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HOW THE EPA SHOULD MODIFY ITS PROPOSED 111(D) REGULATIONS TO ALLOW STATES TO COMPLY BY TAXING POLLUTION



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I. INTRODUCTION

The U.S. Environmental Protection Agency (EPA) is exercising its authority under section 111(d) of the Clean Air Act to limit U.S. greenhouse gas (GHG) emissions from existing stationary sources, beginning with carbon dioxide (CO₂) emissions from fossil-fuel fired electric generating units (EGUs, power plants, or covered sources).¹ This comment examines the extent to which EPA's proposed rule for existing power plants (the EPA proposal) and its existing regulations would allow states to comply with their obligations under 111(d) by adopting and enforcing carbon excise taxes. We find that although states can adopt carbon taxes to comply with 111(d) rules, EPA has inadvertently restricted how states can design their policies, precluding some of the most straightforward approaches. Accordingly, we recommend amendments that would give full flexibility to states to design policies as they see fit, provided those policies are enforceable and will achieve the applicable emissions guidelines.

We are pleased to submit these comments in response to the proposed rule entitled: "Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units" (EPA-HQ-OAR-2013-0602), notice of which EPA provided in the June 18, 2014 Federal Register (79 Fed. Reg. 34830). We also respectfully submit these comments on behalf of the organizations and individuals listed below:

Carbon Tax Center
Friends of the Earth
R Street Institute
Alan Viard

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The first section of this paper reviews the legal context of the EPA proposal and the relative roles of EPA and the states under section 111(d). In Section 2, we discuss the potential

¹ Environmental Protection Agency, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014), at <http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf>

advantages to states of a tax-based compliance approach. In Section 3, we explore how, with some important constraints, the current regulations implementing section 111(d) and the EPA proposal allow states to comply by imposing an excise tax on the carbon content of fuels combusted in regulated sources. In Section 4, we recommend amendments to existing rules and the EPA proposal that would remove those constraints and give states full flexibility in how they can design their pollution tax policies. Section 5 concludes.

Background

Under section 111(d) and the EPA proposal, EPA and states share responsibility for regulating GHG emissions from covered entities.² EPA has proposed emissions guidelines that set state-specific rate-based goals for CO₂ emissions from existing power plants. The standards reflect the degree of emission limitation that EPA has determined that states can achieve through the application of the “best system of emission reduction” (BSER) that, “taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the [EPA] Administrator determines has been adequately demonstrated.”³

The EPA proposal has two main elements: 1) state-specific emission goals, expressed as a limit on the number of pounds of CO₂ emitted per kilowatt hour (kwh) generated (with some adjustments), and 2) guidelines for developing and designing state implementation plans that will achieve the goals. The EPA constructed four “building blocks” of potential actions to determine the state-specific emissions goals, including: improving heat-rates at high-carbon EGUs; substituting generation at high-carbon EGUs with generation from less carbon-intensive EGUs; expanding low- or zero-carbon generation; and reducing emissions by lowering demand for electricity. Compliance occurs in two phases; covered sources in each state must meet an interim target on average over the 2020-2029 period and then a final target in 2030 and thereafter.

Each state can develop an implementation and enforcement plan that it forecasts will achieve the emissions goal EPA has set for it, or states can collaborate to submit a joint compliance plan. EPA can approve, reject, or conditionally approve the plans. Each plan must detail the policies and programs that the states will use to meet their emissions goals. States must submit the plans to EPA, and EPA must approve a plan if it meets EPA’s requirements. Much as states

² See 42 U.S.C. § 7411(d)(1), (2). Section 111(d) applies only to emissions not otherwise regulated under Sections 110 or 112 of the Clean Air Act. Emissions for which EPA has promulgated a national ambient air quality standard (NAAQS) under section 109 are regulated under section 110. 42 U.S.C.

§ 7411(d)(1)(A)(i). EPA regulates hazardous pollutants under section 112. EPA has not promulgated a NAAQS for CO₂, nor has it designated CO₂ emissions a hazardous pollutant.

³ 42 U.S.C. § 7411 (a)(1) and (d).

and the federal government cooperate to achieve national ambient air quality standards under section 110 of the Clean Air Act, under 111(d) EPA sets the GHG goals and states decide how to achieve them.⁴ Indeed, the EPA proposal itself states that EPA believes that this “well-established principle” from the section 110 process also “applies in the context of state plans under section 111(d).”⁵

In its proposal for existing power plants, EPA emphasizes the wide flexibility states have in how they achieve their emissions rate targets. Flexibility is important because states have very different existing emissions rates, mixes of generation technologies, costs of abatement, utility regulatory structures, and electricity demands. EPA says the agency intends to give all states “the opportunity to shape their plans as they believe appropriate for meeting the proposed CO₂ goals”⁶ and to allow states to use strategies that are not explicitly mentioned in any of the four building blocks in their compliance plans, including market-based trading programs.⁷

