to protect the integrity of any mass-based plan, and the CPP FPs and MTR are no exception. The leakage issue is addressed in more detail in section IV. herein.

[41] Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule, 63 Fed. Reg. 57,356 (Oct. 27, 1998).

> the environmental goal articulated in the $NO_x$ SIP call. In contrast, under a non-cap trading program, the addition of new sources to the regulated sector or increased utilization of existing sources could increase total emissions above the level determined to address transport, even though a $NO_x$ rate limit is met.[42]

This is equally true for the CPP FPs and MTR. EPA summed it up well in its proposal: a "mass-based trading system can provide environmental certainty at a lower cost than other policy mechanisms…."[43]

EPA will evaluate state plans implementing the CPP based on whether the state goal will be met through emission reduction measures that meet five basic criteria—i.e., that are quantifiable, verifiable, non-duplicative, permanent and enforceable.[44] A mass-based goal implemented through an allowance trading system simply by its structure can meet these criteria more effectively than an emission rate approach.[45] A mass-based allowance system is preferable to a rate-based system for reasons that include: greater simplicity and transparency, ease of compliance and administration; ease of enforceability; vastly greater experience; and more consistency with present and future carbon policies. CATF discussed these advantages in it's CPP Comments,[46] as we describe below for the FPs and MTR.

i. *Greater simplicity and transparency, resulting in greater ease of compliance and administration.*

EPA's proposed regulation of existing fossil-fueled power plant carbon emissions is a significant undertaking, governing existing sources in the highest $CO_2$-emitting (and one of the

[42] *Id*.; 63 Fed. Reg. at 57,457-58.

[43] 80 Fed. Reg. at 65,011.

[44] 40 C.F.R. §§ 60.5740(a), 60.5775.

[45] One potential drawback of allowance trading systems over broad geographic regions is that they do not ensure similar emission reductions throughout the affected region. This is because some sources may choose to use allowances to emit above the required emission level, while other sources emit below the level. This creates the potential for certain areas to experience no decrease, or even an increase, in emissions. While this potential for emission "hot spots" is a problem in the context of criteria pollutants or air toxics that have localized health and ecosystem impacts, it is not a problem in the context of the CPP, because $CO_2$ impacts are not localized. Nevertheless, EPA should carefully monitor the resulting spatial performance of the co-emitted conventional and hazardous air pollutants under the CPP consistent with its commitment to enhancing Environmental Justice. *See* U.S. EPA, "Guidance on Considering Environmental Justice During the Development of Regulatory Actions (May 2015) (*citing* U.S. EPA, "Draft Technical Guidance for Assessing Environmental Justice in Regulatory Analysis (2013)).

[46] CATF CPP Comments at 103-108.

largest) industries in the country. For this effort to succeed, implementation, compliance and administration must be made as simple and straightforward as possible.[47] A mass-based system with a cap on fossil-fueled power plant emissions will serve this purpose most effectively. A mass-based system is inherently simple and straightforward, because all of the factors that can reduce the emissions of concern are automatically accounted for. By contrast, the rate-based approach that EPA has proposed as a potential approach to FPs and the MTR is more complex and will be less effective at easing CPP implementation and compliance. As EPA has recognized, "a mass-based trading approach would be more straightforward to implement compared to the rate-based trading approach, both for industry and the implementing agency."[48] And, "[m]ass-based trading programs are relatively simple to operate, which reduces administrative time and cost."[49] Furthermore, a simpler system will likely be more transparent, and will therefore be easier for the industry, the states and the public to understand and ultimately accept.

*ii. Ease of quantification, verifiability and enforceability.*

Compliance with a mass-based trading system including a cap on fossil-fueled power plant emissions is much easier to quantify, and compliance is therefore more easily verified and enforced. The complex modeling, projection, allocation and verification systems necessary to track progress under a rate-based system will not be necessary for a mass-based system. Rather, power plant emissions can be simply measured and recorded by widely available, continuous monitoring equipment, and allowances can be easily accounted for. In short, a FP or a MTR employing a mass-based approach will satisfy the core criteria for judging the adequacy of targeted emissions reductions —i.e., that those reductions be quantifiable, verifiable and enforceable—more effectively than with a rate-based approach.

iii. *A wealth of experience.*

Not least of the considerations supporting a mass-based approach to the MTR and FPs, is the much greater amount of experience that EPA and states – not to mention the utility industry -- have in implementing mass-based allowance systems governing industrial air pollution. As EPA recognized in its FP/MTR proposal:

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[47] William F. Pedersen, *Should EPA Use Emissions Averaging or Cap and Trade to Implement §111(d) of the Clean Air Act*?, 43 ELR 10731 (Sept. 2013).

[48] 80 Fed. Reg. at 64,970.

[49] *Id*. at 65,011-12.

> The EPA, industry, and many state agencies have extensive knowledge of and experience with mass-based trading programs. The EPA has more than two decades of experience implementing federally-administered mass-based emissions budget trading programs including the Acid Rain Program (ARP) sulfur dioxide ($SO_2$) trading program, the Nitrogen Oxides ($NO_x$) Budget Trading Program, CAIR and CSAPR. The tracking system infrastructure exists and is proven effective for implementing such programs.[50]

All of these trading programs include the electric utility industry – indeed they include many of the same plants that are affected sources under the CPP.

iv. *Consistency with present and future carbon policies.*

Finally, a number of states have already taken the lead in addressing $CO_2$ emissions, and those states are implementing mass-based allowance systems, not emission rate systems.[51] The sole Congressional effort to date addressing power plant emissions through a trading system – the Acid Rain Program—also includes a mass-based (not rate based) allowance trading system.

Based on this experience, and the evident advantages of a mass-based system, including those previously described, it can be predicted that any future national legislation comprehensively regulating greenhouse gases is highly likely to take the form of a mass-based allowance system rather than a rate-based system. Thus, a MTR and FPs employing a mass-based trading approach would likely be much more easily integrated into any future economy-wide greenhouse gas legislation.[52]

## IV. EPA must include adequate provisions in the MTR and the FP to minimize leakage.

### a. General characterization of the leakage problem.

EPA has required in the CPP that states implementing a mass-based allowance system to address "leakage" – that is, the Agency requires states to make certain that any mass-based state

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[50] 80 Fed. Reg. at 64,970; *see also id*. at 65,012.

[51] The two main state efforts to date are the Regional Greenhouse Gas Initiative ("RGGI") and the California Global Warming Solutions Act program.

[52] According to the comments submitted by the RGGI States on EPA's CPP proposal, "every serious proposal to reduce carbon emissions from EGUs, from proposed US legislation to programs in place in California and Europe, has identified allowance trading as the best approach." RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationery Sources: Electric Utility Generating Units, Doc ID: EPA-HQ-OAR-2013-0602-22395, at 8 (Nov. 5, 2014).

plan approach contains mechanisms to ensure that the final $CO_2$ reductions are equivalent to – or greater than – those achieved by implementing the CPP's required emission standards directly.[53]

The CPP establishes emission performance standards for existing affected EGUs based on EPA's determination of the BSER to reduce $CO_2$ emissions from existing sources in the regulated industry. EPA has provided states with several options to implement these standards. States may apply the performance standards to affected EGUs directly, or they may achieve either an average statewide, rate-based emission goal or a cumulative statewide, mass-based emission goal, *provided that those goals are "equivalent and no less stringent than" the performance standards*.[54] In particular, EPA has specified that for a state choosing a mass-based goal, "such a goal must be equivalent to the $CO_2$ emission performance rates in their application of the BSER, as required by the state and the final emission guidelines."[55] EPA further states that "to ensure the equivalence of mass-based state goals, we must consider how the form of the goal affects its implementation and how the incentives it provides to affected EGUs on the interstate grid affect whether or not the BSER is fully implemented."[56]

EPA then defines "leakage" as:

> the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates in representing the BSER.[57]

A mass-based trading system covering only existing fossil units will likely inadvertently create an incentive for "gas-on-gas" leakage to occur -- that is, the potential for the generation from new NGCC units to displace generation from existing NGCC units, thereby reducing existing source emissions covered by the CPP but not total system emissions. This can occur because the carbon prices associated with the CPP will raise the dispatch cost of existing gas units, and, to the extent these units operate "on the margin" in regional competitive power

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[53] *See, e.g.,* 40 C.F.R. § 60.5790(b)(5); 80 Fed. Reg. at 64,822-23. "Leakage" may be caused by creating incentives for new sources that emit $CO_2$ to replace existing sources of $CO_2$, where the total amount of new source emissions are not constrained.

[54] *See, e.g.,* 40 C.F.R. § 60.5855(a) and (b).

[55] 80 Fed. Reg. at 64,822.

[56] *Id.*

[57] *Id.* at 64,822; *Id.* at 64,977, 65,019.

markets, their higher costs will tend to increase regional wholesale energy prices. New NGCC units in contrast will generally have emission rates below the section 111(b) new source performance standards ("NSPS") and so will not see their dispatch costs increase as a result of those new source regulations. As regional wholesale energy prices rise while the dispatch costs of new NGGCs remain largely the same, new NGCCs will realize higher energy margins. Unless capacity prices respond to changing energy margins fully and instantly (which is unlikely), this will create a financial incentive for new NGCCs to enter the market and displace generation from existing gas units. While in the near term this may result in $CO_2$ reductions, they will not be covered by the CPP, and can lead to total system emissions increases in the longer-term, countering the intent of the CPP.

The extent to which this occurs in any given region or state will depend on a number of factors including the relative amount and efficiency of existing coal and gas generation, the level of carbon prices, whether the construction of new generating capacity is regulated by state government or determined by competitive markets, and how quickly capacity prices in competitive markets respond to rising energy prices. Because of this variability, the potential for gas-on-gas leakage will differ from region to region and is fundamentally uncertain. As a consequence, gas-on-gas leakage may best be described as a risk rather than a certain consequence of the rule.

EPA summarizes this risk of leakage as occurring because "mass-based implementation…can unintentionally incentivize increased generation from unaffected new EGUs as a substitute action for reducing emissions at units subject to the existing source mass goals in ways that would negate the implementation of the BSER and would result in increased emissions. This occurs because…in a mass-based system the allowance price increases the cost of generation from existing NGCC units relative to generation for new NGCC units."[58] [59] EPA accordingly requests comment here on how mass-based plan approaches can address leakage,[60] while remaining "at least equivalent with the emission performance rates, and therefore appropriately reflect[ing] the BSER as required by the statute."[61] As EPA correctly stated in the

[58] 80 Fed. Reg. at 64,823. Commenters note that there are other forms of potential generation shifts to new uncovered sources, *e.g.*, from existing nuclear units and RE units.

[59] *See generally*, Sarah K. Adair and David Hoppock, Duke, Nicholas Institute, *New Sources and the Clean Power Plan: Considerations for Mass-Based Plans* (Dec. 2015), *available at*: https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_pb_15-06_0.pdf.

[60] 80 Fed. Reg. at 65,018, 65,020.

[61] *Id*. at 64,823.

CPP, "the form of mass goals is only equivalent if leakage is satisfactorily addressed in the state plan's establishment of emission standards and implementation measures."[62]

While EPA has focused on "gas-to gas" leakage within a given state, i.e., the shift of generation from existing NGCC units to new NGCC units, other forms of leakage are also a concern. Foremost among them is the potential for the loss of generation at existing nuclear units and other zero or low carbon-emitting units (i.e., renewable generation such as wind and solar, as well as carbon sequestration and storage projects) and its replacement by new fossil-fuel (or biomass-burning) generating units. Another form of leakage can occur when new NGCC units in a state utilizing rate-based compliance displaces the generation from existing NGCC units in a mass-based state within the same power market (the so-called "seams" issue). Increased generation and emissions from new fossil fuel-fired or other non-zero emitting sources that are outside of the existing source mass-based budget is "new source leakage." In considering which mitigation measures for gas-to-gas leakage to include in the FP and MTR, EPA should favor measures that will help avoid other types of leakage as well.

**b. Options to minimize leakage.**

i. *EPA's proposed options to address leakage.*

As stated earlier, the FP and the MTR promulgated by EPA must achieve the same or better $CO_2$ reductions as would be achieved by implementing the performance standards set included in the CPP. Therefore, the mass-based FP and MTR must include provisions to minimize leakage. EPA has proposed two basic options in an attempt to address the problem.[63] First, states may choose to adopt, as a matter of state law, "a mass emission budget of sufficient size to cover both affected EGUs under the existing source mass $CO_2$ goal provided in [the CPP],

[62] *Id*. Some may argue that EPA has no authority to "regulate leakage." Such an argument is without merit. EPA is not requiring leakage to be "regulated." Rather, EPA is requiring states to ensure that affected units actually meet the BSER-based performance standards or their equivalent. One such equivalent is a mass-based trading system. EPA has simply conditioned the implementation of such a system by a state on a satisfactory resolution of the leakage problem, so that the mass-based approach is actually "equivalent." Furthermore, a state is not required to implement a mass-based approach, as it can implement the performance standards on a unit-specific basis, or utilize a different approach, such as a rate-based approach, provided that it is "equivalent" to the BSER-derived performance standards. *See, e.g., id*. at 64,887.

[63] We note that EPA has also provided states a third option in the CPP—that is, rather than taking affirmative action to address new source leakage, mass-based states may demonstrate that it is not likely to occur. 80 Fed. Reg. at 64,823, 64,888. However, in the absence of the adoption by a state of a combined existing and new source mass-based budget, new source leakage is almost certain to occur. Thus, EPA has wisely not included this third option in the FP or the MTR, but proposes to require the implementation of incentives to counteract leakage. *Id*. at 65,027-28. Commenters strongly support the requirement that affirmative steps be taken in the state plan to counteract leakage.

along with sufficient $CO_2$ emission tonnage to cover projected new sources."[64] EPA has not included this option in the proposed FP.

Second, EPA has proposed to include in the FP and in the MTR for states implementing a mass-based allowance plan covering only existing units, several allowance allocation approaches to address new source leakage—that is, an output-based allocation set-aside to existing NGCC units and a set-aside that encourages the installation of RE."[65] The output-based set-aside approach would provide a targeted allocation of a limited portion of the overall allowance budget[66] to existing NGCC units in order to reduce incentives for generation to shift away from those sources to new unaffected NGCCs. Allocations under that system would be based in part on the amount of electricity generated in the most recent compliance period, so that an eligible EGU that increased generation would subsequently receive more allowances.[67]

EPA has also proposed a RE set-aside whereby a small percentage of each state's allowance budget[68] would be reserved for eligible RE projects (limited to on-shore wind, solar, geothermal power and hydropower) and would be awarded based on a project's projected generation incremental to a 2012 baseline.[69]

ii. *The combined new and existing source budget.*

Commenters strongly support EPA's first option to address leakage, i.e., the invitation to states to combine new and existing fossil sources under a single emissions trading budget. Because such an emissions cap (and resulting allowance prices) would apply to all fossil-fired EGUs, both new and existing, there would be no artificial regulatory incentive to build and operate new source generation with emissions not covered by the cap. This option is the simplest and most straightforward approach available, and would produce emission reductions that are "quantifiable, verifiable, non-duplicative, permanent and enforceable."Commenters urge EPA to

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[64] *Id*. at 64,888.

[65] *Id*. at 64,978.

[66] EPA proposes to establish the size of the output-based set aside at "10% of the NGCC capacity in the state multiplied by the hours in a year multiplied by the allocation rate for the set-aside." 80 Fed. Reg., at 65,021. Based on EPA's tabulation of these state output-based set-asides (*Id*., at 65,022, Table 9), on average, they will amount to roughly 6% of the total 2030 state allowance budgets.

