NRDC

March 15, 2016

Dear RGGI Member States:

Thank you for the opportunity to comment on the modeling assumptions and considerations for establishing RGGI's post-2020 carbon cap and compliance under EPA's Clean Power Plan (CPP). Our comments here focus on the impact of bioenergy and the RGGI modeling sensitivities to varying assumptions about biomass. Given the continuing importance of RGGI in the states' efforts to reduce carbon pollution from the region's power sector and in demonstrating the states' compliance with the CPP, we believe that a full understanding of the effects of biomass is essential.

NRDC has commented extensively on the role of biomass energy in the context of the Clean Power Plan, most recently in comments on the draft Federal Plan and Model Trading Rule. Our position, emphatically, is that biomass cannot be treated categorically as "carbon neutral." Specifically, forest-derived biomass cannot be treated as a zero-carbon fuel because its stack emissions are higher than coal, and these emissions typically persist in the atmosphere for many decades – well beyond the compliance periods for the CPP and other timeframes to address climate change.[1] Therefore, burning high-carbon biomass risks eroding the gains made under the CPP program – and under RGGI. We have attached our comments to the U.S. Environmental Protection Agency on the draft Federal Plan.

Highly relevant to the RGGI region is the *Manomet Study*,[2] commissioned by the State of Massachusetts to determine the "carbon debt" associated with burning forest-derived fuels. The study calculated cumulative emissions from burning trees and forest harvest residues assuming the bioenergy emissions are offset over time by forest regrowth and/or avoided decomposition. The study then compared biomass emissions to cumulative emissions from fossil-fired boilers, and calculated how long it would take for net bioenergy emissions to become equivalent to emissions from burning fossil fuels.

The *Manomet Study* found that it would take more than 45 years to offset the emissions from a boiler burning "mixed" wood (i.e., some residues, some whole trees) to the point of equivalency with emissions from a coal-fired power plant. The carbon debt payoff time relative to a natural

[1] Mitchell, S., Harmon, M., and O'Connell, K., Carbon Debt and Carbon Sequestration Parity in Forest Bioenergy Production, *GCB Bioenergy*, May, 2012; Colnes, A., et al., *Biomass Supply and Carbon Accounting for Southeastern Forests*, The Biomass Energy Resource Center, Forest Guild, and Spatial Informatics Group, February 2012, *available at* www.biomasscenter.org/images/stories/SE_Carbon_Study_FINAL_2-6-12.pdf; Hagan, J., *Biomass Energy Recalibrated*, The Manomet Center for Conservation Sciences, January 2012, *available at* http://magazine.manomet.org/winter2012/biomass.html.

[2] Walker, T., et al. 2013. Carbon Accounting for Woody Biomass from Massachusetts (USA) Managed Forests: A Framework for Determining the Temporal Impacts of Wood Biomass Energy on Atmospheric Greenhouse Gas Levels, *Journal of Sustainable Forestry*, 32:1-2, 130-158.

gas plant is more than 90 years. Other published, peer-reviewed studies have come to similar conclusions regarding the long periods of time during which biomass energy generation increases atmospheric CO_2 concentrations relative to what otherwise would have occurred.[3]

Similarly, the New York State Department of Environmental Conservation acknowledges that biomass cannot be treated apriori as "zero carbon," and that eligible biomass needs to be assessed on a case-by-case basis:

> *…the Department* ***does not consider the implicit carbon sequestration of renewable plant growth assumed for biomass to be a sufficient claim of carbon neutrality****. While some biomass production methods may produce low carbon intensity or possibly "carbon neutral" biomass, many do not, especially when taking into account the emissions associated with the growing, harvesting, processing, and combusting of the biomass. In some cases, such as in the generation of electricity alone, biomass may actually be more carbon intense than fossil fuels, resulting in greater GHG impacts, at least in the short term. The premise of biomass carbon neutrality, or low carbon intensity, cannot hold true over time without adequate future re-growth and attendant carbon sequestration to offset the CO_2 emissions from biomass combustion*.[4] (Emphasis added).

Recommendation

The RGGI states should clarify what their modeling assumptions are regarding carbon emissions from bioenergy, and explain the states' rationale for these assumptions. As explained above, there is considerable risk to treating biomass categorically as carbon neutral. We therefore believe it is incumbent upon RGGI to determine the degree to which bioenergy carbon emissions may generate increases in carbon flux under the RGGI program.

We strongly recommend that the RGGI Program Review include modeling/analyses to determine the effect of bioenergy on the region's power sector emissions. Given that a "zero carbon" assumption is often an unreliable one, we recommend that the RGGI states' modeling/analyses include the following sensitivities: (1) an assumed CO_2 emissions rate for biomass that reflects the actual stack emissions at combustion (reflecting no discounting of emissions); and (2) an assumed CO_2 emissions rate for biomass that reflects a partial discounting of CO_2 emissions (reflecting an emissions rate between zero and the full stack emissions).

Sincerely,

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[3] Repo, A., et al., Sustainability of Forest Bioenergy in Europe: Land-use-related Carbon Dioxide Emissions of Forest Harvest Residues, *GCB Bioenergy*, March 2014; Ter-Mikaelian, M., et al., Carbon Debt Repayment or Carbon Sequestration Parity? Lessons from a Forest Bioenergy Case Study in Ontario, Canada, *GCB Bioenergy*, May 2014.

[4] NYSDEC, DAR-12 Response to Comments Summary, *available at* http://www.dec.ny.gov/energy/70483.html.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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	)))))	**Docket No. EPA–HQ–OAR–2015–0199** *Via email and electronic filing* *January 21, 2016*

Thank you for accepting these comments on the proposed *Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed On Or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule*, 80 Fed. Reg. 64,966 (October 23, 2016).

We submit these comments on behalf of the Natural Resources Defense Council (NRDC). NRDC is a national nonprofit environmental organization representing more than two million members and online activists. NRDC uses law, science, and the support of its members to ensure a safe and healthy environment for all living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

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I. Introduction

We strongly support the Clean Power Plan and urge the Environmental Protection Agency to adopt a federal plan and publish model state plans that ensure the greatest possible reduction in emissions of dangerous carbon pollution. The Clean Power Plan is firmly grounded in the Clean Air Act. It is also a key part of our country's national commitment pursuant to the historic Paris Climate Agreement reached last month. Effective implementation of the Clean Power Plan is important both to reduce domestic carbon pollution and also because strong domestic action is a prerequisite to United States' international leadership on climate. Indeed, both the Clean Power Plan and the Paris Climate Agreement will need to be further strengthened over time in order to avoid the worst impacts of climate change.

NRDC appreciates this opportunity to provide comments on EPA's proposed federal plan requirements and model trading rules.

Although we encourage states to promulgate their own state plan, and expect that the majority of states will do so, EPA must be prepared to implement a strong and effective federal plan where states elect not to develop plans or propose plans that are not satisfactory. Likewise, as states begin the work of considering state plan options and developing their plans, model rules from EPA will serve as a helpful resource and provide important guidance on approvable state plan designs.

This comment document roughly follows the organization of EPA's proposed rule: in Section II, we provide general comments on EPA's overall proposed federal plan approach; in Section III we offer more specific feedback on the proposed federal plan structure; in Sections IV and V we provide detailed comments on EPA's proposed rate-based and mass-based implementation approaches; and in Section VI we offer comments on the Clean Energy Incentive Program.

II. General Comments

A. EPA's Proposed Federal Plan Approach

We urge EPA to adopt a federal plan that will achieve the environmental outcome contemplated by the best system of emissions reductions and be administratively straightforward. If and when the implementation of a federal plan becomes necessary, we encourage EPA to consider the mix of approaches that states have selected for their state plans and evaluate whether the federal plan should be consistent with the state plan designs being implemented in the surrounding states, with a particular focus on the electric market region a state is primarily within.

Mass-based compliance plans generally offer a well-known and effective compliance option. But as EPA has recognized, a mass-based plan that covers only existing power plants can fail to achieve the emission reductions set forth in the best system of emission reduction if electricity generation shifts from existing plants to new power plants that are not required to submit allowances, rather than to lower-emitting existing plants and to zero-emitting renewable generation. As we discuss in detail in Section V, EPA's proposed mass-based federal plan approach fails to effectively address emissions leakage to new sources. Although we have a preference for a mass-based approach, we cannot fully endorse a mass-based federal plan approach that covers only existing sources until EPA has developed an effective method for addressing leakage.

The federal plan should be finalized quickly following a determination that a state plan is not approvable or has not been submitted on schedule. We recommend that, before the federal plan is implemented in a state, EPA establish an opportunity for the state and other stakeholders to provide input on the plan. If EPA proposes a mass-based federal plan, EPA should allow the state the opportunity to opt-in new sources and—if new sources are included—request an alternative allowance distribution method. If EPA chooses a rate-based approach, EPA should allow the state the option of developing and implementing an EPA-compliant evaluation, monitoring and verification program for energy efficiency.

B. Proposed Model Trading Rules

We encourage EPA to finalize a variety of model trading rules as guidance to the states. It is essential that EPA provide states strong and clear guidance for both rate and mass-based approaches even if only one will be finalized as a federal plan.

We recommend EPA provide complete model regulatory text for all four "streamlined" approaches identified in the final emission guidelines: subcategory-specific emission performance rates, state-wide rate-based CO_2 goal, existing source only mass-based CO_2 goal with a strong leakage solution, and existing plus new mass-based emissions limit.

III. Federal Plan Structure to Achieve Reductions

A. General

EPA should develop a tracking and trading system for both mass-based and rate-based approaches for states to use if they do not already have an equivalent program in place that meets EPA's criteria (e.g. RGGI and CA). EPA should clearly state the criteria necessary for approval of existing equivalent programs. States seeking to use equivalent programs should indicate so in state plan submittals, and the EPA should review and approve these equivalent programs.

B. Interstate Trading and Linkage

Federally-Enforceable Backstop

EPA should allow for existing state and regional carbon market programs to link with the broader trading program. However, EPA should require states that participate in these existing markets to develop a federally-enforceable backstop to ensure that their electric sector does not exceed the EPA 111(d) budgets. States that participate in existing carbon market programs could include a backstop as part of a state measures plan submittal.

As discussed in detail below, the federally-enforceable backstop should include strong leakage provisions. States should be able to develop a federally-enforceable backstop on both existing and new sources, and include this broader backstop as part of the state plan submittal.

EPA should require that the backstop be designed to reduce the emissions limit (tons) placed on affected EGUs by the amount of excess emissions generated prior to the implementation of the backstop. This will ensure that the environmental integrity of the mass-based standard is maintained and that cumulative state emissions are not greater than in the final rule.

Addressing Potential Leakage from Imports

EPA should establish provisions preventing emissions leakage from mass- and rate-based programs through increases in imported power from Canada and Mexico. For example, if U.S. states in the Southwest have a mass-based program and are increasing the amount of imported power from Mexico (relative to the 2012 baseline), they should be required to hold allowances for the emissions associated with that power. A possible approach EPA could follow is that used by California's cap-and-trade system. Such provisions will not be necessary if the Canadian or Mexican state or province has an equivalent CO_2 constraint on the power sector.

EPA should also add a similar requirement on mass-based states for power imported from new, emitting facilities in rate-based states. This would help ensure that there is no leakage arising in cases when new generation in a rate-based state is supplying other states.

Market Monitor

EPA should work with other financial regulators and FERC to explore the benefit of a market monitor. The monitor would be tasked with overseeing the allowance/ERC markets, as well as auctions, and identifying any attempts by market participants to exercise market power, collude, or otherwise participate in anti-competitive behavior and price manipulation. This will help ensure that the allowance/ERC markets remain competitive.

C. Affected EGUs

EPA requests comment on an alternative compliance pathway that could be made available to units under a mass-based approach. We believe that this approach is not necessary. The administrative requirements of complying with a market-based rate- or mass-based plan do not justify such an option. Operators of even small power plants are sophisticated enough that compliance will not be a problem.

A second possible rationale for this approach may be an effort to counter a possible incentive to continue to operate those plants if they receive an allocation based on their historic emissions and if those plants would lose that allocation at some point following retirement. This retirement disincentive would only occur if allowances are allocated based on historic emissions. As we explain in section V.D., we oppose allocation of allowances based on historic emissions. Such an approach simply rewards the most polluting power plants.

If EPA or a state does decide to pursue this approach, it is important to ensure that the emissions outcome is not weakened. Under both the rate-based and existing-only mass-based approaches, an emissions limitation, without more, will not necessarily achieve the same overall environmental outcome as compliance with the rate-based approach and best system of emission reduction. Specifically, a power plant's emissions and generation may be limited under an alternative compliance program, but if that power plant's generation is replaced by new fossil generation, rather than zero-emitting clean energy resources, overall emissions will increase. Accordingly, EPA must ensure that, if any state adopts an alternative pathway approach for a power plant, the state plan includes provisions that will deliver equivalent emission reductions, including appropriate incentives for clean energy.

D. Compliance Schedule

We do not support additional time for compliance for any units, including small units. There is adequate time for all units to comply with this rule, and the trading EPA has built into both the rate- and mass-based approaches provides ample flexibility for plants.

Market liquidity and price discovery are good ideas, but the CEIP and early allocation or auction of the allowances from the first compliance period should be more than adequate liquidity and price information. There should be no borrowing from future compliance periods.

E. Addressing Reliability Concerns

NRDC agrees with EPA that the proposed federal plan will not create reliability problems and thus no additional reliability provisions are necessary. Indeed, additional unnecessary provisions could prove counterproductive by unnecessarily delaying compliance.

The proposed federal plan provides ample compliance flexibility to ensure that reliability is maintained at all times. As a market-based trading program, the federal plan will allow affected EGUs the opportunity to buy, sell, and bank emissions credits or allowances. Such a program does not restrict unit-level operational decision-making beyond requiring units to hold a sufficient number of tradable permits to cover emissions. This inherent operational flexibility will allow owners and operators to meet their compliance obligations while providing an uninterrupted supply of affordable and reliable electricity. While NRDC is confident that the proposed federal plan has been designed to ensure grid reliability, we do believe the final plan, like the final emissions guidelines, should allow revisions if reliability concerns arise, so long as these potential revisions do not affect the overall emissions reduction trajectory.

Federal and state energy and environmental regulators, regional grid operators, and utility and market participants have proven experience in responding promptly to changing circumstances and unforeseen grid reliability issues. In addition, the EPA, DOE, and FERC have agreed to coordinate efforts to ensure reliable electricity generation and transmission during the implementation of the final rule. These agencies' coordinated effort provides substantial oversight capacity to help anticipate and avoid any grid reliability problems that may arise.[1] Additionally, grid operators and planning authorities already have many tools to protect grid reliability. These tools include legally binding reliability standards, planning and operations practices, and market design. Low-carbon resources are abundant, renewable energy resources are cost-competitive with natural gas in many areas, and the grid can reliably handle much higher levels of renewable power than envisioned under the Clean Power Plan.[2]

FERC released guidance on modeling the Clean Power Plan on January 19, 2016 that will further help evaluate reliability.[3] The guidance establishes principles for grid operators to use when they study the Clean Power Plan, and it is equally relevant to reliability considerations with the federal plan. FERC's guidance will ensure that grid operators more accurately and transparently assess potential impacts, if any, of the federal and state plans, and take the necessary steps to address reliability issues before they occur.

The CEIP will provide for some allocation of allowances and ERCs before 2022, allowing for the creation of banked allowances prior to the first compliance period. While these banks of allowances and ERCs could further reduce reliability concerns, they are unnecessary to ensure reliability. In addition to the CEIP, states and EPA could also establish a reliability or cost containment reserve of allowances that

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[1] Declaration of Eric B. Svenson, Jr. at ¶¶ 31-36, *West Virginia v. EPA*, No. 15-1363 (D.C. Cir. Dec. 8, 2015), available at http://docs.nrdc.org/legislation/files/leg_15120902a.pdf.
[2] *Id*. at ¶¶ 39-40.
[3] FERC, *Staff White Paper on Guidance Principles for Clean Power Plan Modeling* (Jan. 19, 2016), available at http://www.ferc.gov/legal/staff-reports/2016/modelingwhitepaperAD16-14.pdf.

would be available for sale above a certain price point. But it is critical that any such reserve must utilize allowances from within the mass-based budget, and not be additional to it.

Accordingly, there is no reason to believe that the proposed federal plan requires a reliability safety valve. Unexpected emissions increases from plants needed for reliability purposes can be offset with allowances so that the overall emissions trajectory is preserved.

F. Worker Certification

We support worker certification and training associated with upgrades at EGUs and believe it should be encouraged but not required for other project and program types.

G. Remaining Useful Lives

EPA concludes that the federal plan adequately considers the "remaining useful lives" of facilities by allowing individual sources to demonstrate compliance with system-based emission standards through the use of market mechanisms. We support EPA's approach.

We reiterate what we wrote in NRDC's comments on the proposed Clean Power Plan:

> [I]n the context of the flexible, system-based approach that EPA has proposed, there is no need – indeed *no room* – for allowing a state to grant variances that breach the applicable target emission rate (or mass-based limit). The statute provides for recognizing existing sources' "remaining useful life," but it does not define the term or the procedure that must be used. EPA's 1975 regulations constructed a variance process, but that is not the only reasonable way to give effect to "remaining useful life." In fact, the flexible design of the proposed emission guideline for EGUs inherently accommodates the "remaining useful life" of individual units while preserving overall emission reductions.[4]

H. Administrative Appeals Process

NRDC supports EPA's proposed use of (and revision of) the regulations for appeals procedures set forth in 40 CFR part 78 to provide for the adjudication of certain disputes that may arise during the course of implementation of a federal plan. Such disputes could include decisions on an eligibility application for ERCs, decisions on accreditation of independent verifiers, decisions regarding the allocation of allowances from set-asides, or decisions regarding the allocation of allowances to affected EGUs. Designated representatives and other "interested persons" are eligible to file an appeal, and an appeal would be prerequisite to seeking judicial review.

[4] Natural Resources Defense Council, Public Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources 2-10 (Dec. 1, 2014), available at http://docs.nrdc.org/air/files/air_14120101b.pdf.

I. Consistency of Program Structure with Clean Air Act Authority

We agree with EPA's conclusion that the agency has legal authority to establish either of the proposed trading systems as a federal plan under CAA section 111(d)(2).

The federal government unquestionably has the authority to regulate pollution from power plants, in order to address the interstate and international health and environmental effects resulting from a business enterprise with a clear impact on interstate commerce. In some parts of the Clean Air Act, Congress has authorized EPA to regulate power plants directly, with no state role (for example, the regulation of hazardous air pollutants under CAA section 112, or the acid deposition control provisions of Title IV). In other parts of the Act, such as section 110 and 111(d), Congress employed a framework known as "cooperative federalism," under which EPA sets a performance target (a National Ambient Air Quality Standard under section 110; a performance standard reflecting the Best System of Emission Reduction under 111(d)), and the states are invited to regulate power plants as needed to meet that target. If a state elects not to do so, section 111(d)(2), like section 110(c), provides that EPA shall regulate those plants directly as necessary to meet the target.

EPA interprets section 111(d)(2) to provide the agency the same authority to prescribe a federal plan as it possesses under section 110(c). NRDC supports the view, as stated by EPA, that this authority includes setting federally enforceable emissions limits for power plants. We also support EPA's view that emissions trading is a lawful and appropriate form of federal "implementation" of a "standard of performance" under CAA section 111(d)(2). As EPA notes, emissions trading is expressly authorized in federal plans by CAA section 302(y), and is permissible under the more general language defining "performance standard" in section 111(a) as well as the agency's discretion under section 111(d).Finally, legal and administrative precedents for federal trading programs amply support EPA's decision to propose two forms of emissions trading as the method of implementation of the EGs in the federal plan.[5]

J. Treatment of Modified and Reconstructed Sources

EPA proposes that modified power plants will exit the 111(d) program and cease being subject to Clean Power Plan emission reduction obligations.[6] In the October 2015 proposal, EPA asserts that there are mechanisms available to "minimize disruption to state plans if" a power plant modifies and exits the 111(d) program.[7] EPA must identify these mechanisms and to ensure that they prevent the exit of a plant from weakening emission reductions achieved under the Clean Power Plan.

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[5] A recent analysis of prior Clean Air Act programs indicates the many prior programs that have also employed flexible market-based architectures. Richard L. Revesz et al., "Familiar Territory: A Survey of Legal Precedents for the Clean Power Plan," Institute for Policy Integrity Working Paper, December 4, 2015, available at http://policyintegrity.org/files/publications/FamiliarTerritory.pdf.

[6] EPA originally proposed that power plants that modify would remain subject to standards to 111(d) standards that applied to the plant prior to modification. NRDC supported EPA's original interpretation in its comments on the proposed Plan.

[7] 80 Fed. Reg. at 65,039.

The potential weakening of a federal or state plan is most pronounced in the context of an existing-only mass-based plan and a plan that uses the blended-rate. In an existing-only mass-based plan, the exit of a power plant following modification would significantly weaken the Clean Power Plan if the plant were allowed to continue to emit carbon pollution at the same or a greater level while the allowances previously used by the plant were used by the state's remaining existing plants. To avoid this outcome, EPA must require that the existing-only mass cap be recalculated. This requires recalculating the rate-to-mass calculation without including the modified plant. In order to ensure that this happens, EPA should require that existing-only mass-based state plans be revised by the state and approved by EPA prior to the approval of any modification. States should also have the option of requiring that the plant continue to purchase allowances under a federal or state plan. We note that no adjustment would be required for a mass-based plan that includes both existing and new plants, since new and existing plants draw from a common pool of allowances.

Any states using the blended-rate approach should also be required to recalculate their rate. This is necessary because the state's blended rate is set based on the ratio of coal and gas power plants in the state. If a coal plant were to modify and exit the Clean Power Plan, the ratio must be recalculated to reflect the fact that the plant is no longer one of the states existing plants required to purchase credits. Otherwise, the blended rate will be more lenient than it should be and emissions will increase. Again, states should be provided the option of requiring that the modified plant remain within the program.

K. Proposed Amendments to Framework Regulations

EPA proposes six changes to the CAA section 111(d) framework regulations to include procedural tools that were added to section 110 in the 1990 CAA Amendments. These proposed amendments include: authority to partially approve or disapprove plan where elements of the plan are functionally severable; authority to conditionally approve plan that requires only specific amendments to be fully approvable; a procedural mechanism for EPA to call for necessary plan revisions similar to the SIP-call provisions of section 110; an error correction mechanism for EPA to revise a previous erroneous action; minimum criteria and a process for determining plan completeness; and updates to deadlines for EPA action. NRDC supports these amendments, which we believe will help streamline the plan approval process and enable EPA to work cooperatively with states to develop approvable plans.

IV. Rate-Based Implementation Approach

A. Rate Goals

NRDC supports the use of the subcategorized rate approach for a federal plan should EPA elect to implement a rate-based approach to the federal plan. NRDC recommends that EPA finalize model rules for both the subcategory-specific rates and the statewide-blended rate approaches to facilitate decision-making and implementation by states.

B. Crediting Mechanism

NRDC strongly supports placing the obligation to hold sufficient ERCs, and the responsibility for the validity of ERCs, on the EGU as EPA has done. It's essential that the entity responsible for compliance be required to address any ERC issues that arise. We believe that an insurance market will develop, as it has in the California offsets market, to allow EGUs to address risk that ERCs they hold are found to be faulty. Likewise, EGU owners will be able to mitigate risks through their contracts with ERC developers or sellers.

Gas-Shift ERCs

NRDC supports EPA's proposed methodology for determining the Emission Factor when calculating GS-ERCs. The Emission Factor should be calculated on a unit by unit basis in order to incentivize ramp-up of the lowest-emitting NGCCs. In order for crediting to be transparent and simple (and to avoid the need for a true-up if real-time data is not available), the Emission Factor could be calculated and updated prior to each quarter based on the latest available data.

NRDC also supports EPA's approach to awarding GS-ERCs to all generation from existing NGCC units, not just generation above a threshold capacity factor. Requiring that output be above a certain capacity factor creates market distortions without providing any certainty that the generation being incentivized is displacing higher-emitting resources at the margin.

GS-ERCs and other ERCs should all be tradable and look the same to a fossil steam EGU that needs them for compliance, but the tracking system for ERCs should indicate what kind they are and where they are created. This is essential to ensuring compliance and linking any fraudulent ERC creation to the EGU who is ultimately responsible, and to ensuring that GS-ERCs are only available for compliance to fossil steam EGUs.

Eligible Emission Reduction Measures for ERC Generation

We support ERC eligibility for all non-emitting generation and demand-side energy efficiency in both the model and federal plans.

In the federal plan context, we believe it would be appropriate for the state to have the opportunity to implement and oversee ERC EM&V, consistent with EPA requirements and with EPA maintaining the ability to take the responsibility back from the state in the case of inadequate EM&V rigor. It would also be appropriate for a state to opt to implement EM&V for renewable generation from distributed solar.

Energy Efficiency

EPA requests comment on the inclusion of various types of demand-side EE as eligible measures for ERC issuance under the federal plan, such as state and utility EE programs, project-based demand-side EE, state building codes, state appliance standards, and conservation voltage reduction.

NRDC supports inclusion of all types of demand-side energy efficiency in a federal plan, provided that the state agrees to implement the ERC-generating process described in the Emission Guidelines and rate-based model trading rule. We anticipate that EPA would not itself have the resources to directly oversee energy efficiency program eligibility. Reviewing verified MWhs of renewable energy or nuclear energy facilities is substantially more straightforward than reviewing and approving eligibility applications and EM&V reports for energy efficiency.

It is reasonable to expect a state to undertake these tasks, even if they do not agree to implement other parts of the rule. Energy efficiency of all types will continue to take place regardless of whether the state implements the rule, and the state has an interest in ensuring that their citizens get value from this energy efficiency. Absent an agreement by a state to take on the ERC-generating role, energy efficiency should not be eligible for ERC issuance in the federal plan. Moreover, EPA must retain the ability to take ERC-generating oversight back from the state if it is determines that the state is not implementing an EM&V system with adequate rigor.