The EPA proposal specifies several acceptable flexibilities. For example, it allows states to demonstrate compliance on a multi-state basis (allowing any state’s emissions to exceed its assigned goal if it coordinates with others to make up for the difference). This accommodates the Regional Greenhouse Gas Initiative active in nine northeastern states and potentially other future multi-state cap-and-trade systems. Further, states can average emissions over the 2020-2029 period rather than complying on a year-by-year basis. In addition, states can choose to meet either an emissions rate-based target or an equivalent mass-based target. The former requires that covered sources achieve a certain emissions rate per megawatt hour of energy produced while the latter requires that they achieve a certain level of total emissions. EPA also allows states to choose how much of the responsibility for emissions reductions falls on emitting EGUs, and how much is placed on other entities, including the state itself.⁸ In the EPA

⁴ See 42 U.S.C. § 7411(d)(1) (directing EPA to promulgate regulations that are “similar to” section 110 of the Clean Air Act); *Train v. NRDC*, 421 U.S. 60, 79 (1975) (holding that states have the authority under section 110 to propose source-specific emissions limitations); *Michigan v. EPA*, 213 F.3d 663, 688 (D.C. Cir. 2000) (finding that EPA’s NOx Budget Program, promulgated under section 110, did not impermissibly limit state discretion because “states remain[ed] free to implement other ‘cost-effective’ or ‘reasonably cost-effective’ measures” other than those identified by EPA); *Virginia v. EPA*, 108 F.3d 1397, 1410 (D.C. Cir.), *modified on other grounds*, 116 F.3d 499 (D.C. Cir. 1997) (finding EPA cannot condition approval of state plans on the adoption of specific control measures).

⁵ EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34879.

⁶ EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34834.

⁷ EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34837.

⁸ *Op cit* p. 34833.

proposal and accompanying communications, EPA has emphasized that it wants to give states maximum flexibility in their approaches to meeting the targets the agency has set.

2. ADVANTAGES OF A STATE CARBON TAX APPROACH

Despite all this apparent flexibility, the rule does not acknowledge nor explicitly allow for one of the most cost effective options available to states: a carbon excise tax. This section explains why EPA should accept a state carbon tax as a primary means by which a state or group of states meet the emissions guidelines.

A state carbon excise tax makes environmental, economic and administrative sense.

- A carbon excise tax discourages each fuel's use in exact proportion to its damage to the climate. This changes the relative prices of different fuels and encourages all pollution reductions that cost less than the tax.
- A carbon excise tax incentivizes changes at power plants (for example, more efficient boilers and lower-carbon fuels) and greater energy efficiency by consumers. It induces all of the activities in EPA's four building blocks to the extent that they are cost effective.
- A carbon excise tax is market-based, flexible, compatible with existing fuel mixes, accommodates the "remaining useful life" of equipment, and doesn't undermine electricity reliability. It is broadly consistent with a wide variety of electricity market designs.
- A carbon excise tax encourages abatement in ways EPA and states can't predict, for example by helping drive a market for new technologies. Policies based on existing technologies might not do that.
- A carbon excise tax would be relatively easy to implement. Some states already have excise taxes on fuels, and they already monitor greenhouse emissions from regulated sources; they have been required to do so since the early 1990s under the Acid Rain Program.⁹
- States could use the revenue raised by a carbon excise tax however they wish. For instance, they could lower inefficient taxes, potentially providing pro-growth state tax reform along with environmental benefits. Alternatively, states could use the revenue

⁹ 40 C.F.R. § 75.13 (Acid Rain Program monitoring requirements for carbon dioxide emissions); see also 40 C.F.R. § 98.2 (entities that must report emissions under the GHG Reporting Rule).

for priorities that build support for the policy or offset some of its impacts on low-income residents.

- A carbon excise tax approach for power plants would establish legal precedents and administrative capacity that the state can use to comply with future stationary source regulations that EPA promulgates under section 111(d).
- A carbon excise tax approach is compatible with regional approaches to 111(d) compliance because coordination of tax rates is both straightforward and ensures that efficient operation of wholesale electricity markets is unimpaired.

Economic modeling can responsibly show that a carbon excise tax is “at least as stringent” as EPA’s emissions guideline.

A state can demonstrate through economic modeling that its carbon tax program is likely to achieve the emissions standard set by EPA.¹⁰ To demonstrate equivalence, states can employ EPA’s regional air pollution methodology, which the Supreme Court recently upheld in *EPA v. EME Homer City Generation, L.P.* with a 6-2 majority.¹¹ States’ authority to use economic modeling is even stronger in the section 111(d) context than it is under section 110. Section 111(d) explicitly gives states the authority to consider economic conditions.¹² Moreover, in the section 111(d) context, EPA has endorsed “open market concepts,” like carbon taxes, when they are designed to “achieve environmental limits,” “minimize costs,” and facilitate monitoring.¹³

In *EME Homer*, the Supreme Court upheld an EPA program that set emissions limits based on the power sector’s simulated response to cost thresholds, hailing the approach as a cost-effective way to solve a complex problem.¹⁴ EPA’s economic model assumed that regulated entities would reduce emissions in response to emissions pricing. To set the emissions price level, EPA modeled emissions reductions at different emissions pricing thresholds and then identified the price points at which emissions fell significantly. As the Court explained, these price points reflected the threshold at which “a certain type of emissions control strategy

¹⁰ See *Sierra Club v. Costle*, 657 F.2d 298, 332 (D.C. Cir. 1981) (upholding EPA’s authority to use computer models to make economic impact predictions, despite the fact that their results ultimately are shaped by their underlying assumptions).