[67] 80 Fed. Reg. at 65,022.

[68] EPA's proposed that the RE budget be set at 5% of a state's total allowance budget, but is taking comment on a range of 1% to 10%. *Id*. at 65,022.

[69] 80 *Id*. at 65,022-25.

include this option in the MTR as a presumptively approvable means to address leakage. Commenters also urge the Agency to provide states appropriate incentives to encourage them to adopt this option. For example, states that choose to adopt such a combined mass allowance budget could be given wide discretion in choosing allowance allocation schemes, and would not be bound by prescribed allocation methods to address leakage required in the MTR for states not adopting a combined budget, such as the revised output-based allocation approach described below.[70]

iii. *EPA's allocation approaches will not adequately address new source leakage.*

Some states, of course, may not adopt this combined new and existing source budget. In such cases, other options to address new source leakage will be required. While Commenters agree that EPA must address leakage in the FP and MTR by means of allowance allocation approaches, we do not think that the specific set-aside approaches proposed by EPA will actually achieve mass-based systems that are equivalent to the BSER-derived performance standards. EPA has proposed to allocate *for free* the vast majority of allowances to existing EGUs, including high-emitting, coal-fired steam generating units, in a fixed amount based on historical generation, and to allocate only a limited amount of allowances to the two small "set-asides" described above to address leakage. EPA's decision to allocate the majority of allowances to existing affected EGUs, including higher-emitting, coal-fired units, will do nothing to address leakage. Furthermore, the proposed allowance set-asides are not large enough, and in the case of the RE set-aside, will likely not actually produce a substantial amount of incremental energy generation from the targeted sources.

*iv. Commenters' analysis of allocation approaches to gas-on-gas leakage.*

To evaluate the risk of gas-on-gas leakage, Commenters commissioned the Northbridge Group to evaluate the extent to which: 1) the market incentives associated with mass-based goals could result in new NGCC entry and emission leakage in the absence of leakage protection measures, and 2) how new entry and leakage might be reduced under alternative protection measures. The Northbridge analysis relied on a regional economic dispatch market model configured to represent a large and diverse power market, roughly the size of PJM, including a

[70] Analysis by researchers at Resources for the Future suggests that including new and existing sources within the state emission trading budget and allocating allowances on an updating output basis could mitigate "seams" leakage as well. *See* Dallas Burtraw, *et al.*, *A Proximate Mirror: Greenhouse Gas Rules and Strategic Behavior Under the US Clean Air Act*, (Mar. 2015), *available at*: http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-DP-15-02.pdf.

mix of coal steam, natural gas combined cycle, natural gas combustion turbine and oil/gas steam generating units ranging in size, efficiency, and delivered fuel costs.

To represent the market process by which new entry and gas-on-gas leakage could occur, the model was used in an iterative fashion to assess the impact of carbon pricing associated with CPP compliance for existing fossil sources on unit dispatch within the power market, regional wholesale energy prices, the energy revenues that might be realized by newly built NGCCs if constructed, the amount of expected new NGCC entry, carbon emissions from existing and new sources, and the level of carbon prices. This iterative process was repeated under a variety of policy formulations including no leakage protection measures, the updating output based allowance ("OBA") set-aside measure proposed by the EPA, and a modified OBA formulation as described elsewhere in these comments.

As shown in Table 1 below, EPA projected that the implied difference between its "mass-based compliance without RE set-aside" and "mass-based compliance with RE and OBA set-aside" cases is 2.1 percent.

Table 1

| Scenario | Source | EGU Emissions (MM Tons) | Total Emissions (MM Tons) | Reduction Relative to Base Case |
|---|---|---|---|---|
| Base Case | IPM Summary Data | 2,011 | 2,227 | -- |
| Mass-Based Compliance without RE Set-Aside | IPM Summary Data | 1,649 | 1,838 | (17.5%) |
| Mass-Based Compliance with RE Set-Aside | IPM Summary Data | 1,649 | 1,814 | (18.6%) |
| Mass-Based Compliance with RE and OBA Set-Asides | FIP RIA | | 1,791 | (19.6%) |

Sources:
EGU Emissions: EPA Power Sector Modeling, RPE file (available at http://www.epa.gov/airmarkets/analysis-clean-power-plan)
Total Emissions: Final Rule Regulatory Impact Analysis, 3-19 (Base and Mass-Based Compliance with RE Set-Aside); EPA Power Sector Modeling, RPE file (Mass-Based Compliance without RE Set-Aside); Model Rule Regulatory Impact Analysis, 1-32 to 1-33 (Mass-Based Compliance with RE and OBA Set-Asides)

As shown in Table 2, the Northbridge analysis found that in a gas-driven regional power market -- as currently and foreseeably exists given low gas prices -- gas-on-gas leakage has the potential to reduce total system emission reductions by 3.3 percentage points relative to the predicted 20 percent reduction from the CPP. That is, total system emission reductions without gas-on-gas leakage relative to a "No CPP" reference case in 2030 were estimated to be 20.0 percent, whereas reductions with leakage were estimated to be 16.7 percent, allowing 3.3 percent more $CO_2$ to be emitted. Comparison with EPA's leakage estimate of 2.1percent suggests the gas-on-gas leakage risk can in some instances be approximately 50 percent larger than EPA's cases predict.

Table 2

| | Mass Goals for Existing Sources | | | | |
|---|---|---|---|---|---|
| | No New Entry; No OBA | With Entry; No OBA | With Entry; Proposed OBA; 50% supply | With Entry; Proposed OBA; 100% supply | With Entry; Expanded OBA |
| **Capacity (GW)** | | | | | |
| All NGCC | 53 | 58 *(+8%)* | 57 *(+6%)* | 56 *(+5%)* | 55 *(+4%)* |
| **Generation (TWH)** | | | | | |
| Coal | 164 | 185 *(+13%)* | 179 *(+9%)* | 175 *(+6%)* | 170 *(+4%)* |
| Existing Gas | 250 | 199 *(-20%)* | 213 *(-15%)* | 222 *(-11%)* | 231 *(-8%)* |
| New Gas | 55 | 87 *(+58%)* | 79 *(+45%)* | 74 *(+36%)* | 69 *(+27%)* |
| **Emissions (MM Tons)** | | | | | |
| Existing EGUs | 266 | 266 *(0%)* | 266 *(0%)* | 266 *(0%)* | 266 *(0%)* |
| New | 21 | 33 *(+58%)* | 30 *(+44%)* | 28 *(+35%)* | 26 *(+26%)* |
| **Total Emission Reduction from Business As Usual Levels** | -20.0% | -16.7% | -17.5% | -18.0% | -18.5% |
| All percentage changes are relative to results from a "No Leakage" policy case with no OBA unless noted. | | | | | |

*v. Commenters' revised output-based allocation approach.*

Commenters believe that an OBA approach could be a useful tool to address new source leakage, provided that it is expanded substantially beyond EPA's proposal, and structured as an initial, primary allocation approach rather than as a "set-aside." EPA has requested comment on its suggested approaches to address leakage, and more specifically on the OBA approach.[71] Commenters agree with EPA that the basic rationale of this approach is sound—that is, because existing units targeted by this allocation approach would receive allowances based on their recent level of generation, these units would have an incentive to generate more in order to receive more allowances. And such an incentive would have a tendency to counteract any shift in generation from targeted existing lower (or zero) emitting units to new NGCC units.

The Northbridge analysis shown in Table 2 found that EPA's proposed OBA approach would reduce gas-on-gas leakage by about 32 percent (that is, the 3.3 percentage point estimate

[71] 80 Fed. Reg. at 65,020-21.

would be reduced to 2.5 percentage points). This suggests that the EPA's proposed OBA mechanism is helpful in mitigating this problem, but will do so only to a limited extent.

Two features of the proposed OBA mechanism particularly constrain its effectiveness: 1) the restriction that only gas units with capacity factors greater than 50% be eligible to receive the OBA,[72] and 2) the allowances that may be allocated through the OBA are limited to an amount that works out to between 5 and 6 percent of total nationwide allowances.[73] These two constraints must be removed. First, units operating at lower capacity factors than 50 percent can also contribute to maintaining and increasing the level of low- and zero-emitting generation and will thus help to combat leakage; in other words, the 50 percent capacity factor limitation leaves in place an unintended incentive for new gas units to displace existing units operating at capacity factors less than 50 percent. Secondly, the small percentage of allowances that EPA proposes to devote to existing NGCC units in its EPA's proposed output-based set-aside could limit the effectiveness of the OBA approach for existing units operating at 50 percent or higher capacity factors. Thus, OBA allowances should not be capped, but rather should be allocated in whatever amount is necessary to cover existing NGCC emissions.

Removal of these two limitations would substantially improve the effectiveness of the OBA as a measure to reduce gas-on-gas leakage. As Table 2 shows, the Northbridge analysis estimated that the removal of these two limitations, would reduce gas-on-gas leakage to approximately 1.5 percentage points. This represents a 55 percent reduction in gas-on-gas leakage, eliminating almost twice as much leakage-related $CO_2$ increase as would EPA's proposed OBA mechanism.[74]

EPA seeks comment on whether the OBA approach should be expanded to include sources beyond existing NGCC units.[75] In order for this approach to provide an effective means of reducing leakage risk, especially the risk of leakage from retired nuclear units to new NGCC units, it *must* be expanded to include all other existing low- and zero-emitting sources, including generation from existing nuclear units (not merely uprates and other incremental generation),

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[72] EPA proposes to allocate allowances under this OBA only to units that exceed a 50% capacity factor, and only for generation in excess of that factor. *Id*. at 65,021, n.104.

[73] EPA also seeks comment on the amount of allowances that should be allocated under the output-based approach. *Id*. at 65,020-21.

[74] Fully eliminating leakage would likely require additional administrative actions including incorporating 111(b) NGCC units into the 111(d) regulations over time and utilizing the "ex post" review of the impact of differing state regulatory structures and the need for corrective action referenced in the Preamble to the CPP. Both these administrative processes are discussed in more detail below.

[75] 80 Fed. Reg. at 65,020-21.

fossil fuel-fired units employing carbon capture and sequestration ("CCS"), and zero-emitting RE units.[76]

While EPA's proposed approach is designed to create incentives for the continued operation (at expected capacity factors) of existing NGCC units, it also has the potential to dampen wholesale prices. This is because the OBA would offset most or all of the carbon dispatch adder for existing NGCC units that would otherwise result from mass-based goals. During the hours in which those units run "on the margin" and set hourly energy prices, the resulting energy prices would tend to be lower than they would otherwise be. As a consequence, the competitive position of some existing nuclear generating facilities, especially relatively small single-unit merchant facilities, would be eroded. As discussed below at section IX.b., some could be pushed into premature retirement, to be replaced with fossil generation (likely including new NGCC units), raising total system emissions – an unintended impact of the CPP.[77] This phenomenon also potentially could affect the competitive position of renewable units, and /or coal or gas units equipped with CCS.

To address this risk, allocations for the purpose of reducing leakage should be provided not only to lower-emitting, existing NGCC units, but also to existing nuclear and other zero- and low-emitting units. In order to counteract the incentives for premature nuclear unit retirements, it is vital that the FP and MTR allocate allowances not only to incremental nuclear generation (e.g., uprates and new construction), but also to existing levels of generation, in part because an OBA mechanism relying on updating will tend to depress wholesale electric prices, further undercutting the position of existing nuclear units. Commenters agree with EPA that allowances should not be allocated to coal-fired steam generating units under this approach, as those units have higher emission rates and more lenient performance standards than new NGCC units, substantially reducing the net environmental effectiveness of the approach.[78]

Finally, EPA also has requested comment on its proposal to allocate output-based allowances on a delayed basis—that is, to allocate allowances on the output-based generation of

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[76] As discussed *infra*, at section IX.c., biomass is not a zero-emitting source, and will in any event not produce emission reductions that are "quantifiable, non-duplicative, permanent, verifiable and enforceable." A more detailed rationale for including nuclear and CCS units in this allocation is set forth in sections IX.b and IX.a respectively.

[77] A recent study by Third Way concluded that the emissions associated with making up the generation from nuclear units due to premature retirement could offset all the emission reduction gains from the CPP. Samuel Brinton and Josh Freed, Third Way, *When Nuclear Ends: How Nuclear Retirements Might Undermine Clean Power Plan Progress*, 7-8 (Aug. 19, 2015), *available at*: http://www.thirdway.org/report/when-nuclear-ends-how-nuclear-retirements-might-undermine-clean-power-plan-progress.

[78] 80 Fed. Reg. at 65,020-21.

existing NGCC units during the most recent compliance period.[79] However, those compliance periods are two or three years long, meaning that existing units would not receive allowances for as many as three years after the increased generation actually occurred. Such an extended lag time could substantially reduce the effectiveness of the OBA approach. Commenters urge EPA to base the allocation of OBA allowances on the most recent year's generation, not the generation during the most recent CPP compliance period.

In keeping with the above comments, Commenters overall primary recommendation to address new source leakage for states not adopting a combined existing and new source budget, is as follows: EPA should provide for an allowance allocation system that allocates allowances on a priority basis to existing low- and zero-emitting sources on an updating output basis. This approach would be similar to the OBA set-aside proposed for inclusion in the FP and MTR, but would provide for allowances to be initially allocated to existing sources to cover their most recent annual emissions. Once those allocations have been completed, states could be given flexibility on how to further allocate allowances, but not before.

In sum, our approach includes the following primary components:

1. Initial allocation of allowances would be made to eligible existing NGCC units, as well as existing low- and zero-emitting units. Existing and new nuclear units, RE units and CCS equipped units, would be included in this initial allocation.
2. No minimum capacity factor would be required for a unit to be eligible for this initial allocation.
3. Allocations would be updated annually, that is, would be based on the eligible zero- or low-emitting unit's level of generation during the previous year.
4. Allowances could potentially be allocated on a one-time basis to higher-emitting, existing coal-fired units or other sources in the state's discretion, but *only after* all needed allocations to eligible existing units had been completed.

vi. *The proposed RE set-aside is not likely to be an effective anti-leakage measure.*

The RE set-aside, as proposed by EPA, is unlikely to be an effective way to deploy new renewable generation on a widespread basis and, even if the set-aside deploys significant new renewable generation, the resulting renewable generation may not effectively prevent gas-on-gas leakage. This is because EPA derived the RE set-aside from a single point, national-average forecast of annual average levelized cost of electricity technologies in 2030 that does not take into account the considerable regional variation in technology and market conditions that exist

[79] *Id*. at 65,021.

across the country. As a consequence, the RE set-aside in any given state will tend to be too high or too low – states with strong renewable economics will not likely need it, and other states with more challenging economics will likely find it insufficient. Further, even if the set-aside drives new renewable deployment, the resulting generation would primarily reduce energy prices during the hours in which the sun shines and wind blows; it would have only a smaller impact on reducing the need for firm generating capacity. That need for firm capacity will most likely be met with new gas units which, once built, could result in leakage.

In addition, the RE set-aside, as proposed, does not provide allowance support to all zero-carbon emitting generation. Instead, a technology-neutral approach should be finalized and all forms of new low and zero carbon generation, including new CCS equipped units and new nuclear units should be eligible to receive this set-aside.[80] That would both improve the effectiveness of this set-aside, but also preempt claims that the proposed mechanism is unduly targeted and discriminatory.