Distributed Generation

For the purposes of ERC issuance in a rate-based program, EPA has proposed that generation from renewable resources must be measured by revenue-quality meters. This would exclude a large portion of customer-sited resources, and in particular distributed solar PV, a rapidly growing technology. Distributed solar PV is a zero-emitting generation technology which displaces generation, and therefore emissions, from affected EGUs, and as such there is no legal or analytical reason it should be excluded from eligibility. Revenue grade meters are both cost prohibitive for small systems, and unnecessary for accurately tracking generation. As documented by the Solar Energy Industries Association in its comments to EPA, the generation measurements of solar inverters must meet strict accuracy requirements; therefore, inverters can be used to track generation in place of revenue grade meters.

Much like EM&V for energy efficiency, there must be a robust process in place to ensure that generation from distributed solar capacity is not overestimated or fraudulent. NRDC strongly recommends that EPA develop a separate stakeholder process on EM&V practices for distributed solar energy.

In developing its baseline guidance, EPA can follow the lead of many states, including California, New York, Arizona, and Colorado, which estimate solar PV generation for RPS compliance purposes or other emission reduction goals, and do not require revenue-grade meters. The California Solar Initiative provides a leading example of robust practices for estimating generation from distributed solar.

Nuclear

EPA proposes that new nuclear units and capacity uprates at existing nuclear units that meet all requirements for eligible resources and ERC issuance be eligible to generate ERCs. NRDC supports this proposal, and we note that crediting of nuclear generation should be done consistently with other generation, and must be based on incremental MWh of generation above 2012 levels based on an NRC approved capacity uprate.

Combined Heat and Power

In the EGs model trading rule, EPA proposes that eligible, non-affected Combined Heat and Power units qualify for generation of ERCs. EPA states in the EGs that ERCs must represent one MWh of electricity generated or saved with zero associated CO_2 emissions. Combined heat and power units displace grid electricity, and the thermal energy produced by the system displaces thermal energy that would have come from another source, like a boiler. EPA proposes a method to quantify the CO_2 emissions attributable to the electricity produced by the CHP unit. This method is flawed and underestimates the CO_2 emissions attributable to electricity production. Then, EPA leaves the ERC-calculation methodology ambiguous by not specifying the reference rate to which CHP system electric emissions will be compared. EPA should correct both of these errors in the final version of the model rule.

To determine the CO_2 emissions attributable to electricity production, EPA proposes to subtract the CO_2 emissions attributable to the unit's useful thermal output. However, this *useful* thermal energy may not be actually *used* by the host facility. When a portion of the thermal energy is not actually used by the host facility, the CO_2 emitted to produce this wasted thermal energy should be attributed to electricity production, increasing the unit’s electric CO_2 emission rate. Boilers, as comparatively independent pieces of equipment, are more likely to be turned off or down when thermal energy is unneeded. The problem of dumping thermal energy is not theoretical: it was a problem in California's Self-Generation Incentive Program, where many units were put in place in facilities without reliable thermal needs: the incentive in the program was based on the size of the system[8]. EPA has a number of options to deal with the problem of dumping of thermal energy:

- redefine UTO (currently at 64996, C.3. as "the *used and* useful thermal output from a counterfactual industrial boiler that would have existed to meet thermal load in the absence of the CHP unit."

- similar to design criteria applied to Waste Heat Energy units, require CHP units to be designed to meet the "baseload" thermal needs of the host facility, reducing the amount of dumping.

Another issue with EPA's calculation methodology is the method for determining how many ERCs are produced for each MWh a unit produces, based on the unit's electric CO_2 emission rate, discussed above. EPA states that this unit-specific electric CO_2 emission rate should be compared to the subcategory-specific rate-based emission standard (see footnote 64, 64996), presumably of the EGU

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[8] Itron, Inc., CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation, Final Report Submitted to PG&E and the Self-Generation Incentive Program Working Group, July 7, 2011, Page 4-19 - 4-23.

that ultimately uses the ERC. This is problematic. It leaves the project developer uncertain, because it will not know how many ERCs their project creates until it sells the credit. Second, it creates tracking challenges: each MWh will create a bigger-fraction ERC if bought by a fossil steam plant, and a smaller-fraction ERC if bought by a NGCC plant. We recommend that the comparator be a weighted average emission rate-limit, like the limits proposed for individual states, but calculated nationally. This would better-reflect the regional nature of the electric grid, and would create certainty for project developers. It would also avoid over-crediting CHP units, which would happen if the comparator were the buying EGU's own emission rate. This would incorrectly credit CHP units with displacing CO_2 emissions that already were going to be displaced according to the underlying policy. It would also not acknowledge that the CHP unit is itself a fossil fuel-fired resource: emissions from other fossil fuel-fired resources are compared to emission limits in generating ERCs.

Biomass

NRDC supports EPA's proposal to not include biomass combustion from the list of eligible emission reduction measures for generating emission rate credits (ERCs) in the Federal Plan and Model Trading Rule (MTR). EPA has appropriately excluded biomass for four key reasons, which we discuss in detail below.

First, biomass combustion fundamentally fails to meet the EPA's eligibility criteria for ERCs. Second, most forms of biomass fuel do not have zero or low carbon emissions within the relevant compliance timeframes. Third, in no case should the agency "pre-approve" a biomass feedstock or list of feedstocks, as no set of assumptions, scenarios, or counterfactuals could be universal—the condition necessary to pre-approve a feedstock as "qualified biomass."

Finally, the Agency should reject so-called "sustainably-derived" forest feedstocks as a compliance measure altogether. Sustainability cannot be justified scientifically as a proxy for carbon accounting. In particular, EPA should reject several frequently promoted but erroneous approaches, each of which fail to produce "additional" carbon benefits and therefore cannot be used as a basis for identifying "greenhouse gas beneficial" biomass feedstocks: (i) regional reference point accounting; (ii) sustained yield forestry; (iii) certification regimes and/or best management practices; and (iv) treating forest thinnings and residues as "waste." In sum, biomass should not be an eligible measure for rate-based crediting in the final FIP, nor should it be eligible for set-asides under a mass-based FIP or as a compliance option in the MTR.

Biomass Combustion Does Not Meet the EPA's Eligibility Criteria for ERCs

EPA's proposal specifies several kinds of renewable energy as eligible for ERCs in states that are subject to a FIP:

> *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.

The proposal lists several criteria used by the Agency to justify the issuance of ERCs to wind, solar, geothermal, and hydropower systems. Biomass fails to meet several of these criteria, outlined below.

1. Biomass combustion does not "have the ability to provide data from a revenue quality meter" to demonstrate emission reductions, and biomass-burning electric generating units (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 emission reductions.[9] EGUs that burn biomass—especially biomass originating in forests—cannot meet this criteria because the emissions reduction attributable to biomass combustion is either based (at best) on modeled projections of forest growth and other complex natural systems or (at worst) on unsupported assumptions about carbon neutrality. The only relevant data a biomass-burning EGU can reliably measure are the CO_2 emissions from its stack, which will be higher than the CO_2 emissions from an otherwise identical coal or gas-burning EGU.

2. Evaluation, Measurement and Verification (EM&V) for biomass combustion cannot be implemented "in a way that is rigorous, straightforward, [or] widely demonstrated."

To preserve the integrity of its regulatory system, EPA requires the use of EM&V methods that can be implemented "in a way that is rigorous, straightforward, [and] widely demonstrated." The difficulty and complexity of accounting for emissions from burning biomass for electricity preclude any quantification of "biomass ERCs" with the same level of reliability, precision, and transparency that EPA uses to support the issuance of ERCs to wind, solar, geothermal, and hydropower systems. Moreover, currently available methods for monitoring and verifying biomass supply from a forest are uncertain and contingent. Because forest management activities vary widely and are based on landowner/forester discretion, EM&V systems for forest-based activities would have difficulty qualifying as rigorous, straightforward or widely demonstrated.

3. EPA's approach to biogenic CO_2 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."[10] 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." In fact, if states are permitted to develop different carbon accounting methods, the

[9] 80 Fed. Reg. at 64,994/2.
[10] *Id.* at 64,994/3.

Agency's legitimate preference for broadly applicable, readily deployed EM&V measures is likely to be frustrated.

For these reasons, NRDC supports EPA's decision to exclude biomass combustion from the list of ERC-eligible energy systems in a rate-based federal plan. (For similar reasons outlined below, EPA should also confirm that forest-derived biomass combustion is ineligible for renewable energy (RE) set-asides in a mass-based federal plan and should not be included in the mass-based model state plan).

Most forms of biomass are not zero or low-emitting sources, and therefore should not be eligible to generate ERCs or RE set-asides

Under the final CPP regulations, CO_2 control measures that are zero or low emitting can earn whole or partial emission reduction credits.[11] Likewise, the proposed federal plan/model plan provides that an ERC qualifies for compliance if it "represents one whole MWh of actual energy generated or saved with zero associated carbon dioxide emissions."[12]

EPA's regulations also require that "affected EGUs achieve CO_2 emissions performance rate or CO_2 emissions goal, as applicable, over the [following] periods": the interim period (2022 through 2029), each of the interim steps (of which there are three: 2022 through 2024, 2025 through 2026, and 2027 through 2029), and the final reporting periods.[13]

Taken together, the final emission guideline appropriately requires that emission reductions must have already occurred before any ERC is generated. Any claimed reductions or avoided emissions not occurring within or prior to a compliance period cannot satisfy this requirement. Most biomass combustion incurs a "carbon debt" lasting anywhere from several years to many decades. Therefore, most if not all biomass combustion cannot reliably generate even partial allowances or ERCs within relevant compliance timeframes under the CPP. Accordingly, EPA cannot allow biomass combustion to serve as a compliance option unless it results in low or zero emissions by the end of the compliance year.[14]

Regulators should use a counterfactual modeling approach to assess if CO_2 emissions from forest biomass-burning EGUs could plausibly be offset in the future when new plant matter regrows on the harvested land, or through avoided emissions that would otherwise occur as a result of biomass decay or burning. However, there is uniformly a significant "carbon debt" period between the point at which stack emissions are released and the point at which emission reductions can be achieved, during which

[11] 80 Fed. Reg. 64,662, 64,949, 64,834.
[12] 80 Fed. Reg. 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.").
[13] 40 C.F.R. § 60.5770(b).
[14] Unlike facilities that generate electricity from wind or solar energy, facilities that burn biomass to generate electricity emit significant amounts of CO_2. 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. Therefore, CO_2 emissions are indisputably "associated" with biomass combustion. 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.

time carbon emissions persist in the atmosphere. As we demonstrate below, the use of most types of forest-derived biomass would not result in a net reduction during the CPP compliance years of 2022-2030.

Burning wood for electricity is highly inefficient. By substituting trees for coal, power plants avoid fossil-fuel carbon emissions. But trees are approximately half water by weight and this significantly lowers the heat input per unit of carbon emissions compared to coal and other fossil fuels. To generate the same amount of electricity from trees as from fossil fuels, many more trees have to be burned, resulting in roughly 40 percent more CO_2 emissions at the smokestack per unit of energy generated. At the same time, if left alone, trees will continue to grow and sequester carbon.

Research shows that the initial increase in carbon pollution at the smokestack and the lost carbon sequestration mean it can take anywhere from 35 to 100 or more years for forest regrowth and the associated carbon sequestration to break even with fossil fuels—i.e. the point at which burning the biomass is no worse for the climate than burning the fossil fuel (the actual timing depends in large part on whether biomass combustion replaces coal or gas).[15] This is much longer than the compliance periods discussed above, yet it is only after this point that wood-fueled bioenergy begins delivering net carbon benefits. In a scenario where forestry residues that would otherwise decay and release their carbon are burned, the payback period is typically shorter because it is tied to the region-specific decomposition rate of that material and its size, but still on the order of decades—far longer than the CPP's compliance timeframes.[16] [17]

Putting aside the long period required to sequester the carbon released by burning biomass, tracking biomass poses significant practical challenges. Especially in the case of slash and residues which have no customary treatment (they are sometimes left on-site to decay and other times burned), it is very difficult to track feedstock origins and establish the counterfactuals. State plans would need extraordinarily comprehensive monitoring and verification requirements—far beyond the resources likely to be available under a federal plan. True industrial waste (such as black liquor) is more

[15] Mitchell, S., Harmon, M., and O'Connell, K., *Carbon Debt and Carbon Sequestration Parity in Forest Bioenergy Production*, GCB Bioenergy, May, 2012.
Colnes, A., et al., *Biomass Supply and Carbon Accounting for Southeastern Forests*, The Biomass Energy Resource Center, Forest Guild, and Spatial Informatics Group, February 2012
www.biomasscenter.org/images/stories/SE_Carbon_Study_FINAL_2-6-12.pdf
Hagan, J., *Biomass Energy Recalibrated*, The Manomet Center for Conservation Sciences, January 2012.
http://magazine.manomet.org/winter2012/biomass.html

[16] Schulze, E. D., C. Körner, B. E. Law, H. Haberl and S. Luyssaert. 2012. *Large-scale bioenergy from additional harvest of forest biomass is neither sustainable nor greenhouse gas neutral*. GCB Bioenergy: 4(6): 611-616.
Stephenson, A. L., and MacKay, D., *Life Cycle Impacts of Biomass Electricity in 2020: Scenarios for Assessing the Greenhouse Gas Impacts and Energy Input Requirements of Using North American Woody Biomass for Electricity Generation in the UK*, UK Department of Energy and Climate Change, July 2014.
www.gov.uk/government/uploads/system/uploads/attachment_data/file/349024/BEAC_Report_290814.pdf

[17] Repo, A., et al., *Sustainability of Forest Bioenergy in Europe: Land-use-related Carbon Dioxide Emissions of Forest Harvest Residues*, GCB Bioenergy, March 2014.
Ter-Mikaelian, M., et al., *Carbon Debt Repayment or Carbon Sequestration Parity? Lessons from a Forest Bioenergy Case Study in Ontario, Canada,* GCB Bioenergy, May 2014.

straightforward as the counterfactuals are well known and customary and emissions reductions are contemporaneous, occur onsite, and thus can be monitored at the stack. Accordingly, it is possible that such industrial waste may qualify, but EPA can and should only make that determination after articulating a clear set of criteria for what constitutes "qualified biomass."

Finally, post-harvest regrowth is not always assured. If a forest that has been harvested for bioenergy does not regrow, there is no basis whatsoever for claiming a CO_2 reduction credit. The connection between the entity that burns the biomass and the 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.

In sum, biomass fuel sourced from a forest (trees, residues, slash, thinnings, etc.) cannot be demonstrated to categorically meet the standard of low or zero emissions in the compliance year. For these reasons, EPA should not approve any state plan under the CPP that gives emissions reduction credits or other compliance preferences to any biomass materials taken directly from a forest.

The agency should not "pre-approve" any biomass feedstock or list of feedstocks

EPA also requests comment on "an option for biomass treatment" in which it would "specify a list of pre-approved qualified biomass fuels."[18] The list would potentially be used by regulators when assessing compliance with a rate-based FIP or a mass-based MTR, and when calculating covered emissions at co-firing EGUs.[19] 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."[20]

Any use of biomass combustion to meet the CO_2 reduction requirements of Section 111(d) must ensure that biomass-related energy generation has zero or low-emitting associated CO_2 emissions, that biomass combustion results in reductions that are achieved at affected sources, and that any reductions tied to biomass combustion must occur within or prior to the compliance year.

As described, these criteria are not met by most biomass. Any claim that these requirements are met must be supported by an analysis of the specific biomass-burning facility and the specific feedstocks used. In the case of forest biomass feedstocks, this requires substantial knowledge of and/or assumptions about biomass harvest and other forestry practices on the landscape, which frequently vary by state or region, and are by definition removed from the regulated EGU or other biomass-burning facility.

Most importantly, no set of assumptions, scenarios, or counterfactuals can be considered universal—the condition necessary to pre-approve a feedstock as "qualified biomass." This is especially true for the forestry sector where land use decisions depend on land managers, market conditions, and other factors that vary widely. Absent universally-applied assumptions, scenarios, and/or counterfactuals, *it is*

[18] 80 Fed. Reg. at 64,995/3.
[19] *Id.*
[20] *Id.* at 64,996/1.

impossible for the Agency to establish any form of pre-approved list. This is true even for practices that may appear to be typical (for example, while it is widely assumed that mill residues are customarily burned, it is not uncommon for those materials to be used in particleboard production). Accordingly, EPA should not develop a pre-approved list of biomass feedstocks that qualify for ERCs or allowance set-asides.

EPA must reject "sustainably-derived" forest biomass sources as a CPP compliance measure and other erroneous approaches for determining "greenhouse gas beneficial" biomass feedstocks

The Agency must clarify that claims that biomass is "sustainably-derived" cannot be used to establish that the biomass qualifies as a CPP compliance measure. "Sustainability" says very little, if anything, about the amount of biogenic CO_2 emitted by a given biomass source or the net effect of those emissions on atmospheric carbon over time. There is no scientific basis for use of sustainable forestry as a proxy for carbon accounting. In particular, EPA should reject several erroneous approaches for determining "greenhouse gas beneficial" biomass feedstocks, each of which fail to produce additional carbon benefits and so cannot be used as a basis for identifying "greenhouse gas beneficial" biomass feedstocks: (i) regional reference point accounting; (ii) sustained yield forestry; (iii) certification regimes and/or best management practices.

A key requirement is that any emission reductions EPA credits must be *additional*—that is, the emissions reductions must be above and beyond what would have happened under a business-as-usual (BAU) scenario. The only way EPA might make this determination is to use an analysis that compares changes in forest carbon stocks from increased biomass harvesting against a BAU baseline absent biomass demand for bioenergy. The net change in stored carbon is the difference between two cases.

Biomass-burning facilities cannot take credit for sequestration that would have occurred anyway without it resulting in increased CO_2 emissions to the atmosphere. For forest biomass to generate CO_2 emission reduction credits, regulated entities must demonstrate that stored forest carbon is increasing under the biomass harvest scenario compared to the BAU scenario (which might involve, e.g., managing the forest to supply wood for framing lumber, pulp, and other relatively long-lived products).

Below we assess several commonly-cited approaches for determining "sustainably derived" biomass against this fundamental standard of additionality. In all the cases examined, the proposed approach fails to justify crediting carbon benefits.

1. Fixed Reference Point Accounting

Reference point accounting compares forest carbon stocks over time across some pre-defined region, independent of the specific activities (logging, burning, etc.) that take place within that region. According to this carbon accounting method, biomass harvested in regions where overall forest stocks are increasing is deemed carbon beneficial. This approach fundamentally violates the principles of baseline and additionality: it cannot accurately capture the additional carbon sequestered or lost as a result of bioenergy because it does not establish a baseline absent the bioenergy production. For forest-derived woody biomass, the fixed reference point baseline was roundly rejected by the EPA's own

Biogenic Carbon Emissions Panel of the Scientific Advisory Board in its first assessment of the Agency's Framework:

> *"…The choice of a fixed reference point may be the simplest to execute, but it does not properly address the additionality question, i.e., the extent to which forest stocks would have been growing or declining over time in the absence of bioenergy. The agency's use of a fixed reference point baseline coupled with a division of the country into regions implies that forest biomass emissions could be granted an exemption simply because the location of a stationary facility is in an area where forest stocks are increasing. The reference point estimate of regionwide net emissions or net sequestration does not indicate, or estimate, the difference in greenhouse gas emissions (the actual carbon gains and losses) over time that stem from biomass use. As a result, [it] fails to capture the causal connection between forest biomass growth and harvesting and atmospheric impacts and thus may incorrectly assess net CO_2 emissions of a facility's use of a biogenic feedstock."*

2. Sustained Yield Forestry

Under a sustained yield approach, landowners manage a "regulated" forest in which annual cutting occurs (on average) in an area equal to the total managed forest area divided by rotation in years. These increments of forest are cut to generate a product while the remaining forest regrowth replaces the removed forest stock annually. Thus growth equals or exceeds removals.

By definition, sustained yield programs are existing, ongoing, long-term commitments by a landowner to a forest management program. Therefore, the sustained yield program represents a BAU baseline, NOT the bioenergy scenario. As such, an existing sustained yield forestry program cannot be treated as a carbon-beneficial land management approach.

Moreover, two bioenergy scenarios are possible against this baseline[21]: (i) biomass replaces existing wood uses; (ii) biomass displaces existing wood uses. In either case, biomass harvest for bioenergy production increases carbon emissions, because absent bioenergy demand, the harvest would not occur. According to Ter-Mikaelian et. al., *Journal of Forestry* (January, 2015):

> *An assumption that bioenergy harvesting in forests managed on a sustained yield (also called sustainable yield) basis does not create a carbon deficit is one of the most common errors in forest bioenergy accounting…Stating that sustained yield management is carbon neutral is incorrect because it fails to account for the case involving no harvest for bioenergy in the reference fossil fuel scenario.*[22]

Finally, NRDC's own modeling shows that when additional (more frequent and/or more intensive) thinnings are included within an existing sustained yield regime to produce biomass (both for

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[21] Presumably the sustained yield baseline produces a relatively longer-lived product.

[22] Ter-Mikaelian, M., S. J. Colombo, and J. Chen. *The Burning Question: Does Forest Bioenergy Reduce Carbon Emissions? A Review of Common Misconceptions About Forest Accounting.* Journal of Forestry, 113(1): 57-68.

plantations and naturally regenerating forests), the bioenergy scenario produces a carbon debt that exceeds the carbon impact of fossil fuels for five decades.[23]

3. Best management practices (BMPs), forest certifications, and other "sustainable forestry" regimes.

For reasons similar to those above, BMPs, certifications and other sustainable forestry regimes cannot, in and of themselves, be construed as GHG-beneficial practices. These regimes are, *by definition,* existing, ongoing, long-term commitments by a landowners and/or states to a set of forest management practices. Here again, they represent a BAU baseline, NOT the bioenergy scenario. As such, an established BMP or certification regime, while beneficial for ecosystems and wildlife protection, cannot be treated as a carbon-beneficial land management approach.

4. Treating Forestry Residues and Thinnings as "Waste"

Forestry residues (including the "slash" left behind from logging operations) typically take years to decades to decompose, and combustion of these materials can incur a significant carbon debt period.[24] One could argue that if logging residues otherwise would be burned in the open, using those same materials for bioenergy might result in a very short carbon payback period. This may be theoretically accurate, but there are at least three major obstacles to accurately establishing a genuine "additionality." First, unlike combustion in a bioenergy facility, broadcast and pile burning of logging slash does not tend to consume all of the material; a significant portion may remain uncombusted on site. According to Forest Service research, fuel consumption in slash piles can range as low as 75%.[25] Combustion factors for broadcast understory burning of coarse woody debris can be as low as 60%.[26] Second, open burning of slash is not a universal practice, nor is it universally permissible; rather, it depends on local conditions, including weather and relevant air quality regulations.[27] And third, EPA would have to verify that specific materials in this category (a) result from logging operations that would have occurred regardless of any economic influence exerted by the presence of a nearby biomass facility, and (b) otherwise could have and would have been burned in the open if not used for bioenergy at combustion efficiencies approaching 100%. All of these factors require site-specific analysis and

[23] http://www.nrdc.org/land/bioenergy-modelling.asp

[24] EPA has acknowledged that forestry residues, for example, may take 10-15 years to decompose if not used for bioenergy. Deferral for CO_2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs: Proposed Rule, 76 Fed. Reg. 15249, 15259/1 (March 21, 2011). Other studies have shown that larger "residues" may take much longer to decompose. *See* Anna Repo, et al., *Indirect Carbon Dioxide Emissions from Producing Bioenergy from Forest Harvest Residues*, Global Change Biology Bioenergy (2010) ("Repo 2010"), doi: 10.1111/j.1757-1707.2010.01065.x.

[25] Colin C. Hardy, *Guidelines for Estimating Volume, Biomass, and Smoke Production for Piled Slash*, U.S. Dept. of Agriculture, Forest Service, Pacific Northwest Research Station, Gen. Tech. Rep. PNW-GTR-364 (1996).

[26] *See* Eric E. Knapp et al., *Fuel Reduction and Coarse Woody Debris Dynamics with Early Season and Late Season Prescribed Fire in a Sierra Nevada Mixed Conifer Forest*, 208 Forest Ecology & Mgmt. 383 (2005).

[27] *See, e.g.*, North Coast Unified Air Quality Management District (California), Regulation II , *available at* http://www.ncuaqmd.org/index.php?page=rules.regulations; Placer County (California) Air Pollution Control District, Regulation 3, *available at* http://www.placer.ca.gov/departments/air/rules.

careful monitoring and verification (including documentation of timber harvest operations and practices and chain-of-custody verification of the source of materials).

Biomass proponents often argue that non-merchantable trees and understory materials from thinning operations intended to reduce wildfire severity should be used for bioenergy. Several studies, however, have demonstrated that thinning forests and burning the resulting materials for bioenergy can result in a loss of forest carbon stocks and a transfer of carbon to the atmosphere lasting many years. Because it is impossible to know in advance that wildfire will occur in a thinned stand, thinning operations may remove carbon that never would have been released in a wildfire; one recent study concluded, for this and other reasons, that thinning operations tend to remove about three times as much carbon from the forest as would be avoided in wildfire emissions.[28] Another report from Oregon found that thinning operations resulted in a net loss of forest carbon stocks for up to 50 years.[29] Under basic physical mass balance principles, that carbon stock loss represents an equivalent increase in atmospheric carbon. Another report found that even light-touch thinning operations in several Oregon and California forest ecosystems incurred carbon debts lasting longer than 20 years; even where carbon payback times were shorter than two decades, the study's conclusions depended on ecosystem-specific characteristics.[30] Even under a best-case scenario, therefore, it is highly unlikely that materials from forest thinning operations can be associated with genuine additional benefits or carbon payback times short enough to represent low or zero carbon generation within the CPP's compliance periods.