¹¹ *E.P.A. v. EME Homer City Generation, L.P.*, 12-1182, 2014 WL 1672044, *19 (U.S. Apr. 29, 2014).

¹² See 42 U.S.C. § 7411(d)(1).

¹³ EPA, Federal Plan Requirements for Large Municipal Waste Combustors Constructed on or Before September 20, 1994, 63 Fed. Reg. 3,509, 3,514 (Jan. 23, 1998).

¹⁴ *EME Homer*, 12-1182, 2014 WL 1672044 (U.S. Apr. 29, 2014) (upholding, and acknowledging the utility of, a section 110 emissions budget program, used in EPA’s Transport Rule, that was developed using cost thresholds). Justice Alito did not participate in the decision; Justices Scalia and Thomas dissented. *Id.*

bec[ame] cost-effective.” Accordingly, EPA used these cost thresholds to allocate emissions budgets to states; evidence showed that the emissions pricing-based budgets would compel regulated entities to reduce emissions. Each budget represented the “quantity of pollution” a state would produce in a year “if its in-state sources implemented all pollution controls available at the chosen cost thresholds.”

The EPA process for designing a cap-and-trade program reviewed in *EME Homer* shows that states can demonstrate that carbon taxes, which are in essence cost thresholds, will achieve EPA’s emissions guideline. To do so, they need only develop a model similar to that used by EPA in *EME Homer* and in the EPA proposal.¹⁵ States can do this regardless of the formula for emissions guideline, including rate-based and mass-based standards. States can work with EPA to vet economic modeling approaches and tax options. Finally, just as for any other state implementation strategy, if a carbon tax for some reason failed to produce the forecast emission reductions, a state must increase the stringency of its policies, for example by increasing the tax trajectory.¹⁶ In any case, there exists longstanding EPA precedent for the idea that a tax or other cost-based threshold can be used to show that power sector emissions will fall to a predetermined level.

A carbon tax has advantages over other policies that price carbon.

A carbon tax is economically analogous to a cap-and-trade system. Both encourage regulated entities to change their production processes to reduce emissions to avoid paying the emissions-based fee.¹⁷ In the case of a cap-and-trade, designed to achieve a particular emissions rate in the power sector, the cap requires covered sources to surrender valuable permits equal to the sources’ emissions to the state regulator at the end of each compliance period. The value of these permits reduces firm incentives to burn fossil fuels in exactly the same way that a tax on carbon-based fuels would – by raising the costs of their use.

It is unclear how states could add new source categories to existing cap-and-trade programs because the Clean Air Act requires states to meet each goal for each source category

¹⁵ EPA utilized versions of the Integrated Planning Model (IPM) developed by ICF International to develop both the state emissions budgets for the Cross State Air Pollution Rule at issue in *EME Homer* and the estimates of coal-fired to natural gas combined cycle redispatch for building block 2 of the EPA proposal.

¹⁶ EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34952.

¹⁷ Lawrence H. Goulder & Andrew R. Schein, Carbon Taxes vs. Cap and Trade: A Critical Review 3 (Aug. 2013) (unpublished manuscript), available at <http://www.stanford.edu/~goulder/Papers/Published%20Papers/Carbon%20Taxes%20vs%20Cap%20and%20Trade%20-%2015%20Aug%20'13.pdf> (last visited May 4, 2014).

individually, even for the same pollutant. That means that allowances for one source category could not be fully fungible with allowances from other source categories. States would effectively have to set up separate cap-and-trade programs for each regulated source category. States that already have multi-source-category cap and trade programs (or will by the time EPA regulations are complete) will have trouble showing they can use those programs for 111(d) compliance.

In contrast to cap-and-trade, under a tax approach states would not have to allocate allowances, administer auctions, create an allowance registry, monitor trades and positions, or enforce a price floor. States also would not have to measure electricity generation, transmission, or consumption. A carbon tax can also be implemented by a single state agency, rather than requiring complex coordination between air, energy, and other regulatory bodies, as envisioned in the EPA proposal. To ensure compliance with a rate-based standard, all a state needs to do is monitor fossil fuel use and collect the money.

Taxes also offer a way for states to harmonize policies without formally linking them. For example, through economic modeling a group of states could show that a particular tax trajectory adopted in all states would jointly achieve their collective emissions targets. The states could each agree to adopt the specified tax as part of a multi-state compliance plan. This approach would avoid interstate transfers and requirements for tracking cross-state allowance trades. At the same time, it would promote abatement where it is least costly and limit distortions in investment and economic activity across state borders.

States can easily expand their tax base when and if EPA regulates additional source categories under section 111(d). As with EGUs, states would set a tax rate for the new source category designed to achieve EPA's category-specific emissions target. This tax rate could be different than the tax rate the state imposes on previously regulated categories. This might happen if the BSER in a future 111(d) rule for a particular source category implies a higher or lower marginal abatement cost than the EPA proposal for power plants. Alternatively, states could choose a single tax rate high enough to achieve the goals for all source categories, albeit with the outcome that they would overcomply with some.