As we discuss in section VI., the proposed set-aside of allowances for new and incremental RE generation should be repurposed to address unwarranted expansion of the mass-budgets through the addition of allowances that correspond to the *potential* incremental RE generation permitted under a rate-based system.

vi. *Other potential approaches to address leakage*.

Commenters offer the following additional approaches for consideration by EPA as it finalizes the MTR or any FP.

1. <u>Track and Adjust for Existing Source Gas Emissions</u> – An alternative gas-on-gas leakage mitigation mechanism for the MTR and the FP could involve tracking the utilization of the existing gas fleet in a given state, assessing whether in fact gas-on-gas leakage appears to be occurring, and in the event it is, requiring the state to true-up for the emission consequences of that leakage in the subsequent compliance period. A key element of this mechanism would be the "test" used to determine whether gas-on-gas leakage had occurred. This could be based on a pre-determined threshold capacity factor for the existing gas fleet or alternatively a formula reflecting changes in gas, fossil steam, renewable and other generation sources over time.

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[80] For the reasons, set forth in section IX.c., biomass is not a low- or zero-emitting source and must not be included in any expanded version of this set-aside. Incremental nuclear and CCS units should be included, however, for the reasons set forth in section IX.b. and IX.c., respectively.

The following additional options could be considered by EPA in the context of the MTR, but most likely not the FP:

2. Carbon Fee for New Sources – A state can choose to establish a carbon fee that would apply solely to emissions from new fossil units that are not regulated under section 111(d) of the Act. If such a carbon fee were set equal to the carbon price resulting from 111(d) regulations, then new and existing fossil units in that state would be subject to consistent carbon price signals and the incentive for leakage between existing and new gas plants would be mitigated.

3. Carbon Price in IRP Decisions – States with vertically integrated electric utilities and integrated resource planning ("IRP") processes typically conduct economic planning analyses to determine the timing, quantity and type of new generating resources that are required. If such states incorporate a carbon price in their evaluation of the economics of new fossil generating plants equal to the carbon price resulting from 111(d) regulations, then the treatment of existing and new sources in the state planning process would be reasonably consistent and the risk of gas-on-gas leakage would be mitigated.

4. Track and Adjust for New Source Emissions – Under this approach, compliance would be determined on the basis of whether existing source emissions were equal to or less than the total of the existing source budgets plus the New Source Complements less actual new source emissions and, if so, would require the state to true-up for the emission consequences of that leakage in the subsequent compliance period. In this way, any emissions from new gas units would be offset by corresponding emission reductions from existing sources so that the net system emissions intended by the rule would be achieved. This approach is similar to the combined new and existing source cap approach discussed in section IV.b.ii of these comments.

5. Floor Price for 111(d) Emissions – Setting a floor on the price of carbon allowances for existing sources would maintain the incentive for emission reductions regardless of new gas entry and the resulting gas-on-gas leakage.

Table 3 below summarizes the various leakage reduction options that Commenters recommend for EPA consideration.

| Applicability | Description | Impacts and Recommendations |
|---|---|---|
| Federal Plan | 1. EPA proposed updating output-based allocation (OBA) mechanism for existing gas | Expand, as first allocation priority, to all existing gas and other low- and zero-emitting generation |
| Federal Plan | 2. EPA proposed RE set-aside (RE-SA) mechanism for new RE | Expand and make technology neutral for new zero carbon resources |
| Federal Plan | 3. Track capacity factor of existing NGCCs, other metrics and true up emissions if falls below threshold | Explore alternative formulations and analyze impacts |
| Model Rule Options for States | 4. In competitive markets, set carbon fee for new sources equal to 111(d) price | New source carbon price addresses unintended incentive for new gas |
| Model Rule Options for States | 5. In regulated states, require carbon price = or > 111(d) price be used in IRP decisions | New source carbon price addresses unintended incentive for new gas |
| Model Rule Options for States | 6. Track actual new source emissions in determining existing source compliance | New source emissions are offset by reductions from existing sources |
| Model Rule Options for States | 7. Set floor price for 111(d) allowances | Maintains emission reduction incentives even with new gas entry |
| Administrative Processes | 8. As in Preamble, EPA to conduct ex-post review of impact of differing state regulatory structures and the need for action | Issue clarifying guidance |
| Administrative Processes | 9. Over time, incorporate 111(b) resources into 111(d) regulations | --- |

### c. Subsequent EPA review of CPP and MTR leakage provisions.

EPA acknowledges in the final CPP that despite its efforts to address leakage and interstate effects that might compromise the effectiveness of the CPP, it cannot anticipate all potential generation incentives across states and unit subcategories that might cause an unintended loss of $CO_2$ emission reductions.[81] EPA therefore stated its intention in the CPP to

> …assess how emission performance across states may be affected by the interaction of different regulatory structures through state plans. Based on that evaluation, the EPA will determine whether there are potential concerns and what course of action may be appropriate to remedy such concerns.[82]

[81] 80 Fed. Reg. at 64,890.

[82] *Id*.

Such an ex-post review could be beneficial, both as a means to rectify any new source leakage that actually develops when the rule is implemented, and also as a warning signal and a before-the-fact means to deter future gas-on-gas leakage. Commenter urge EPA to reiterate its CPP commitment to conduct such an assessment, in the final MTR/FP text rule. EPA can, and should, provide clarifying guidance to states, affected sources, other stakeholders and the public regarding the manner in which it may assess emission performance across states, including market developments, changes in generation patterns and related matters, as well as when such assessment will be conducted and how any needed adjustments to the CPP, the FP or the MTR will be accomplished.

In addition, we note that EPA recognizes—and Commenters strongly agree—that any unintended leakage and other similar unintended effects that could undermine the effectiveness of the CPP are more likely "in an environment where various states are implementing a variety of state plan approaches in a shared region."[83] While Commenters understand EPA's desire to provide states with ample flexibility in implementing the CPP in the spirit of cooperative federalism, the MTR (and any FP as needed) provide a good opportunity for EPA to promote options that will reduce the likelihood of interstate conflict between different types of state plans—and the most direct and effective way to do this is to promulgate a single type of trading plan only for both the MTR and the FP—and as explained earlier, that should be a mass-based allowance budget trading system.

## V. ***EPA should commit* to reviewing and revising the Clean Power Plan – and the Model Trading Rule -- every eight years in conjunction with the NSPS review and incorporating sources built since the last review into the section 111(d) program.**

As CATF commented to the Agency on the proposed CPP, EPA should commit to periodic review and updating of the CPP at least every eight years. We hereby incorporate and repeat those comments, expanding this idea to include periodic review and updating of the MTR, and of any FP that may subsequently be required (in order to implement any proposed changes to the CPP as a result of the periodic updates to that rule).

Reviewing and revising the CPP every eight years will ensure that it reflects the best system of emission reduction and will also incorporate EGUs built since the CPP was finalized, thereby minimizing leakage to new sources. While section 111(d) does not contain an explicit requirement for periodic review of the existing source performance standards, the purpose of the statute, its relationship to section 111(b) (which does require review every eight years),[84] its

[83] *Id*.

[84] 42 U.S.C. § 7411(b)(1)(B).

reference to a section 110 procedure, and longstanding EPA interpretations requiring periodic review, give the Agency ample authority to finalize a commitment for periodic review of the CPP (and the associated Model Trading Rule and FP).

For new sources, the Administrator must "at least every 8 years, review and, if appropriate, revise the [performance standards]."[85] In the CPP proposal, EPA recognized that this "requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly."[86] This same principle applies to the CPP, and also to the MTR and the FP associated with the CPP. All of "section 111 was intended to assure the use of available technology and to stimulate the development of new technology."[87] In order to be consistent with the track of the new source standards, and continue to promote new technology for pollution control on sources as they age, the CPP similarly must be periodically updated. There is support for this idea in section 111(d), which requires the EPA to "prescribe regulations, which shall establish a procedure similar to that provided in [section 110] under which each State shall submit to the Administrator a plan…."[88] This includes a cross reference to the requirement to revise state plans "from time to time as may be necessary to take account of revisions of such national primary or secondary ambient air quality standard or the availability of improved or more expeditious methods of attaining such standard."[89] While $CO_2$ is not a criteria pollutant, the language in CAA section 111(d) requiring a "procedure similar to that provided by section [110]" may be read to extend to all section 110 review requirements as well. Therefore, state CPP plans – whether or not based on the Model Trading Rule -- must also be subject to review when section 111(b) standards are updated and incorporated in state plans.

This is consistent with EPA's longstanding regulatory framework. The general 111(d) regulations require that, when corresponding NSPS is proposed an emission guideline must also be proposed. The 1975 preamble also states EPA's expectation that there will be subsequent plans submitted after the initial emissions guidelines are set.

> [40 C.F.R.] § 60.22 … require[s] proposal… of an emission guideline after promulgation of the corresponding standard of performance… [B]y proposing (or

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[85] *Id.*

[86] 79 Fed. Reg. at 34,908.

[87] *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981).

[88] 42 U.S.C. § 7411(d).

[89] 42 U.S.C. § 7410(a)(2)(H).

> publishing) an emission guideline after promulgation of the corresponding standard of performance, the Agency can benefit from the comments on the standard of performance in developing the emission guideline. … Extensive control strategies are not required, and after the first plan is submitted, *subsequent plans* will mainly consist of adopted emission standards.[90]

EPA has previously concluded that the periodic review associated with some NSPS is also applicable to an existing source performance standard promulgated under section 129. Existing solid waste combustion units are regulated under CAA section 111(d) with emissions limits based on CAA section 112 and must comply with all CAA section 129(a) requirements. Section 129 does include an explicit five-year periodic review requirement for new sources, but not for existing sources.[91] However, when EPA finalized emissions guidelines for existing municipal waste combustors in 1991 under CAA sections 111(d) and 129, the Agency committed to review the standard 4 years[92] from the date of promulgation as required by the CAA. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.[93]

The procedural reference to CAA section 110 and the regulations for adoption and submittal of state plans for existing sources provide EPA with ample authority to require periodic review of the CPP (including the MTR and the FP). Further, EPA has a history of including the CAA section 111(b) periodic review requirement when setting CAA section 111(d) emissions guidelines. Because the CAA is silent regarding the periodic review of CAA section 111(d) standards, "the question…is whether the agency's answer is based on a permissible construction of the statute."[94] An agency's interpretation is reasonable if it is not only a logical construction of

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[90] 40 Fed. Reg. 53,340, 53,345 (Nov. 17, 1975) (emphasis added).

[91] *Compare* 42 U.S.C. § 7429 (a)(5) (requiring review of new source standards every 5 years) *with* 42 U.S.C. § 7429(b) (no such explicit requirement).

[92] Because the CAA section 111 standards were originally promulgated decades ago, it is important to note that CAA section 111(b) was originally written to allow review of NSPS from "time to time." On August 7, 1977 "time to time" was substituted with "shall, at least every four years review…" 1977. Act Aug. 7, 1977. And on November 15, 1990 "eight" was substituted for "four." Act Nov. 15, 1990.

[93] 56 Fed. Reg. 5,514, 5,515 (Feb. 11, 1991) (emphasis added), *withdrawn in part on other grounds and replaced by* Standards of Performance for New Stationary Sources and Emissions Guidelines for Existing Sources, 60 Fed. Reg. 65,387, 65413 (Dec. 19, 1995) (noting that the Act requires that the new source standards *and* the existing source guidelines must be reviewed not later than 5 years following initial promulgation and at 5-year intervals thereafter).

[94] *Chevron v. NRDC*, 467 U.S. 837, 843-44 (1984).

the specific provision but also gives effect to the statute as a whole.[95] The purpose of the section 111 is to apply the BSER and "assure the use of available technology and to stimulate the development of new technology."[96] A periodic review of all aspects of the CPP, including the Model Trading Rule and the FP, would ensure that $CO_2$ from existing power plants are controlled to the greatest degree practicable and would spur innovation in pollution control. We urge EPA to commit to a periodic review of these standards.

## VI. EPA must reserve mass-based allowances in the FP and MTR to provide an incentive for states to build and generate the added RE included in EPA's rate to mass translation.

EPA determined in the final CPP that the BSER for existing EGUs includes "substituting increased generation from new zero-emitting RE generating capacity for generation from affected fossil fuel-fired generating units" ("building block 3").[97] Due to the interconnected nature of the electric grid, if RE output increases and electricity demand remains relatively stable, output from existing EGUs will decrease along with $CO_2$ emissions.[98]

The emission performance standards for affected sources in the CPP were derived from this BSER. As described previously in section IV.a., the CPP permits states to demonstrate compliance with the BSER-derived performance standards by achieving rate- or mass-based statewide emission goals set by EPA that are equivalent to or no less stringent than those standards.[99] EPA first translated the emission performance standards into average statewide emission rate goals and then translated the rate-based goals into mass-based budgets for each state.

EPA took a conservative approach when it quantified the incremental renewable generation available for the BSER in the CPP, identifying a "reasonable, rather than maximum amount[]…."[100] For the purpose of translating the state's emission rate goal into a mass emission allowance budget, EPA first multiplied the rate goal by the state's 2012 affected EGU

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[95] *See Robinson v. Shell Oil Co.,* 519 U.S. 337, 341 (1997); *Ass'n of Tex. v. Timbers of Inwood Forest Assoc.,* 484 U.S. 365, 371 (1988) "Statutory construction is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme."

[96] *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981).

[97] 80 Fed. Reg. at 64,768-69.

[98] *Id*. at 64,729.

[99] *See*, *e.g.,* 40 C.F.R. §§ 60.21(e) and 60.24(c).

[100] 80 Fed. Reg. at 64,809.

generation.[101] However, EPA then *added* to that figure "emissions associated with the ability of affected EGUs to expand output under rate-based compliance *if* they deployed the amount of RE quantified under building block 3 that was not captured in the ultimate quantification of the source category-specific performance rates."(emphasis added).[102] However, EPA did not condition the addition of those incremental allowances on any demonstration that the "excess building block 3 generation" would actually be built and deployed. As a result, unless the excess RE assumed by EPA is actually deployed, actual emissions under a mass-based system will be less stringent than those under a rate-based system and *not equivalent* to the BSER-derived performance standards.[103]

Over the course of the CPP compliance period, this RE-derived adjustment to the mass based state allowance budgets could, without adequate redress, add nearly 1.3 *billion* tons of $CO_2$ to the emission guidelines, an increase of approximately 8.5 percent.[104]

However, as discussed above, the mass-based and rate-based emission guidelines must be equivalent to the BSER, and therefore to each other. EPA's assumption that every state choosing a rate-based system will maximize RE output seems dubious at best. First it doesn't recognize the different roles NGCC and RE units play in the interconnected energy system. Second, it is unlikely that electricity demand will increase sufficiently to accommodate the assumed RE expansion,[105] and in the event that it does, EPA fails to discuss the economic feasibility of such an RE build-out. Finally, EPA's assumption that states will expand RE beyond what is called for under building block 3 to enable high-emitting, affected sources to increase output is problematic. Due to the interconnected nature of the electricity grid (upon which the CPP

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[101] U.S. EPA, *$CO_2$ Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule*, at 21 (Aug. 2015).

[102] *Id*.