Biomass Combustion at Affected EGUs Cannot Be Used to Comply with Mass-Based Plans

Most of the Agency's discussion about the treatment of biomass combustion occurs in the preamble addressing the rate-based implementation approach (Part IV), but EPA also raises the possible use of biomass in its discussion of a mass-based implementation approach (Part V of the preamble). Specifically, EPA requests comment on the following:

> *[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.*[31]

For all of the reasons discussed above, EPA must not finalize this approach. As described, biomass combustion does not result in contemporaneous or timely emissions reductions from affected EGUs and thus cannot meet the eligibility criteria that EPA has established for ERCs. Likewise, EPA may not allow biomass to discount stack emissions in a mass-based (or rate-based) plan or to receive issuance of set-aside allowances.

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[28] John L. Campbell, et al., *Can fuel-reduction treatments really increase forest carbon storage in the western US by reducing future fire emissions?* Front. Ecol. Env't (2011), doi:10.1890/110057.
[29] Joshua Clark, et al., *Impacts of Thinning on Carbon Stores in the PNW: A Plot Level Analysis*, Final Report (Ore. State Univ. College of Forestry May 25, 2011).
[30] Tara Hudiburg, et al., *Regional carbon dioxide implications of forest bioenergy production*, Nature Climate Change (2011), doi: 10.1038/NCLIMATE1264.
[31] 80 Fed. Reg. at 65,012/3.

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

C. ERC Tracking and Compliance Operations

Compliance with Emission Standards

EPA proposes that EGUs will be required to meet compliance obligations by November 1 in the year following a performance period, 10 months after a performance period ends. This is more time than necessary to calculate an observed emission rate and buy the needed amount of ERCs, and EPA should move this deadline forward. In setting a more reasonable compliance deadline, EPA should align the deadline with the compliance demonstration requirement for mass-based plans (for which EPA has proposed May 1 of the year following the end of a compliance period). EPA should also consider alignment with compliance deadlines in other power sector trading programs, such as the Acid Rain Program, the Regional Greenhouse Gas Initiative, and California's Cap-and-Trade Program.

EPA proposes that, if an EGU fails to hold enough ERCs to comply with its emission rate limit, it must provide to EPA two ERCs for each one ERC the EGU did not hold as required to cover emissions. The purpose of this "make-up rate" is to make non-compliance much more expensive than compliance. NRDC believes this two-to-one ratio does not impose a sufficient penalty to deter non-compliance. Other market-based programs use higher ratios—for example, California's Cap-and-Trade program requires surrender of four allowances per ton exceeded,[32] and RGGI requires three.[33] NRDC recommends that EPA increase the ERC "make up rate" to four ERCs per one ERC not held.

Recordation of ERC Generation and ERC Issuance

EPA proposes to issue ERCs once per-year, after a notice and a 30-day comment period. For resources with streamlined EM&V, like renewable energy resources with a revenue-quality meter, it may be preferable to issue ERCs quarterly, providing ERCs into the compliance market sooner. EPA's comment period is important, because it is the only opportunity, aside from citizen suits, for parties to dispute an M&V report or ERC claim. States should issue ERCs according to the same notice and comment process.

The importance of the timing of ERC issuance is mitigated, however, by EGUs' ability to contract with a renewable energy or energy efficiency provider for ERCs. EPA should ensure that this contracting is allowed.

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[32] California Code of Regulations § 95857(b)(2).

[33] Regional Greenhouse Gas Initiative, Fact Sheet: RGGI CO_2 Allowance Tracking System (RGGI COATS), http://rggi.org/docs/Documents/RGGI_COATS_FactSheet.pdf.

ERC Banking and Borrowing

NRDC supports EPA's proposal to allow ERC banking, including between the interim and final performance periods. This will provide flexibility for EGUs. Borrowing – allowing an EGU to demonstrate compliance with an ERC from a future compliance period -- should be prohibited. As EPA rightly points out, future ERC generation is not guaranteed, and as the emission limits become more stringent, the EGU may need more ERCs than before, assuming output is constant. Borrowing would undermine the environmental integrity of the rate-based program.

Emissions Monitoring and Reporting

NRDC supports requiring emissions monitoring and reporting in the year prior to the first performance period: i.e., in 2021. This will help EGUs prepare for actions necessary to demonstrate compliance with the emission rate limits.

ERCs and Existing REC Markets

RECs and ERCs need to be separately tracked. Different entities need a REC for RPS compliance (load serving entity) vs. an ERC for CPP compliance (fossil EGU). State RPS law may potentially limit separate use of a renewable MWh used for REC compliance as a CPP ERC. Since this is a question of state law, the federal plan and model trading rules do not need to address this directly.

Independent Verifiers

Independent verifiers are important to EPA's system for ensuring that ERCs represent real emission reductions: verifying the eligibility of a resource, the EM&V plan used to measure the impact of that resource, that the EM&V plan was followed, and ultimately proposing the amount of ERCs a project should receive. These professionals will help states and EPA manage oversight needed to create ERCs. Verifiers must be independent of project developer influence.

NRDC supports EPA's proposed accreditation procedures for independent verifiers, procedures for avoiding conflicts of interests, and process for revocation of accreditation status for independent verifiers. EPA only partly addresses an important potential conflict of interest, however: that substantial non-verification business with the project developer, or the prospect of that business, might influence the content of a verification report. Independent verifiers should be required to report non-verification business with a project developer, and notify EPA of any new non-verification business with the project developer for a period of 1 year after the submission of the verification report.

Evaluation, Measurement, and Verification (EM&V)

Demand-side energy efficiency -- i.e., saving energy in buildings and factories -- lowers energy bills, improves productivity and comfort, reduces the need to build expensive power plants, and takes the place of electricity produced by fossil fuel burning power plants, lowering emissions of carbon dioxide and other pollutants. In the Emission Guidelines, EPA included eligible demand-side energy efficiency among the resources that can generate Emission Rate Credits.[34] Demand-side energy efficiency could be included in a clean energy set-aside in a mass-based plan.[35] Unlike the electricity produced by zero-emission resources like wind and solar, the electricity saved by demand-side energy efficiency cannot be directly measured, because we cannot be certain that the change in electricity use before and after an energy efficiency activity is undertaken is entirely due to the activity itself. Other factors, like a change in the number of people working in a house or office, weather, or a pre-existing trends towards more efficiency, could have caused the change. Therefore, electricity savings from demand-side energy efficiency must be estimated.

Because it is critical that Emission Rate Credits represent real reductions in CO_2 emissions, and important that energy savings credited in a clean energy set aside be real, EPA must articulate minimum standards for estimating savings from demand-side energy efficiency. These standards must avoid several risks: that savings will overestimated because of the use of biased methods or evaluators, that savings estimates will be incorrect because of measurement or random error, that providers will apply incorrect baseline assumptions or employ quantification methods not appropriate for the activity, that the same measure or program will be estimated differently across and within states, that states will compete to lower quantification standards, and that regulators will not adequately review savings estimates. EPA must also avoid creating an overly costly, burdensome, or confusing system that inhibits use of demand-side energy efficiency to reduce emissions. EPA's system does a good job of mitigating these risks and balancing accuracy with cost. While the system could in some places be strengthened and clarified, it is generally sound.

Below we address EPA's specific requests for comment on the draft model rule and federal plan.

Quantification and Verification Criteria

The EPA seeks comment on the broad quantification and verification criteria for each ERC-eligible resource, including "comment on the substantive content of the criteria, and seeks comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule, and whether the criteria should differ for each eligible resource."

In EPA's system, owners of ERC-eligible resources submit an EM&V plan to the state, the state reviews the EM&V plan, and if approved enters the resource into the tracking system. After the project is complete and in operation, the owner submits to the state an M&V report describing how the EM&V plan was applied to produce a savings estimate. The state then reviews this M&V report, and issues the appropriate number of Emission Rate Credits into the tracking system. Independent verifiers submit reports to the state on each resource, verifying that the resource is eligible for ERCs, that the EM&V plan meets requirements, that the resource was implemented as described in the eligibility application, and that the EM&V plan was implemented to produce a savings estimate.

[34] CPP Final Emission Guidelines, 80 Fed. Reg. at 64,950.
[35] *Id*. at 64,951.

Verification Reports

In the EGs,[36] EPA requires that state plans require that each ERC eligibility application include a report from an independent verifier that verifies the eligibility of the resource to be issued an ERC and that the EM&V plan meets requirements. After the measure has been installed, EPA requires in the EGs (60.5835(b)(1)) that the first M&V report -- the first time the project owner requests ERCs -- include documentation that energy-saving measures were put into place as described in the eligibility application.

EPA's proposals, together with its requirements and proposals for independent verification, will help ensure ERCs represent real emission reductions by checking the information provided by the project owner, and checking the resource's measurement plan and savings claim. EPA should address two shortcomings, though. First, independent verifiers may not be in a position to verify that the MWh savings from a measure are not being claimed by another project owner: i.e., that the measure is non-duplicative. Duplicate ERC claims are probably most likely to occur when different programs target the same type of efficiency in the same market. For example, a city could claim savings from a "stretch" building code at the same time a utility claims savings from a new construction that funds the extra level of efficiency. A retailer could claim savings from a LED lighting strategy at the same time a utility is paying a manufacturer to reduce the price of LEDs. In these situations, verifying that a resource is non-duplicative requires a vertical view through a market, which requires an understanding of every savings claim for a particular type of measure. The state may be best-positioned to judge that measures are not-duplicative. Second, EPA should make clear in which document a project owner and/or independent verifier will officially present a determination of how much energy was saved by a particular demand-side energy efficiency activity. In the model trading rule, this occurs in the second and subsequent verification reports, but this is an important step in the process of creating an ERC and should be highlighted.

EM&V Plans

EM&V plans describe in detail how savings from demand-side energy efficiency measures will be quantified and verified. Together with the M&V reports that follow program implementation, they allow regulators to understand if EPA and state requirements are followed. EPA requires[37] states that plan to issue ERCs or set-aside allowances to demand-side energy efficiency resources to require specific EM&V criteria in EM&V plans included in the eligibility application of each resource. The plan must include: quantification and verification of savings on a retrospective basis, using industry best-practice methods that yield accurate and reliable savings estimates; analysis of independent factors that might have affected the change in energy use, the expected period of time the resource will save energy, measurement of savings from a baseline of what would have happened in the absence of the demand-side energy efficiency activity. Each plan must also demonstrate how best practice EM&V protocols were applied to estimate savings, and explain how these protocols were selected. Later reporting must demonstrate and explain how the EM&V plan was followed.

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[36] *Id*.
[37] *Id*. at 64,952.

EPA's EM&V criteria help ensure that the policy goal of accurate, reliable savings is achieved. In general, EPA's criteria, as expressed in the model trading rule are neither too prescriptive nor too vague. Below we comment on specific criteria, and where applicable, respond to EPA's specific requests for comment related to those criteria. One additional criteria EPA should consider: a general requirement that providers and evaluators use the best available information to quantify savings.

Common Practice Baseline

EPA requests comment on "whether, when, and how common practice baselines should and should not be used in calculating electricity savings from EE activities, projects, programs, and measures, including comment on which common practice baselines should be used in which circumstances."Common practice or counterfactual baselines -- those that measure electricity savings from a baseline of what would have likely occurred without the project, program, or measure -- are critical to ensuring that ERCs represent real emission reductions. The use of a common practice or counterfactual baseline should be required of all EE activities, because this is the only baseline that seeks to isolate the impact of an energy efficiency activity. With other baseline assumptions, EPA risks granting credit to activities that are already included in the electricity demand forecast used to formulate the emission limits, or granting differing credits to the same project based solely on the type of energy efficiency provider.

If an energy efficiency provider randomly determined whether or not customers got energy efficiency upgrades, and the two groups were in other ways the same, the provider could measure electricity savings by comparing the energy use of the two groups. Among a similar group of customers, one received the program and the other did not, meaning the difference between the two is the impact of the program. In most programs, however, customers choose whether to participate. Estimating the impact of the program in opt-in programs means comparing electricity use before the energy efficiency activity to a pre-activity baseline. A common practice baseline, as defined in the Emission Guidelines, is "based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure." An evaluator, as proposed by EPA in the model trading rule, determines the baseline by examining the details of the program, how it is delivered, the local consumer and market characteristics, the applicable minimum codes and standards and average compliance rates, and the EM&V method applied. By taking these conditions into account, the evaluator is able to better isolate the impact of an activity than if another baseline assumption were used. In the alternative, the evaluator could use a historic baseline, comparing energy use pre-activity with post-activity energy use. But because processes and buildings are getting more efficient over time, this would overestimate savings from an activity. Suppose, for example, an auto engine factory shut down temporarily to prepare to manufacture a new engine model and integrated some energy efficient features into the new production line. Use of a historic or "existing conditions" baseline in this case would attribute any change in energy use to the energy efficiency program, even though the production process would have fundamentally changed with or without the influence of an energy efficiency program. Similarly, an ESCO project could include a combination of measures: some that retrofit still-operating lighting fixtures and others that replace those at the end of their life. A historic baseline would overestimate savings, because the end-of-life fixtures would have had to be replaced with more efficient models with or without the program. Finally, without the protection provided by a common practice baseline, a utility energy efficiency program could provide incentives for a measure just barely more efficient than minimum standards, and claim credit for the entire difference between pre-activity and post-activity energy use. The consistent use of a common practice or counterfactual baseline is thus essential for ensuring savings estimates are credible and ERCs represent real emission reductions.

The Regional Technical Forum's Roadmap for the Assessment of Energy Efficiency Measures[38] specify appropriate counterfactual baselines for different types of measures. A "current practice" baseline should be used when an activity affects systems, equipment, or practices that are at the end of their lives or for activities that affect new systems, equipment, or practices. A "pre-conditions" baseline is appropriate when an activity affects a system, equipment, or practice that is replaced before it has failed.

Because projects often include a combination of necessary and discretionary measures (replacing something that has failed, removing something before its useful life is complete, etc.) using a historic or negotiated baseline will consistently overestimate savings. Moreover, it is not the case that determining what likely would have happened had the project not occurred is overly burdensome or expensive: utility programs, which generally spend 3-8% of the budget on estimating savings, typically compare post-project electricity use to what would have happened without the project, taking into account current practices and relevant codes and standards.

Methods used to Quantify Savings

<u>Comparison Group Methods</u>

Randomized Controlled Trials -- where the program implementer randomly determines whether a customer participates in a program -- increase validity of savings estimates, because if the participant/non-participants are otherwise similar, the only difference between the two groups is whether they were treated by the program, solving the baseline issue described above. However, RCTs are not able to implemented in most energy efficiency programs, because programs are designed so that customers choose whether to participate in a program, instead of being randomly assigned. EPA should soften its preference for RCTs in favor of a broader preference for experimental and quasi-experimental research designs: those that attempt to isolate the impact of the program by exploiting program design features that cause otherwise similar customers to be treated or not treated by a program. One such design, regression discontinuity, for example, leverages arbitrary program eligibility thresholds, comparing energy use among participants who are barely eligible with non-participants who are barely ineligible. Other quasi-experimental research designs randomly assign customers to a "delay" condition: they receive the program, but after other program participants, and serve as a contemporaneous control group for the program participants. Quasi-experimental designs are more tractable than RCTs because they leverage existing program design features to provide a better, natural experiment, comparison between treatment and control groups. EPA should also note, in the description of comparison group methods, that the goal is to have the comparison group be as similar as

[38] Regional Technical Forum, Roadmap for the Assessment of Energy Efficiency Measures, June 17, 2014, Section 3.2, Page 14

possible to the treatment group. In at least one evaluation of a behavioral program, an evaluator compared energy use of program participants to energy use of a dissimilar control group, ignoring self-selection and overestimating savings.[39]

Deemed Savings

NRDC supports the inclusion of deemed savings -- agreed-upon, data-based savings values and calculation methods for measures that individually save a small amount energy and are relatively homogenous -- because using deemed savings values helps lower the costs of estimating savings, with little tradeoff in accuracy, at least for appropriate measures. However, there are several potential risks incurred in using deemed savings estimates:

- Estimates could be applied to energy efficiency activities for which they are not valid;
- Estimates could be created for inappropriate measures, such as those that have a large variation in savings;
- Deemed calculations -- agreed upon methods for estimating savings -- could include invalid parameters; i.e., an evaluator could ignore important information in estimating savings.

The model trading rule protects against some of these bad outcomes, but could be strengthened. First, EPA, in the model trading rule, should specify that deemed savings estimates should only be created for individual, physical measures, and only for measures where actual, measured savings are within a small range (a range that could be defined in final guidance). This would prevent the creation of deemed savings estimates for measures where a single, point estimate badly describes actual savings. Second, developers applying deemed savings values or deemed calculation methods should be required in the model trading rule to use the best available information in developing savings estimates. Not making reasonable efforts to gather good primary or secondary data in creating a savings estimate should be grounds for revoking the qualification status of an independent verifier. Finally, the model trading rule should specify that a deemed savings estimate should only be used for "specific EE measure for which they were derived, and only when the conditions in which it is being applied match the conditions described in the TRM." This will prevent project developers from applying deemed savings estimates in situations where they are invalid.

NRDC strongly supports the minimum TRM public access and peer review standards proposed in the model trading rule. They are not overly prescriptive, aside from the requirement that opportunities to comment be advertised on "social media." Without minimum peer review and public access standards, parties could create a TRM without substantive public input, containing biased savings estimates, leading to overestimates of savings and invalid ERCs.

Best Practice Methods

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[39] Comments of the Natural Resources Defense Council and Ohio Environmental Council, Case No. 12-1533-EL-EEC, et al., Public Utilities Commission, July 16, 2012, Page 3, available at: http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=6c85b4f5-4fc7-4f26-97aa-733d88bb48ad.

The model trading rule states that savings must be estimated using an industry best practice protocol: one that has been peer-reviewed and has been employed by at least one state regulatory commission. The use of a protocol by a single state should not be sufficient to have a method deemed best practice. Instead, EPA should state that best practice methods are additionally those that produce savings estimates that are not systematically biased, and likely to be as accurate as a method, if any, described in EPA EM&V guidance.

Quantifying Savings

EPA states that if sampling is used to quantify savings, the resulting savings estimate must meet confidence and precision standards. The use of field data -- instead of assumptions or engineering models -- should be encouraged. Together with a good research design, the use of sampling will help ensure that savings estimates best approximate the actual savings of the energy efficiency activity. NRDC recommends that EPA describe a range of acceptable confidence and precision, with lower requirements for small programs, defined as a certain absolute amount of electricity savings.

Interstate Crediting

The EPA requests comment on what criteria it should include in the final model rule that would ensure that similar projects in different states receive the same number of ERCs, and how to prevent forum-shopping by a project developer.

There are valid reasons why similar activities in different states could save different amounts of energy: markets, baseline technologies, and practices could be different across states. EPA, however, must ensure that savings estimates in one state are not systematically biased, or that energy efficiency providers forum-shop when seeking ERCs. A race-to-the-bottom on EM&V standards would risk the creation of ERCs that do not represent real emission reductions. EPA can take three actions to prevent these bad outcomes. First, energy efficiency providers should only be issued ERCs in the state where projects occur. Second, EPA should implement a system to compare savings estimates and savings estimation methodologies across states. This would allow EPA to identify outliers and understand whether over-estimated savings are due to valid differences between states or due to systematic biases. Recent research has shown that there is in fact divergence in EM&V methods and savings estimates across states.[40] EPA could repeat this research at regular intervals. EPA could also develop a national database of savings estimates for measures and programs. Initially, EPA could compare TRM savings estimates for similar measures. EPA should include in the model trading rule a requirement for ERC seekers to supply information to a national database, which could leverage the reporting tool developed

[40] Schiller, S., Goldman, C., and Galawish, E., National Energy Efficiency Evaluation, Measurement and Verification (EM&V) Standard: Scoping Study of Issues and Implementation Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-4265E, April 2011, available at: http://emp.lbl.gov/publications/national-energy-efficiency-evaluation-measurement-and-verification-emv-standard-scoping.

by Lawrence Berkeley National Laboratory, which allows energy efficiency program providers to report program details and savings estimates in a consistent format.[41]

D. Federal Plan and State Plan Interactions

NRDC supports EPA's proposal that if a state with a federal plan elects to develop a state plan, the transition from federal to state plan should only happen at the end of a compliance period.

[41] Rybka, G., Hoffman, I., Goldman, C., and Schwartz, L., Flexible and Consistent Reporting for Energy Efficiency Programs: Introducing a New Tool for Reporting Spending and Savings for Programs Funded by Utility Customers, Lawrence Berkeley National Laboratory, LBNL-1003879, 2015, available at: https://emp.lbl.gov/publications/flexible-and-consistent-reporting.

V. Mass-Based Implementation Approach

A. General Recommendations

NRDC generally supports a mass-based approach as a well-known and effective compliance option. However, as EPA has recognized in the Emission Guidelines, a mass-based plan that covers only existing fossil fuel-fired power plants can fail to achieve the emission reductions consistent with the BSER due to leakage to new sources. NRDC cannot endorse a mass-based approach that covers only existing sources until EPA develops an effective way to address leakage. We provide more detailed comments about addressing leakage in Section V.B. below.

NRDC strongly opposes allocation of allowances to affected EGUs on a permanent historic basis without updating, as EPA has proposed. Instead, we favor the use of an auction, or alternatively allocation to electricity customers via electric distribution companies. However, in the case of an existing only mass-based approach, alternative allocation approaches will be required to address leakage if new sources are not included in a state plan. NRDC supports state flexibility in replacing EPA's federal plan allowance distribution with a state-determined method but we recommend that this option should only be available to states that elect to cover new sources under a mass-based approach. More detailed comments about allowance distribution under federal and state plans follow in Sections V.D. and V.E.

Additionally, we recommend that EPA proactively affirm that states can choose to tighten their mass-based goals, retire allowances, or use mechanisms like auction reserve prices to deliver a better environmental outcome. States should be able to do so in their state plan as submitted, or to do so at a later date without necessitating plan revision or re-approval by EPA.

B. Addressing Potential Emissions Leakage to New Sources

NRDC has significant concerns about the potential for emissions leakage to new fossil fuel-fired sources under a mass-based approach that covers only existing sources. We support EPA's effort to prevent this problem by requiring that mass-based state plans address leakage, and we strongly prefer that states do so by covering both new and existing sources under one mass-based emission limit. The other options for addressing leakage—an allocation methodology or an alternative approach proposed by the state—must be substantially revised before NRDC can support a mass-based approach that covers only existing sources.

Background

EPA's final Emission Guidelines establish subcategory-specific emission performance rates that reflect quantification of the BSER. As alternative options for states, EPA also finalized state-specific rate-based and mass-based goals as equivalent quantitative expressions of the BSER. States and other stakeholders requested the ability to use mass-based approaches, and EPA has provided mass goals as a core option for consideration by states and as a potential approach for a federal plan. To calculate state mass goals, EPA estimated the emissions from existing and new sources under a rate-based approach and used that estimate to set a mass-based emissions limit for existing sources only and a limit for existing and new sources using the New Source Complement.

In the final rule, EPA identified "a concern that a mass-based state plan that failed to include appropriate measures to address leakage could result in failure to achieve emission performance levels consistent with the BSER."[42] This concern arises under a mass-based emission limit that covers only existing sources, which creates "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."[43] That is, a mass-based program that covers only existing sources creates an incentive to shift generation to new fossil fuel-fired sources not covered by the mass emission limit.

EPA's final rule appropriately requires that mass-based state plans address the risk of potential emission leakage. The final rule regulatory text indicates that in order to address leakage a plan must include "[r]equirements that address increased emissions from new sources, beyond the emissions expected from new sources if existing EGUs were given standards of performance in the form of the subcategory-specific emission performance rates."[44] Since EPA calculated the mass-based CO_2 goals and New Source Complements to be quantitatively equivalent to the subcategory-specific rate-based expression of the BSER, it is appropriate to assess the effectiveness of any proposed method of addressing leakage by comparing the total emissions outcome delivered by the leakage solution with the total mass-based emissions limit for existing plus new sources set by EPA.[45] [46]

EPA has authority to require mass-based plans to address potential leakage to new sources. Since EPA has provided the mass-based approach as an option for states to use in lieu of the subcategory-specific emission performance rates, EPA has the authority to condition the use of that optional approach on the inclusion of safeguards to assure an equivalent environmental outcome—in particular, to prevent or compensate for shifts of generation from existing to new sources that that would result in increased emissions. Contrary to the assertion by some commenters, imposing such leakage prevention measures does not impermissibly regulate new source emissions; rather such measures regulate the emissions of

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[42] CPP Final Emission Guidelines, 80 Fed. Reg. at 64,821.

[43] *Id.* at 64, 822. In a rate-based approach, for each MWh of generation from an affected source that is above the performance rate, the source must purchase a credit from lower-emitting generation. Thus, the BSER is implemented through a shift from higher-emitting coal plants to lower-emitting existing gas plants and from both coal and gas plants to low- or zero-emitting generation. In a mass-based context, if only emissions from existing fossil plants are constrained by an emissions budget without sufficient incentives for clean energy or existing gas generation, new fossil plants could meet demand that under a rate-based approach would have been met using cleaner resources.

[44] CPP Final Emission Guidelines, 80 Fed. Reg. at 64,949.

[45] We also note that assessment of emissions leakage is made more complicated by allowing states to trade emissions allowances under a mass-based approach, as market forces and emissions reduction opportunities may deliver more emissions in one state and less in another.

[46] Another way to assess leakage is to evaluate whether the electricity demand served by existing fossil plants and clean energy resources (renewable energy and energy efficiency) is equal to the electricity demand that would be served under the rate-based scenario used to establish the mass-based limits (i.e., the generation from existing fossil plants under that rate-based scenario plus renewable generation providing ERCs).

existing sources to prevent emissions leakage, or to compensate for such leakage as it occurs, in order to assure an equivalent emissions outcome under optional approaches to implementing the BSER.