A tax approach may also have advantages over another way to price carbon suggested by other stakeholders. In their joint preliminary comments on the EPA proposal, Great River Energy and the Brattle Group suggested that an Integrated System Operator (ISO) could impose a carbon price on affected sources via its bid mechanism for operation of day ahead and real-time operations in organized wholesale electricity markets.¹⁸ This market-based regional approach

¹⁸ Judy Chang, Jurgen Weiss, and Yingxia Yang, A Market-Based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector: An ISO-administered carbon price as a compliance option

incentivizes dispatch in an economically efficient manner, much like carbon excise taxes would, but it has other limitations. First, it would not necessarily produce retail electricity prices that reflect the full carbon price, as a tax would. Rather, the GRE-Brattle approach would “[minimize] the impact on end-user customers by fully refunding carbon charges imposed on generators.”¹⁹ This could potentially offset the incentive to reduce electricity use. Second, the ISO approach could result in substantial transfers from ratepayers in one state to entities in another state, introducing potential political challenges. In contrast, a state excise tax ensures that carbon charges collected in a state remain in that state.

Another potential drawback of the GRE-Brattle approach is that many states are incompletely covered by a single ISO. Some states host more than one ISO and/or have areas in which no ISO operates. Each of these areas requires separate treatment in the state compliance plans. Finally, even if an ISO approach worked well for the power plant rule, it would create no administrative structure that would be useful for other stationary source categories. Thus, states would have to develop compliance approaches from scratch for any future III(d) rules. In contrast, states could easily extend an excise tax policy from power plants to other sources upon future regulation by EPA.

EPA should maximize states’ compliance options as long as they are enforceable and effective.

Section III(d) explicitly grants states the authority to act independently of EPA in developing their compliance plans. First, section III(d) gives states, not EPA, the first opportunity to develop implementation and enforcement plans that are projected to achieve EPA’s national emissions guideline.²⁰ EPA can only reject state plans if it finds them unsatisfactory (i.e., the plans fail to satisfy section III(d) requirements or section III(d) regulations).²¹

Second, section III(d) gives states the opportunity to address local conditions, including economic factors like the remaining useful life of regulated sources.²² This sensitivity to local conditions is central to regulating existing sources under section III(d). Even if EPA finds a state plan unsatisfactory and acts to implement federal standards of performance in lieu of the state plan, EPA must still consider local state conditions.²³ Through its emphasis on local

for EPA’s Existing Source Rule, Discussion Paper Prepared for Great River Energy by the Brattle Group (April 2014), 2-4, at http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector.pdf.

¹⁹ Press release from Great River Energy, dated February 5, 2014, accessed August 19, 2014. http://www.greatriverenergy.com/aboutus/pressroom/020514_ghg_reg.html

²⁰ 42 U.S.C. § 7411(d)(1).

²¹ 42 U.S.C. § 7411(d)(2).

²² 42 U.S.C. § 7411(d)(1).

²³ 42 U.S.C. § 7411(d)(2) (requiring EPA to consider the remaining useful life of regulated sources).

circumstances and state flexibility in the section 111(d) framework, Congress asserted that states are in the best position to design plans most appropriate for them.

Third, section 111(d) directs EPA to develop a procedure “similar to” the section 110 process.²⁴ In fact, the structure of section 111(d) mirrors the section 110 framework: EPA sets the standard; states figure out how to achieve it.²⁵ Thus, the precedent of the State Implementation Plan process for ambient air quality standards, which focuses on the division of responsibility between states and EPA, applies here. Longstanding Supreme Court precedent interpreting section 110 of the Clean Air Act supports this conclusion.

Section 111(d), like section 110, relegates EPA to a “secondary role” in designing compliance plans.²⁶ EPA acts as a backstop by setting the standards and ensuring states propose and enforce plans that will achieve these emissions targets. States should enjoy the same independence under section 111(d) that they enjoy under section 110. Like section 110, section 111(d) “does not enable EPA to force particular control measures on the states.”²⁷ Rather, EPA may only require states to adopt a federal plan when they fail to submit adequate plans that comply with the Act.²⁸

EPA has long recognized this cooperative relationship in its 111(d) practice and adopts exactly this interpretation of its authority in the EPA proposal and its legal Technical Support Documents. In the rule’s preamble, EPA interprets the statute to give a state the “discretion in determining the measures in its plans.” Further, EPA states that, consistent with the legal precedent and statutory interpretation outlined above, that a state is “not limited to the measures that EPA identifies.”²⁹ Thus although EPA does not mention a carbon tax as a potential plan measure, it does articulate a legal rationale that should allow states to use carbon taxes as plan measures if they choose to do so.

A tax may not be more difficult to adopt than other abatement policies

²⁴ 42 U.S.C. §§ 7410(d)(1) (requiring EPA to prescribe regulations similar to section 110); (2)(A) (allowing EPA to “prescribe a plan for the State” just as it would under section 7410(c) if a state fails to submit a satisfactory plan).