[103] EPA hypothesized that under a rate-based system, states could possibly develop incremental renewable generation to the fullest extent, beyond that quantified in BSER building block 3. EPA asserted that under a rate-based system, not only could RE be substituted for existing affected fossil unit generation, but the excess building block 3 generation could also allow those affected sources to expand output and associated emissions so long as the unit held emission reductions credits associated with this "excess" generation. In translating the state emission goals from rate to mass, EPA determined in the CPP to allow states that chose a mass goal to take advantage of the hypothetical excess RE generation on the unsupported assumption that states would expand renewable generation to its maximum potential extent. Therefore, EPA translated the emissions associated with maximizing ERCs generated by renewable sources under a rate system into mass-based allowances, and added them to the mass goals without any coinciding requirement to actually build and generate the RE.

[104] *$CO_2$ Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule,* at Appendix 4.

[105] U.S. EIA, *Annual Energy Outlook 2015*, at 8 (predicting 0.7%/year growth in electricity demand on average).

justifiably relies), it is not at all clear that expanding renewable generation will lead to increased generation at affected fossil sources, yet EPA increased the state mass-based budgets on the assumption that this will happen to the maximum extent theoretically possible in every state.

While the CPP is final, and Commenters are not advocating here that it be changed, EPA does have the opportunity in the FP and MTR to provide incentives for states to actually "earn" these additional tons by deploying the RE generation that EPA has assumed in expanding the state mass allowance budgets based on the *potential* for such incremental RE deployment. In particular, Commenters urge EPA to reserve or set aside allowances in both the FP and the MTR in the amount associated with "excess building block 3 generation"—that is, in the amount of the RE increment that EPA added to the state mass-based goals. Allowances would be reserved for this purpose after allowances were allocated pursuant to the updating OBA recommended in section IV.b.v. Such a set-aside could be similar in structure to EPA's proposed RE set-aside. That is, RE generators would apply to receive a portion of the set-aside allowances based on projected generation, subsequently adequately demonstrated consistent with rigorous evaluation, measurement and verification ("EM&V") requirements.[106] The RE generator could sell those allowances to affected facilities to use for compliance with the allowance budget.

Without a requirement to actually build and operate the renewable generation associated with the allowances awarded in EPA's rate to mass translation, the mass-based approach risks non-equivalence with the rate-based guidelines, and the BSER. By setting aside the allowances associated with "excess building block 3 generation" and requiring states and generators to earn them ahead of time as is required in the rate-based system, EPA will take important steps toward maintaining the stringency of the Clean Power Plan.

## VII. Modified and reconstructed affected sources.

EPA should finalize its original interpretation articulated in the proposed CPP, which precluded affected existing sources from exiting the CPP subsequent to modification or reconstruction.[107] Under the Act, if an existing source modifies or reconstructs it becomes something other than an "existing source" – by definition it becomes a "new source."[108] However, the statute and regulations are silent regarding whether and how an existing source of designated pollutants, with section 111(d) obligations, that subsequently undergoes modification

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[106] 80 Fed. Reg. ] at 65,024.

[107] Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, at 34,903-04 (June 18, 2014)

[108] *Compare* 42 U.S.C. § 7411(a)(2) with (a)(4).

or reconstruction triggering the need to comply with section 111(b), must continue to comply with its CAA section 111(d) obligations, in addition to any "new source" requirements. This presents an unfortunate opportunity for total emissions performance backsliding, which should be addressed by the Agency in the final MTR/FP.

EPA's original interpretation that "all existing sources that become modified or reconstructed sources which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b)," is not only consistent with the statute, but also is reasonable as it ensures the integrity of the CPP.[109] Because the CAA is silent regarding the continuation of CAA section 111(d) plan obligations after a source modifies or reconstructs "the question…is whether the agency's answer is based on a permissible construction of the statute."[110] An agency's interpretation is reasonable if it is not only a logical construction of the specific provision but also gives effect to the statute as a whole.[111]

When considering the structure of the statute, in particular how Congress organized section 111, it becomes clear that requiring a source to continue to comply with its obligations under CAA section 111(d) after reconstruction or modification best gives effect to the statutory scheme. If CAA section 111(d) requirements ceased upon a unit's modification or reconstruction, state plans that relied on the source or unit meeting the 111(d) emission standards could become unworkable and would require revision. If the modified and reconstructed source standards were less stringent than the state plan, the plan would need to ensure more pollution reductions from the other sources remaining within that plan, making planning difficult because the state's actual emissions rate could increase above the target rates in unpredictable ways.[112] So, for example, if a source had a very strict CPP emissions limit imposed by the state (a scenario well within a state's authority to require), and the section 111(b) modified reconstructed performance standard was less stringent, EPA's current proposal to release the source from its section 111(d) obligations, could create an incentive for the owner of the unit to modify or reconstruct, in order to evade its section 111(d) emissions limit.

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[109] 79 Fed. Reg. at 34,963.

[110] *Chevron v. NRDC*, 467 U.S. 837, 843-44 (1984).

[111] *See Robinson v. Shell Oil Co.,* 519 U.S. 337, 341 (1997); *Ass'n of Tex. v. Timbers of Inwood Forest Assoc.,* 484 U.S. 365, 371 (1988) "Statutory construction is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme."

[112] *See* 79 Fed. Reg. 34,829, 34,837 (EPA proposed state-specific rate-based goals that state plans must be designed to meet).

Congress designed section 111 to ensure "that [performance] standards reflect 'the greatest degree of emissions control which the Administrator determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'"[113] Should a state participate in a mass-based allowance trading system with other states, keeping modified and reconstructed sources within the 111(d) frame could be the basis of more rapid achievement of the overall 111(d) goals.[114]

Notwithstanding the above, EPA did not finalize its original proposal, but instead now proposes to effectively release an existing source from its obligations under section 111(d) and the CPP upon the modification or reconstruction of the source.[115] EPA provides no real support for this reversed interpretation, other than to note that a source cannot be an existing and a new source at the same time. EPA also states that "there will be other ways to minimize disruption to state plans if such a modification or reconstruction were to take place," but does not describe any ways to minimize such disruption.[116] If EPA does finalize a rule wherein a source subject to the CPP is released from its obligations subsequent to modification or reconstruction, the emission guidelines (both rate and mass) must be tightened upon that source's departure from the program, to ensure the integrity of the emission guidelines. Commenters propose that the simplest and most effective way to "minimize disruption to state plans" in a mass-based context would be to permanently retire emission allowances in an amount that is equal to the 2012 baseline emissions of the modified or reconstructed source.[117]

## VIII. Further comments on the proposed mass-based FP and MTR.

As explained in section III. of our comments, Commenters urge EPA to finalize mass-based trading plans for both the FP text and the MTR. We offer the following comments on certain of the particular aspects of EPA's mass-based proposal.

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[113] *Portland Cement Ass'n v. Ruckelhaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (*quoting* S. Rep. No. 9-1196, 91st Cong., 2d Sess. 16 (1970)), *cert. denied*, 417 U.S. 921 (1974).

[114] *See Robinson v. Shell Oil Co.,* 519 U.S. 337, 341 (1997); *Ass'n of Tex. v. Timbers of Inwood Forest Assoc.,* 484 U.S. 365, 371 (1988) "Statutory construction is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme."

[115] 80 Fed. Reg. at 65,038-39.

[116] *Id*. at 65,039.

[117] We note that this issue should not be a problem in states that have adopted the combined new and existing mass-budget approach to leakage.

1. Commenters support EPA's proposal to allow allowance banking, and to prohibit allowance borrowing.[118]

2. Commenters also support EPA's proposal to treat FPs as "ready-for-interstate trading" plans under the CPP, and to allow allowance trading between EGUs in mass-based FP states and those in mass-based "linked" states also having approved "ready-for-interstate trading" plans, so long as the state plans use identical compliance instruments and an EPA-administered tracking system.[119]

3. Commenters favor the inclusion in the FP and the MTR of some type of intervening compliance requirement along the lines of those contained in the CARB Cap and Trade Program or the RGGI program. We do not favor EPA's proposal to require compliance only at the end of each multi-year compliance period. A further option would be to require states falling significantly behind a pro rata annual share of the target reduction for the full compliance period (i.e., those with a 20 percent or greater allowance deficit) in a particular year to make up that deficit in the next year. Requiring compliance on a more frequent basis will likely result in greater compliance at less cost in the long run.

4. Commenters support EPA's proposal not to allocate allowances to affected EGUs for any compliance period following the cessation of operation for two consecutive years. However, those allowances should not be reallocated solely to an RE "set-aside," but rather to all zero-emitting generation in the context of an updating output-based allocation system as we discuss in section IV. of these comments.[120]

5. Commenters agree with EPA that the substantial flexibility provided by a mass-based trading system, combined with the extended compliance period, is sufficient to provide confidence that the CPP will not impact electric system reliability.[121] Therefore, there is no need for a "reliability safety valve" or any allowance set-aside (or similar mechanism) to be included in either the FP or the MTR. The existing protections inherent in the

[118] 80 Fed. Reg. at 65,014.

[119] *Id*. at 64,976-77. Commenters do not support expansion of interstate trading to states using an EPA-designated tracking system rather than one administered by EPA.

[120] Commenters note that if an existing nuclear plant or any other zero carbon-emitting source in the 2012 baseline is shut down, EPA must provide in the FP and the MTR that any resulting plan revision will maintain the integrity of the original "emission performance rates and state emission performance goals" are protected (*i.e.,* that the revised plan is "satisfactory"). 80 Fed. Reg. at 64,864.

[121] *Id*. at 64,981-82.

design of the FP and MTR are more than sufficient to address any reliability issues.

## IX. Treatment of particular resources.

As mentioned in our discussion of leakage (section IV., *supra*), EPA must, in order to ensure that mass-based allowance systems are equivalent to the BSER-derived performance standards in the CPP, include provisions in the FP and the MTR that will reduce the incentive for new NGCC generation that will result in emissions beyond those regulated by a state's existing source allowance budget and thus result in new source leakage. For states not adopting the combined new and existing source budget approach, allowance allocation approaches that reduce new source leakage must be employed. A key characteristic of such allocation systems (either the updating OBA approach proposed by Commenters, or the set-aside approach proposed by EPA) is that incentives must be provided through allowance allocations to existing NGCC units and to *all* zero carbon-emitting generation, including CCS-equipped and nuclear units, but not to biomass units, for reasons we explain below. In this section, Commenters provide additional justification for our proposals.

### a. Carbon capture and sequestration.

EPA should provide a clear path for CCS projects to generate allowances in the final model rule, as well as ERCs if EPA finalizes a rate-based model rule. For the foreseeable future, fossil fuel-fired power plants will provide a significant portion of electricity in the U.S.[122] Therefore, to "meet demand projections, grid reliability requirements and [$CO_2$] emissions goals, [CCS] will be necessary for many power generation facilities."[123] CCS separates $CO_2$ from power plant emissions, compresses it and injects it underground for permanent storage. It is the only technology currently available that allows fossil fuel-fired power plants to operate without emitting $CO_2$. "If CCS is removed from the list of emissions reduction options in the electricity sector, the capital investment needed to meet the same emissions constraint is increased by 40 [percent]."[124] In fact, if CCS is not included in such a list, the ability to achieve target [$CO_2$] levels *ever*, is reduced by 0.5°C (scientists recommend keeping global warming below 2°C)F.[125]

[122] U.S. EIA, *Annual Energy Outlook 2015*, at 24. In 2040, natural gas accounts for 31% of total electricity generation, while coal accounts for 34%.

[123] Elizabeth Burton, *et al*., *California' s Policy Approach to Develop and Carbon Capture, Utilization and Sequestration as a Mitigation Technology*, 37 ENERGY PROCEDIA 7639, 7645 (2013).

[124] IEA, *Technology Roadmap: Carbon Capture and Storage*, at 8 (2013); *See also generally* Krishna Priya G.S. *et al*., *Power system planning with emission constrains: Effects of CCS retrofitting*, 92 PROCESS & SAFETY ENVTL. PROT. 447 (2014) (finding that allowing CCS retrofit of existing plants reduces costs significantly).

[125] Gunnar Luderer *et al*., *Economic mitigation challenges: how further delay closes the door for achieving climate*

CATF submitted extensive technical documentation of the technical feasibility of CCS and the technology's importance in supporting EPA's suite of carbon rules for EGUs to EPA in its comments on the carbon pollution standards for new sources,[126] modified and reconstructed sources,[127] and the Clean Power Plan.[128] We incorporate those comments by reference here.

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*targets,* 8 ENVTL. RESEARCH LETTERS 034033 at 7 (2014) (finding that existing sources have already consumed much of the 2.0°C target and delaying comprehensive emissions reductions another 15 years may push the target out of reach). Ruth Nataly Echevarria Huaman and Tian Xiu Jun, *Energy related $CO_2$ emissions and progress on CCS projects: A review*, 31 RENEWABLE AND SUSTAINABLE ENERGY REVIEW 368, 369 (2014) (each year of delay will result in a global cost of $500 billion in terms of mitigation costs from 2014 to 2030).

[126] Comment submitted by Ann Brewster Weeks *et al*., Senior Counsel and Legal Director, Clean Air Task Force (CATF), Appendix Accompanying Chapter III, Doc. ID: EPA-HQ-OAR-2013-0495-9664

[127] Comment submitted by James P. Duffy, Legal Fellow & Ann Brewster Weeks, Senior Counsel and Legal Director, Clean Air Task Force (CATF), MRSPS Technical Appendix, Doc. ID: EPA-HQ-OAR-2013-0603-0280

[128] Comment submitted by Ann Brewster Weeks, Legal Director et al., Clean Air Task Force (CATF) (Appendices and Exhibits to OAR-2013-0602-22612), Appendix B - Carbon Capture and Storage Retrofit Technical Appendix, Doc. ID: EPA-HQ-OAR-2013-0602-25574.

Since CATF's last submission, it has only become more clear that CCS is adequately demonstrated, technically feasible and integral to achieving the emission reduction goals set out in EPA's recently promulgated carbon rules. For example:

Two large-scale CCS projects became operational in 2015:

- The Quest project, located in Alberta, Canada ($CO_2$ capture capacity of approximately 1 Mtpa) was launched in November 2015. The project, involving the manufacture of hydrogen for upgrading bitumen into synthetic crude oil, is North America's first large-scale CCS project to store $CO_2$ exclusively in a deep saline formation.
- The Uthmaniyah $CO_2$-EOR Demonstration Project, located in the Kingdom of Saudi Arabia was launched in July 2015. The project is capable of capturing around 0.8 Mtpa of $CO_2$ from the Hayiwah NGL (natural gas liquids) Recovery Plant.

Two more industrial CCS projects are expected to become operational in early 2016:

- The Illinois Industrial CCS Project ($CO_2$ capture capacity of 1 Mtpa) is located at the Archer Daniel Midlands corn-to-ethanol production facility in Decatur, Illinois (United States). The project, the world's first bio-CCS project at large scale, will be the first integrated CCS project in the United States to inject $CO_2$ into a deep saline formation at a scale of 1 Mtpa.
- The Abu Dhabi CCS Project ($CO_2$ capture capacity of 0.8 Mtpa), the world's first iron and steel project to apply CCS at large scale, will involve $CO_2$capture from the direct reduced iron process used at the Emirates Steel plant in Abu Dhabi.

Large-scale CCS projects in the power sector are now a reality, demonstrated by:

- The world's first large-scale power sector CCS project – the Boundary Dam Carbon Capture and Storage Project in Canada ($CO_2$ capture capacity of 1 Mtpa) – becoming operational in October 2014.
- Commissioning activities on a new-build 582 megawatt (MW) power plant beginning at the Kemper County Energy Facility in Mississippi (United States, $CO_2$ capture capacity of 3 Mtpa) with $CO_2$ capture expected to commence around the middle of 2016.
- The Petra Nova Carbon Capture Project at the W.A. Parish power plant near Houston, Texas (US, $CO_2$ capture capacity of 1.4 Mtpa) entering construction in July 2014, with $CO_2$ capture anticipated by the end of 2016.