EPA's Proposed Approaches for Addressing Emissions Leakage

The final rule provides three options for states to demonstrate that leakage has been addressed:

> 1. Regulate new non-affected fossil EGUs as a matter of state law in conjunction with emission standards for affected EGUs in a mass-based plan…
> 2. Use allocation methods in the state plan that counteract incentives to shift generation from affected EGUs to unaffected fossil-fired sources...
> 3. Provide a demonstration in the state plan, supported by analysis, that emission leakage is unlikely to occur due to unique state characteristics or state plan design elements that address and mitigate the potential for emission leakage.[47]

EPA has proposed the use of Option 2, an allocation methodology, for both the federal plan and as a presumptively-approvable strategy to address leakage in the model trading rule. But EPA has not conducted sufficient analysis to demonstrate that the options they propose would actually prevent emissions leakage. As discussed below, NRDC and others have conducted analysis which shows that the specific allocation measures EPA has proposed are not adequate to prevent very substantial leakage to new sources. NRDC also has concerns about the lack of rigor in EPA's proposal for demonstrations submitted under Option 3, and we recommend specific safeguards for the use of this approach below.

As discussed above, the final Emissions Guidelines define leakage as "increased emissions from new sources, beyond the emissions expected from new sources" under the subcategory-specific emission performance rates.[48] The effectiveness of the proposed approaches should therefore be assessed on the basis of the emissions outcomes they achieve. Since the sum of the mass-based CO_2 goals plus the New Source Complements were intended by EPA to be quantitatively equivalent to the subcategory-specific rates, it is appropriate to compare the overall emissions outcomes delivered by the proposed approaches to the total mass-based emissions limit for existing plus new sources.

The technical analysis described below demonstrates that neither Option 2 nor Option 3 effectively addresses leakage as required by the Emissions Guidelines. We believe that finalizing either of these options as proposed would be arbitrary and fail to satisfy the Clean Air Act's requirements, because neither would assure the requisite equivalent emissions outcome. If EPA were to finalize the options as proposed, NRDC would have to consider whether to challenge a federal plan or any approved state plans that relied either of those approaches.

Option 1 – Cover New Sources

Option 1 is to apply the applicable mass target (i.e., the state mass CO_2 goal plus the New Source Complement) to all existing and new fossil fuel-fired EGUs. This approach clearly prevents emissions

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[47] CPP Final Emission Guidelines, 80 Fed. Reg. at 64,888.
[48] *Id*. at 64,949.

leakage to new sources and is guaranteed to deliver an emissions outcome consistent with EPA's quantification of emissions under a rate-based approach, as total emissions are limited and all fossil sources are covered.[49] NRDC believes this approach best satisfies the emissions-based assessment set forth above, and it is also the most administratively straightforward approach.

NRDC recommends that EPA issue a model trading rule that uses this approach. EPA should clearly encourage states to adopt this approach as the preferred option and allow interstate trading among states that have adopted this approach.

EPA has indicated that the agency does not intend to implement a federal plan that includes new sources without state cooperation, and has therefore proposed to use Option 2 in a mass-based federal plan. NRDC recommends that EPA provide states the opportunity to elect to use Option 1 to address leakage under a federal plan. We further recommend that only states that utilize this option should be able to replace the federal plan allowance distribution with another method of the state's choosing, as discussed below in Section V.E.

Option 2 – Allocation Methodology

Option 2 is to establish a mass-based target for existing sources only and distribute allowances using "allowance allocation methods that align incentives to generate to existing or new sources."[50] EPA has proposed an allocation methodology for both the federal plan and model trading rule which involves allocating most CO_2 emission allowances to existing affected EGUs on a historic generation basis and using two small set-asides to address potential emission leakage: a limited output-based allocation set-aside for existing natural gas units beginning in the second compliance period, and a set-aside that reserves five percent of the state's allowances for renewable energy projects.

EPA's proposed allowance distribution method is entirely inadequate to address emissions leakage.[51] For an allowance method in an existing-only mass-based plan to effectively address emissions leakage to new sources and achieve an emissions outcome consistent with the BSER, the program structure must deliver incentives for existing natural gas and new non-emitting generation that are consistent with the incentives under the subcategory-specific rate-based standard, which awards renewable energy generation and energy efficiency significantly more credit per MWh than existing natural gas generation. As demonstrated below, the proposed set-aside for existing NGCC is not large enough to counteract the

[49] Under some modeling scenarios, a rate-based approach could deliver a better emissions outcome than that which EPA quantified in calculating the mass-based CO_2 goals and New Source Complements. *See* M.J. Bradley & Associates, EPA's Clean Power Plan: Summary of IPM Modeling Results (Jan. 13, 2016), *available at:* http://mjbradley.com/sites/default/files/MJBA_CPP_IPM_Analysis.pdf.

[50] CPP Final Emission Guidelines, 80 Fed. Reg. at 64,949.

[51] In addition to failing to address emissions leakage, EPA's proposed allocation approach suffers from implementation-related flaws. The proposed set-aside for existing natural gas generation is made unnecessarily complex by allocating only to those units operating above a specified capacity factor for that portion of their output; any output based set aside for existing natural gas generation should be allocated to all eligible generators (i.e., removing the capacity factor threshold). Additionally, EPA's proposed "lagged accounting procedure" creates too much delay between eligible generation and allocation; NRDC recommends allowances be allocated quarterly on an updating output basis.

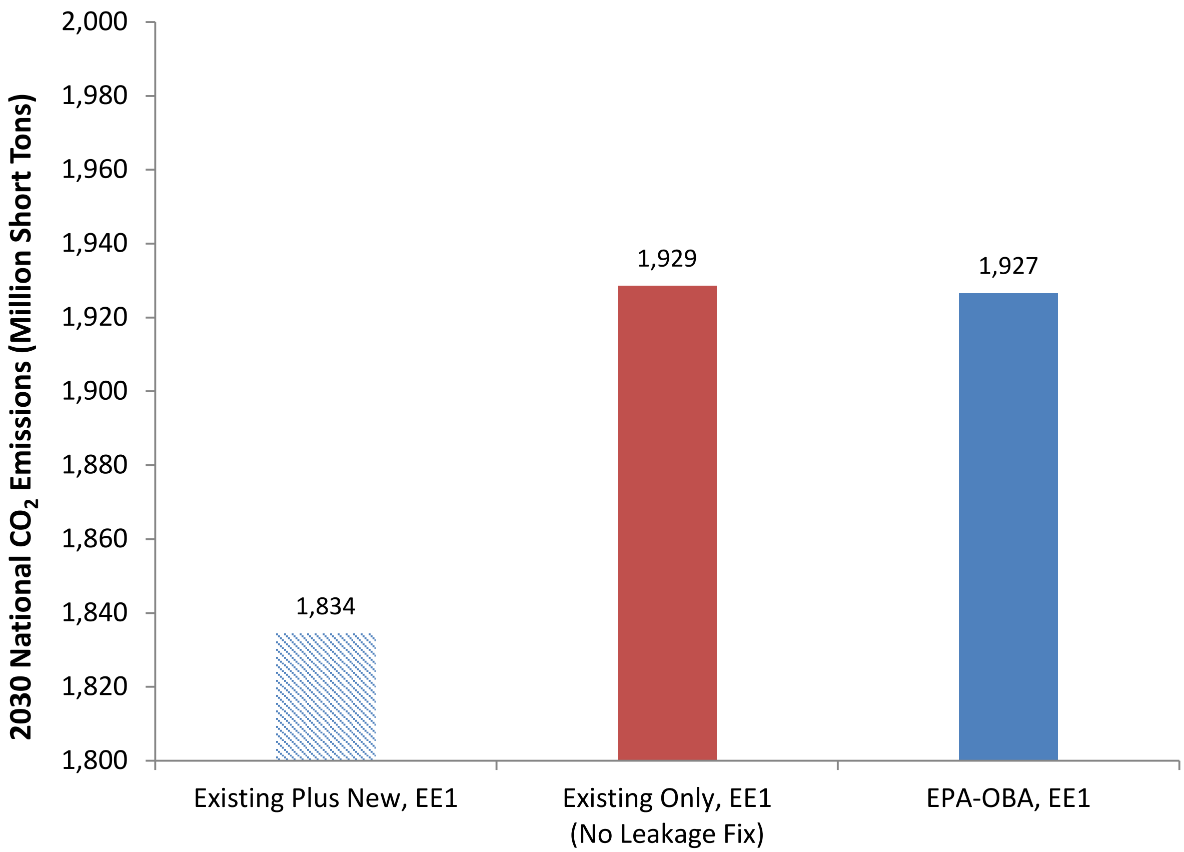
incentive to shift generation from existing NGCC to new NGCC. Similarly, the proposed five-percent set-aside for new renewable energy is not large enough to counteract the potential for significant additions of new fossil generation to meet demand.

A recent analysis by M.J. Bradley & Associates (MJB&A),[52] based on Integrated Planning Model (IPM®) runs conducted by ICF International with assumptions developed by MJB&A, shows that the proposed allocation method results in a significantly worse emissions outcome than the existing plus new emissions limit. According to this analysis, total CO_2 emissions in 2030 from the power sector would increase by 94 million tons under an "Existing Only" mass target (without leakage mitigation provisions) compared with emissions under an "Existing plus New" mass target—that is, emissions leakage of 94 million tons is projected to occur without provisions to address leakage. A third model run (which we refer to as "EPA-OBA" for "EPA Output-Based Allocation") with assumptions to represent the updating output-based allocation for NGCC generators and the set-aside for new non-emitting generation shows that EPA's proposed allocation has a negligible impact on projected emissions compared to an "Existing Only" target with no leakage provisions at all.[53] Specifically, the model projected that the total CO_2 emissions from the electric power sector would be 1,929 million short tons in 2030 in the "Existing Only" case, compared with 1,834 million tons in the "Existing plus New" case and 1,927 million short tons in the "EPA-OBA" case in the same year. This small difference in emissions compared with the "Existing Only" case—2 million tons, or 2 percent of the 94 million ton gap between the "Existing Only" case and the "Existing Plus New" case—demonstrates that the EPA's proposed approach is inadequate and would not fulfill the EPA requirement to mitigate leakage in mass-based plan. Figure 1 below demonstrates the minimal impact of the allocation approach in the "EPA-OBA" run.

[52] M.J. Bradley & Associates, EPA's Clean Power Plan: Summary of IPM Modeling Results (Jan. 13, 2016), available at http://www.mjbradley.com/sites/default/files/MJBA_CPP_IPM_Analysis_1.pdf. The full report is attached to this comment as Appendix A.

[53] All three runs assume an available level of energy efficiency savings of 1% per year ("EE1"), equal to the energy efficiency savings levels EPA included in its analysis of the Clean Power Plan. More details on the modeling of energy efficiency can be found on slides 6 and 25 of the MJB&A IPM Summary Report.

Figure 1: National power sector CO_2 emissions in 2030 in an Existing Plus New approach, compared to an Existing Only approach both with and without EPA's leakage fix



NRDC built upon the MJB&A analysis and utilized the same IPM® modeling platform[54] to evaluate how the impact of EPA's proposed output-based allocation and set-aside approach would change if it were adjusted to reflect the options on which EPA requests comment in the federal plan proposal. EPA is taking comments from stakeholders on whether to increase the set-aside of allowances for renewable energy generation from 5 percent to 10 percent of the total pool of allowances, as well as other components of the NGCC allocation, including the size of the allocation, the allocation rate, and the allocation procedures. Our analysis examines expanding the set-aside for renewables to 10% and removing the utilization rate constraint for the output-based allocation to existing NGCC units, and concludes that these two changes are insufficient to address leakage.

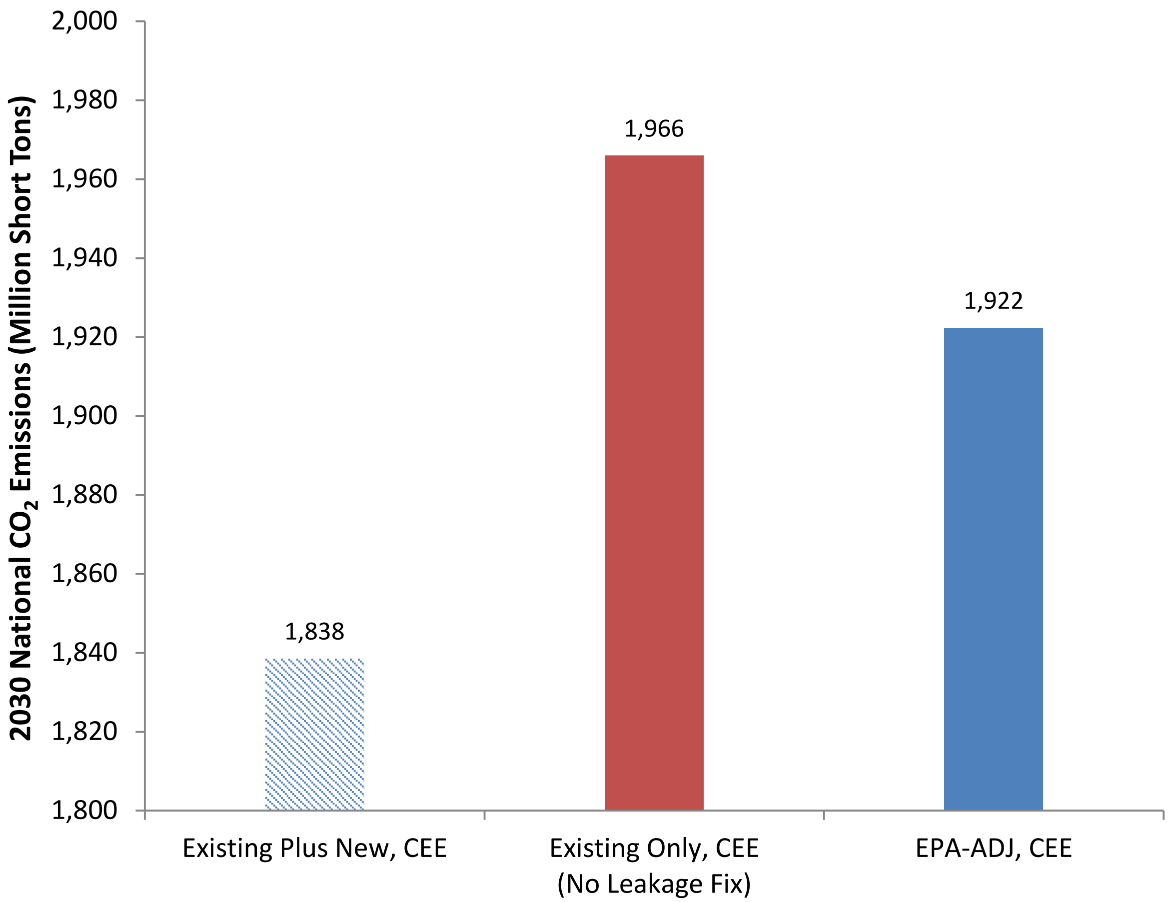
NRDC constructed a model run to reflect these adjustments, assuming extensions of current levels of energy efficiency ("CEE").[55] Figure Y below illustrates the additional emission reductions that the

[54] ICF performed the analysis in IPM® using NRDC assumptions and policy specifications. NRDC relied on the same assumptions as the MJB&A analysis.

[55] The Current EE ("CEE") assumptions used here assume an extension of current (2013) levels of energy efficiency savings. NRDC chose to vary the energy efficiency assumption in this case to test the potential for the adjusted

adjusted approach, identified as "EPA – ADJ," is projected to deliver, along with "Existing Only" and "Existing plus New" scenarios using the same efficiency assumptions for comparison. Total CO_2 emissions in "EPA – ADJ" reach 1,922 million tons in 2030, compared with 1,966 million tons in the "EPA – OBA" and "Existing Only" cases. Based on this projection, "EPA – ADJ" reduces leakage by 44 million tons, or 34% out of the total 128 million tons of leakage initially observed between the "Existing Only" and the "Existing plus New" cases at current levels of energy efficiency savings. Because the projected emission reductions in "EPA – ADJ" are not consistent with those projected in the "Existing plus New" case, this analysis shows that "EPA – ADJ" does not sufficiently mitigate leakage.[56]

Figure 2: National power sector CO_2 emissions in 2030 in an Existing Plus New approach, compared to an Existing Only approach both with and without EPA's adjusted leakage fix



Given the ineffectiveness of EPA's proposed approach and the adjustments on which EPA requests comment, NRDC recommends that the option to address emissions leakage using an allocation

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program to drive new zero-emitting generation. The CEE assumptions used by NRDC are consistent with the CEE assumptions used for certain scenarios modeled by MJB&A in the analysis discussed above.

[56] Note that NRDC's "EPA – ADJ" policy case is not directly comparable to MJB&A's "EPA – OBA" case because of the difference in the amount of energy efficiency savings between the two scenarios.

methodology should only be retained if EPA can demonstrate through electric sector modeling that there is an allocation approach that achieves an emissions outcome consistent with the existing plus new limits and delivers incentives consistent with the subcategorized rate approach.

Alternative Allocation Methods Analyzed by NRDC

NRDC has conducted preliminary analysis of a range of updating allocation options to identify allocation methods that better align the incentives for new non-emitting resources and existing natural gas with the incentives under the subcategorized rate approach to achieve emissions outcomes equivalent to the existing plus new limits.[57] Of the modeled approaches, we have identified two that improve the incentives for new non-emitting resources and existing natural gas, and significantly reduce—but do not eliminate—the emissions increase between an existing only program and an existing plus new program. The first, "NGCC + Clean 3," is an updating output-based allocation to new non-emitting and existing natural gas generation designed to mimic the incentives under a subcategorized rate standard. The second, "Index," is an updating output-based allocation to all resources based on an indexed emissions factor. Several other allocation options modeled were significantly less effective at mitigating emissions leakage. The methodology and results of this analysis are summarized below; more detail on this preliminary analysis is provided in Appendix B. NRDC plans to continue working on other approaches to leakage mitigation, and will further analyze a broad menu of options. Assuming new and improved approaches and results, NRDC will publish additional results in the coming months as a resource for EPA, states, and other stakeholders.

Methodology

Updating OBA "NGCC + Clean 3" – Output based allocation to new non-emitting and existing natural gas to mimic subcategory-specific rate incentives

The "NGCC + Clean 3" approach is designed to recreate the incentives for new non-emitting generation and existing natural gas generation similar to what would exist under the subcategory-specific emission performance rates.[58]

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[57] This work is preliminary and NRDC plans to continue to develop and expand on the market-based approaches described here. It is important to note here that this entire set of runs does not include the recent phase-down of the PTC and extension of the ITC, which should further mitigate leakage by providing additional incentives for renewable energy prior to the beginning of the CPP.

[58] The credit provided for GS-ERCs, depending on the unit's emissions rate and the incremental generation factor, can range from about 0.10 to 0.13 GS-ERCs per MWh in the interim period. New non-emitting resources receive 1 ERC per MWh, leading to a larger incentive for these resources than for existing NGCC units (as is consistent with EPA's methodology for determining the best system of emission reductions). The impact of this incentive structure is borne out by the MJB&A IPM Summary Report analysis, which demonstrates a large build-out of renewable resources under the subcategorized rate program. It is important to note that the build-out of renewables in the subcategorized rate modeling more closely resembles the levels of renewables assumed by EPA when setting the mass-based limits, and the levels of zero-emitting resources can even exceed those levels under certain levels of energy efficiency. In contrast, under an existing only approach without leakage provisions, there does not exist the same incentive to develop non-emitting resources rather than ramping up new natural gas generation, unless appropriate steps are taken to replicate the subcategorized rate incentives for non-emitting resources.

Allowances are allocated quarterly on an updating output basis. First, allowances are allocated on an output basis to existing natural gas at a rate of 0.5 tons per MWh generated. This allocation approximates the incentives under a subcategorized rate program, in which existing NGCC units have both an ERC obligation and a credit in the form of GS-ERCs and new non-emitting resources receive one full ERC for every MWh they generate. There is no capacity factor threshold in this allocation approach – all existing NGCC generation is eligible to receive allowances. Second, the remainder of the allowance budget is allocated to new non-emitting resources, defined with the same eligibility requirements as is necessary for ERC creation, on an updating output basis. Due to total allowance budget constraints, new non-emitting generation is allocated 2.0 to 3.5 tons per MWh of output.[59]

Updating OBA "Index" – Output based allocation to all resources based on an emissions factor

This method of allocation uses an updating emissions index to create similar, but not identical, incentives as the subcategory-specific rate-based standard. The emissions index operates by assigning an emissions factor to all generation according to its emissions intensity:

- Emissions rate >= 2000 lbs/MWh = 0x
- Emissions rate = 1000 lbs/MWh = 0.5x
- Emissions rate = 0 lbs/MWh = 1x

Allowances are then allocated quarterly on an updating output basis to all existing fossil and new non-emitting generation by multiplying the appropriate emissions factor by generation. In this approach, the actual allocation per MWh by resource varies such that the allowance budget is fully utilized.[60]

Updating OBA "NGCC + Clean 1"

This approach is similar to the "NGCC + Clean 3" approach. Existing NGCC units receive 0.5 tons/MWh on an updating output basis, with no capacity factor threshold for eligibility. This approach differs from the "NGCC + Clean 3" approach by only allocating 1 ton/MWh to new non-emitting resources, and assumes the remainder of the budget is auctioned.

Updating OBA - All

All existing fossil and existing and new non-emitting resources are eligible to earn allowances on a generation basis, with no adjustment for each unit's emissions. Allocation is 0.68 tons/MWh in 2025, declining to 0.62 tons/MWh in 2030.

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[59] An iterative approach in IPM was used in order to determine the allocation to new non-emitting resources such that the allowance budget was not exceeded. The final allocation in 2025 was: 0.5 tons/MWh to existing gas; 3.32 tons/MWh to new non-emitting. The final allocation in 2030 was: 0.5 tons/MWh to existing gas; 2.12 tons/MWh to new non-emitting.

[60] An iterative approach in IPM was used in order to determine the allocation to new non-emitting resources such that the allowance budget was not exceeded. The final average allocation in 2025 was: 0.75 tons/MWh to Oil/Gas Steam units; 1.14 tons/MWh to existing NGCC units; 1.9 tons/MWh to new non-emitting resources. The final average allocation in 2030 was: 0.48 tons/MWh to Oil/Gas Steam units; 0.84 tons/MWh to existing NGCC units; 1.41 tons/MWh to new non-emitting resources.

New Source Fee

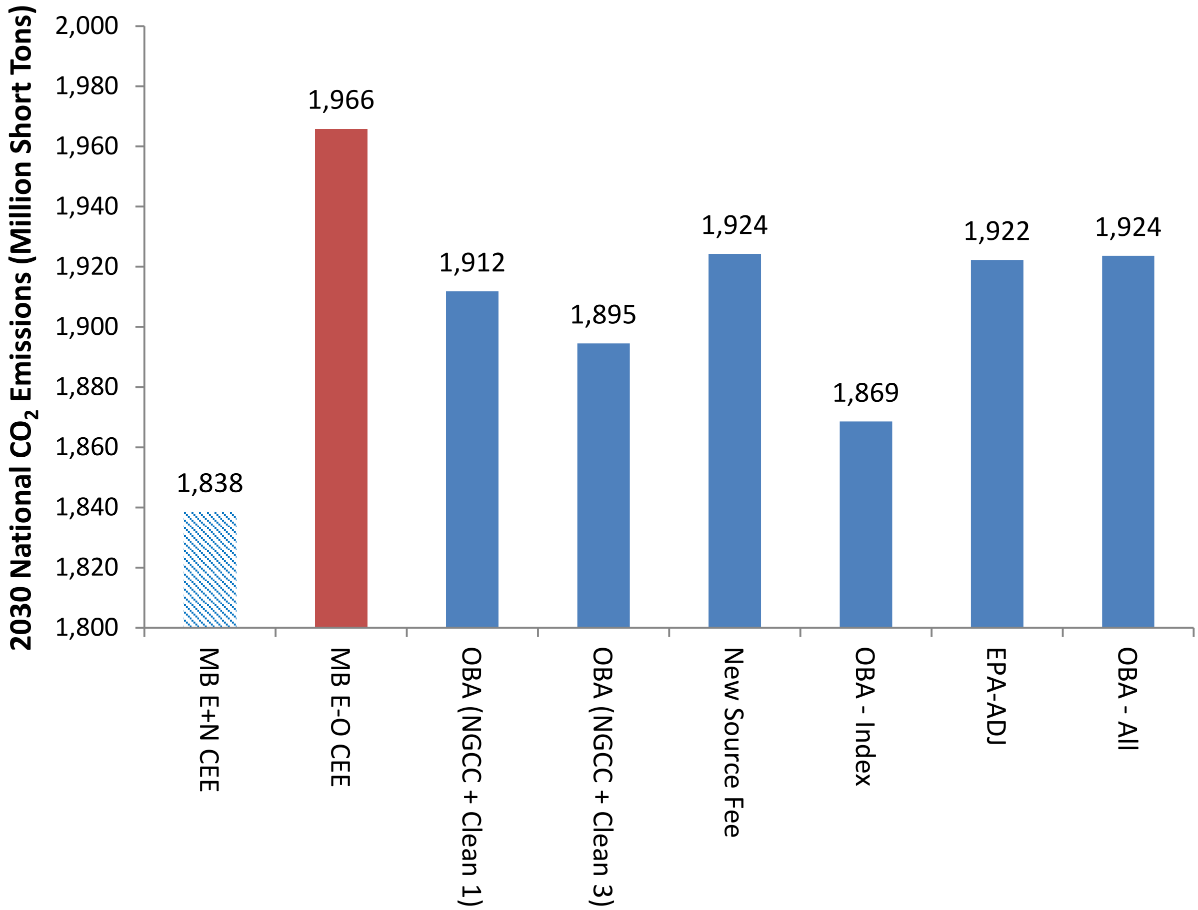
EPA would not implement a fee on new sources under the federal plan, but states may choose to do so as one option to mitigate leakage. NRDC modeled the fee on new sources based on the allowance price found in the “Existing + New” case, while the mass-based limits were imposed on existing sources only.