²⁵ 42 U.S.C. § 7411(d); see also, EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34879, 34897.

²⁶ See *Train*, 421 U.S. at 78-79; *Michigan*, 213 F.3d at 686 (explaining *Train*, 421 U.S. at 78-79).

²⁷ *Virginia*, 108 F.3d at 1410 (holding that “EPA may not, under section 110, condition approval of a state’s implementation plan on the state’s adoption of a particular control measure”).

²⁸ *Train*, 421 U.S. at 79.

²⁹ EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34853, 34879, 34897.

One potential drawback of an excise tax approach is that states must pass a law to pursue it. The requirements for legislating new taxes vary from state to state, with some more stringent than others. Because section 111(d) requires a source category-by-source category approach to regulation, states may have to adopt a different tax rate for each category of emitters – or may opt to adopt a single rate sufficient to ensure compliance for all source categories. In some states, this may require separate legislative actions.

On the other hand, states likely will have to amend state law to adopt other policies to implement the EPA proposal and future 111(d) regulations. For example, in most states, new legislation is necessary to strengthen renewable portfolio standards and authorize new building and appliance energy efficiency standards.³⁰ While some states have strong legislative support and regulatory capacity to address greenhouse gas emissions, others may need a simple approach that accomplishes other goals as well. A carbon tax, especially if state fiscal reforms are desirable for other reasons, might not be a heavier lift than other legislative or regulatory changes that could implement the EPA rule.

Allowing a carbon tax in the EPA proposal is an important precedent for future rules.

Even states that currently have a clear policy approach for reducing CO₂ emissions from EGUs, such as an existing cap-and-trade system, may have an interest in ensuring that state excise taxes are available for other states under the power plant rule. That is because the 111(d) power plant rule sets a precedent for regulating other categories of existing stationary sources. It may not be feasible to incorporate all stationary source categories within RGGI, for example, and states may find it preferable simply to tax emissions from other sources rather than set up another cap-and-trade system for them. Further, an acknowledgement now that other source categories may be subject to a tax under 111(d) might prompt those sources to reduce emissions in advance of regulation.

3. HOW EXISTING 111(D) RULES AND THE EPA PROPOSAL ALLOW A STATE CARBON TAX

Eisenberg et al (2014) show that the text of section 111(d) and Supreme Court precedent give EPA the authority to allow states to adopt a carbon excise tax to achieve their emissions

³⁰ The Title 24 building energy efficiency program in California is one of the oldest and most successful programs in the country. It is also an important component of California's approach to reducing its state greenhouse gas emissions. See, Cal. Health and Safety Code Sec. 18901-18949.31; Cal. Code Reg. Title 24.

targets.³¹ The question posed here is whether the implementing regulations of section 111(d) – both existing regulations that proscribe how EPA implements section 111(d) in general and the EPA proposal for CO₂ from existing power plants – are consistent with a state excise tax approach.³² We show that it is possible for states to adopt a carbon excise tax to comply with the EPA proposal, but that they must do so in specific ways. They must either: 1) design the tax to comply with the existing definitions of “emission standard” in the regulations that implement section 111(d) authority for a wide variety of pollutants and stationary source categories; or 2) design the tax to meet the expanded definition of “emission standard” in the EPA proposal, which only applies to power plants. Let us consider these in turn.

Existing regulations implementing section 111(d) authority

The definition of “emission standard” as it relates to the control of any pollutant or stationary source category under section 111(d) appears in two places in Title 40 of the existing Code of Federal Regulations. The first instance is in 40 C.F.R. § 60.21 (Definitions).³³ It reads:

Emission standard means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

An elaboration of this definition of “emission standard” appears in 40 C.F.R. § 60.24(b)(1) (Emission standards and compliance schedules)³⁴:

Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

³¹ Samuel D. Eisenberg, Michael Wara, Adele Morris, Marta R. Darby, and Joel Minor, “A State Tax Approach to Regulating Greenhouse Gas Emissions Under the Clean Air Act,” Brookings, May 22, 2014.

³² 42 U.S.C. § 7411(d) (requiring EPA to develop regulations that establish a procedure “similar to” 42 U.S.C. 7410); *Train*, 421 U.S. at 79 (citing 42 U.S.C. § 7410(a)).

³³ 40 C.F.R. § 60.21, available at <http://www.law.cornell.edu/cfr/text/40/60.21>.

³⁴ 40 C.F.R. § 60.24(b)(1), available at <http://www.law.cornell.edu/cfr/text/40/60.24>.

On plain reading, the language of 40 C.F.R. § 60.21 suggests that an excise tax on a GHG or fossil fuel does not appear to qualify as an “emission standard.” A tax does not set forth an allowable rate of emissions, it is not an allowance system, and it doesn’t prescribe equipment.