Global CCS Institute, *Large Scale CCS Projects – Project Overview*, http://www.globalccsinstitute.com/projects/large-scale-ccs-projects.

New CCS-equipped power plants can provide low- or zero-emitting generation to substitute higher-emitting affected sources under the CPP just like building block 2 and 3 sources. Existing affected sources may also choose to comply through retrofit CCS technology.[129] CATF's own modeling demonstrated the potential for up to 22 retrofit CCS projects and two new CCS projects in response to the proposed CPP, under certain scenarios.[130] It is therefore essential for EPA to provide a clear path for sources that construct and operate new and retrofit CCS projects to generate allowances and ERCs under the FP and the MTR. Further, EPA should clarify that in developing their compliance plans, states may support development of CCS power plant projects through allowance allocation.

i. *Set-aside allowances for new CCS power plants*

Commenters understand that "set-aside allowances" described in 40 C.F.R. § 60.5815(c) are meant to be distinguished from a general allocation of allowances. Setting aside allowances to eligible resources would be used to counteract leakage, defined as incentives to shift generation from affected EGUs to unaffected fossil-fired sources, under a mass-based approach to the CPP.[131] Awarding allowances from the set-aside must be contingent on a source producing generation equivalent to the amount of the award.

However, EPA's CPP regulations state that "[p]rovisions for allocation of *set-aside allowances, if applicable* may only be established to provide set-aside allowances to eligible resources that meet the same requirements for ERC eligible resources.[132] As discussed below, it is unclear whether new CCS power plants are eligible to generate ERCs based on the incremental $CO_2$ reductions below the applicable performance standard, and therefore it is equally unclear whether allowances can be set-aside for new CCS power plants to combat leakage to $CO_2$-

[129] 80 Fed. Reg. at 64,756.

[130] Comment submitted by Ann Brewster Weeks, Legal Director et al., Clean Air Task Force (CATF), at Sec. III.a.iv, Doc. ID: EPA-HQ-OAR-2013-0602-22612.

[131] *See, e.g.,* 80 Fed. Reg. at 64,887-90.

[132] 40 C.F.R. § 60.5815(c) (emphasis added)

emitting, unaffected, fossil-fired sources. EPA proposes in the FP and the MTR a five percent allocation of allowances to a RE set-aside to combat leakage.[133] Allocating allowances to new CCS power plants would have the same effect as allocating the allowances to RE. Commenters urge EPA to provide clarification that new CCS power plants are eligible to receive set-aside allowances.

*ii. Set-aside allowances for retrofit CCS power plants*

The FP and the MTR should contain incentives for existing CCS power plants to operate more than unaffected fossil-fired sources to avoid leakage. As Commenters propose in section IV, this should be accomplished by means of a general updating OBA system that would include initial allocations to all zero-emitting and low-emitting sources, including CCS units. In the event that EPA decides to retain a set-aside approach, EPA should make it clear that allowances included in a set-aside may be allocated to existing retrofit CCS power plants.

The CPP regulations indicate that in order for a source to receive a set-aside allowance it must meet the requirements of section 60.5800, which defines those sources eligible for ERCs.[134] However, affected EGUs can also generate ERCs to the extent that their emission rate is below the unit specific emission standard.[135] It would be inconsistent for existing sources to be able to generate ERCs but not receive set-aside allowances. This may be a clerical error wherein EPA intended to link set-asides to both sections but failed to do so. Commenters request that EPA clarify and correct this problem.

*iii. General Allocation of Allowances*

EPA evinces a strong preference for allowing a state to promulgate its "own allowance-distribution provisions, using any approach to distribute allowances that the state chooses…").[136] A state could therefore initially allocate allowances to new or retrofit CCS projects in accordance

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[133] 80 Fed. Reg. at 65,022-25

[134] 40 C.F.R. § 5815(c).

[135] 40 C.F.R. § 60.5795(a)(1).

[136] 80 Fed. Reg. at 65,015; *See also* 40 C.F.R. § 60.5790(b)(5)(i) (allowing states to include requirement in their state plans "for emission budget allowance allocation methods that align incentives to generate to affected EGUs or EGUs covered by subpart TTTT …that result in the affected EGUs meeting the mass-based $CO_2$ emission goal.").

with 40 C.F.R. § 60.5815. A state, for example, could issue allowances equivalent to historical emission to an affected source, which has committed to a CCS retrofit. The affected source would then have excess allowances, which it could sell to other affected sources and defray the costs of the CCS installation. A state could also allocate allowances to a new CCS project, which is not subject to the CPP. The new plant could sell all of the allowances to affected sources and use the proceeds to defray the costs of construction. Commenters request that EPA confirm this compliance pathway by including it in the final MTR and, as applicable, any FP.

#### iv. *Emission reduction credits for new CCS power plants*

It is not entirely clear under the CPP whether ERCs are available for newly developed fossil-fuel plants subject to the section 111(b) performance standards and equipped with CCS. On the one hand, "ERCs may not be issued to or for … [n]ew, modified or reconstructed EGUs that are subject to subpart TTTT …."[137] Any new electric generating unit meeting certain applicability requirements is subject to subpart TTTT.[138] However, the regulations also indicate that carbon capture and utilization may qualify as an eligible resource for ERCs without limiting it to retrofit carbon capture.[139] New CCS plants are not explicitly listed as an eligible resource for ERCs but the regulations provide that a state could identify a category in its plan and receive approval from EPA.[140] EPA should finalize MTR provisions clearly allowing new CCS plants to generate ERCs for the incremental $CO_2$ emissions reductions they achieve below the applicable section 111(b) performance standards.

#### v. *Emission reduction credits for retrofit CCS on existing affected units*

Affected EGUs with $CO_2$ emission rates below the emission standard assigned to it in the state plan may generate ERCs so long as the state plan includes certain methods to quantify ERCs. [141] Further, if an affected EGU captures $CO_2$ to meet the applicable emission limit the

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137 40 C.F.R. § 60.5800(c)(1).

138 40 C.F.R. § 60.5509.

139 40 C.F.R. § 60.5800(d)(3).

140 40 C.F.R. § 60.5800(a)(4)(vii).

141 40 C.F.R. § 60.5795.

owner or operator must report in accordance with 40 C.F.R. § 60.5860(f). The pathway for affected EGUs to comply with a rate-based plan through retrofit CCS is well-defined.

Retrofit and new CCS technology have the potential to contribute significant $CO_2$ emission reductions from the affected sources in the CPP. The final model rule should outline a clear pathway for new and existing CCS projects to contribute to compliance in either a rate or mass-based state plan.

**b. Nuclear plants.**

Existing nuclear power plants currently provide reliable, zero carbon-emitting, baseload electricity, and emerging technologies will provide more flexible operation in the future.. In 2012 nuclear power accounted for 19 percent of electricity in the United States.[142] This electricity is included in the CPP's baseline. While EPA does not permit states to reduce the stringency of their plans if an existing, zero-emitting nuclear plant retires,[143] it is likely that a retired nuclear plant would be replaced by new NGCC generation, along with its attendant $CO_2$ emissions.[144] If the existing nuclear plant were replaced with incremental RE, the renewable source could generate ERCs, which would then allow affected sources to emit more $CO_2$ even though the renewable generation was not substituting for affected source generation. This scenario presented serious leakage risks.

CATF commissioned The Northbridge Group to estimate this potential impact. Northbridge found that if a 1,000 MW nuclear unit operating at 80 percent capacity factor retires and is replaced by 100 percent gas with an average emission rate of 0.4 tons/MWh, the increase in annual emissions would be 2.8 MM tons. (1,000 MW * 8760 hrs/yr * 80% capacity factor * 0.4 tons/MWh). PJM, which is essentially the size of the market region modeled in the Northbridge leakage gas-to-gas leakage analysis, has five nuclear units considered to be at risk of early retirement (Quad Cities 1 and 2; Byron 1 and 2; and Davis-Besse). So for rough approximation purposes, the nuclear leakage risk could be bracketed by a range of 3 to 15 MM

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[142] EIA, "International Energy Statistics," 2012, https://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=2&pid=2&aid=12.

[143] 80 Fed. Reg. at 64,864.

[144] Lucas Davis and Catherine Hausman, *Market Impacts of Nuclear Power Plant Closure,* 8 APPLIED ECONOMICS 1, 2 (forthcoming 2016) [hereinafter "Davis & Hausman"]; *See also* Samuel Brinton and Josh Freed, Third Way, *When Nuclear Ends: How Nuclear Retirements Might Undermine Clean Power Plan Progress*, 7-8 (Aug. 19, 2015), *available at*: http://www.thirdway.org/report/when-nuclear-ends-how-nuclear-retirements-might-undermine-clean-power-plan-progress [hereinafter "Third Way Report"].

tons (which compares to an estimated gas-on-gas leakage risk for the modeled region of 12 MM tons). In concept, with sufficient allowances allocated to them, these at-risk nuclear units would be economic to operate and the avoided nuclear leakage would range between 3 and 15 MM tons.

Even without the CPP, retirements are predicted; due to low natural gas prices, low electricity demand, increasing uranium prices and the costs associated with increasingly stringent safety regulations, existing nuclear plants are retiring before their licenses expire and more premature retirements are anticipated.[145] There are currently 100 nuclear power plants licensed to operate in the United States.[146] Sixteen of those plants have applications for license extensions pending; [147] extension is not guaranteed.[148]. Four plants[149] (five reactors) have retired in the past four years, reducing nuclear capacity by more than 4,000 MW.[150] Additionally, Exelon recently announced that it will retire its 637 MW Oyster Creek Plant in New Jersey by the end of 2019.[151] In October 2015, Entergy announced that it would be shutting down the 688 MW Pilgrim Plant in Massachusetts no later than June 1, 2019.[152] And most recently, Entergy announced in November 2015, that it would close its 838 MW Fitzpatrick Nuclear Power Plant in New York in

[145] Davis & Hausman at 1-2.

[146] U.S. Nuclear Regulatory Commission, "Power Reactors," http://www.nrc.gov/reactors/power.html.

[147] Andrew Engblom and Hira Fawad, "As Pilgrim Falls, 11% of Nuclear Generation at Risk of Early Closure," SNL FINANCIAL (Oct. 16, 2015) https://www.snl.com/InteractiveX/article.aspx?CDID=A-34103057-13109&ID=34103057&Printable=1. Preparations are underway at the regulator and industry level to begin applications for additional license extensions (up to 80 year lifetimes) for plants that are performing well and can be safely operated beyond 60 years. These extensions also are not assured; equipment upgrades will likely be required to support them, and appropriate policy mechanisms that incentivize these life extensions may provide additional carbon-free generation at lower cost than greenfield generation.

[148] *See generally*, American Physical Society, *Renewing Licenses for the Nation's Nuclear Power Plants*, (Dec. 2013), *available at*: https://www.aps.org/policy/reports/popa-reports/upload/nuclear-power.pdf. "The decision on whether or not to continue operating a nuclear plant is complex, involving interrelated technical, safety, economic, regulatory, and public policy issues." *Id*. at 3.

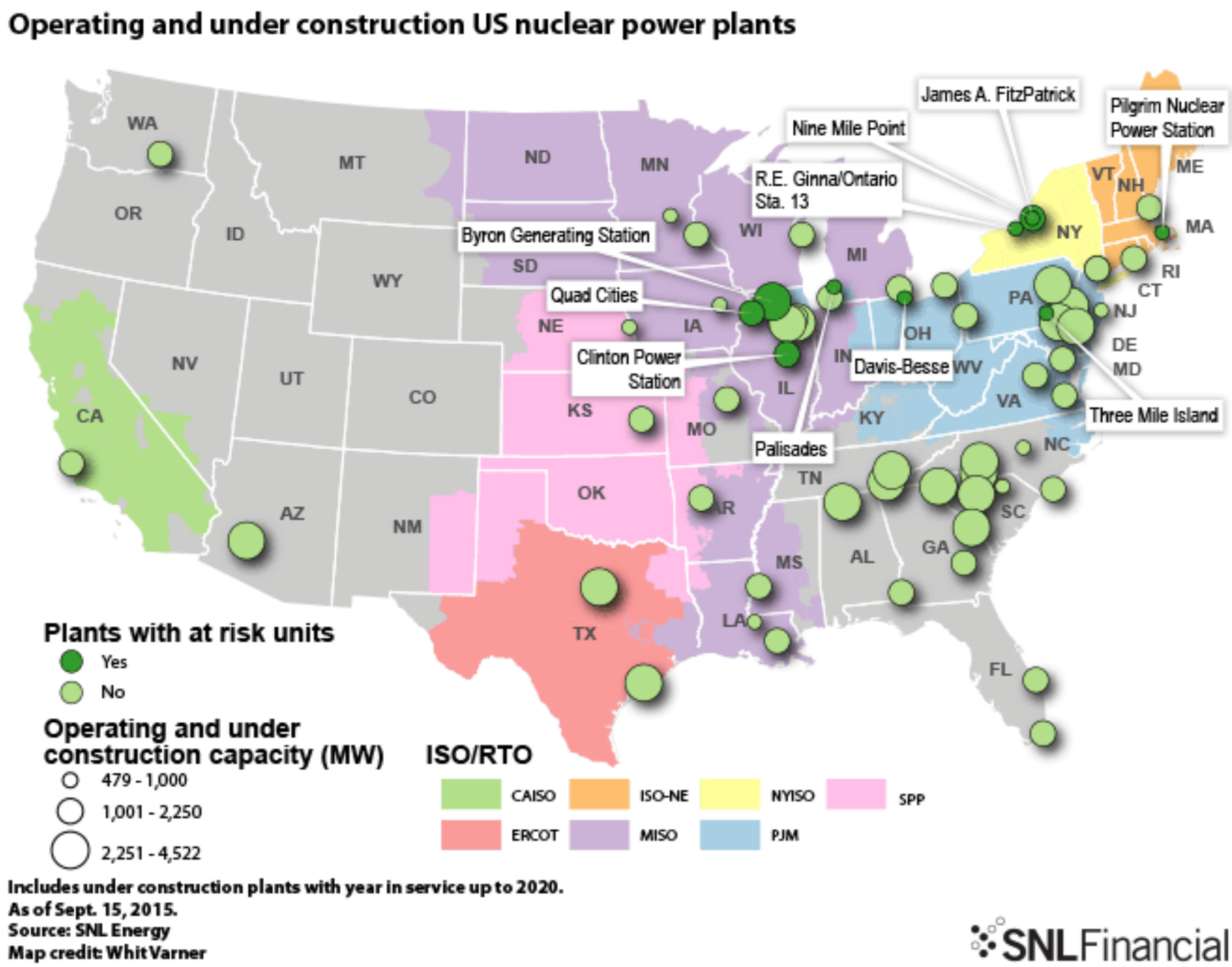
[149] Crystal River, Kewaunee, San Onofre and Vermont Yankee.

[150] EIA, "Despite Recent Closures, U.S. Nuclear Capacity is Scheduled to Increase by 2020," (Nov. 2, 2015), *available at*: https://www.eia.gov/todayinenergy/detail.cfm?id=23592.

[151] Thomas Overton, "U.S. Faces Wave of Premature Nuclear Retirements," POWER (Jan. 14, 2015), *available at*: http://www.powermag.com/u-s-faces-wave-of-premature-nuclear-retirements/.