Results

Using “current EE” assumptions, the gap in overall emissions between an “existing only” and “existing plus new” mass-based program can reach up to 128 million tons—that is, up to 128 million tons of emissions leakage may occur. Our results indicate that the approaches that most closely resemble the incentives under the subcategorized rate structure – the updating allocation approaches, “NGCC + Clean 3” and “Index” – are also the most effective in mitigating leakage and reducing the gap between those existing only approaches and the “existing plus new” emissions outcome. In this analysis, those approaches reduce the difference in overall emissions outcomes between the “existing only” and “existing plus new” mass-based programs by 56% (“NGCC + Clean 3”) to 76% (“Index”). Both of these approaches utilize the entire allowance budget for updating allocation; NRDC believes that 100 percent utilization is necessary to re-create the strong incentives for zero and lower-emitting resources that occur under the subcategorized rate approach.

The “New Source Fee”, “OBA – All”, and “NGCC + Clean 1” allocation methods are significantly less effective at mitigating leakage, only reducing the emissions gap by between 33% and 42%. All three approaches achieve very similar emissions outcomes; the projected generation mix varies as a result of the allocation approach. In comparing the “NGCC + Clean 1” case and “NGCC + Clean 3” case, the results demonstrate significant improvement in emissions outcome when 100% of the allowance budget is directed towards leakage mitigation. Figure 3 below shows the differences in overall emissions outcomes among the modeled allocation approaches.

Figure 3: National power sector CO_2 emissions in 2030, in all modeled approaches



Conclusions on Allocation

Analysis by MJB&A and NRDC demonstrate that EPA's proposed allocation methodology and alternatives do not effectively address leakage. Recent analysis from Resources for the Future also supports the conclusion that EPA's proposal is ineffective and the alternative approaches they analyzed, which have some similarities to NRDC's analysis, deliver improved emissions outcomes but not a full solution.[61] If EPA retains an allocation methodology as a leakage remedy under the mass-based compliance option, its proposal must be revised to improve the incentives created for existing natural gas and new non-emitting resources (primarily renewables and energy efficiency) in order to prevent leakage and achieve an emissions outcome consistent with the emissions limit for existing and new sources.

[61] Resources for the Future, Approaches to Address Potential CO_2 Emissions Leakage to New Sources under the Clean Power Plan: Technical Background for Comments to EPA (January 20, 2016), available at: http://www.rff.org/files/RFF-CPP_Technical-Background.pdf.

NRDC strongly believes that any allocation method included in the model rule or federal plan must achieve an emissions outcome consistent with the emissions limit for existing plus new sources.[62] Based on NRDC's preliminary analysis, for an allocation method to effectively address leakage, it must re-create the strong incentives for zero and lower-emitting resources that occur under the subcategorized rate approach. Our analysis shows that 100 percent of the state's allowance budget (after removing the CEIP set-aside, if applicable) should be utilized to prevent leakage in an "existing only" mass-based approach. Finally, NRDC believes that any allocation to coal units is neither economically efficient nor effective as a leakage provision. The production incentive provided by an allocation to coal units is counteracted by the mass limits, and drives allowance prices artificially higher. NRDC strongly recommends that EPA not include an allocation to coal units in the leakage provisions the agency finalizes.

If EPA can develop and analyze an alternative allocation approach that delivers a consistent emissions outcome, then it could be included as a presumptively approvable allocation approach for a state plan. This would allow a state to commit to the allocation approach and receive approval to trade with other states. This approach would also be suitable for a mass-based federal plan.

If EPA is unable to develop an allocation approach that delivers the appropriate emissions outcome, then EPA should remove the option of using an allocation method to address leakage in a mass-based approach that covers existing sources only and limit the mass-based approach to one where states opt-in new sources.

Option 3 – State Demonstration

Under Option 3 for addressing leakage to new sources, a state may provide its own demonstration—supported by analysis—that emission leakage is unlikely to occur. While it is reasonable for EPA to provide a route for case-by-case assessment of alternative leakage-prevention approaches in a mass-based state plan, such an option must contain robust performance criteria. Without such criteria, a case-by-case approach could become an avenue for gaming the analysis supporting such demonstrations and could result in substantial emissions leakage. Any case-by-case approach will contain inherent uncertainties regarding whether leakage may occur in the real world. Accordingly, if EPA chooses to retain this option, it is imperative that EPA provide clear guidance regarding approvable approaches <u>and</u> require a backstop to ensure an equivalent emissions outcome.

The backstop should take the form of a requirement for states to assess and make up any emissions that exceed the existing plus new emission limits, in a manner similar to the state measure approach. The state plan should describe a mechanism by which the state would "true-up" any emissions exceedance; this true-up requirement could be achieved by covering new sources, committing to expand non-emitting resources, or adjusting downwards the emissions limit for existing sources. Total emissions from existing and new sources should be assessed at the end of every 3 or 2 year compliance period,

[62] The analysis provided here examines only 2030 emissions outcomes; however, to demonstrate that an allocation method prevents it must deliver an emissions outcome equivalent to the existing plus new source emission limits in each compliance period.

and the backstop should be automatically triggered by an exceedance as is done under a state measures approach. In aggregate, total emissions from existing plus new sources over the interim period must not exceed the cumulative limits for the period.

Additionally, because of the uncertainty inherent in this approach and the difficulty of implementing the necessary tracking and adjustments in a multi-state trading context, NRDC recommends that EPA allow the use of Option 3 only in states that do not participate in interstate allowance trading, or in states trading with specified partners, all of whom adopt harmonized backstop and true-up provisions.

C. Compliance Timing and Allowance Banking, Borrowing, and Tracking

EPA has proposed to evaluate compliance at the end of each multi-year compliance period. NRDC supports this approach, but encourages EPA to add an intervening compliance requirement to hold a minimum portion of allowances at the end of each year. An intervening compliance requirement is an important mechanism to address situations where EGUs are financially distressed or in bankruptcy. The RGGI program provides an example of this approach.[63]

NRDC supports EPA's proposal that allowances may be banked for use in a future compliance period. NRDC also supports EPA's proposal to not allow borrowing of allowances from future compliance periods. NRDC does favor early auction of allowances to support price discovery, but these allowances would need to be banked until the appropriate compliance period.

EPA's proposal would require sources to demonstrate compliance (i.e., allowance true-up) on May 1 of the year after the last year in the compliance period. NRDC recommends that EPA consider whether to align this deadline with compliance deadlines in other power sector trading programs, such as the Acid Rain Program, the Regional Greenhouse Gas Initiative, and California's Cap and Trade Program.[64] We also note that EPA should not allow borrowing of allowances from the subsequent compliance period, even if those allowances are available prior to the compliance demonstration date.

EPA proposes that if a source fails to hold allowances as required to cover its emissions over the compliance period, the source must surrender two allowances for every one allowance it failed to hold. NRDC believes this two-to-one ratio does not impose a sufficient penalty to deter non-compliance. Other market-based programs use higher ratios –for example, California's Cap and Trade program requires surrender of four allowances per ton exceeded,[65] and RGGI requires three.[66] NRDC recommends that EPA increase the allowance deduction requirement to four allowances per one allowance not held.

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[63] Regional Greenhouse Gas Initiative Model Rule (Dec. 31, 2008), https://www.rggi.org/docs/Model%20Rule%20Revised%2012.31.08.pdf.
[64] In Section IV.C. above, we recommend that EPA move the proposed November 1 compliance deadline for rate-based programs forward and align that deadline with the mass-based compliance demonstration deadline.
[65] California Code of Regulations § 95857(b)(2).
[66] Regional Greenhouse Gas Initiative, Fact Sheet: RGGI CO_2 Allowance Tracking System (RGGI COATS), http://rggi.org/docs/Documents/RGGI_COATS_FactSheet.pdf.

D. Initial Distribution of Allowances

EPA has proposed to allocate allowances on a permanent historic basis without updating. NRDC is strongly opposed to this approach. Emissions allowances have immediate and substantial financial value, and initial allowance distribution decisions will have significant impacts on distributional equity. A firm should not receive this value indefinitely based on historic generation. Freely allocating allowances to regulated entities creates the potential for windfall profits, particularly in competitive markets where compliance costs will be passed on to consumers. Such an allocation method also fails to promote investment in non-emitting resources.

As addressed above, any mass-based program that covers only existing sources must contain a robust method for preventing potential emissions leakage to new sources. The following discussion of allowance distribution methods assumes that an effective leakage provision (i.e., covering new sources or an improved allowance set-aside approach) is in place.

NRDC's favored approach to allowance distribution is the use of an auction of all allowances on behalf of the state, with a third party to conduct the auction and deposit auction revenue in an account designated by the state. Revenues generated by auctioning allowances can be used to achieve public policy goals, such as investing in energy efficiency, minimizing impacts on vulnerable customers and communities, and incentivizing clean energy development.

Alternatively, NRDC would also support allocation of allowances to electricity customers. This method would use electric distribution companies (not load serving entities, which can also be competitive suppliers) as the recipient, and would require the state utility commission to oversee the sale and use of allowances for customer benefit.

NRDC generally disfavors free allocation to electricity generators. However, if such a method were used it would be important to allocate to both fossil fuel-fired and non-emitting generators (and energy efficiency providers). It would also be important for such a method to include regular updating of the baseline on which the allocation is determined, in order to accommodate changes in the market over time. Finally, such an allocation should incentivize clean and low-emitting generation; therefore it should be based on output rather than proportional emissions (or alternatively, the allocation could be based on the inverse of emissions, such that zero-emitting generators get the highest per-MWh allocation).

NRDC does not support allocation to only fossil fuel-fired EGUs, and we oppose allocation based on proportional emissions.

E. State-Determined Allowance Distribution

EPA proposes that a state in which a federal plan is implemented may choose to replace the federal plan allowance distribution with another method of the state's choosing, as long as the approach addresses emissions leakage and includes the Clean Energy Incentive Program. NRDC recommends that this option should only be made available to states that elect to cover new sources. In order to invoke this option, the state should be required to request it immediately upon EPA providing notice of a federal plan or at least one year prior to the next compliance period, so that a shift from the federal plan approach to a state-designed allocation approach occurs only at the end of a compliance period.

As discussed above, NRDC recommends that EPA eliminate allocation of allowances on a historic emissions basis from their approach in the model and federal plan. EPA should also disallow the use of permanent historic allocation approaches and require that states allocating allowances to generators must use updating allocation approaches.

We also recommend that EPA either require or indicate a preference for auction and allocation approaches that are customer-focused (e.g., allocation to distribution companies with value returned to customers) or provide additional incentives for clean energy development that will be essential to meeting the CPP goals.

F. Treatment of States Entering or Exiting the Trading Program

NRDC supports EPA's proposal to allow states to replace the federal plan with an approved state plan, and agrees with EPA that this transition should only occur at the end of a compliance period and before federal plan allowances for the next compliance period have been recorded. However, NRDC also recommends that EPA also require that a state electing to replace a federal plan must retain the same policy approach—that is, if the federal plan is mass-based, the state may only replace it with an approved mass-based state plan.

G. Emissions Monitoring and Reporting Requirements

EPA requests comment on whether to require early emissions and generation monitoring and reporting at least a year prior to the start of the program. NRDC supports this requirement, which will produce the data necessary to implement an output based allocation approach.

VI. Clean Energy Incentive Program

NRDC supports the goals of the Clean Energy Incentive Program (CEIP), which is designed to encourage early investment in clean energy resources. The renewable energy technologies eligible for the CEIP are an important part of the best system of emission reductions, and the objective of the CEIP is to help remove market barriers that would prevent or delay the build-out of these technologies until the initial compliance period, which could in turn lead to over-reliance on natural gas generation as a compliance strategy.[67]

NRDC describes below initial recommendations to improve the CEIP – including steps that can be taken to provide a more transparent price signal to investors and drive new investments, and ensure that allowances are not solely or primarily awarded to projects that would have occurred without the CEIP in place. Importantly, in order for the CEIP to deliver cumulative emission reductions, the program must spur new investments, beyond what would occur absent the program. It is thus important that EPA implement safeguards to prevent business as usual (BAU) projects from undermining the incentives for additional (beyond BAU) renewables and low-income energy efficiency.

NRDC offers the following recommendations to improve the CEIP with respect to four primary goals: (1) provide safeguards to avoid potential emissions erosion from the program; (2) create a clear and transparent market signal to RE investors in order to drive new investment; (3) ensure that the incentives for additional renewables and low-income energy efficiency are not undermined; and (4) extend access to CEIP crediting to distributed solar, an important and growing zero-emitting technology.

Driving new investment and a stronger environmental outcome

The recent extension of federal tax credits for onshore wind and solar PV technologies is an important policy development that will help ensure that clean energy is prioritized as part of the Clean Power Plan. These policy extensions are expected to drive significant renewable energy development between now and the start of the CPP compliance period, and are critically important for meeting U.S. climate goals. However, by expanding the pool of projects eligible for the CEIP, the tax credit extensions also heighten the potential for the CEIP to reward renewables projects that would have occurred anyway without the CEIP in place. As noted, if the CEIP simply rewards compliance value to business-as-usual projects, it will increase cumulative emissions over the 2020-2030 time period.[68]

[67] On December 15, 2015, NRDC submitted comments to EPA on the Clean Energy Incentive Program focused on the program's provisions for delivery of energy efficiency to low-income communities. The December comments are attached to this comment document as Appendix C.

[68] Under a mass-based program, if 1 million matching tons provided by EPA are given to projects that would have occurred without the CEIP, this adds 1 million tons to a state's mass budget in the 2022-2024 compliance period without resulting in any emission reductions in the 2020-2021 period, because that project would have been developed without the CEIP in place. On the other hand, projects that are incentivized by the CEIP (i.e. would not have occurred without the CEIP in place) receive 1 million tons from EPA, to be added to the 2022-2024 budget, while reducing emissions by 2 million tons in 2020-2021. Therefore, this project incentivized by the CEIP would reduce cumulative emissions by 1 million tons.

The impacts and interactions of the PTC and ITC with the CEIP have not been fully analyzed. NRDC has significant concerns that the CEIP may no longer drive additional early renewables deployment that would not have otherwise occurred given the new expected baseline level of renewables absent the CEIP. NRDC recommends that EPA further analyze, and request comment on, the interactions of the tax credit extensions and the CEIP. For example, EPA could request comment on possible adjustments such as making the quantity of the CEIP credit inversely proportional to the size of the tax credit received, such that a project receiving the full value of the tax credits would be awarded fewer CEIP credits than a project only receiving a phased-down fraction of the tax credits. In this way, EPA could both minimize emissions erosion from allowance awards to BAU projects, and provide stronger incentives for new, additional projects. Likewise, EPA should take comment on and evaluate different approaches to distributing the matching tons in order to maximize the additional (beyond BAU) RE projects and minimize the risk that the CEIP results in weakening the emission outcome.

NRDC is continuing to analyze the impact of the CEIP and would appreciate the opportunity to refine its views in an additional comment period. But at present, pending further NRDC analysis of the CEIP and tax extensions, NRDC recommends that the timeline of the CEIP, in terms of both project eligibility and the banking period, remain as proposed. The current eligibility date requirements can serve as an incentive for states to submit state plans prior to the 2018 deadline. Earlier submission of state plans is a positive development for all stakeholders, including renewable energy developers, and is an additional reason EPA should maintain the proposed eligibility timeline.

Additionally, to ensure that the CEIP is capable of driving additional projects as intended, EPA should help reduce the uncertainty surrounding the value of the program. NRDC recommends that EPA provide states with the option of providing CEIP allowances (including EPA's matching tons) earlier than 2020. Without changing the banking period of 2020-2021, allowances could be awarded early (before 2020) in order to allow developers to begin the price discovery process, and better understand how much value the allowances will have. NRDC expects that some utilities and/or financial institutions will wish to purchase and hold allowances/ERCs before the first compliance period begins. Such sales would provide an earlier revenue stream for developers, alleviating some of the uncertainty around the program and encourage increased development of additional (beyond BAU) RE projects. A true-up mechanism would be required in 2020-2021 to adjust for any variation between projected generation and actual generation levels. This is an important step EPA can take to ensure that additional projects are incentivized by the CEIP and emission reductions are achieved.

NRDC recommends that EPA also further analyze the appropriate division of the CEIP between renewables and low-income efficiency. EPA should evaluate the comparative incentives and barriers to low-income efficiency and renewable energy, including the implications of the recent tax extensions, to determine the size of each pool and whether this split should be done on a tonnage or MWh basis. EPA should request comment on this issue in its upcoming notice. NRDC understands that EPA will not re-

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As a result, at least 50% of EPA's matching pool for RE (75 million tons nationally) must be given to projects that are incentivized by the CEIP in order to achieve a neutral or stronger emissions outcome. There is a risk that most of the budget could instead be utilized by projects that would have occurred anyways, thus weakening cumulative emissions reductions over the 2020-2030 period.

allocate allowances from efficiency to renewables or between states. If this understanding is incorrect, then regardless of the size of each pool, NRDC strongly recommends that EPA provide sufficient period of time (at least until 2020) for low-income energy efficiency programs to take advantage of their share of the matching pool, and for states with historically low development of renewables to take advantage of the incentives, or consider not re-allocating those allowances if there is a risk those allowances will go primarily to BAU projects.

Eligibility of distributed energy resources

For the purposes of crediting under the CEIP, and for ERC issuance in a rate-based program, EPA has proposed that generation from renewable resources must be measured by revenue-quality meters. As discussed in more detail in our comments on the rate-based federal plan and model trading rule (Section IV), EPA should ensure that distributed solar is not excluded from ERC or CEIP eligibility, and should develop a separate stakeholder process to develop robust EM&V guidance for distributed energy.

Function of the CEIP under a rate-based program

EPA has requested comment on any adjustments to the rate targets that should be made under a rate-based program as a result of the CEIP. EPA must ensure that the size of the CEIP pool, and the stringency of the targets, is maintained regardless of whether the CEIP is implemented in a rate-based or mass-based policy approach. One way to do so would be to adjust the rate target downward to account for the presence of state-awarded ERCs to the system:

$$Adjusted\ rate = \frac{Original\ Rate * Projected\ Generation}{Projected\ Generation + State\ ERCs}$$

In this way, assuming projected generation remains constant, affected EGUs still have to meet the same stringency as they would without the state issuance of early action ERCs, but the EPA matching ERCs would assist in compliance, consistent with the intent of the CEIP design. Note that this adjustment could make the rate more or less stringent if generation was greater or less than projected, respectively. A back-calculation step could be used from the adjusted state rate in order to adjust the subcategory rates in that state as well, although the impacts of this adjustment on trading with out-of-state EGUs also needs to be further analyzed. NRDC recommends that EPA propose a methodology and request further comment in its upcoming notice, as this is a complex issue that is important to ensuring the stringency of the program is maintained.

The foregoing comments are respectfully submitted on behalf of NRDC.

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January 21, 2015

The following members of the NRDC team contributed to the writing and editing of these comments. Questions on the comments should be directed to Ben Longstreth (blongstreth@nrdc.org), Derek Murrow (dmurrow@nrdc.org), and Starla Yeh (syeh@nrdc.org).

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Appendix A – M.J. Bradley & Associates, EPA's Clean Power Plan: Summary of IPM Modeling Results





EPA's Clean Power Plan

Summary of IPM Modeling Results

JANUARY 13, 2016

Acknowledgments

The following analysis of EPA's final Clean Power Plan (CPP) is based on Integrated Planning Model (IPM®) runs conducted by ICF International, and assumptions developed by M.J. Bradley & Associates (MJB&A). IPM® is a detailed model of the electric power system that is used routinely by industry and regulators to assess the effects of environmental regulations and policy. It integrates extensive information on power generation, fuel mix, transmission, energy demand, prices of electricity and fuel, environmental policies, and other factors.

These model runs are illustrative and not intended to be a prediction of the future; rather, the modelling is intended to assist stakeholders in understanding the implications of key policy decisions and assumptions, such as the form of the standards, the level of energy efficiency, and the degree of compliance flexibility (i.e., trading).

This report and the assumptions and scenarios for this analysis were developed by M.J. Bradley & Associates (MJB&A).

We would also like to acknowledge the valuable insights and constructive feedback of the following individuals in preparing this analysis: Derek Murrow, Starla Yeh, and Kevin Steinberger (Natural Resources Defense Council); Derek Furstenwerth (Calpine Corporation); Kathleen Robertson (Exelon Corporation); Ray Williams, Jeff Brown, and Xantha Bruso (PG&E Corporation); Michael Goggin (American Wind Energy Association); Jennifer Macedonia (Bipartisan Policy Center); Nicholas Bianco (Environmental Defense Fund); Rick Umoff (Solar Energy Industries Association); and Noah Kaufman and Kevin Kennedy (World Resources Institute).

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Executive Summary

The following report summarizes the results of 16 IPM model runs, evaluating two Reference Cases (business-as-usual scenarios) and 14 alternative Clean Power Plan (CPP) regulatory scenarios. For example, several of the cases assume that states adopt EPA's mass-based emissions goals. The cases also assume varying levels of demand-side energy efficiency. Based on the model runs completed to date, we offer the following observations and insights:

- Across a wide range of scenarios and assumptions, the results show that CPP targets are very achievable.
- The ability for power producers to trade leads to significant cost savings and flexibility for power producers.
- Increasing investment in energy efficiency programs reduces overall compliance costs because plants purchase less fuel and fewer new plants need to be built.
- States can meet the Clean Power Plan's emissions goals while relying on a diverse mix of supply- and demand-side resources, including energy efficiency, renewables, nuclear, natural gas and coal.
- EPA requires that mass-based state plans address the potential for "emissions leakage." Leakage results from the incentives under a mass-based plan to shift generation and emissions to new fossil-fired power plants outside the program. Our analysis shows that CO_2 emissions would increase with an "existing only" mass-based program versus an "existing plus new" source program. The most straightforward approach to address this issue is to adopt the "existing plus new" source mass limits, which is an option available to the states under the CPP. In addition, in the proposed model rule and federal plan, EPA has proposed a method for allocating allowances within an existing-only program to mitigate leakage. Although our modeling indicates the particular method proposed would have a minor impact on emissions leakage, EPA is taking comment on other approaches that could be more effective.
- There are additional sensitivity runs that were not evaluated as part of this study, which we hope to continue evaluating over the coming months, including: potential retirement of existing nuclear units; low gas prices; California's participation in trading systems with other states; additional "patchwork" policy and trading scenarios.
- This analysis was designed prior to Congressional approval of the phase-down of the Production Tax Credit (PTC) for wind energy and the extension of the Investment Tax Credit (ITC) for solar energy. We will plan to include these tax extensions in future model runs.

Methodology

Assumptions

- This analysis was based on IPM runs conducted by ICF International. M.J. Bradley & Associates relied on the assumptions from EPA's Base Case 5.15 implementation of IPM® as the starting the point for the assumptions that were used for this analysis. These assumptions are detailed here: http://www2.epa.gov/airmarkets/power-sector-modeling-platform-v515.
- EPA's Base Case (5.15) relies on AEO 2015 Demand Growth assumptions, updated cost and performance assumptions for renewable technologies, updated gas supply assumptions, and existing regulatory requirements (e.g., CSAPR and MATS). The PTC and ITC were assumed to expire as previously required by law.
- Consistent with EPA's modeling of the Clean Power Plan, this analysis does not assume banking of allowances and ERCs.
- In addition, M.J. Bradley & Associates made several modifications to EPA's assumptions, as detailed below.

- Some additional firm fossil unit retirements (17 units; 5.6 GW) were added, based on public announcements.
- Energy efficiency adoption was modeled in the policy cases based on a simplified "supply curve" of program costs developed from a comprehensive Lawrence Berkeley National Laboratory (LBNL) cost study.
- AB 32 CO_2 Allowance Prices were based on the California Energy Commission (CEC) IEPR "High Energy Consumption Case" through 2020; prices were held constant at 2020 levels (in real terms) post-2020. This is higher than the allowance prices that EPA had used in its CPP modeling.
- California's SB 350 RPS policy was implemented in the model.
- The carbon emissions charge on electricity imports to California was removed in 2022 and beyond in the CPP policy cases based on the logic that the country has transitioned to a national CO_2 program for the power sector.
- RGGI was assumed to remain at its 2020 goal in the Reference Case and Policy Cases.

Scenarios Evaluated

- The modeling included two Reference Case scenarios (no CPP) and 14 Policy Case scenarios:
  - Two Reference Case scenarios: (1) "RCa" assumes no additional energy efficiency savings beyond what is reflected in EIA's AEO 2015 demand forecast; and (2) "RCb" assumes our "business-as-usual" level of energy efficiency savings described below (what we call the "current EE" savings levels)
  - Seven mass-based scenarios (both "Existing Only" and "Existing plus New")
  - Three blended rate scenarios (these are the state-specific fossil rates in the final rule)
  - Two dual rate scenarios (steam and NGCC)
  - One patchwork scenario that combined mass-based and rate-based standards
- The Policy Case scenarios are based on EPA's final rule published in the Federal Register on October 23, 2015.
- The modeling varied the extent of allowance/ERC trading across the Policy Cases to reflect the choices that states have in implementing the rule (see slide 12).
- The modeling varied the amount of energy efficiency available in our "supply curve" across the cases (see appendix for more detail):
  - **Current EE (CEE):** States can achieve savings up to their current (2013) annual savings rates between 2018 and 2030. This results in the lowest total energy efficiency savings among the three approaches.
  - **Modest EE (EE1):** States achieve up to a 1% annual savings rate (the same levels assumed by EPA in its RIA modelling). Nineteen states either have achieved, or have established requirements that will lead them to achieve, this rate of incremental electricity demand reduction on an annual basis.
  - **Significant EE (EE2):** States achieve up to a 2% annual savings rate.
- Most of the mass-based scenarios assumed that allowances would be auctioned; one of the scenarios modeled EPA's proposed Federal Plan allocation methodology.