However, EPA does not define an “allowance system” in the section 111(d) implementing regulations. In theory, a state could establish an allowance system in which it requires all regulated emissions to have an allowance (or permit) and sells the allowances at a pre-determined price (but not a pre-determined quantity).³⁵ This approach would be equivalent to a tax for practical purposes, but a state could call it an allowance system. However, states may be concerned that EPA intends “allowance system” to convey solely a (usually tradable) emissions permit system in which a fixed quantity of emissions permits are issued for use in a given time period. Thus although the language of 40 C.F.R. § 60.21 might in theory permit a carbon tax, the rule is not obviously and categorically supportive of one.

EPA has substantial discretion to determine the meanings of ambiguous terms in its statutes and regulations as long as the agency’s interpretation is reasonable.³⁶ If EPA is supportive of a state excise approach to compliance, then the agency could approve a fixed-price allowance system. However, a state could not necessarily rely on this interpretation. Further, EPA approval of a state compliance plan relying on a fixed-price allowance system would be subject to legal challenges. If EPA is in fact supportive of a carbon tax approach, EPA should make this clear to states and other parties by amending the regulatory definition of “emission standard,” as described below, when it finalizes the section 111(d) rule.

EPA proposal

In section 60.5740(a)(5) of its proposal, EPA requires states to identify in their compliance plan

emission standards for each affected entity, compliance periods for each emission standard, and demonstration that the emission standards are, when taken together, sufficiently protective to meet the state emissions performance level.

Thus, as long as a carbon tax meets the rule’s definition of an “emission standard” and a state demonstrates that its tax trajectory will foreseeably reduce emissions enough to achieve the state’s emissions performance level, the section 60.5740(a)(5) language appears fully consistent with a state carbon tax compliance strategy. The rest of this section focuses on how to ensure that a state-imposed carbon tax can be considered an “emission standard.”

³⁵ David Bookbinder noted this approach in personal communications with the authors.

³⁶ *Chevron v NRDC*, 467 U.S. 837 (1984).

In the EPA proposal, at section 60.5820, the agency defines “emission standard” to mean, in addition to the definition in 40 C.F.R. § 60.21 discussed above,

any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.

The examples EPA gives in the definition indicate that the intent of this additional option is to allow state policies that control emissions through electricity demand side management. The question is whether this proposed addition to the definition of “emission standard” would also allow a state to use a carbon excise tax to comply with the EPA proposal. Certainly a tax is a “requirement.” But it would also have to apply to an “affected entity other than an affected source” and have the effect of “reducing utilization of one or more affected sources.” We address these questions in turn.

Could a carbon tax apply to an “affected entity other than an affected source”?

Section 60.5820 of the EPA proposal defines “affected entity” as:

any of the following: An affected EGU, or another entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines.

So what is an “affected entity other than an affected source”? From the context, EPA appears to mean it is an entity that is not a regulated EGU but has some other obligation placed on it by the state plan. For example, it could be an electricity-using business that a state requires to adopt more energy-efficient technology or an electric utility that must implement an energy efficiency program for its customers.

Importantly, if a state imposes a carbon tax on fuels used by an EGU such that the tax liability is on the *seller* of the fuels, not on the EGU that buys them, then the obligation would fall on fuel suppliers (“affected entities” by virtue of their state tax liabilities) and not EGUs (an “affected source”). This upstream approach would deftly meet the condition that an emission standard is a “requirement applicable to any affected entity other than an affected source.” Economically, the effect is the same whether the statutory incidence of the tax is on the fuel supplier or the fuel purchaser.³⁷ Likewise, the Great River Energy-Brattle Group proposal to price carbon

³⁷ EPA defines “EGU” elsewhere in the EPA proposal but does not specify whether or not the owner of an EGU would count as an affected entity or an affected source for purposes of the definition of

through an ISO would constitute a requirement on an “affected entity other than an affected source,” and thus would be consistent with EPA’s proposed expansion of the definition of emission standard.

Alternatively, a state could impose a carbon tax on the distributors of electricity in proportion to the carbon intensity of the electricity it distributes. This would be a bit more complicated than the fuel tax approach because it would require an attribution of carbon emissions to specified electricity quantities purchased by distributors. An example of this downstream tax approach exists currently in California, where the “first deliverer” of electricity into the state is liable for the emissions associated with the imported power in that state’s cap-and-trade program.³⁸ Under EPA’s proposal, the main constraint would be that the state law places the tax obligation somewhere in the supply chain other than on the regulated EGUs, either upstream or downstream from affected sources.

An upstream tax easily accommodates any potential future EPA regulation of additional source categories under section 111(d). States can simply extend their carbon excise tax base to the fuels used in those additional sources. A downstream tax on the imputed carbon in electricity after it has left the power plant might be useful in states that wish to account for carbon in electricity imports, as California does, even though such accounting would not be required under 111(d).³⁹ However, a downstream approach might be difficult to apply to additional source categories under section 111(d), such as oil refineries and chemical manufacturing plants, because those facilities produce many kinds of products with varying carbon contents.

In conclusion, states can tax carbon upstream or downstream in the electricity supply chain such that the taxed entities qualify as affected entities other than affected sources. However, the EPA proposal does not allow for what is likely the simplest approach, taxing the EGUs themselves.

Does a carbon tax have the effect of “reducing utilization of one or more affected sources”?