[152] Entergy, "Entergy to Close Pilgrim Nuclear Power Station in Massachusetts No Later than June 1, 2019," http://www.pilgrimpower.com/operational-update/.

late 2016 or early 2017.[153] At least eleven additional nuclear plants are at risk for early retirement.[154]

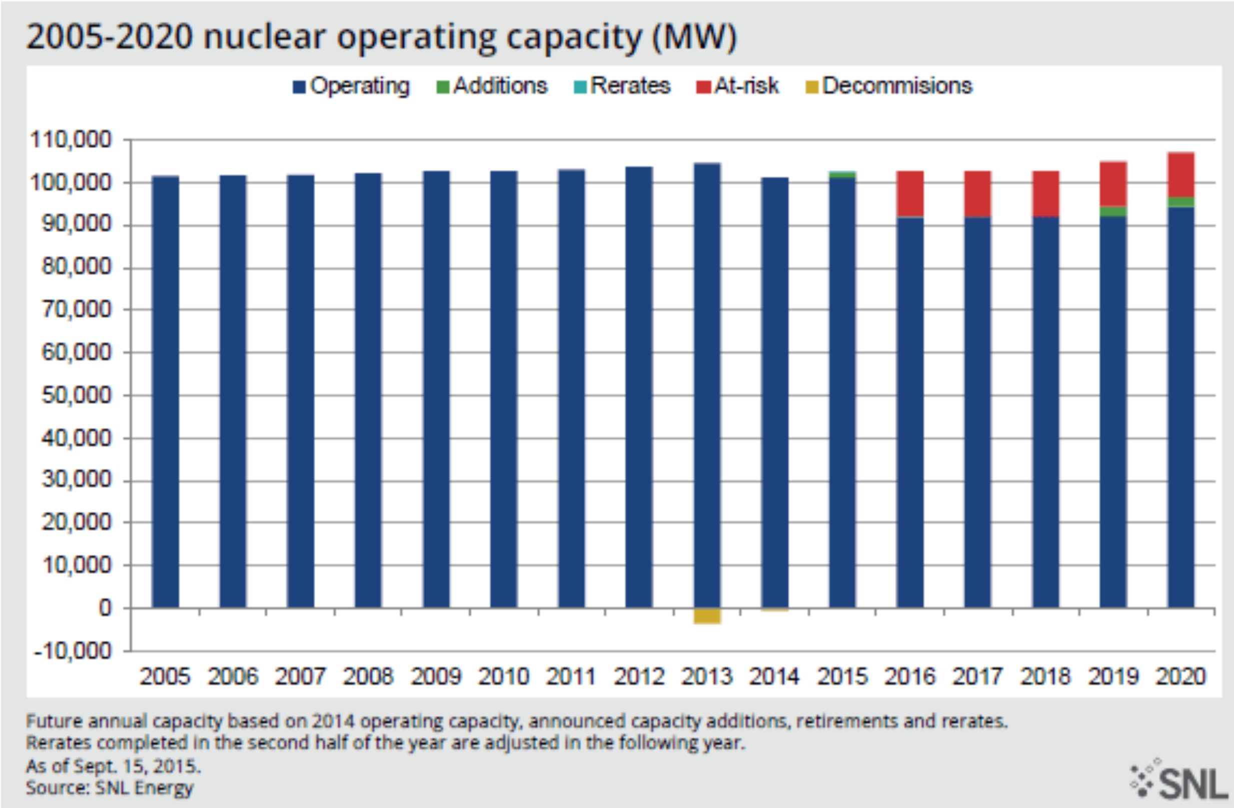



If these additional nuclear plants retire, even with expected additions and uprates, aggregate nuclear capacity would drop 5,929 MW by 2020.[155]

[153] Sheharyar Khan, "Entergy to Close Fitzpatrick Nuke by Early 2017," (Nov. 2, 2015), *available at*: https://www.snl.com/InteractiveX/Article.aspx?cdid=A-34365175-11568&mkt_tok=3RkMMJWWfF9wsRojs6TAcO%2FhmjTEU5z17uwtUaWyg4kz2EFye%2BLIHETpodcMSMBhMb7YDBceEJhqyQJxPr3FJNANysRuRhDgCw%3D%3D.

[154] Andrew Engblom and Hira Fawad, "As Pilgrim Falls, 11% of Nuclear Generation at Risk of Early Closure," SNL FINANCIAL (Oct. 16, 2015) https://www.snl.com/InteractiveX/article.aspx?CDID=A-34103057-13109&ID=34103057&Printable=1.

[155] *Id*.




A recent study found that if the current nuclear fleet ceases operation at the end of their 40-year licenses, almost two-thirds of the nuclear fleet would retire by 2025 and only a few plants would remain in 2035.[156] These retirements would lead to a 12.5 percent $CO_2$ emissions increase in 2025.[157] Another study out of U.C. Berkeley reviewed the impacts of San Onofre Nuclear Generating Stations retirement in February 2012 and found that the closure "increase[ed] carbon dioxide emissions by nine million tons in the first twelve months."[158] These emission increases "imply external costs of almost $320 million…"[159] The study cautioned that "[c]urrent policies aimed at reducing emissions tend to focus on wind, solar, and other renewables, but keeping existing nuclear plants open longer could mean hundreds of millions of tons of carbon abatement."[160]

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[156] Third Way Report.

[157] *Id*.

[158] Davis & Hausman, at 2-3.

[159] *Id*. at 3.

[160] *Id*. at 29.

Other than marginally increasing the cost of operating an existing affected source and thereby improving existing nuclear plants competitive position, the CPP fails to do anything to help avoid the serious potential for $CO_2$ backsliding associated with the retirement of existing nuclear facilities. While EPA did not include the preservation of existing nuclear generation in the BSER used to develop the CPP performance standards, existing nuclear plants are included in the baseline 2012 $CO_2$ emissions against which CPP reductions are measured.[161] And under the final CPP, new or uprated nuclear generation can generate ERCs or allowances for affected EGUs to use for compliance.[162]

EPA has also provided that if a nuclear unit ceases generation unexpectedly a state may be able to modify the emission standards to allow affected EGUs to cover a shortfall in generation.[163] However, this reliability safety valve is only available temporarily, and only to respond to extremely serious and unexpected events. After a limited period, the state would have to comply with its original approved implementation plan or submit a revision, which would need to be equivalent to the emission guidelines for individual sources.[164]

As discussed above, however, it is unlikely generation from a retired, existing nuclear plant would be replaced by generation from existing, affected sources. More likely, the generation would be replaced by new NGCC generation, thus resulting in new source leakage. The most efficient way to curb this leakage from zero-emitting nuclear power plants to new NGCC power plants, as described in section IV of these comments, is for EPA to include in the MTR a combined mass cap on new and existing units, and for states to adopt the MTR. This approach would also curb emission increases associated with nuclear retirement by discouraging states from replacing that generation with new NGCC power plants.

If a state does not adopt a mass-based cap on new and existing plants, EPA should alternatively finalize Commenters' allocation approach to leakage described in section IV, that is, the allocation of allowances on an updating output basis to all zero- and low-emitting generators, including existing nuclear plants. If an existing nuclear plant retires, those allowances should be permanently retired, or in the event that EPA decides to retain an enhanced version of a zero- and low-emitting unit set-aside, allocated to that set-aside, to reduce the incentive for new NGCC generation to replace the retired plant.

[161] 80 Fed. Reg at 64,738.

[162] *Id*. at 64,735.

[163] *Id*. at 64,878.

[164] *Id*. at 64,864.

Finally, a rate-based plan is undesirable and could undermine the stringency of the CPP; in a state where a nuclear plant is retired, renewable generation might increase to replace the nuclear plant generation but it would also generate additional ERCs and allow existing affected sources to emit more pollution than would be the case if the nuclear plant remained active.

**c. Biomass**

Commenters' position on biomass inclusion in either the FP or the MTR is straightforward—biomass combustion is not low- or zero-$CO_2$ emitting, either as measured at the affected source in the compliance periods for the CPP, or even on much longer time frames, and therefore must not be included in the MTR or the FP as an acceptable form of compliance. We set forth below our rationale for this position.

*i. Summary of key points on biomass.*

Biomass combustion does not reduce the amount of $CO_2$ emitted from the electric generating sector, nor can it generate megawatt hours of electricity that are "associated with zero $CO_2$ emissions," as required by EPA's regulations.[165] Biomass combustion also fails to meet the ERC and set-aside eligibility criteria that EPA has proposed, particularly because none of the available methods for tracking, allocating, and regulating biogenic $CO_2$ emissions are "rigorous, straightforward, and widely demonstrated"—the criteria that EPA has set forth.[166]

Commenters therefore support the EPA's proposal to exclude biomass combustion from the list of eligible emission reduction measures for ERC generation under a rate-based FP. Biomass should not be an eligible measure for rate-based crediting in the final FP,[167] nor should it be eligible for allowance set-asides under a mass-based FP or as a compliance option in the MTR.

[165] EPA has not (and cannot) identify any authority under section 111(d) for regulating an affected facility on the basis of its lifecycle $CO_2$ emissions instead of its actual, real-time $CO_2$ emissions. *See* 80 Fed. Reg. at 64,994-96, 65,012 (failing to cite authority). Nor has EPA explained how a biomass-based approach to compliance—with its necessary reliance on carbon sequestration that may (or may not) happen in the future—is consistent with the CPP's prohibition against borrowing from future compliance periods. 40 C.F.R. §60.5790(c)(4), 80 Fed. Reg. at 64,949/3 (implementation plans "must include … provisions not allowing any borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources"); 80 Fed. Reg. at 64,907 (State plans must also prohibit borrowing of any ERCs from future compliance periods by affected EGUs or eligible resources).

[166] 80 Fed. Reg. at 64995/1.

[167] *Id.*

ii. *Background: Climate challenges posed by biomass combustion.*

In most instances, an EGU that burns biomass instead of natural gas or coal will increase the amount of $CO_2$ it emits per kilowatt generated, mainly because the energy density of biomass is lower than that of fossil fuels.[168] Allowing states to meet their CPP $CO_2$ reduction requirements by relying on biomass combustion would therefore be highly problematic, particularly when the feedstock is woody biomass.

The first major problem is that any effort to mitigate climate change using biomass-based energy generation is fundamentally an offset scheme. Burning biomass rather than fossil fuel at an electric generating unit does not reduce the volume of $CO_2$ emissions emitted by the power sector. Instead, in order to claim a net emissions reduction, the owner/operator of the biomass-fueled EGU must take credit for carbon uptake that happens later, in forests and other landscapes—outside the electricity generating system.[169] This approach is consistent with the commonly understood definition of a forest offset program, including EPA's own definition.[170]

But a key basic requirement of offsets is that the reductions must be *additional*—that is, the carbon reductions or carbon uptake must be above and beyond what would have happened under a business-as-usual scenario.[171] So for forest biomass to generate $CO_2$ reduction credits in accordance with the requirements offset programs, the land managers must be able to demonstrate that the land under their control is sequestering more $CO_2$ in the harvest-combust-regrowth scenario than under other non-biomass scenarios (which might involve managing the forest to supply wood for framing lumber and other long-lived products). Biomass combustors cannot simply take credit for sequestration rates that are no higher than those that would have occurred anyway in a healthy, well managed forest.

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[168] Thomas Walker, *et al*. *Biomass and Carbon Policy Study* (report by the Manomet Center for Conservation Sciences) 103-104 (2010), *available at*: https://www.manomet.org/publications-tools/sustainable-economies/biomass-sustainability-and-carbon-policy-study-full-report.

[169] As detailed below in section IX.c.iii., though, section 111(d) and EPA's regulations require all control measures that qualify for ERCs or set-asides to produce emissions reductions at affected EGUs. Reductions achieved by virtue of land use decisions do not qualify.

[170] *See, e.g.*, Sarah Hines, USFS Northern Research Station, *Forest Carbon for the Private Landowner (1): Basics of Carbon Offsets, Markets and Trading* (2011) *available at*: http://www.fs.usda.gov/ccrc/sites/default/files/carboncourse/transcripts/13.Hines.pdf; 80 Fed. Reg. at 64,766/3 ("Because the emission standards must apply to the affected sources, actions taken by affected sources that do not result in emission reductions from the affected sources—for example, offsets (e.g., the planting of forests to sequester $CO_2$)—do not qualify for inclusion in the BSER").

[171] Timothy Searchinger and Ralph Heimlich, *Avoiding Bioenergy Competition for Food Crops and Land* (installment from World Resources Institute, CREATING A SUSTAINABLE FOOD FUTURE) 4 (2015); Timothy Searchinger, *Biofuels and the Need for Additional Carbon*, ENVIRON. RES. LETT. 5 (2010); Hines at 4 ("It's really important that we create offsets and credits that are real, *additional*, verifiable, and permanent.") (emphasis added).

Second, there is a significant delay between the time at which the $CO_2$ is released when biomass is burned to generate megawatts, and the time (if ever) at which emission reductions would be achieved. For example, if standing trees are harvested and burned in a power plant, then it takes 35-100+ years for forest regrowth and the associated carbon absorption to pay back the additional emissions and lost sequestration associated with biomass combustion (the actual timing depends in large part on whether the counterfactual involves burning coal or gas).[172] If forestry residues such as limbs and tree tops are burned instead, the payback period is shorter because it is tied to the region-specific decomposition rate of that material—but is still on the order of decades.[173] The delay in the reductions creates several legal and substantive problems. As explained in more detail below, nothing in section 111(d) of the CAA or EPA's implementing regulations authorizes regulated facilities to rely on net emissions reductions that are significantly delayed. The timing of reductions is also important because the CPP's $CO_2$ emission reduction goals are near-term goals – complete compliance must be achieved by 2030 (fewer than 14 years from now). And near term reductions are critical in order to avoid the worst impacts of climate change. An approach that increases emissions for the next several decades and does not provide a net benefit until, for example, 2076, would clearly undermine the reduction targets set for 2030[174] and 2050.[175, 176]

Third, even if a significant delay in emissions reductions was acceptable under section 111(d), carbon re-sequestration by means of forest regrowth is not assured. Ecological and economic research has identified several ways in which forest bioenergy harvesting might reduce post-harvest carbon sequestration. Whole-tree and intensive bioenergy harvesting practices might reduce overall forest carbon storage by altering post-harvest forest structure, particularly

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[172] Walker, *et al*. at 112; Jon McKechie, *et al*., *Forest Bioenergy or Forest Carbon? Assessing Trade-Offs in Greenhouse Gas Mitigation with Wood-Based Fuels*, 45 ENVTL. SCI. TECH. 789 (2011); Michael Ter-Mikaelian, *et al*., *The Burning Question: Does Forest Bioenergy Reduce Carbon Emissions? A Review of Common Misconceptions about Forest Carbon Accounting*, JOURNAL OF FORESTRY 57-69 (2015).

[173] Biomass Energy Resource Center, *et al*., *Biomass Supply and Carbon Accounting for Southeastern Forests* 100-103 (2012) *available at*: https://www.nwf.org/pdf/Global-Warming/NWF-SE-Carbon-Study.pdf.

[174] 80 Fed. Reg. at 64,665/1 (CPP to achieve 32% reduction in power sector $CO_2$ emissions by 2030).