Mass-Based Scenarios

Case No.	Assumptions Key for Charts	Sources	Allocation	EE Levels	Trading Zones
MB01	e+n state ee1	Existing + New	Auction	Modest (1%)	State-by-state compliance (except RGGI)
MB02	e+n national cee	Existing + New	Auction	Current (Historic Savings Rates)	Nationwide (except California)
MB03	e+n national ee1	Existing + New	Auction	Modest (1%)	Nationwide (except California)
MB04	e+n national ee2	Existing + New	Auction	Significant (2%)	Nationwide (except California)
MB05	e national cee	Existing Only	Auction	Current (Historic Savings Rates)	Nationwide (except California)
MB06	e national ee1	Existing Only	Auction	Modest (1%)	Nationwide (except California)
MB07	e national ee1 oba	Existing Only	Federal Plan	Modest (1%)	Nationwide (except California)

Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

Key: MB = mass based, e+n = existing + new, e = existing only, state = no trading, national = nationwide trading (except Cal.), cee = current EE, ee1 = modest EE levels, ee2 = significant EE levels, oba = output based allocation (federal plan proposed allocation methodology)

Rate-Based Goal Scenarios

State-Specific Blended Rate Scenarios

Case No.	Assumptions Key for Charts	Rate Approach	EE Levels	Trading Zones
BR01	br ee1	Blended Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE ERCs are traded within the zone; EE generates ERCs in-state)
BR02	br ee1	Blended Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs are traded within the zone)
BR03	br ee1	Blended Rate	Modest (1%)	Constrained EE and ERC trading
BR04	br ee2	Blended Rate	Significant (2%)	Constrained EE and ERC trading

Subcategory-Specific Dual Rate Scenarios

Case No.	Code	Rate Approach	EE Levels	Trading Zones
DR01	dr ee1	Dual Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs and GS-ERCs; Nuclear ERCs available in the state where generated)
DR02	dr ee2	Dual Rate	Significant (2%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs and GS-ERCs; Nuclear ERCs available in the state where generated)

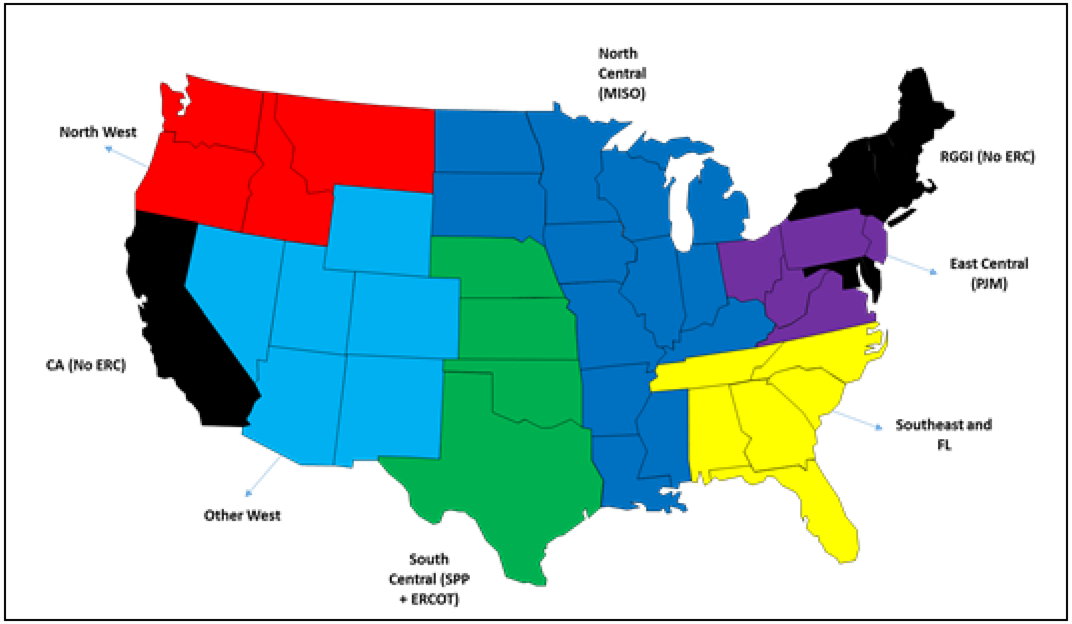
Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

These ERC trading scenarios are more constrained than what EPA allows under the final rule, but states may choose to limit trading and/or the geographic scope of ERC eligibility.

Patchwork Scenario

Case No.	Code	Regulatory Approach	EE Levels	Trading Zones
PW01	MB/EN/DR ee1	Mix of rate and mass	Modest (1%)	See map

Key: PW = Patchwork, MB/EN/DR = Combination of Mass Based (Existing plus New) and Dual Rate, ee1 = modest EE



Assumes multiple mass-based trading zones with the exception of the Southeast and Florida, which is assumed to adopt a dual rate approach. Mass-based states are assumed to regulate both existing and new sources. There is no trading of allowances across zones. Also, mass-based states do not generate ERC credits for use in the Southeast region.

Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

ERC Modeling

Blended Rate Scenarios

- Under the Blended Rate scenarios, the geographic scope of ERC crediting and trading varied across the cases:
  - Option1. EE and RE projects can apply for ERCs in any other rate-based state (within each trading zone) – BR02
    - This option represents the flexibility inherent in the final rule
  - Option 2. Only RE projects can apply for ERCs in any other rate-based state; EE ERCs are only available for compliance in the state where they are generated – BR01
  - Option 3. EE and RE projects can apply for ERCs within each market region, to mimic deliverability (i.e., PPA) requirements – BR03 and BR04
    - This scenario may be more likely to occur in practice
- Additionally, existing NGCCs are credited at the difference between the plant emissions rate and the state blended rate; these ERCs are only available in the state where they are generated

Dual Rate Scenarios

- Under the Dual Rate scenarios, ERCs were credited and traded within two zones to reduce the computational burden on the model: East (plus Texas) and WECC.
- The model credits incremental renewable generation, energy efficiency, and under construction nuclear generation. The model also credits existing NGCC with GS-ERCs. As required by the rule, GS-ERCs can only be used by steam generating units; however, there are always sufficient steam MWhs within each of the trading zones to consume all of the GS-ERCs.
- Nuclear ERCs were only available for compliance in the state where they were generated.

Results

The Clean Power Plan is Projected to Achieve a 16%-22% Reduction in Electric Sector CO_2 Emissions by 2030 (from 2012 levels) Across a Range of Scenarios

The Clean Power Plan is projected to achieve a significant reduction in electric sector CO_2 emissions across a range of different policy cases (i.e., mass-based targets, rate-based targets, and a patchwork scenario).

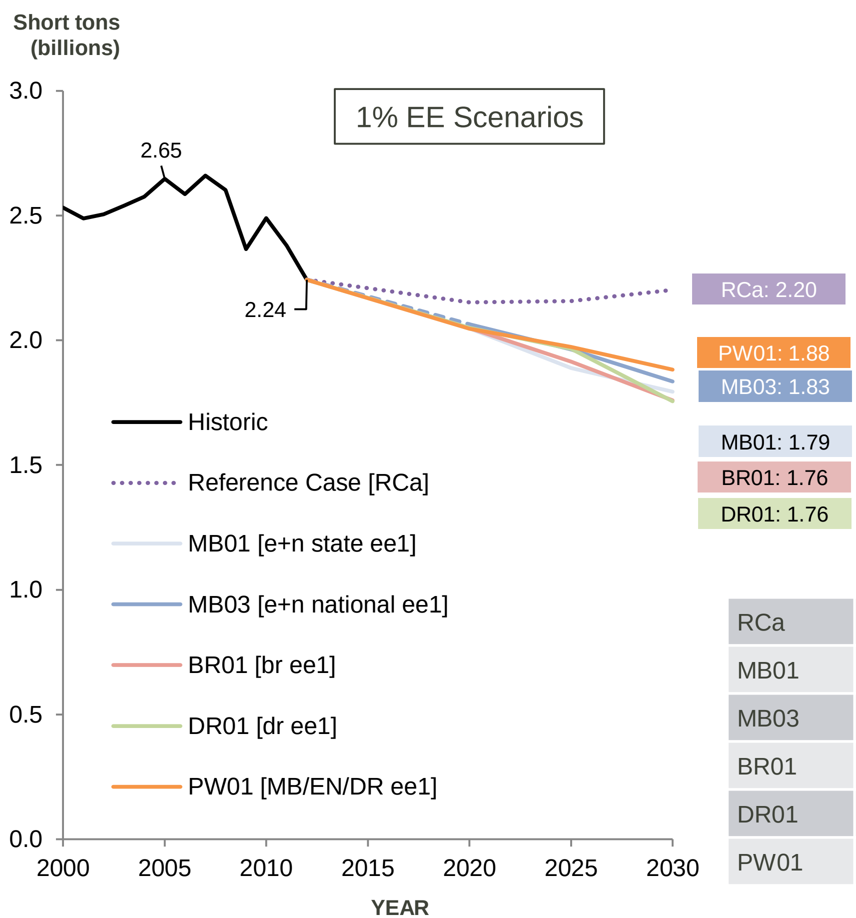
Across the "1% EE" scenarios, emissions are projected to decline between 16% and 22% below 2012 levels. See chart.

This translates to an emissions reduction of between 362 million and 490 million tons of CO_2 per year.

The emission outcomes under the rate-based scenarios, unlike the mass-based approach, are not fixed, and may vary if economic conditions (e.g. natural gas prices, renewable technology prices) differ from the assumptions used in this report.

Note: the electric sector reduced its CO_2 emissions by roughly 15 percent between 2005 and 2012. Across these model runs, emissions would be reduced between 29 and 34 percent from 2005 levels.

Historic and Projected CO_2 Emissions – 2000-2030



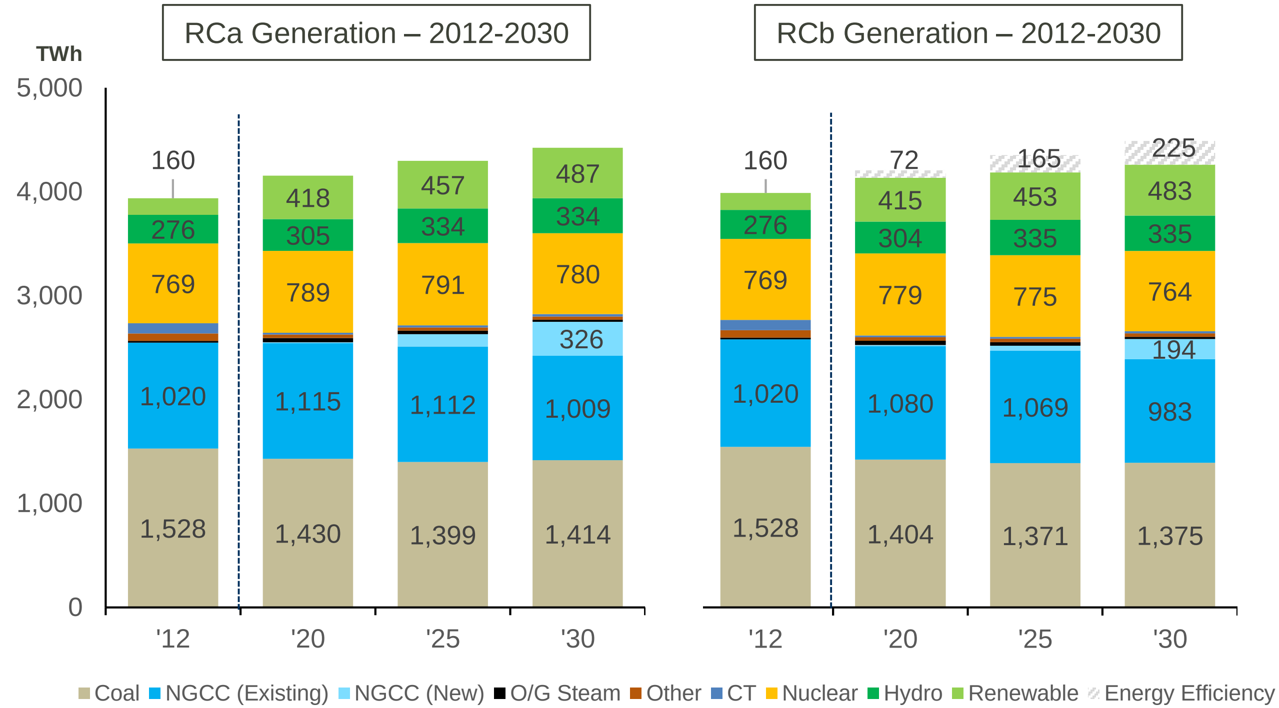
% Change (2012-2030)

RCa	-2%
MB01	-20%
MB03	-18%
BR01	-22%
DR01	-22%
PW01	-16%

The Reference Case Projects an Increase in Total Electricity Generation (from 2012 to 2030) with Increases in Renewable and Natural Gas-Fired Generation

Reference Case Highlights

- Assumes existing power sector regulations (MATS, CSAPR, 316(b), AB 32, RGGI, state RPS)
- No Clean Power Plan
- AEO 2015 demand growth
- Henry Hub Gas price = $5.14 to $6.00 ($/mmBtu)*
- PTC and ITC were assumed to expire
- 80 GW of coal retirements by 2030, including 17 GW of firm (announced) retirements after 2016.
- 5.5 GW of nuclear retirements by 2030, including 3 GW of firm (announced) retirements after 2016.



Note: RCb assumes additional energy efficiency savings beyond what is reflected in the AEO 2015 demand growth forecast. States are assumed to achieve their current (2013) annual savings rates between 2018 and 2030.

*Natural gas prices were projected based on ICF's Integrated Gas Module, a component of the IPM model that models the natural gas market in the U.S. based on resource cost curves, pipeline data, and storage facilities consistent with EPA IPM v5.15 assumptions.

Total Generation and the Generation Mix Varies Across the Policy Cases Depending on the Level of Energy Efficiency Deployed (Current, Modest, Significant)

MB02 – Current EE

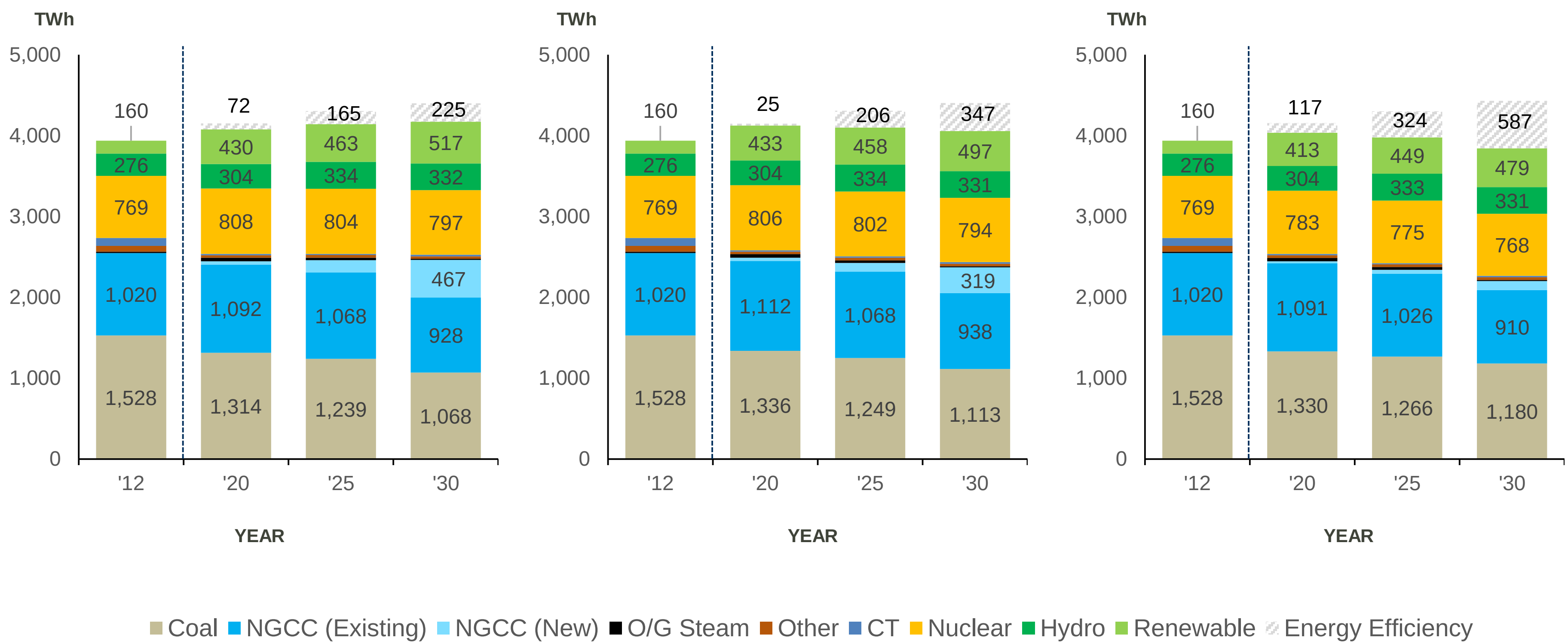
Existing + New, Current EE, Nationwide Trading

MB03 – Modest EE

Existing + New, 1% EE, Nationwide Trading

MB04 – Significant EE

Existing + New, 2% EE, Nationwide Trading



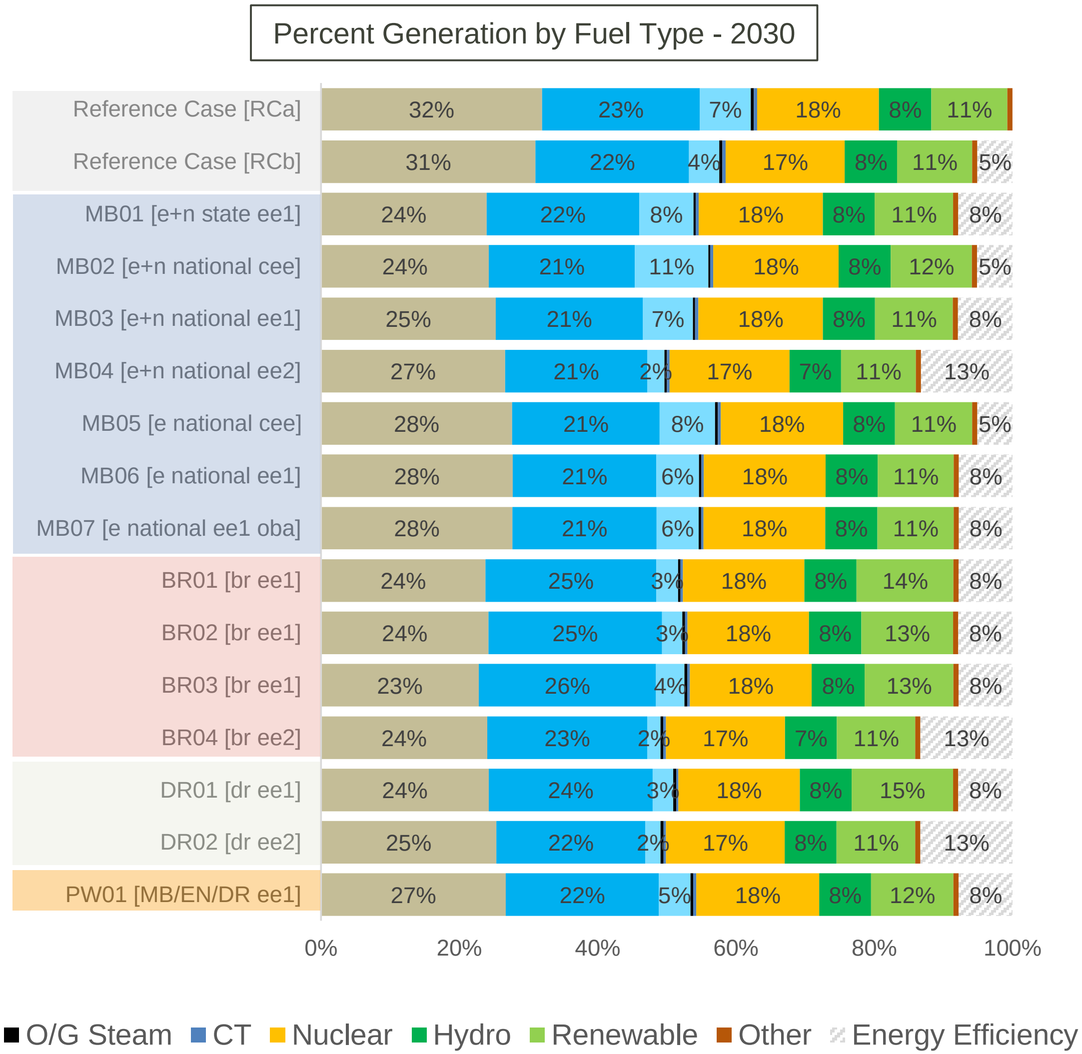
The Clean Power Plan's Emissions Goals Are Achievable While Relying on a Diverse Mix of Resources

Across all of the model runs, there is variability in the projected generation mix.

Relative to the Reference Case, coal generation declines, on average, by 21% in 2030 (averaging across all of the scenarios), but continues to supply between 23% and 28% of electricity, across all of the cases evaluated.

Natural gas (NGCC) is projected to supply between 25% and 32% of electricity in 2030, across all of the cases evaluated.

Renewable energy is projected to supply between 11% and 15% of electricity in 2030, across all of the cases evaluated.



The Mass-Based Policy Runs Project Modest Allowance Prices in the Early Years of the Program; Increasing the Level of EE Moderates the Prices Even Further.

Five model runs assumed mass-based, nationwide trading (except California), producing national allowance prices. The allowance prices are relatively modest across the scenarios, particularly in the early years of the program.

As the level of energy efficiency increases, the model forecasts a reduction in allowance prices (see cases MB02, MB03, and MB04 in the table below).

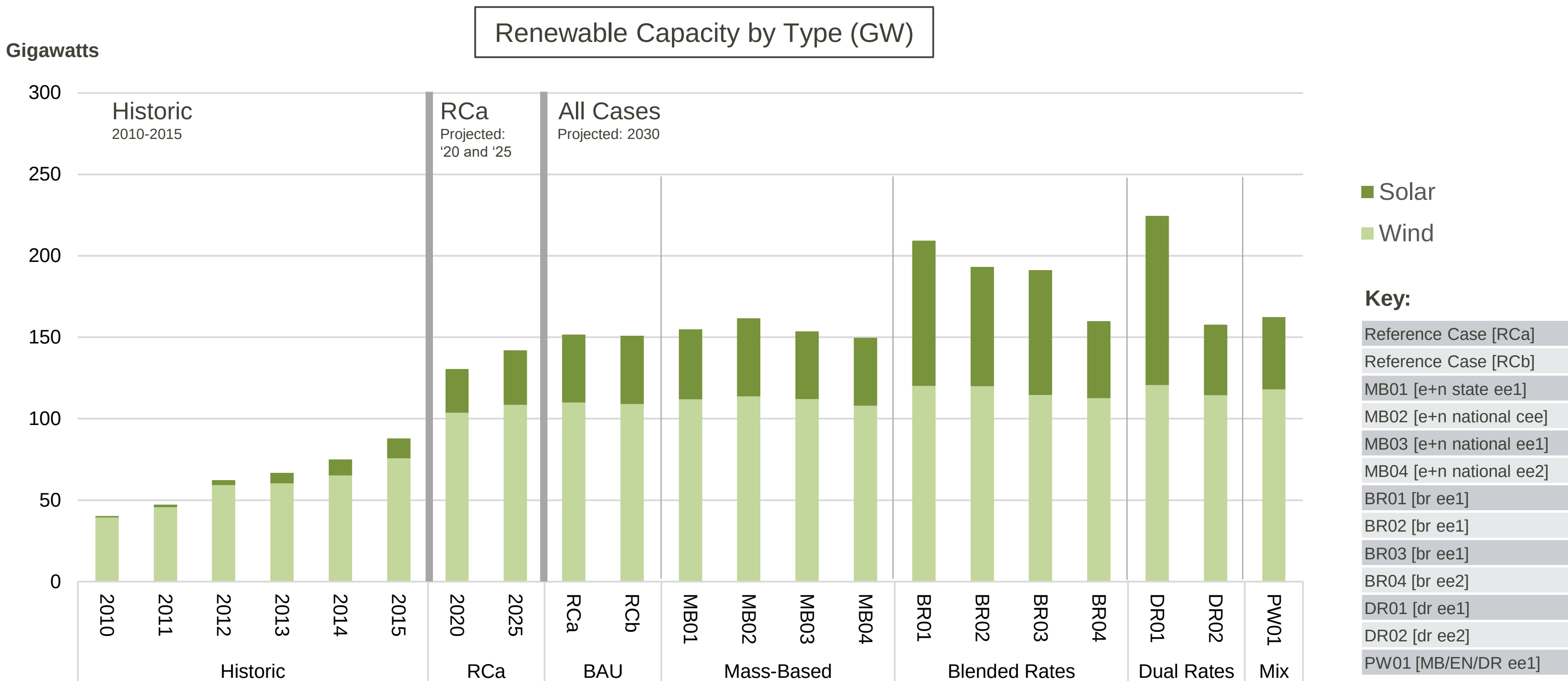
Scenario	Assumptions	2025 (2012$)	2030 (2012$)
MB02	Existing + New, Current EE, Nationwide	$0.76	$19.55
MB03	Existing + New, 1% EE, Nationwide	$0	$16.37
MB04	Existing + New, 2.0% EE, Nationwide	$0	$7.10
MB06	Existing Only, 1% EE, Nationwide, auction	$0.69	$9.05
MB07	Existing Only, 1% EE, Nationwide, federal plan allocation	$1.00	$8.80

Note: this analysis does not assume banking of allowances and the CPP goals are assumed to remain constant post-2030.