Under the EPA proposal, in addition to imposing the tax upstream or downstream of the regulated sources, states would have to show that the tax would have the effect of reducing the “utilization” of regulated sources. States can show this straightforwardly through electricity

“emission standard.” An open question is whether or not a state could tax an owner of an EGU as an “affected entity” based upon fuel purchases for or emissions from “affected sources” that it owns. Given the significance of the interaction between the definition of affected EGU or source and other affected entities, EPA should consider clarifying its view of these terms. See EPA, Carbon Pollution Plan for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg., 34954; 34956.

³⁸ 17 Cal. Code. Reg. § 95802(145)-(147); 95811(b).

³⁹ California uses NERC e-tags for this purpose. 17 Cal. Code. Reg. § 95802(145).

sector modeling. Indeed, EPA engaged in just such an exercise when developing its power plant BSER. EPA calculated Building Block 2 of the BSER – redispatch from coal-fired to natural gas combined cycle power plants – by simulating a carbon tax of \$30 per ton CO₂. To accomplish this, the agency used ICF International’s Integrated Planning Model.⁴⁰ Thus EPA’s own Technical Support Documents already demonstrate that a carbon tax will “reduce utilization of one or more affected sources.” Other studies also show carbon taxes reduce output of high-carbon electricity.⁴¹ Finally, recent changes in the relative prices of coal and natural gas, similar to what would occur under a carbon tax, helped decrease coal-fired electricity generation,⁴² so strong real world evidence suggests that a carbon tax will shift generation from more carbon-intensive to less carbon-intensive EGUs.

Nonetheless, the real purpose of the emission standards is to reduce emissions, not utilization. EPA should not care which BSER building blocks any given emission standard mobilize as long as the approach reduces emissions.

So can states tax carbon as a compliance strategy?

Yes. Under the existing rules and the EPA proposal, a state can use a carbon tax to comply with III(d) requirements. Although a carbon tax approach is not necessarily what EPA intends to allow in the modified definition of “emission standard” in its proposal, the expansion of its meaning does provide a legal basis (in addition to the fixed-price “allowance system” approach described above) for states to adopt a carbon tax to comply with their III(d) obligations. However, EPA’s existing and proposed rules do not give states full flexibility in how they might design their carbon excise taxes, and the language specifically precludes what may be the simplest approach: placing the tax liability on final purchasers of fuels.

⁴⁰ Environmental Protection Agency, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units: GHG Abatement Measures, 3-24, at <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures>. This is the same model the Supreme Court recently found valid in *EME Homer*. See *supra*, note 15.

⁴¹ Michael W. Wara, Danny Cullenward, Jordan Wilkerson, and John Weyant, “Analysis of the Climate Protection Act of 2013,” Stanford Law and Economics Olin Working Paper No. 459, at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2392656. In addition, EIA routinely runs sidecases as a part of its Annual Energy Outlook that estimate that \$10 and \$25 carbon taxes, escalating at 5% per year, will produce substantial reductions over the 2020 to 2030 period. U.S. Energy Information Administration, Annual Energy Outlook 2014, MT-34 (DOE/EIA-834(2014)), at <http://www.eia.gov/forecasts/aeol/>.

⁴² See, Energy Information Administration, Today in Energy: U.S. Coal’s Share of Total Net Generation Continues to Decline (June 5, 2012), at <http://www.eia.gov/todayinenergy/detail.cfm?id=6550>.

4. RULE AMENDMENTS CAN GIVE STATES MORE FLEXIBILITY

Eisenberg et al (2014) note that to give states full flexibility to use a carbon tax to comply with their 111(d) requirements, EPA should broaden the definition of emission standard.⁴³ To do that, EPA could:

- 1) amend 40 C.F.R. § 60.21 and § 60.24(b)(1); or
- 2) modify the definition of “emission standard” in emissions guidelines for specific categories of stationary sources, including the EPA proposal.

The advantage of the first approach, amending the definition of “emission standard” in 40 C.F.R. § 60.21 and § 60.24(b)(1), is that the revised definition would apply to all pollutants and stationary source categories regulated under section 111(d), not just CO₂ from power plants. That would assure states that a GHG or carbon tax approach would be acceptable under all future 111(d) GHG rules and would allow states to plan accordingly, perhaps even adopting a state tax that covers those emissions before EPA regulates them.

Some may argue against such a revision by noting that emissions taxes may not be appropriate or feasible for all pollutants, or even all GHGs, regulated under section 111(d). In particular, strict quantitative limits may be most appropriate for pollutants that cause localized health concerns, such as pollutants regulated under the Large Municipal Waste Combustor rule.⁴⁴ Thus, tax-friendly language might best appear only in emissions guidelines for those GHGs or GHG source categories for which a tax is appropriate.

On the other hand, sections 60.21 and 60.24(b)(1) already mandate flexible standards “except when it is clearly impracticable.” That is because those approaches tend to be more cost effective than technology mandates or facility-by-facility emissions caps. Situations in which a rate-based standard or allowance trading system is feasible may well be just as appropriately addressed with a tax. This is especially true given the legal requirement that whatever policies a state chooses, the state must show that those policies will achieve the environmental goals established by EPA. If particular pollutants or sources pose local risks, then EPA can limit states’ flexibility in emissions guidelines under section 60.22 in those instances. Certainly for GHGs,

⁴³ See 40 C.F.R. § 60.24 (requiring that state compliance plans include “emission standards,” which “shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable”); *id.* § 60.21(f) (defining “emission standard” as “a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions”).