[175] White House, FACT SHEET: U.S.-China Joint Announcement on Climate Change and Clean Energy Cooperation (November 11, 2014) (targeting "deep economy-wide [$CO_2$ emissions] reductions on the order of 80 percent by 2050") *available at*: https://www.whitehouse.gov/the-press-office/2014/11/11/fact-sheet-us-china-joint-announcement-climate-change-and-clean-energy-c.

[176] This understanding animates EPA's final CPP requirement that states cannot "borrow" ERCs and allowances from future periods to meet current compliance obligations. 40 C.F.R. § 60.5790(c)(4), 80 Fed. Reg. at 64,949/3. For the very same reason, biomass combustion cannot generate ERCs or allowances based on future emissions "reductions" connected to biomass regrowth.

reducing the amount of downed woody debris,[177] and/or by reducing soil organic carbon.[178] Moreover, post-harvest stand composition might be different than the original composition, either as a result of natural regeneration of planting, and the regrown species or species mix might not be able to sequester as much carbon as the original forest.[179] Finally, possibly as a result of new price incentives for harvesting smaller-diameter boles, forest owners/managers might short rotation ages, which reduces forest carbon storage. Under any of these circumstances, there is no basis whatsoever for claiming a $CO_2$ reduction credit. The connection between the entity that burns the biomass and entity that manages the harvested forest is usually limited or nonexistent, and EPA's proposed and final CPP materials do not adequately specify how states and regulated facilities must monitor and verify regrowth.[180]

As illustrated below, each of these problems undermines the legality and practicality of biomass combustion as a compliance option in the FP and MTR.

iii. *Biomass facilities are not zero- or low-emitting sources in the year of compliance or in prior years, so they cannot be used to generate ERCs or RE set-asides.*

Unlike facilities that generate electricity from wind or solar energy, facilities that burn biomass to generate electricity emit significant amounts of $CO_2$. As documented by EPA and others, the $CO_2$ emissions per kilowatt from electricity generating facilities that combust biomass are typically higher than from generating facilities that combust coal or natural gas.[181] Because $CO_2$ emissions from biomass facilities that are part of the electric system grid—regardless of whether the facilities predominantly combust biomass or co-fire it with a fossil fuel—will be greater than zero in the year of compliance or in prior years,[182] such facilities should not be able to generate ERCs or be eligible for RE set-asides.

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177 C.E. Littlefield and W.S. Keeton, *Bioenergy harvesting impacts on ecologically important stand structure and habitat characteristics*, 22 ECOLOGICAL APPLICATIONS 1892–1909 (2012).

178 D.L. Achat, *et al*., *Forest soil carbon is threatened by intensive biomass harvesting*, 5 SCI. REP. 15991 (2015).

179 Michael Ter-Mikaelian, , *et al. The carbon neutrality assumption for forest bioenergy: a case study for northwestern Ontario*, 87.5 THE FORESTRY CHRONICLE 644-652 (2011).

180 *Compare to* 40 C.F.R. § 60.5860(f) (80 Fed. Reg. at 64,883-84) (requiring regulated entities to verify any reductions achieved through the application of CCS).

181 Walker *et al*., at 103-104.

182 EPA's regulations require "affected EGUs to achieve each $CO_2$ emissions performance rate or $CO_2$ emissions goal, as applicable, over the [following] periods": the interim period (2022 through 2029), each of interim steps (of which there are three: 2022 through 2024, 2025 through 2026, and 2027 through 2029), and the final reporting periods. 40 C.F.R. § 60.5770(b).

1. Biomass combustion does not result in emissions reductions from affected sources as required by section 111(d) and EPA's implementing regulations.

Under the final CPP regulations, $CO_2$ control measures can earn one ERC for every megawatt hour of actual energy generated or saved, *provided* that the megawatt hour has "zero associated $CO_2$ emissions":

> § 60.5790 What must I do to meet my plan obligations?
>
> (2) Your plan must specify that an ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if the ERC meets the requirements of paragraphs (c)(2)(i) through (iv) of this section.
>
> (ii) An ERC must represent one MWh of actual energy generated or saved *with zero associated $CO_2$ emissions*.[183]

Likewise, in the preamble to the final CPP rule, EPA describes an ERC as "a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO2 emissions."[184]

$CO_2$ emissions are indisputably "associated" with biomass combustion. When an EGU burns biomass, it emits $CO_2$ into atmosphere—unless it uses CCS to capture 100 percent of its carbon emissions. Biogenic $CO_2$ emissions are real and undeniable: they will have an actual, physical impact on the atmospheric concentration of $CO_2$ and, consequently, on global climate change. Emitting biogenic $CO_2$ is like incurring a debt: the possibility that the debt might be eventually paid off makes it no less consequential in the interim. $CO_2$ emissions associated with biomass combustion are real regardless of whether they are eventually offset by future regrowth or by avoided decomposition, and they are real regardless of whether regulators are authorized to quantify that offset and credit it against emission reduction requirements. Simply put, biomass combustion has "associated $CO_2$ emissions" and that disqualifies it from earning ERCs.

The requirement that an ERC must represent one MWh of actual energy generated or saved with zero associated $CO_2$ emissions is carried over to the proposed FP/MTR:

> § 62.16420 What emission standards and requirements must I comply with?
>
> (c) $CO_2$ emission standard requirements … (2) An ERC qualifies for the

183 80 Fed. Reg. at 64,949 (emphasis added).

184 *Id*. at 64,834.

> compliance demonstration specified in paragraph (c)(1) of this section if it: … (ii) Represents one whole MWh of actual energy generated or saved *with zero associated carbon dioxide emissions*[.][185]

Although Commenters urge EPA not to finalize a rate-based plan in the FP or the MTR, as set forth in section III of these comments, if EPA nevertheless does so, the final FP/MTR must include this definition of ERCs, including the requirement that ERC-qualified energy must be "generated or saved with zero associated carbon dioxide emissions," so as to guarantee the legitimacy of ERCs and to ensure consistency across different elements of EPA's power plant carbon regulations (CPP, FP, MTR).

The regulatory requirement that restricts ERCs to measures that that have "zero associated carbon dioxide emissions" is also consistent with CAA Section 111(d). EPA cannot include biomass combustion in the list of presumptively eligible control options because biomass combustion simply does not reduce $CO_2$ emissions in a way that is cognizable under section 111. Section 111 focuses on stationary sources and the pollution emitted from those sources; it does not authorize EPA to create trading schemes that allow otherwise unlawful offsets of a source's actual stack emissions due to reductions that are achieved only outside the interconnected electric system and during the distant future. Consequently, because sources that burn biomass emit *more* $CO_2$ per unit of energy generated, and in the time period for compliance, than sources that burn fossil fuels, biomass combustion cannot constitute an "emissions reduction" under Section 111.

The only way to credit biomass combustion with any reduction in GHG emissions is to use a lifecycle analysis that estimates net emissions over some extended timeframe. But EPA does not identify any CAA authority that would allow it to conduct a lifecycle analysis under Section 111, nor can it as no such authority exists. Congress has demonstrated elsewhere in the Clean Air Act that when it intends for EPA to regulate on the basis of lifecycle emissions, it transmits that authority clearly.[186]

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[185] 80 Fed. Reg. at 65,091-92 (emphasis added); *see also id*. at 64,990 ("An ERC is a tradeable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated $CO_2$ emissions.").

[186] *See* 42 U.S.C. § 7545 (o)(1)(B), (D), (E), (H) (requiring certain liquid biofuels to achieve reductions in "lifecycle greenhouse gas emissions" as compared to petroleum-based fuels, and defining lifecycle greenhouse gas emissions as "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.").

2. EPA lacks authority to regulate "$CO_2$ levels in the atmosphere" under section 111 of the CAA.

EPA seeks comment on whether the combustion of certain pre-approved types of biomass—called "qualified biomass—can be used to generate ERCs "under the rate-based federal plan [and] also potentially apply to eligible generation under the proposed mass-based model trading rule allowance set-aside and to the calculation of covered emissions for affected EGUs that are co-firing biomass."[187] The Agency defines "qualified biomass" as "biomass feedstock that is demonstrated as a method to control increases of $CO_2$ levels in the atmosphere."

EPA simply is not authorized by section 111(d) to approve emission control measures based on their ability to "control increases of $CO_2$ levels *in the atmosphere*." Rather, as the U.S. Court of Appeals for the D.C. Circuit made clear in *Potomac Electric Power Co. v. EPA*, 650 F.2d 509 (D.C. Cir. 1981) ("PEPCO"), the NSPS provisions of the Clean Air Act are squarely focused on affected sources and their emissions, not on the impact those emissions have on some broader context:

> [B]ecause the purpose of the PSD program is to preserve existing air quality in those portions of the country where the air is now cleaner than the National Ambient Air Quality Standards require, the emphasis in that program should be upon the net emissions from an entire plant resulting from construction or modification of one or more emitting sources within the plant. The NSPS regulations, on the other hand, require the use of the best demonstrated pollution control technology in the construction or modification of a pollutant-emitting facility without regard to the effect the emissions from that facility will have on overall air quality. It is therefore appropriate in the NSPS program for the EPA to focus on the 'affected facility' to which the NSPS will be applied and in which the best demonstrated technology must be incorporated.

*PEPCO*, 650 F.2d at 518.

EPA acknowledges the statutory focus on affected facilities elsewhere in its power plant carbon rulemakings. According to the Agency, "The purpose of [the CPP] is to protect human health and the environment by reducing $CO_2$ *emissions from fossil fuel-fired power plants* in the U.S.,"[188] and approvable CPP measures must "control $CO_2$ *emissions from affected sources*."[189] Because the $CO_2$-levels-in-the-atmosphere criterion does not ensure that the implementation of the CPP will reduce $CO_2$ emissions from affected EGUs (in fact, biomass combustion will

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[187] 80 Fed. Reg. at 64,995/3.

[188] *Id*. at 64,662 (emphasis added).

[189] *Id*. at 64,784 (emphasis added).

*increase* their $CO_2$ emissions), it contradicts section 111(d) of the Act, EPA's characterization of its general authority under CAA section 111(d), and the stated purpose of EPA's rule. [190]

Moreover, assuming arguendo that section 111(d) did authorize EPA to regulate affected EGUs on the basis of lifecycle emissions (it does not), the use of most types of forest-derived biomass would not result in a net reduction during the CPP compliance years of 2022-2030.[191] Accordingly, EPA cannot lawfully allow biomass combustion to serve as a compliance option unless it results in zero associated emissions during the compliance year or prior years.

3. Biomass-based compliance contradicts EPA's prohibition against the borrowing of future ERCs or allowances

The theory behind biomass-based compliance is that future emissions reductions (due to plant growth or the avoided decomposition of biomass) can be relied upon to excuse current emissions. In addition to having no foundation in section 111(d), this approach contradicts language in the final CPP that prohibits states from "borrowing" ERCs and allowances from future periods to meet current compliance obligations.[192] EPA therefore cannot allow EGUs to comply with the requirements of the CPP on the basis of reductions that may (or may not) be achieved in the future.

4. Biomass combustion does not meet the eligibility criteria for ERCs described by EPA for the CPP FP

The proposal specifies several kinds of RE as eligible for ERCs in states that are subject to a FP:

> § 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs?
>
> (a) ERCs may only be issued to an eligible resource that meet each of the requirements in paragraphs (a)(1) through (4) of this section. All categories of resources other than on-shore utility scale wind, utility scale solar photovoltaics, concentrated solar power, geothermal power, nuclear energy, or utility scale hydropower, and all provisions of this subpart relating to such resources, are not available or applicable in States where this subpart has been promulgated as a federal plan pursuant to section 111(d)(2) of the Act.

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[190] EPA's "reducing $CO_2$ levels in the atmosphere" concept also contradicts the final CPP regulations which do not permit borrowing future emissions reductions for current year compliance, insofar as that is exactly what the test boils down to for the affected facility at which compliance must be measured. *See supra* notes 167 and 178.

[191] *See supra* note 184.

[192] 40 C.F.R. § 60.5790(c)(4), 80 Fed. Reg. at 64,949/3 (prohibiting affected EGUs from borrowing future ERCs to meet compliance obligations under a rate-based plan); 40 C.F.R. § 60.5815 80, Fed. Reg. at 64,951-952 (prohibiting affected EGUs from borrowing future allowance to meet current reduction obligations under a mass-based plan).

The list of ERC-eligible resources does not include biomass combustion, nor should it. For a range of reasons detailed in this section, Commenters support EPA's decision to exclude biomass combustion from the list of ERC-eligible energy systems in a rate-based FP. (For similar reasons outlined in section IX.c.v.2, below, EPA should also confirm that biomass combustion is ineligible for RE allowance set-asides in a mass-based FP and/or MTR).

In its proposal, EPA lists several criteria used by the Agency to justify the issuance of ERCs to wind, solar, geothermal, and hydropower systems. Biomass combustion does not make the list of "specific categories of RE resources [that] are eligible to be issued ERCs" because it fails to meet each of the four criteria identified by EPA and described in subsections a. though d. below.

a. Even if biomass combustion were a lawful compliance option, biomass combustion does not "have the ability to provide data from a revenue quality meter" in order to demonstrate emission reductions, and biomass EGUs cannot "use their existing metering infrastructure to quantify generation and submit it for ERC issuance."

In its proposal, EPA requires that ERC-eligible technologies "have the ability to provide data from a revenue quality meter" in order to demonstrate the generation of carbon-free electricity.[193] EGUs that burn forest biomass cannot meet this criteria, because the $CO_2$ reduction attributed to biomass combustion is based on modeled projections of forest growth and other complex natural systems (at best) or unsupported assumptions about carbon neutrality (at worst). The only relevant data that a biomass-burning EGU can reliably measure are the emissions of $CO_2$ from its stack, which will be higher than the $CO_2$ emissions from an otherwise identical coal- or gas-burning EGU.

Similarly, biomass combustion fails to meet EPA's criteria that restricts ERC eligibility to technologies that "provide the simplest and most timely path for EM&V implementation under a FP, because they can use their existing metering infrastructure to quantify generation and submit it for ERC issuance."[194] The process of showing a net reduction in $CO_2$ emissions from biomass combustion—especially when forest-derived woody biomass is burned—requires complicated modeling that is neither simple nor conducive to timely compliance

[193] 80 Fed. Reg. 64,994/2.

[194] *Id*. at 64,994/2-3.

demonstrations.[195]

b. Even if biomass combustion were a lawful compliance option, biomass combustion may not "be able to deploy on an economic basis during the compliance period."

Per EPA, RE technologies should only be eligible for ERCs if they are "expected to be able to deploy on an economic basis during the compliance period."[196]

According to an analysis conducted by EPA, however, it is unlikely that facilities that co-fire biomass will meet this requirement. In its 2014 technical support document on *GHG Abatement Measures*, EPA wrote:

> This analysis indicates that while the co-firing of biomass with coal is technically feasible as a means of reducing the coal-based $CO_2$ emission rate due to the substitution of biomass for coal, it generally has limited economic feasibility due to the generally higher cost of energy from biomass as compared to coal. This general finding largely explains the very limited amount of biomass co-firing currently practiced in the U.S.[197]

EPA references a "reasonably representative" study by Maryland that found that biomass co-firing is not an economic method of emissions control at a fossil fuel-fired EGU *even if* the unit's biogenic $CO_2$ emissions are completely ignored.[198] These analyses and others[199] suggest that biomass co-firing is unlikely to be deployed on an economic basis during the CPP compliance period.