Renewable Energy is Projected to Continue to Expand in All Cases

The Reference Case and CPP Policy Cases project continued growth in solar and wind energy capacity.

Under the Clean Power Plan, incremental renewable energy capacity (post-2012) is eligible to generate "Emission Rate Credits" (ERCs) under a rate-based trading program, and under a mass-based program renewables help to meet the mass-based targets by providing a zero-emission source of energy.



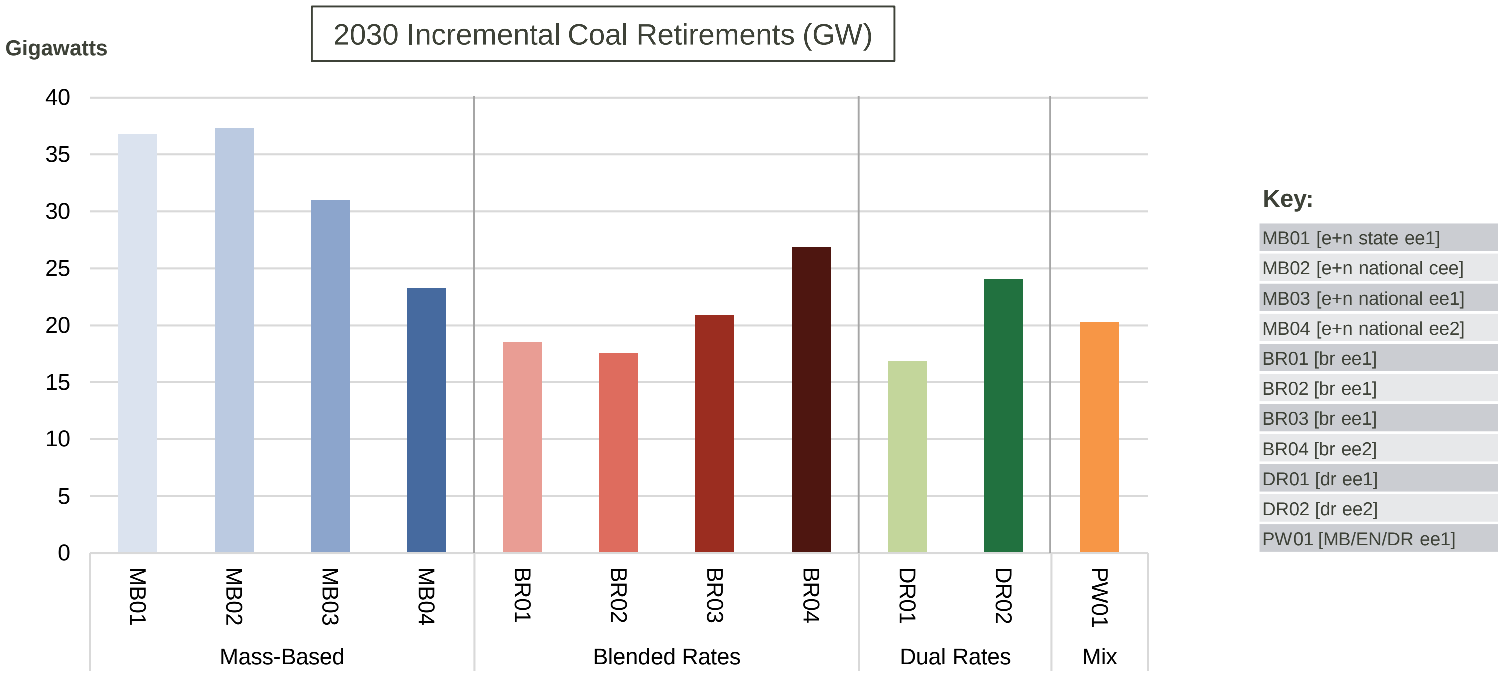
Note: The PTC and ITC are assumed to expire as previously required under federal law. Solar capacity is utility-scale only. Historic data is from EIA's AEO 2015 and AEO 2013.

Compliance Flexibility Reduces the Level of Projected Coal Retirements

Trading and increasing the level of energy efficiency reduces incremental coal retirements:

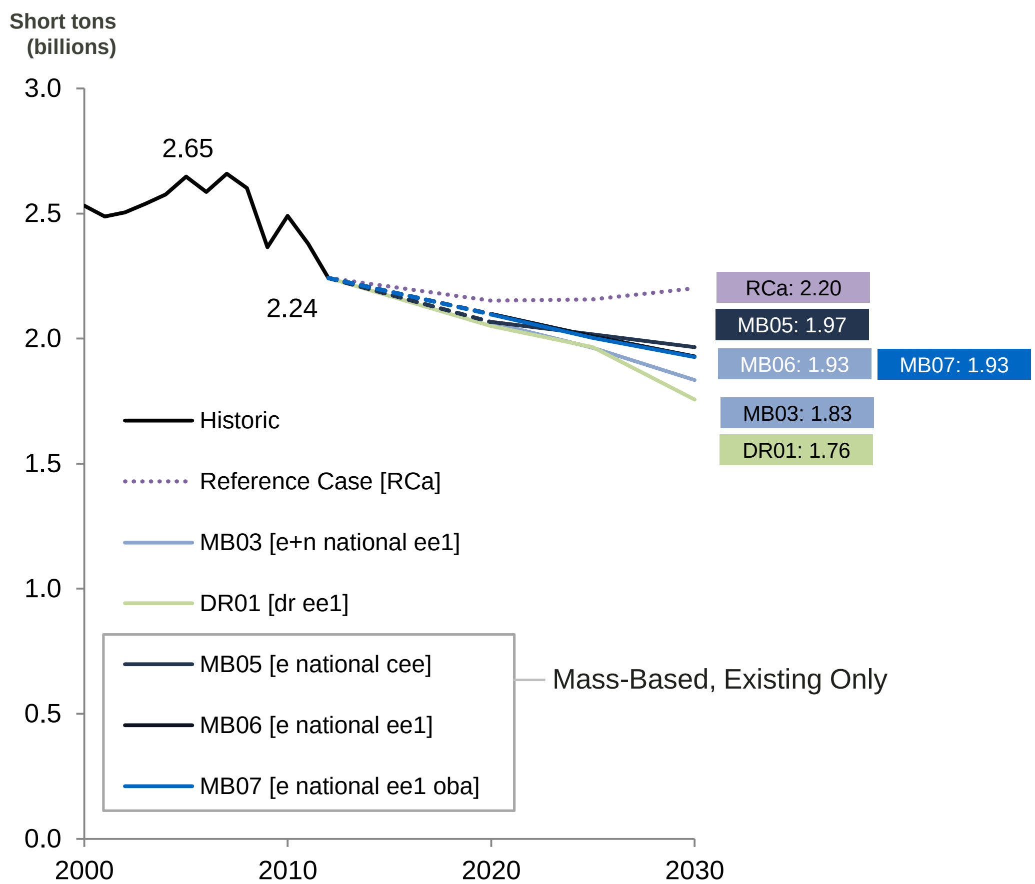
- Coal retirements are reduced by 6 GW (-16%) between MB01 [e+n state ee1] and MB03 [e+n national ee1], which assumes nationwide allowance trading (except California).
- Coal retirements are reduced by 14 GW (-38%) between MB02 [e+n national cee] and MB04 [e+n national ee2] .

The chart below summarizes the incremental coal retirements (above Reference Case levels) through 2030.



EPA Requires Mass-Based Plans to Address the Potential for "Emissions Leakage" under an Existing Only Cap; EPA's Current Proposal Has a Very Modest Impact on Emissions.

Historic and Projected CO_2 Emissions – 2000-2030



The modeling shows that CO_2 emissions would increase with an "Existing Only" mass target versus an "Existing plus New" mass target or "Dual Rate" program, both of which would be presumptively approvable to address "leakage."

Projected emissions in 2030 are 94 million tons higher (annual) under an "Existing Only" approach versus an "Existing plus New" scenario.

The modeling also suggests that EPA's proposed output-based allocation to certain existing NGCC units and a 5% set aside of allowances for renewables had a negligible impact on projected emissions (MB06 vs. MB07). EPA is taking comment on the issue, and stakeholders are currently working to offer EPA alternative allocation approaches that could be more effective.

	% Change (2012-2030)
RCa	-2%
MB03	-18%
DR01	-22%
MB05	-12%
MB06	-14%
MB07 [oba]	-14%

Mass-Based, Existing Only

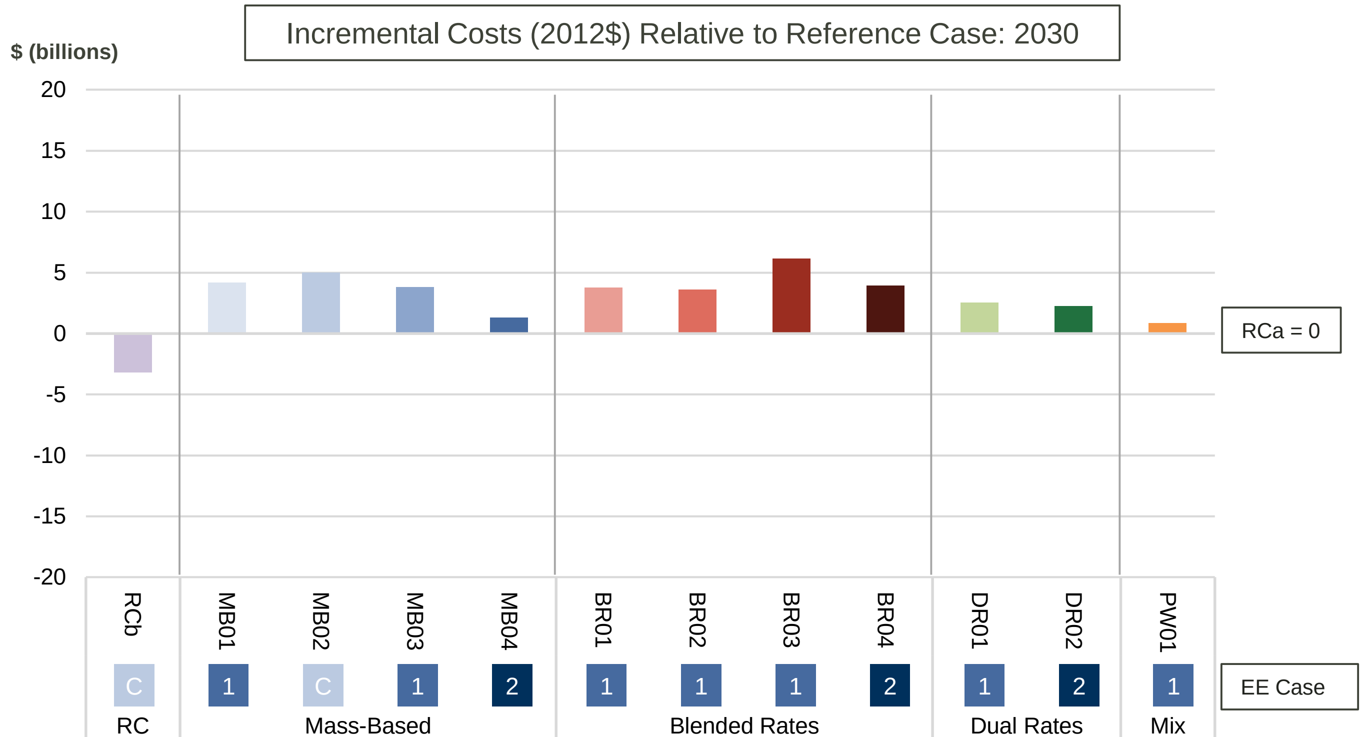
The Analysis Projects Modest Impacts on Electric System Costs under the Clean Power Plan Across a Wide Range of Scenarios

Electric system costs include: fuel, capital, O&M, and energy efficiency program costs (both utility and participant costs).

IPM projects modest increases in electric system costs under the Clean Power Plan based on the scenarios evaluated. For example, projected costs are 1.9% higher in 2030 under scenario MB03.

Based on the methodology used by EPA in the final CPP Regulatory Impact Analysis, we estimate that the benefits of reducing CO_2 and other pollutants (SO_2 and NOx) exceed the costs by $33 billion to $86 billion (2012$) in 2030.

Note: The existing only scenarios, MB05 and MB06, do not address leakage, so are not included here.



	% Change (from Reference Case, RCa)
MB01 [e+n state ee1]	2.1%
MB02 [e+n national cee]	2.5%
MB03 [e+n national ee1]	1.9%
MB04 [e+n national ee2]	0.7%
BR01 [br ee1]	1.9%

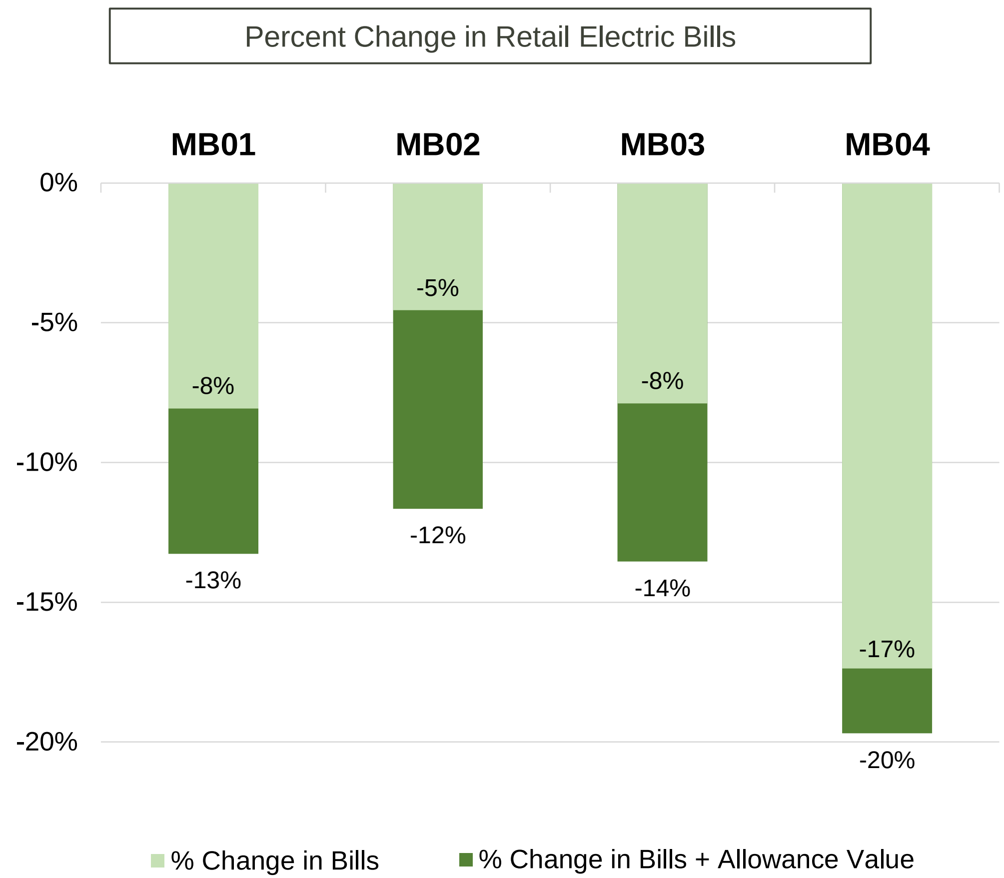
BR02 [br ee1]	1.8%
BR03 [br ee1]	2.0%
BR04 [br ee2]	0.1%
DR01 [dr ee1]	1.3%
DR02 [dr ee2]	1.1%
PW01 [MB/EN/DR ee1]	0.4%

The Analysis Projects Reductions in Monthly Household Electric Bills

Based on the methodology developed by EPA using projected changes in electric system costs, ICF International estimated the resulting impact on sales-weighted average retail bills for the continental U.S.

U.S. households would save between 5% and 20% on their monthly electricity bills in 2030. The high range estimates assume that revenue from auctioning allowances is invested in bill assistance programs and/or clean energy services that benefit electricity customers. Conversely, the low estimates assume auction revenue is utilized for other purposes.

Increased investment in energy efficiency also results in greater bill savings for households; for example, savings (without rebates) more than double between MB03 and MB04.



Note: Average retail bills are compared to Reference Case (RCa). The participant costs of energy efficiency programs are excluded from these retail bill estimates. Instead, those costs are included in the calculation of incremental compliance costs, as shown on slide 20. Including participant costs would have a minimal impact on the magnitude of these bill estimates.

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Appendix

Run Year Structure

Model Year:	Representative of:
2020	2019-2022
2025	2023-2027
2030	2028-2033

Note: throughout this summary report, when we refer to results in 2020, 2025, and 2030, we are referring to the model years above.

Demand-Side Energy Efficiency Assumptions

- Historic rates of energy efficiency savings differ for each state and were drawn from the data reported by utilities in Energy Information Administration (EIA) Form 861, 2013, available at http://www.eia.gov/electricity/data/eia861/.
- In the "Current EE" scenario, the available supply of EE is calculated based on an extension of each state's 2013 annual savings rate. The annual savings rate is held constant between 2018 and 2030 to derive incremental annual savings and cumulative savings estimates for each state.
- In the "Modest EE" scenario, the available supply of EE is calculated based on the methodology in EPA's Regulatory Impact Analysis (RIA) for the Clean Power Plan. Cumulative efficiency savings are projected for each state for each year by ramping up from historic savings levels to a target annual incremental demand reduction rate of 1.0 percent of electricity demand over a period of years starting in 2020, and maintaining that rate throughout the modeling horizon.
  - Consistent with EPA's approach, the pace of improvement from the state's historical incremental demand reduction rate is set at 0.2 percentage points per year, beginning in 2020, until the target rate of 1.0 percent is achieved.
  - States already at or above the 1.0 percent target rate are assumed to achieve a 1.0 percent rate beginning in 2020 and sustain that rate thereafter.
- In the "Significant EE" scenario, the available supply of EE is calculated based on the same methodology as the "Modest EE" scenario, but each state ramps up to a target annual incremental demand reduction rate of 2.0 percent of electricity demand.
- In the "Modest EE" and "Significant EE" scenarios, adoption of efficiency was modeled endogenously using a supply curve of program costs. In this simplified supply curve approach, the highest amount of savings assumed to be available to states in the supply curve varies by scenario, as described in the methodology above. The costs are based on LBNL's comprehensive 2015 cost study, available at: https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf.
- Participant costs are accounted for in the calculation of total system costs.

ERC Background

Under the dual-rate structure in the proposed state model rule for rate-based trading, ERCs can be created by three categories of activities:

1 Incremental Zero-Emitting Energy and Energy Efficiency

- Renewable & nuclear capacity installed post-2012
- Energy efficiency projects begun post-2012
- Each MWh generated / saved creates one ERC

2 Affected EGUs

- Any affected EGU that emits at a rate below its compliance target
- Number of ERCs generated per MWh based on difference between EGU rate and compliance rate

3 Existing NGCC

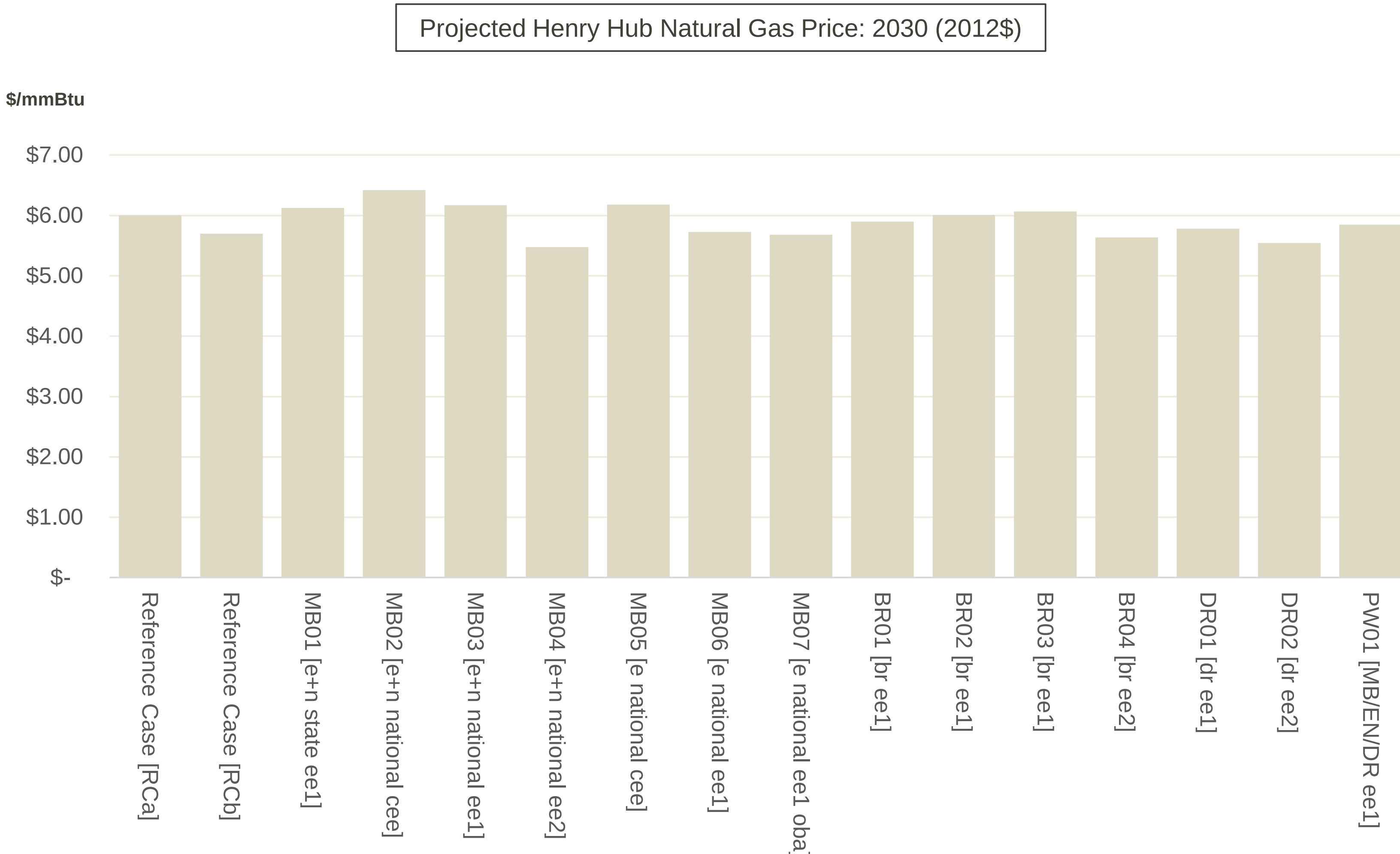
- All NGCCs earn partial “Gas Shift ERCs” for every MWh
- Provide credit for increases in NGCC generation projected to displace coal-fired generation
- GS-ERCs can only be used by fossil steam sources for compliance

Note: The proposed Federal Plan would not credit energy efficiency. The GS-ERC crediting formula is up for comment.

ERC Background, continued

Location of Generation/Savings	Location of ERC Credit Award	ERC Eligibility Under Clean Power Plan
Dual Rate or Blended Rate	Dual Rate	**Project can apply for ERCs in any dual rate-based state.** The ERCs can then be sold to affected sources in any state with the same rate-based plan type. The project cannot earn ERCs in both states.
Dual Rate or Blended Rate	Blended Rate	**Project can apply for ERCs in any blended rate-based state.** The ERCs can then be sold to affected sources in that state (or region, if states agree to a common blended rate). The project cannot earn ERCs in both states.
Mass	Dual Rate	**Project can apply for allowances or ERCs in either state or another rate-based state (as long as the application to a rate-based state is accompanied by a PPA showing delivery to a rate-based state).** The allowances or ERCs can be used for compliance by affected sources covered by the same plan type. In all cases, a project that applies for ERCs cannot also apply for allowances from a set-aside in a mass-based state.

Natural Gas Prices: All Scenarios



Appendix B – NRDC IPM Summary Tables

Table 1. IPM Implementation of Output-Based Allocation Runs

Run ID	Description	IPM Implementation
MB E+N CEE	Mass-based, Existing + New Mass Limits with historical energy efficiency savings levels	* With RGGI and CA modeled separately, a national mass cap equivalent to the sum of the existing+new mass caps (tons) set by EPA for the remaining states was established over the qualifying units as defined by EPA. Interstate trading was allowed under the national program and allowances were auctioned to the qualifying fossil generators.
MB EO CEE	Mass-based, Existing Only Mass Limits with historical energy efficiency savings levels	* With RGGI and CA modeled separately, a national mass cap equivalent to the sum of the existing only mass caps (tons) set by EPA for the remaining states was established over the qualifying units as defined by EPA. Interstate trading was allowed under the national program and allowances were auctioned to the qualifying fossil generators.
MB E+N 1%	Mass-based, Existing + New Mass Limits with 1% annual, incremental energy efficiency savings levels	* With RGGI and CA modeled separately, a national mass cap equivalent to the sum of the existing+new mass caps (tons) set by EPA for the remaining states was established over the qualifying units as defined by EPA. Interstate trading was allowed under the national program and allowances were auctioned to the qualifying fossil generators.
MB EO 1%	Mass-based, Existing Only Mass Limits with 1% annual, incremental energy efficiency savings levels	* With RGGI and CA modeled separately, a national mass cap equivalent to the sum of the existing only mass caps (tons) set by EPA for the remaining states was established over the qualifying units as defined by EPA. Interstate trading was allowed under the national program and allowances were auctioned to the qualifying fossil generators.
EPA - OBA	EPA output-based allocation as proposed, 5% of total allowance budget set-aside for new RE	Starting from a counterfactual run with a national mass cap over existing units - with RGGI and CA modeled separately - compliance periods were set based on run years (i.e., CP1=2025, CP2=2030, CP3=2040). Output-Based Allocation * For output-based allocation, all existing NGCC units under the mass cap with >50% capcity factors receive a subsidy. * The state-specific subsidies are calculated using a lagged approached as follows: CP1 subsidy (Total $) = CP2 Set-Aside (Tons)*CP2 Shadow Price ($/Ton), *where the CP2 set-aside is calculated by EPA based on incremental existing NGCC generation going from a 50% to 60% implied capacity factor and the 111(b) NGCC emission rate. The CP2 shadow price reflects the cost of compliance in the national mass cap.* * State level constraints were created for qualifying NGCC units that allow the units to sell a "test level generation" at a price calculated as follows: Price ($/MWh) = Total Subsidy ($)/Test Level Generation (MWh), *where Test Level Generation equals a 10% increase over the sum of generation from qualifying units* RE Set-Aside * The RE set-aside is equal to 5% of each state's mass cap. Using the set-aside (tons), and the shadow price in that compliance period ($/Ton), a subsidy was calculated for all qualifying RE units in that state as follows: CP1 Subsidy (Total $) = CP1 Set-Aside (Tons)*CP1 Shadow Price ($/Ton) * State level constraints were created for qualifying RE units that allow the units to sell a "test level generation" at a price calculated as follows: Price ($/MWh) = Total Subsidy ($)/Test Level Generation (MWh), *where Test Level Generation equals a 10% increase over the sum of generation from qualifying units* With the remaining allowances in each state auctioned, the counterfactual is then re-run with the addition of the state-specific output-based allocation and RE set-aside constraints to incent increased generation from qualifying NGCC and RE units (Run 1). Using the results of Run 1, new state specific subsidies and Test Level Generation levels are calculated and applied to the qualifying units (Run 2). This iterative process was continued until no incremental generation between Run (n+1) and Run (n) occurred.