⁴⁴ Environmental Protection Agency, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Large Municipal Waste Combustors; Final Rule, 71 Fed. Reg. 27324 (May 10, 2006).

EPA should be comfortable with both price- and quantity-based policies as long as states meet their overall long-term performance goals.

Recommended amendments to 40 C.F.R. § 60.21 and § 60.24(b)(1)

Our recommended amendment to 40 C.F.R. § 60.21 emphasizes the dual requirements that emission standards be enforceable and reduce emissions and also provides examples of such policies:

Emission standard means a legally enforceable regulation that reduces air pollution emissions, such as setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications.

Our recommended amendment to 40 C.F.R. § 60.24(b)(1) would remove the list of policy designs from which states must choose, while preserving the preference for flexible performance standards in cases where EPA decides that states must include equipment standards in their plans:

The EPA will identify cases in the guideline documents issued under § 60.22 in which plans must prescribe equipment standards. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

Our recommended approach would clarify that as long as an emission standard is legally enforceable and reduces emissions, states can use it to comply.

Ample precedent exists for amendments to these regulations. EPA has amended 40 C.F.R. §§ 60.21 and 60.24(b)(1) multiple times, including in a 2005 rulemaking in which EPA expanded the definition of “emission standards” to include cap-and-trade programs in light of EPA’s 2005 Clean Air Mercury Rule.⁴⁵ Given EPA’s previous willingness to expand its definition of “emission

⁴⁵ Compare 40 C.F.R. § 60.24(b)(1) (2006) (“Emission standards shall *either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable.*”) (emphasis added), with 40 C.F.R. § 60.24(b)(1) (2005) (“Emission standards shall prescribe allowable rates of emissions except when it is clearly impracticable.”); see also Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28606, 28633 (amending 40 C.F.R. § 60.24 “to make clear that a standard of performance for existing sources under CAA section 111(d) may include an allowance program of the type described today”); see also 77 Fed.

standards” when it sought to recommend a cap-and-trade system as a compliance option for the Clean Air Mercury Rule, EPA should not continue to constrain states’ ability to use taxes to reduce pollutant emissions under section 111(d).

Recommended amendments to the EPA proposal

If EPA prefers not to modify 40 C.F.R. §§ 60.21 and 60.24(b)(1), the agency could instead modify the proposal’s definition of “emission standard” in section 60.5820. We recommend that EPA modify section 60.5820 to read as follows:

Emission standard means in addition to the definition in § 60.21, any requirement applicable to any affected entity that has the effect of reducing emissions of one or more affected sources, including, for example, renewable energy and demand-side energy efficiency requirements.

This amended language would allow states to impose a tax liability on regulated sources instead of upstream or downstream entities. It also replaces “reducing utilization” with “reducing emissions” of affected sources, keeping the emphasis on the objective of the rule and EPA’s role in setting the emissions guideline.

If EPA makes no other amendments, the implicit authorization for state carbon taxes would apply only to power plants. To be sure, EPA could include similar language in future section 111(d) regulations that control GHGs from other source categories, such as refineries, and the agency could suggest in the proposal’s preamble that EPA plans to do so. But such a piecemeal approach would not assure states that they can use alternatives like carbon taxes until EPA promulgates those rules. This uncertainty could complicate state efforts to plan for future rules as they develop plans to comply with EPA’s current rulemaking for power plants.

5. CONCLUSION

Consistent with EPA’s public commitments and Supreme Court precedent, states should be free to comply with section 111(d) rules using policies of their own choosing, so long as the policies achieve the emissions guideline set by EPA. Taxing carbon is an effective, simple, pragmatic, and cost-effective approach to reducing CO₂ emissions. EPA should allow states to use carbon taxes as a primary compliance strategy. Although the EPA proposal as written will allow states that wish to adopt a carbon excise tax to do so, it inadvertently precludes the

Reg. 9304 (Feb. 16, 2012) (Mercury and Air Toxics Standards (MATS) Rule) (amending 40 C.F.R. §§ 60.21, 60.24 but retaining allowance systems).

logical option of imposing the tax liability on EGUs themselves. Instead, the proposal's expanded definition of "emission standard" appears to require states to place the statutory incidence of the tax only on entities upstream or downstream from the regulated sources.

EPA could remove this barrier in two ways:

- 1) EPA could change the section III(d) implementing regulations to clarify that any measure that is enforceable and reduces emissions can be an "emission standard"; or
- 2) EPA could revise the expanded definition of "emission standard" in the proposed rule to allow reductions in emissions caused by regulation of any affected entity, including EGUs themselves.

These changes are straightforward, but the first is more broadly applicable. It would apply not only to power plants but also to other source categories, thus assuring states that the flexibility EPA is offering for power plants will extend to other source categories in future emissions guidelines.