University of San Diego School of Law

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California to Paris: Linking Climate and Energy Policy at the State, National, and International Levels

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OVERVIEW OF THE CLEAN POWER PLAN

CUTTING CARBON POLLUTION FROM POWER PLANTS

On August 3, President Obama and EPA announced the Clean Power Plan – a historic and important step in reducing carbon pollution from power plants that takes real action on climate change. Shaped by years of unprecedented outreach and public engagement, the final Clean Power Plan is fair, flexible and designed to strengthen the fast-growing trend toward cleaner and lower-polluting American energy. With strong but achievable standards for power plants, and customized goals for states to cut the carbon pollution that is driving climate change, the Clean Power Plan provides national consistency, accountability and a level playing field while reflecting each state's energy mix. It also shows the world that the United States is committed to leading global efforts to address climate change.

WHAT IS THE CLEAN POWER PLAN?

- The Clean Power Plan will reduce carbon pollution from power plants, the nation's largest source, while maintaining energy reliability and affordability. Also on August 3, EPA issued final Carbon Pollution Standards for new, modified, and reconstructed power plants, and proposed a Federal Plan and model rule to assist states in implementing the Clean Power Plan.

- These are the first-ever national standards that address carbon pollution from power plants.

- The Clean Power Plan cuts significant amounts of power plant carbon pollution and the pollutants that cause the soot and smog that harm health, while advancing clean energy innovation, development and deployment, and laying the foundation for the long-term strategy needed to tackle the threat of climate change. By providing states and utilities ample flexibility and the time needed to achieve these pollution cuts, the Clean Power Plan offers the power sector the ability to optimize pollution reductions while maintaining a reliable and affordable supply of electricity for ratepayers and businesses.

- Fossil fuels will continue to be a critical component of America's energy future. The Clean Power Plan simply makes sure that fossil fuel-fired power plants will operate more cleanly and efficiently, while expanding the capacity for zero- and low-emitting power sources.

- The final rule is the result of unprecedented outreach to states, tribes, utilities, stakeholders and the public, including more than 4.3 million comments EPA received on the proposed rule. The final Clean Power Plan reflects that input, and gives states and utilities time to preserve ample, reliable and affordable power for all Americans.

WHY WE NEED THE CLEAN POWER PLAN

- In 2009, EPA determined that greenhouse gas pollution threatens Americans' health and welfare by leading to long-lasting changes in our climate that can have a range of negative effects on human health and the environment. Carbon dioxide (CO_2) is the most prevalent greenhouse gas pollutant, accounting for nearly three-quarters of global greenhouse gas emissions and 82 percent of U.S. greenhouse gas emissions.

- Climate change is one of the greatest environmental and public health challenges we face. Climate impacts affect all Americans' lives – from stronger storms to longer droughts and increased insurance premiums, food prices and allergy seasons.

- 2014 was the hottest year in recorded history, and 14 of the 15 warmest years on record have all occurred in the first 15 years of this century. Recorded temperatures in the first half of 2015 were also warmer than normal.

- Overwhelmingly, the best scientists in the world, relying on troves of data and millions of measurements collected over the course of decades on land, in air and water, at sea and from space, are telling us that our activities are causing climate change.

- The most vulnerable among us – including children, older adults, people with heart or lung disease and people living in poverty – may be most at risk from the impacts of climate change.

- Fossil fuel-fired power plants are by far the largest source of U.S. CO_2 emissions, making up 31 percent of U.S. total greenhouse gas emissions.

- Taking action now is critical. Reducing CO_2 emissions from power plants, and driving investment in clean energy technologies strategies that do so, is an essential step in lessening the impacts of climate change and providing a more certain future for our health, our environment, and future generations.

BENEFITS OF IMPLEMENTING THE CLEAN POWER PLAN

- The transition to clean energy is happening faster than anticipated. This means carbon and air pollution are already decreasing, improving public health each and every year.

- The Clean Power Plan accelerates this momentum, putting us on pace to cut this dangerous pollution to historically low levels in the future.

- When the Clean Power Plan is fully in place in 2030, carbon pollution from the power sector will be 32 percent below 2005 levels, securing progress and making sure it continues.

- The transition to cleaner sources of energy will better protect Americans from other harmful air pollution, too. By 2030, emissions of sulfur dioxide from power plants will be 90 percent lower compared to 2005 levels, and emissions of nitrogen oxides will be 72 percent lower. Because these pollutants can create dangerous soot and smog, the historically low levels mean we will avoid thousands of premature deaths and have thousands fewer asthma attacks and hospitalizations in 2030 and every year beyond.

- Within this larger context, the Clean Power Plan itself is projected to contribute significant pollution reductions, resulting in important benefits, including:

  - Climate benefits of $20 billion

  - Health benefits of $14-$34 billion

  - Net benefits of $26-$45 billion

- Because carbon pollution comes packaged with other dangerous air pollutants, the Clean Power Plan will also protect public health, avoiding each year:

  - 3,600 premature deaths

  - 1,700 heart attacks

  - 90,000 asthma attacks

  - 300,000 missed work days and school days

HOW THE CLEAN POWER PLAN WORKS

- The Clean Air Act – under section 111(d) – creates a partnership between EPA, states, tribes and U.S. territories – with EPA setting a goal and states and tribes choosing how they will meet it.