Table 1. IPM Implementation of Output-Based Allocation Runs (continued)

Run ID	Description	IPM Implementation
OBA (NGCC + Clean 3)	Allocation of 0.5 Ton/MWh to existing NGCC. Allocation of 2-3 ton/MWh to new non-emitting until total cap reached.	This run implementation is identical to the "OBA (NGCC + Clean 1)" approach with the exception of how the allocation to non-emitting resources was calculated. * The subsidy to non-emitting units was calculated as follows: Generation from all qualifying non-emitting units in CP1 (MWh)**x* (ton/MWh) = Total CP1 Allocation to non-emitting units (Tons), *where the x (ton/MWh) allocation rate is chosen such that total allocated tons = mass cap (tons)* CP1 Subsidy (Total $) = CP1 Allocation to non-emitting units (Tons)*CP1 Shadow Price ($/Ton) * As in the "OBA (NGCC + Clean 1)" case, an iterative approach was taken until no further incremental non-emitting or NGCC generation between Run (n+1) and Run (n) occured.
New Source Fee	Existing sources subject to existing-only limit. New sources subject to tax set at allowance price level of New + Existing.	This approach started with a national trading run with a mass cap over new and existing units (Run 1). A second run was then set up with an existing-only mass cap. The shadow price ($/Ton) generated from the national new and existing mass cap (Run 1) was imposed as a tax over new and existing units in Run 2.
OBA - Index	Allocation based on MWh to all existing + new generation (not including new fossil) times the appropriate emissions factor	Starting from a counterfactual run with a national mass cap over existing units - with RGGI and CA modeled separately - compliance periods were set based on run years (i.e., CP1=2025, CP2=2030, CP3=2040). Using an updating allocation mechanism, allocation rates (ton/MWh) were calculated for qualifying NGCC, non-emitting and oil/gas steam units. To calculate the allocation rates, results from the counterfactual run were used to create an allocation index based on the emission intensities of the three capacity types relative to coal. Once the allocation rates were calculated, the additional run setup followed that of other OBA runs: * State constraints were created for qualifying NGCC, non-emitting and oil/gas steam units * Subsidies were calculated for each capacity type using the allocation rate generated by the allocation index. * The remaining allowances were auctioned and an iterative approach was taken until no further incremental NGCC, non-emitting or oil/gas steam generation between Run (n+1) and Run (n) occurred.
OBA (NGCC + Set-aside)	10% set aside for new RE allocated based on MWh output in the prior quarter. Allocation of up to 0.5 Ton/MWh to existing NGCC	Starting from a counterfactual run with a national mass cap over existing units - with RGGI and CA modeled separately - compliance periods were set based on run years (i.e., CP1=2025, CP2=2030, CP3=2040). * The universe of qualifying NGCC units is equal to all existing NGCCs covered by the mass cap. Qualifying RE and EE units are those identified by EPA as eligible to generate ERCs in rate cases. * As in the other OBA runs, state specific constraints were created allowing qualifying NGCC and non-emitting units to sell Test Level Generation at a $/MWh price. * The NGCC subsidy was calculated in the same manner as "OBA (NGCC + Clean 1)" and "OBA (NGCC + Clean 3)" * The 10% set-aside for qualifying RE units was set up like the "EPA - OBA" case, except that the set-aside used to calculate the subsidy was 10% of each state's mass cap instead of 5%. * The remaining allowances were auction and an iterative approach was taken until no further incremental NGCC, non-emitting or oil/gas steam generation between Run (n+1) and Run (n) occurred.
OBA - All	Allocation based on MWh to all existing + new generation (not including new fossil)	Starting from a counterfactual run with a national mass cap over existing units - with RGGI and CA modeled separately - compliance periods were set based on run years (i.e., CP1=2025, CP2=2030, CP3=2040). Using results from the counterfactual run, allocation rates were calculated for NGCC, non-emitting, oil/gas steam and coal units based on each capacity type's share of qualifying generation. Qualifying fossil generation was defined as generation from units covered under the existing only mass cap. Qualifying generation from non-emitting was defined as generation from units eligible to generate ERCs under a rate-based state plan. Once the allocation rates were calculated, the additional run setup followed that of other OBA runs: * State constraints were created for qualifying NGCC, non-emitting, oil/gas steam and coal units * Subsidies were calculated for each capacity type using the allocation rate calculated from their generation share * As in the other OBA runs, an iterative approach was taken until no further incremental NGCC, non-emitting or oil/gas steam generation between Run (n+1) and Run (n) occurred.

Table 2. Summary IPM Results of Output-Based Allocation Runs (2030)

2030 Results								
Run Description	**Emissions**	**Coal Generation**	**New NGCC Generation**	**Existing NGCC Generation**	**Total NGCC Generation**	**Wind Generation**	**Solar Generation**	**Energy Efficiency Savings**
	Thousand Short Tons	TWh	TWh	TWh	TWh	TWh	TWh	TWh
Mass, Existing + New, Current EE	1,838,481	1,068	467	928	1,396	339	90	225
Mass, Existing + New, 1% EE	1,834,398	1,113	319	938	1,257	333	77	347
Mass, Existing Only, Current	1,965,896	1,220	352	942	1,294	328	78	225
Mass, Existing Only, 1% EE	1,928,552	1,226	272	917	1,189	322	79	347
Mass, Existing Only, EPA Proposed Allocation, 1% EE	1,926,560	1,224	269	920	1,189	324	80	347
Updating OBA - NGCC + Clean 1, Current EE	1,911,818	1,152	274	1,058	1,332	334	106	225
Updating OBA - NGCC + Clean 3, Current EE	1,894,532	1,152	231	1,062	1,293	340	139	225
New Source Fee, Current EE	1,924,279	1,176	269	1,013	1,282	339	95	225
Updating OBA - Index, Current EE	1,868,538	1,096	213	1,151	1,364	336	132	225
EPA - ADJ, Current EE	1,922,287	1,153	296	1,059	1,355	331	84	225
Updating OBA - All, Current EE	1,923,627	1,187	271	1,002	1,273	333	131	225

Table 3. Allocation per MWh in Output-Based Allocation Runs

Allocation Rate (Tons/MWh)

Updating OBA - NGCC + Clean 1	2025	2030	2040
Existing NGCC	0.5	0.5	0.5
Non-Emitting Resources	1	1	1
Oil/Gas Steam	0	0	0
Coal	0	0	0

Updating OBA - NGCC + Clean 3	2025	2030	2040
Existing NGCC	0.5	0.5	0.5
Non-Emitting Resources	3.32	2.12	1.57
Oil/Gas Steam	0	0	0
Coal	0	0	0

Updating OBA - Index	2025	2030	2040
Existing NGCC	1.14	0.84	0.77
Non-Emitting Resources	1.9	1.41	1.28
Oil/Gas Steam	0.75	0.48	0.56
Coal	0	0	0

EPA - ADJ	2025	2030	2040
Existing NGCC	0.5	0.5	0.5
Non-Emitting Resources	0.42	0.32	0.21
Oil/Gas Steam	0	0	0
Coal	0	0	0

Updating OBA - All	2025	2030	2040
Existing NGCC	0.68	0.62	0.59
Non-Emitting Resources	0.68	0.62	0.59
Oil/Gas Steam	0.68	0.62	0.59
Coal	0.68	0.62	0.59

EPA - OBA	2025	2030	2040
Existing NGCC	0.11	0.14	0.15
Non-Emitting Resources	0.57	0.45	0.17
Oil/Gas Steam	0	0	0
Coal	0	0	0

Percent of Mass Cap Allocated by Capacity Type

Updating OBA - NGCC + Clean 1	2025	2030	2040
Existing NGCC	24%	26%	21%
Non-Emitting Resources	23%	32%	47%
Oil/Gas Steam	0%	0%	0%
Coal	0%	0%	0%
Total	47%	58%	68%

Updating OBA - NGCC + Clean 3	2025	2030	2040
Existing NGCC	24%	26%	21%
Non-Emitting Resources	76%	74%	79%
Oil/Gas Steam	0%	0%	0%
Coal	0%	0%	0%
Total	100%	100%	100%

Updating OBA - Index	2025	2030	2040
Existing NGCC	55%	52%	35%
Non-Emitting Resources	44%	48%	65%
Oil/Gas Steam	1%	0%	0%
Coal	0%	0%	0%
Total	100%	100%	100%

EPA - ADJ	2025	2030	2040
Existing NGCC	24%	26%	21%
Non-Emitting Resources	10%	10%	10%
Oil/Gas Steam	0%	0%	0%
Coal	0%	0%	0%
Total	34%	36%	31%

Updating OBA - All	2025	2030	2040
Existing NGCC	31%	30%	25%
Non-Emitting Resources	16%	21%	28%
Oil/Gas Steam	1%	0%	0%
Coal	52%	49%	47%
Total	100%	100%	100%

EPA - OBA	2025	2030	2040
Existing NGCC	5%	5%	5%
Non-Emitting Resources	5%	5%	5%
Oil/Gas Steam	0%	0%	0%
Coal	0%	0%	0%
Total	10%	10%	10%

Appendix C – NRDC Comments on the Clean Energy Incentive Program

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Clean Energy Incentive Program for the Clean Power Plan

Docket ID Number EPA-HQ-OAR-2015-0734

Via regulations.gov
December 15, 2015

Thank you for accepting these comments on the Clean Energy Incentive Program, proposed as part of the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. 80 Fed. Reg. 64,662, 64,664 (Oct. 23, 2015).

We submit these comments on behalf of the Natural Resources Defense Council (NRDC). NRDC is a non-profit environmental organization representing 1.4 million members and online activists. NRDC uses law, science, and the support of its members to ensure a safe and healthy environment for all living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

Introduction

The following comments respond to the Environmental Protection Agency's (EPA) proposed Clean Energy Incentive Program (CEIP), which states may use to incentivize early investments in wind and solar power generation, and demand-side energy efficiency measures (EE) in low-income communities. These comments focus on the CEIP's provisions for delivery of energy-efficiency to low-income communities. Reducing barriers to EE in low income communities will help ensure that the benefits of the Clean Power Plan are shared broadly across society.

We agree with EPA on the value of reducing barriers to EE in low-income communities. Home energy expenses are a significant and growing component of low-income household budgets.[1] Households that earn less than the national median income spend 17 percent of their budget on energy costs.[2] Nominal spending by renters on home energy increased by 53 percent from 2000 to 2010, compared to a 22 percent increase in spending on all other types of goods and services.[3] At the same time, there is a large opportunity to improve energy efficiency in buildings where low income people live. This opportunity has

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[1] Low income communities have also been disproportionately harmed by power plant pollution. *See* NAACP, 2013 "Coal Blooded: Putting Profit Before People," available at http://www.naacp.org/page/-/Climate/CoalBlooded.pdf.

[2] Gary Pivo, *Unequal access to energy efficiency in US multifamily rental housing: opportunities to improve* (Building Research and Information, 2014), 42:5, pp. 551-573.

[3] Id.

historically been under-served by both electric utility energy efficiency programs[4] and federal weatherization programs, which should be scaled up significantly. By providing an added incentive for energy efficiency projects in the buildings where low-income people live, the CEIP can help address this problem.

As EPA finalizes the CEIP, the agency must ensure that the program does not 1) undermine the environmental integrity of the Clean Power Plan, or 2) divert attention from the poorly served low income housing sector, while also making the program easy to understand and implement in communities. Below we explain these considerations and then address EPA's specific questions.

Maintain environmental integrity

In the CEIP, EPA allows for the creation of double credit for qualifying energy efficiency projects. This double-crediting means that the emission reductions achieved under the Clean Power Plan will be weakened if energy efficiency projects that would have happened anyway are credited under the CEIP.[5] We agree with EPA's decision not to require that projects demonstrate that they are “additional” or surplus relative to business-as-usual in order to be eligible. But the potential weakening of the targets due to the double-credit for EE means that EPA should shape EE project eligibility criteria to make sure that only EE in genuinely hard-to-reach sectors is granted credit. Granting eligibility to energy efficiency projects in well-served sectors of low-income regions of the state, or projects that provide only indirect benefits to low income people would undermine the emission reductions achieved by the Clean Power Plan.

Focus on the hard-to-reach low income housing sector

The CEIP will best serve low income communities if it is focused on directly improving efficiency in the spaces where people spend most of their time: housing. These efficiency improvements will also improve comfort and safety. We urge that EPA not generally open the CEIP to any energy efficiency project that occurs in low income areas. If industrial efficiency projects in such areas qualify for the CEIP, there is a substantial risk that CEIP

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[4] Energy Efficiency for All, Program Design Guide. 2014, available at http://energyefficiencyforall.org/program-design-guide .

[5] Imagine two energy efficiency projects that occur in 2021, one that would have happened without the CEIP, and another that was encouraged by the CEIP. Imagine that both have the same MWh savings, and that these savings convert to 5 tons of avoided CO_2. Compared to a world without the CEIP, the first, non-additional project does not reduce emissions, the second, additional project does. But with broad eligibility criteria, both projects would get 10 allowances: 5 from the state’s mass budget (for this example, in 2029) and 5 from EPA’s reserve. Assume these 10 allowances are sold in 2022. Where the project was additional, emissions in 2021 are 5 tons lower than they would otherwise be, emissions in 2022 are 10 tons higher, and emissions in 2029 are 5 tons lower. The net effect is zero: -5 + 10 – 5 = 0. Where the project is not additional, emissions in 2021 are not lower than they would otherwise be, emissions in 2022 are 10 tons higher, and emissions in 2029 are 5 tons lower. The net effect is 5 tons of increased emissions: 0 + 10 – 5 = 5)

program investments would be directed at the industrial sector, diverting money and attention from the low income housing sector.

Low income households and building owners face two big barriers when making efficiency investments: "split incentives" and the need for upfront financing to pay for upgrades. Where renters pay energy bills but owners make investments in durable equipment in the building, neither party can fully capture the benefit of an investment in energy efficiency, leading to the split incentive. Since these tenants are more likely to move, they have less incentive to spend their own money on efficiency since they will not enjoy the benefits of long-lived investments. Low income households, including most renters, [6] have little surplus in their budget to pay for the upfront cost of energy efficiency upgrades. The up-front cost of efficiency investments are particularly acute for renters in multifamily buildings, where close to 50 percent of our nation's low-income renters live.

Nonetheless, the opportunity to improve energy efficiency in low income households is significant. A recent retrospective evaluation found that retrofits in large New York City buildings, funded by the Weatherization Assistance Program, reduced a unit's energy use by 23.2 percent on average.[7] Likewise, a study released by Energy Efficiency for All estimates efficiency programs in multifamily affordable housing could cut electricity usage by as much 26 percent, based on data from a sample of states.[8] Delivering energy efficiency in low income residences is relatively more expensive on a total cost basis than other types of energy efficiency and therefore needs more support and focus. On average, low income efficiency programs cost $0.142 per-kilowatt hour of savings versus $0.033 per-kilowatt hour of savings in the general residential sector and $.055 per-kilowatt hour of savings in the general commercial and industrial sector,[9] showing that the sector deserves special attention.[10]

Make the program easy to implement and understand

EPA must also make the program easy to implement and understand. While the program should focus on the low income housing sector, project developers should not have to

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http://www.jchs.harvard.edu/sites/jchs.harvard.edu/files/jchs_americas_rental_housing_2013_1_0.pdf.

7 Blasnick, et al., National Weatherization Assistance Program Impact Evaluation: Energy Impacts for Large Multifamily Buildings, Oak Ridge National Laboratory Environmental Sciences Division, Publication, ORNL/TM-2014/332, September 2014, Page xviii, Table 9.

8 Optimal Energy, *The Potential for Energy Savings in Affordable Multifamily Housing,* prepared for the Natural Resources Defense Council, May 2015. Available at: http://www.energyefficiencyforall.org/potentialenergy-savings.

10 Hoffman, et al., The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: Estimates at the National, State, Sector and Program Level, Lawrence Berkeley National Laboratory Electricity Markets and Policy Group, April 2015, Page 2, Table 1.

verify the income of every household that benefits from the program. If a sufficient percentage of people in a community are low income, then all residential energy efficiency projects that occur in that community should be eligible. Projects that occur outside of defined low income communities but primarily and directly benefit low income people should also be eligible. Definitions of project eligibility should use income-based primary definitions, supplemented with secondary definitions that use definitions from existing federal programs to identify low income people or institutions that serve them.

Responses to Questions posed by EPA

What definition(s) of 'low income community' should be required for eligible energy efficiency projects? What criteria should be used to define ... eligible EE projects implemented in low income communities?

EPA must ensure that only projects or programs that primarily and directly benefit low income people are eligible, and that the program targets hard-to-reach sectors, because of the considerations described above. Only projects in low-income housing and in institutions that predominantly serve low-income people should be eligible. Projects in for-profit businesses will only indirectly benefit low income people, and this sector is better-served by utility energy efficiency programs and private efficiency businesses.

The objective of furthering projects that primarily and directly benefit low income people requires that EPA think about the definitions of "low-income community" and eligible project together. With any reasonable geographic definition of low-income community, many low income people would still live outside that community, and there is no policy justification for denying CEIP eligibility to programs that benefit low-income people who live outside of defined low-income geography. According to a Census Bureau report on concentrated poverty, in 2010 46.5 percent of people in poverty lived in census tracts where less than 20 percent of the population lived below the official poverty line. Subsidized housing in low-poverty neighborhoods can deliver enormous benefits to poor families, including major improvements in adults' health and children's long-run earnings. Conversely, even within a defined low-income geographic area, not every energy efficiency project should be eligible. Fifty-nine million people live in census tracts where between 20 and 40 percent of the population is in poverty, 45.5 million of those people live above the official poverty line.[11] Granting CEIP credit to all residential energy efficiency that occurs in these census tracts is likely to result in a program that primarily benefits households above the official poverty line. On the other hand, this is less of a concern for census tracts where a very high percentage of residents have low incomes and allowing all residential energy efficiency that occurs in such tracts could ease program implementation.

Accordingly, we recommend that the geographic definition of "low-income community" be sufficiently narrow so that EPA can – without much leakage to those with higher incomes –

[11] Bishaw, A., Changes in Areas with Concentrated Poverty: 2000 to 2010, American Community Survey Reports, US Census Bureau, Page 22, Appendix Table 1

allow *all* residential energy efficiency that occurs in that defined geography to be eligible for the CEIP. Project eligibility criteria, on the other hand, should seek to identify programs and projects that primarily and directly benefit low income people, even if they live outside of the defined "low-income community." Project eligibility criteria should be sector-specific, with separate criteria for single-family housing, multi-family housing, municipal facilities, schools, and health facilities.

EPA should use the HUD Income Limits for both the geographic and project eligibility criteria. Developed to implement federal housing programs, they are updated annually and include median income estimates for both non-metropolitan and metropolitan areas within states, estimates that take into account high/low housing costs and high/low average incomes.

We propose an "either/or" definition of project eligibility. Eligible projects are:

- residential energy efficiency in defined geographies, designed to capture communities of concentrated poverty, or
- projects and programs inside or outside of these defined geographies, which directly and primarily benefit low income people, in the housing, school, municipal, and healthcare sectors

For the geographic definition, we propose that a low income community be defined as a census tract with poverty rates of 40 percent or more, or, alternatively a census tract where 40 percent or more of the households earn less than HUD's very low income limit for the appropriate jurisdiction. For comparison, HUD's U.S. very low income limit for a family of four in 2015 is $32,900, while the 2015 poverty guideline for a same-sized family is $24,250. Inside these defined low income communities, all residential energy efficiency projects would be eligible. This definition aligns with historic definitions of concentrated poverty, and with the Census Bureau's 4-level categorization of census tracts by poverty rates.

Outside of these geographically defined low income communities, eligibility criteria would be sector-specific:

- For single-family, the following would be eligible:
    - projects in houses whose rents are affordable (no more than 30 percent of income) to low income tenants, using HUD's low income limits for the relevant geography
    - projects in houses where residents earn no more than HUD's low income limit for the relevant geography
    - projects in houses whose residents or owners already qualify or participate in federal affordable housing programs, including the Housing Choice Voucher Program, Section 521 Rural Rental Assistance Program, Section 502 Direct Loan Program, Single Family Housing Guaranteed Loan Program, Weatherization Assistance Program, Low-Income Housing Tax Credit, and Low Income Heating Assistance Program

    - electric utility, state, or third-party administered programs where 80 percent of the participants earn less than HUD's low income limit, or where 80 percent of the participants qualify or participate in the above-listed programs
- For multi-family, the following would be eligible:
    - projects in buildings whose rents are affordable (no more than 30 percent of income) to low income tenants, using HUD's low income limits for the relevant geography
    - projects in buildings that already qualify or participate in federal affordable housing programs, including the Section 8 Project-based Rental Assistance Program, Section 202 Supportive Housing for the Elderly Program, Section 811 Supportive Housing for Persons with Disabilities Program, Section 521 Rural Rental Assistance Program, Section 515 Rural Rental Housing Loans program, the Weatherization Assistance Program, homeless assistance programs administered by HUD, and Low-Income Housing Tax Credit
    - electric utility, state, or third-party administered programs where 80 percent of the participants earn less that HUD's low income limit, or where 80 percent of participants qualify or participate in the Housing Choice Voucher Program, the Low Income Heating Assistance Program, or the above-listed programs

Eligibility criteria should ensure that tenants benefit from energy efficiency investments in participating rental properties where tenants do not pay their electricity bill directly. We will include more detail in our comments on the Proposed Federal Plan and Model Rule on how EPA can implement this.

Retrofitting a municipal building, school, or hospital that serves primarily low income people can provide indirect benefits: lower operating costs could be reinvested into programs that benefit these customers. Because this sector is generally more easily served by energy efficiency programs and the ESCO industry than low income housing, EPA should ensure that these projects do not absorb a large portion of the potential CEIP credits. EPA can do this by limiting the portion of the energy efficiency pool that can be taken by such projects. We will be commenting more on this in our later comments on the Proposed Federal Plan and Model Rule.

We propose the following non-housing projects would be eligible:

- projects at schools where the majority of pupils are from low-income households, as defined in the HUD income limits, or schools listed in the most recent Annual Directory of Designated Low-income Schools for Teacher Cancellation Benefits or a similar list of schools that serve predominantly low income pupils, all elementary and secondary schools operated by the Bureau of Indian Education (BIE), or operated on Indian reservations by Indian tribal groups under contract with BIE, or
- projects at non-profit clinics and hospitals where the majority of clients are from low-income households, as defined in the HUD income limits, or that are designated

as Disproportionate Share Hospitals, or that have a similar designation from the Department of Health and Human Services
- projects at community facilities where the majority of users are from low-income households, as defined in the HUD income limits, and are owned or operated by a municipality or other political subdivision.

EPA should also examine project development strategies that bundle retrofits across sectors, like BlocPower.[12] BlocPower works with community leaders and institutions to assemble four or more buildings in financially underserved communities into a "block" of potential retrofits. This method increases project size, spreading performance risk and reducing costs. This method could increase the attractiveness of energy efficiency projects in low income housing, by bundling these projects with more cost-effective municipal, school, or hospital projects.

Projects at for-profit businesses (housing excluded) should not be eligible, because projects here would only provide indirect benefits to low income communities and this sector is better-served by energy efficiency programs.

What should be the evaluation, measurement and & verification (EM&V) requirements for eligible projects; the requirements for M&V reports of quantified megawatt-hour (MWh); and the requirements for verification reports from an independent verifier?

The EM&V requirements for eligible projects should be the same as those required in the emission guidelines: projects should file an EM&V plan and subsequent savings report with the state, signed by an independent verifier, where savings are quantified on an ex-post basis, using best-practice methods, accounting for independent factors that might have affected the change in energy use, and measuring savings from a baseline of what would have happened in the absence of the demand-side energy efficiency activity.

States that adopt a mass-based plan that includes existing and new sources would otherwise not have to develop an EM&V system that meets the requirements articulated in the emission guidelines. EPA should make sure that the need to quantify savings with accuracy and reliability is not a barrier to CEIP implementation in these states. It can do this by clarifying best-practice methods for low-income housing programs and allowing "existing plus new" states to rely on independent verifiers accredited in another state or by EPA.

Respectfully submitted,

December 15, 2015

s/ Dylan Sullivan

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[12] See: www.blocpower.org.

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