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[195] EPA has worked with its Science Advisory Board on a framework for assessing biogenic $CO_2$ since 2011 but has not yet finalized an accounting approach. Moreover, it is clear from the most recent draft that the Framework is not being designed to meet the specific requirements of the CPP and Section 111(d). EPA, *Framework for Assessing Biogenic $CO_2$ Emissions from Stationary Sources* 2 (2014) ("Biogenic $CO_2$ Framework") ("EPA has not yet determined how the framework might be applied in any particular regulatory or policy contexts or taken the steps needed for such implementation.")

[196] *Id*. at 64,994/2.

[197] EPA, *Technical Support Document: GHG Abatement Measures* 6-11 – 6-12 (2014).

[198] *Id*. (*citing* The Potential for Biomass Cofiring in Maryland, Maryland Department of Natural Resources, at 53 (Mar. 2006) *available at*: http://esm.versar.com/pprp/bibliography/PPES_06_02/PPES_06_02.pdf .

[199] *See, e.g*., U.S. EIA, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014 at 7 (Table 2) (Apr. 2014) (finding a levelized cost of electricity of $92.30 to $122.60 per MWh for biomass generation depending on regional variations; this is slightly higher than the levelized cost of advanced nuclear generation and advanced NGCC generation with CCS—both of which produce MWh with zero associated $CO_2$ emissions) *available at*: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm .

c. Even if biomass combustion were a lawful compliance option, EM&V for biomass combustion cannot be implemented "in a way that is rigorous, straightforward, [or] widely demonstrated."

The CPP must achieve $CO_2$ emissions reductions that are "quantifiable, non-duplicative, permanent, verifiable, and enforceable."[200] In order to preserve the integrity of its regulatory system, EPA requires the use of EM&V methods that can be implemented in a "in a way that is rigorous, straightforward, [and] widely demonstrated."[201] The difficulty and complexity of accounting for all emissions associated with biomass fuel use preclude any quantification of "biomass ERCs" with the same level of reliability, precision, and transparency that EPA references to support the issuance of ERCs to wind, solar, geothermal, and hydropower systems. The currently available methods for monitoring and verifying net $CO_2$ emissions from biomass combustion are experimental, non-empirical, and burdened with questionable assumptions. Biogenic emissions accounting depends on modeled projections of complicated systems characterized by high levels of uncertainty. There is no consensus among regulators, generators, and other stakeholders about how to best assess the lifecycle $CO_2$ emissions associated with biomass combustion, much less about an EM&V system that would qualify as rigorous or straightforward or widely demonstrated.

d. Even if biomass combustion were a lawful compliance option, EPA's approach to biogenic emissions accounting is incompatible with "an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions."

The challenges associated with biogenic $CO_2$ emissions accounting will also frustrate EPA's interest in "an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions in the time frame allowed by the federal plan."[202] EPA has compounded this problem by failing to explain what kind of accounting process would be required of states that might attempt to use biomass combustion to comply with their $CO_2$ reductions obligations under the CPP.[203, 204]

[200] 80 Fed. Reg. at 64,833.

[201] *Id*. at 64,995/1.

[202] *Id*. at 64,994/3.

[203] EPA has failed to provide a practical and legally valid accounting process for biogenic $CO_2$ emissions even though the Agency has already issued proposed emission guidelines for new and existing EGUs, final emission guidelines for both source categories, a proposed FP/MTR for existing EGUs, and dozens of technical support documents, all while being engaged in a protracted process with the Science Advisory Board ("SAB") to develop a

If EPA allows states to develop and submit their own accounting methods for determining which types of biomass combustion can generate ERCs, the resulting patchwork of divergent (and possibly contradictory) analyses will substantially undermine the Agency's interest in "an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions." Moreover, EPA's hands-off approach increases the possibility of a "race to the bottom" among states hoping to attract biomass-based generation to their states. Consequently, it is unlikely at best that an EM&V method for biomass combustion will be implemented "across many jurisdictions" in a streamlined manner. In fact, EPA's approach throughout this rulemaking has contributed to the unfortunately likelihood that different states will develop different lifecycle analyses, thereby frustrating the Agency's legitimate preference for broadly applicable, readily deployed EM&V measures.

iv. *Even if biomass combustion were a lawful compliance option, reductions attributed to biomass combustion are functionally indistinguishable from forestry sector offsets, which are ineligible for ERCs.*

Burning biomass instead of coal or natural gas does not reduce the amount of $CO_2$ an EGU emits to the atmosphere; rather, it increases the unit's $CO_2$ emissions per kilowatt generated. If any reduction in atmospheric $CO_2$ levels occur when standing trees are burned as fuel, it happens because the forest from which the biomass was harvested regrows in such a way that at some future point the amount of carbon in the forest after the harvest exceeds the pre-harvest level. This is an offset according to the definition used by the World Resources Institute and other authorities: the carbon absorbed from the atmosphere during the regrowth of the harvested forest is being used to compensate for the $CO_2$ that the EGU emitted to the atmosphere when it burned wood harvested from the forest.[205]

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*Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources* ("*Biogenic $CO_2$ Framework*") for biogenic carbon emissions.

[204] EPA writes: "Information in the revised *Framework* and the second SAB peer review process, including stakeholder comments will assist EPA in assessing potential qualified feedstocks in federal plan applications." *Id*. at 64995/3. The *Framework* is poorly suited to that purpose, however. First, per EPA's instructions to the panel assembled by the SAB, the Framework was not designed to address the specific legal and practical requirements of section 111(d) or the CPP. *Biogenic $CO_2$ Framework* at 2. Second, as a result of EPA's insistence that the *Framework* not address any specific policy context, the most recent available draft version of the *Framework* appears to signal an openness to multi-decade analytic horizon when assessing the net emissions associated with biomass combustion. *Id*. at 33-38. As such, its analysis is functionally irrelevant to whether biomass combustion meets the requirement of section 111(d) or the CPP, under which emission reductions must be achieved no later than 2030.

[205] WRI, *The Bottom Line on Offsets* 1 (2010) (defining an offset as "a unit of carbon dioxide-equivalent ($CO_2e$) that is reduced, avoided, or sequestered to compensate for emissions occurring elsewhere") *available at*: http://www.wri.org/sites/default/files/pdf/bottom_line_offsets.pdf; *see also* Hines at 4.

Biomass combustion was also characterized as an offset scheme by Judge Brett Kavanaugh of the D.C. Circuit. In *Center for Biological Diversity v. EPA*, 722 F.3d 401 (D.C. Cir. 2013), which vacated EPA's attempt to exempt biogenic CO2 emissions from regulation under the Prevention of Significant Deterioration ("PSD") and Title V programs of the Clean Air Act, Judge Kavanaugh wrote in a concurrence that EPA decided not to apply PSD and Title V to biomass-burning facilities

> because it thinks that regrowth of plant life—and the resulting recapture of carbon dioxide—might 'offset' emissions of biogenic carbon dioxide. But the statute forecloses that kind of 'offsetting' approach because the statute measures emissions from stationary sources that 'emit' (or have the potential to emit) air pollutants.

722 F.3d at 413-14 (Kavanaugh, J., concurring)

Judge Kavanaugh's point is at least equally applicable to Section 111(d), which requires stationary sources to achieve "standard of performance" defined in terms of an "emission reduction" from regulated sources.[206] Consistent with Judge Kavanaugh's concurrence in *Center for Biological Diversity*, EPA's proposed FP regulations (as well as the final CPP) prohibit the use of offsets—and specifically forest offsets—as a compliance measure:

> § 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs?
>
> (c) ERCs may *not* be issued to any of the following: … (3) Measures that reduce $CO_2$ emissions outside the electric power sector, *including GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors*, direct air capture, and crediting of $CO_2$ emission reductions that occur in the transportation sector as a result of vehicle electrification[.][207]

*v. Biomass combustion at affected EGUs cannot be used to comply with mass-based plans.*

Most of the discussion in the proposal about the treatment of biomass combustion occurs in the preamble section that addresses a potential rate-based implementation approach (Part IV),

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[206] 42 U.S.C § 7411(b), (d).

[207] 80 Fed. Reg. at 65,094 (emphasis added); *see also id*. at 64,904/3 (prohibiting states from complying with final emission guidelines based on "GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors").

but EPA also raises the possibility of biomass-based compliance in a mass-based implementation approach (Part V of the preamble). Specifically, EPA requests comment on the following approach:

> [F]or purposes of compliance with the proposed mass-based federal plan trading program, the affected EGU would need to hold allowances equal to its emissions less the emissions attributed to the co-fired qualified biomass; such an approach would reduce the number of allowances the affected EGU would need to hold to demonstrate compliance.[208]

EPA must not finalize this approach because, as described above in sections IX.c.iii.1-2, biomass combustion does not result in emissions reductions from affected EGUs during the compliance period (if ever), as required by both section 111(d) and EPA's implementing regulations; it cannot meet the eligibility criteria that EPA has established for ERCs; and it constitutes an emissions offset scheme, and is therefore disqualified from generating ERCs. Each of these problems are applicable to a mass-based plan and the issuance of set-aside allowances.

Instead of exempting emissions from the combustion of "qualified biomass" (or any other form of biomass), EPA must ensure that each and every affected EGU (whether or not it burns biomass) holds enough allowances to cover its total actual compliance period $CO_2$ emissions, and the Agency must prohibit the issuance of allowance set-asides to any biomass-burning EGU that does not reduce emissions in the compliance year or prior years.

1. An affected EGU must hold allowances equal to its total actual $CO_2$ emissions, regardless of whether it co-fires biomass.

EPA cannot finalize a regulatory approach (either FP or MTR) that would essentially ignore the biogenic $CO_2$ emissions from an EGU that is co-firing "qualified biomass."[209] As explained in section IX.c.ii.2 of these comments, the $CO_2$-levels-in-the-atmosphere criterion created by EPA's definition of "qualified biomass" does not ensure that the implementation of the CPP will reduce $CO_2$ emissions from affected EGUs (in fact, biomass combustion will *increase* $CO_2$ emissions). Furthermore, as is the case with ERCs, states cannot "borrow" allowances from future periods to meet current compliance obligations.[210]

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[208] 80 Fed. Reg. at 65,012/3.

[209] *Id*. at 65,012/3.

[210] 40 C.F.R. § 60.5815 What are the requirements for State allocation of allowances in a mass-based program? (a) For a mass-based trading program, a State plan must include requirements for $CO_2$ allowance allocations according to paragraphs (b) through (f) of this section … (f) *Provisions not allowing any borrowing of allowances from future compliance periods by affected EGUs*. 80 Fed. Reg. 64,951-952 (emphasis added).

EPA's suggested approach therefore contradicts section 111(d) of the Clean Air Act (which requires reductions from the affected sources), as well as EPA's characterization of its general authority under CAA section 111(d) and the stated purpose of the CPP.

2. Biomass combustion is ineligible for RE set-asides.

Consistent with the legal and practical concerns described above, EPA's proposed regulatory text excludes biomass combustion from the list of energy technologies that are eligible for set-asides in a mass-based FP:

> § 62.16245 How are set-aside allowances allocated?
>
> (a)(2) Eligible renewable energy capacity. To be eligible to receive renewable energy set-aside allowances, an eligible resource must meet each of the requirements in paragraphs (a)(2)(i) through (v) of this section. Any resource that does not meet the requirements of paragraphs (a)(2)(i) through (v) of this section *cannot receive set-aside allowances*.
>
> (i) The resource must be a renewable energy resource that falls into one of the following categories of resources: onshore utility scale wind, solar, geothermal power, or utility scale hydropower.[211]

For the reasons provided above, EPA should finalize the exclusion of biomass combustion in the list of technologies eligible for set-aside allowances. The Agency must also remove the provision that would allow biomass-based compliance in a mass-based MTR.

vi. *Mandatory elements of any biomass combustion-based compliance pathway.*

EPA "requests comment on options for how EGUs would demonstrate that feedstocks meet the requirements that to be accepted as a pre-approved qualified biomass feedstock[]."[212] Assuming the lawfulness of a biomass compliance pathway (which we do not, as discussed above), any such compliance pathway must at a minimum ensure that:

1. Each ERC allowance or set-aside must "represent[] one whole MWh of actual energy generated or saved with zero associated carbon dioxide emissions" during the compliance year or prior years.

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[211] 80 Fed. Reg. at 65,098 (emphasis added).

[212] *Id*. at 64,996/1.

2. Any allowance set-asides or ERCs tied to biomass combustion must be generated on the basis of reductions of $CO_2$ emissions "from affected sources" per Section 111(d), rather than on the basis of purported capacity to "control increases of $CO_2$ levels in the atmosphere."
3. Any reductions attributed to biomass combustion must be fully achieved either during or before the year in which compliance is required under the CPP compliance period, regardless of the state or region in which the affected EGU is located.[213]

*vii. Conclusion: Biomass combustion cannot be eligible for compliance with FP or MTR*

EPA requests comment on whether biomass combustion should be eligible for ERC issuance under a rate-based FP, as a basis for reducing the mass emissions attributed to a co-firing EGU under a mass-based FP, or as a method of compliance under the MTR. Commenters oppose each of these approaches on legal and administrative grounds. For the reasons set forth in section III of these comments, Commenters also oppose the inclusion in the FP or the MTR of *any* rate-based plan.

Biomass combustion does not reduce the amount of $CO_2$ emitted from the electric generating sector, nor can it generate MWh of electricity that are "associated with zero $CO_2$ emissions." EPA has not (and cannot) identify any authority under Section 111(d) to regulate a facility on the basis of its lifecycle $CO_2$ emissions instead of its actual, real-time $CO_2$ emissions. Biomass combustion also fails to meet the ERC and set-aside eligibility criteria that EPA has proposed, in large part because none of the available methods for tracking, allocating, and regulating biogenic $CO_2$ emissions are "rigorous, straightforward, and widely demonstrated."

Commenters therefore support the EPA's proposal to exclude biomass combustion from the list of eligible emission reduction measures for ERC generation under a rate-based FP. Biomass should not be "an eligible measure for rate-based crediting" in the final FP.[214] Likewise, Commenters believe that biomass combustion should be ineligible for set-asides under a mass-based FP.

EPA also requests comment on "an option for biomass treatment" in which it would "specify a list of pre-approved qualified biomass fuels."[215] The list would potentially be used by

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[213] *See supra* note 184.

[214] 80 Fed. Reg. at 64,995/1.

[215] *Id*. at 64,995/3.

regulators when assessing compliance with rate-based FP or a mass-based MTR, and when calculating covered emissions at co-firing EGUs.[216] More specifically, EPA "requests comment on options for how EGUs would demonstrate that feedstocks meet the requirements to be accepted as a pre-approved qualified biomass feedstock[]."[217] Commenters believe that any measure that allows the use of biomass combustion to meet the $CO_2$ reduction requirements of Section 111(d) must ensure that biomass-related energy generation has zero associated CO2 emissions, that biomass combustion results in reductions that are achieved at affected sources, and that any reductions tied to biomass combustion must occur within the compliance year or in prior years. The process of ensuring that these requirements are met at a biomass-burning facility is highly fact-dependent and requires a facility-specific analyses. Accordingly, EPA should not develop a pre-approved list of biomass feedstocks that qualify for ERCs or set-asides.

## X. Conclusion

EPA should promulgate a FP and MTR that incorporates a mass-based trading system—and only a mass-based trading system—that maintains the integrity of the BSER-based performance standards, that will produce the level of quantifiable, verifiable, non-duplicative, permanent and enforceable emission reductions promised by the CPP, and that will provide adequate protection against leakage.

Respectfully submitted,

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[216] *Id*.

[217] *Id*. at 64,996/1.