- The final Clean Power Plan follows that approach. EPA is establishing interim and final carbon dioxide (CO_2) emission performance rates for two subcategories of fossil fuel-fired electric generating units (EGUs):

  - Fossil fuel-fired electric steam generating units (generally, coal- and oil-fired power plants)

  - Natural gas-fired combined cycle generating units

- To maximize the range of choices available to states in implementing the standards and to utilities in meeting them, EPA is establishing interim and final statewide goals in three forms:

  - A rate-based state goal measured in pounds per megawatt hour (lb/MWh);

  - A mass-based state goal measured in total short tons of CO_2;

  - A mass-based state goal with a new source complement measured in total short tons of CO_2.

- States then develop and implement plans that ensure that the power plants in their state – either individually, together or in combination with other measures – achieve the interim CO_2 emissions performance rates over the period of 2022 to 2029 and the final CO_2 emission performance rates, rate-based goals or mass-based goals by 2030.

- These final guidelines are consistent with the law and align with the approach that Congress and EPA have always taken to regulate emissions from this and all other industrial sectors – setting source-level, source category-wide standards that sources can meet through a variety of technologies and measures.

HOW EPA DETERMINED EMISSION PERFORMANCE RATES

- Under section 111(d) of the Clean Air Act, EPA determines the best system of emissions reduction (BSER) that has been demonstrated for a particular pollutant and a particular group of sources by examining technologies and measures already being used.

- Consistent with previous BSER determinations in 111(d) rulemakings, the agency considered the types of strategies, technologies and measures that states and utilities are already using to reduce CO_2 from fossil fuel-fired power plants.

- In the final Clean Power Plan, EPA determined that BSER consists of three building blocks:

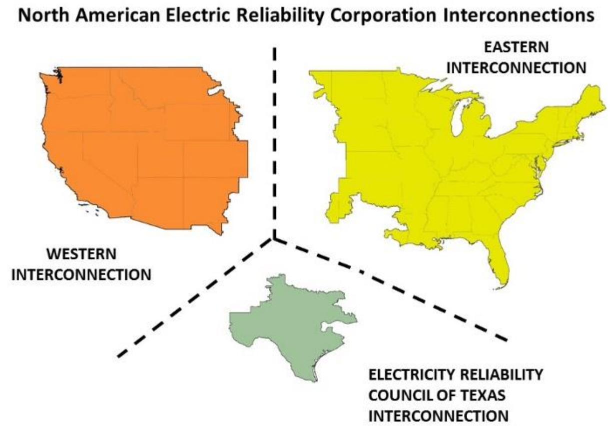
  - **Building Block 1** - reducing the carbon intensity of electricity generation by improving the heat rate of existing coal-fired power plants.

  - **Building Block 2** -substituting increased electricity generation from lower-emitting existing natural gas plants for reduced generation from higher-emitting coal-fired power plants.

  - **Building Block 3** - substituting increased electricity generation from new zero-emitting renewable energy sources (like wind and solar) for reduced generation from existing coal-fired power plants.

- In determining the BSER, EPA considered the ranges of reductions that can be achieved at coal, oil and gas plants at a reasonable cost by application of each building block, taking into account how quickly and to what extent the measures encompassed by the building blocks could be used to reduce emissions.

- In assessing the BSER, EPA recognized that power plants operate through broad interconnected regional grids that determine the generation and distribution of power, and thus the agency based its analysis on the three established regional electricity interconnects: the Western interconnection, the Eastern interconnection and the Electricity Reliability Council of Texas interconnection.



- EPA applied the building blocks to all of the coal plants and all of the natural gas power plants in each region to produce regional emission performance rates for each category.

- From the three resulting regional coal plant rates, and the three regional natural gas power plant rates, EPA chose the most readily achievable rate for each category to arrive at equitable CO_2 emission performance rates for the country that represent the best system of emission reductions.

- The same CO_2 emission performance rates were then applied to all affected sources in each state to arrive at individual statewide rate-based and mass-based goals. Each state has a different goal based upon its own particular mix of affected sources.

- The agency is setting emission performance standards for tribes with affected EGUs—Navajo, Fort Mojave, and Ute (Uintah and Ouray). At this time, EPA is not setting CO_2 emission performance goals for Alaska, Hawaii, Guam or Puerto Rico so that the agency can continue to collect data that can form the basis of standards for power plants there in the future.

STATE PLANS

- The final Clean Power Plan provides guidelines for the development, submittal and implementation of state plans that establish standards of performance or other measures for affected EGUs in order to implement the interim and final CO_2 emission performance rates.

- States must develop and implement plans that ensure the power plants in their state – either individually, together, or in combination with other measures – achieve the equivalent, in terms of either or rate or mass, of the interim CO_2 performance rates between 2022 and 2029, and the final CO_2 emission performance rates for their state by 2030.

- States may choose between two plan types to meet their goals:

- **Emission standards plan**– includes source-specific requirements ensuring all affected power plants within the state meet their required emissions performance rates or state-specific rate-based or mass-based goal.

- **State measures plan**– includes a mixture of measures implemented by the state, such as renewable energy standards and programs to improve residential energy efficiency that are not included as federally enforceable components of the plan. The plan may also include federally enforceable source-specific requirements. The state measures, alone or in conjunction with federally enforceable requirements, must result in affected power plants meeting the state's mass-based goal. The plan must also include a backstop of federally enforceable standards on affected power plants that fully meet the emission guidelines and that would be triggered if the state measures fail to result in the affected plants achieving the required emissions reductions on schedule. States may use the final model rule, which EPA proposed on August 3, for their backstop.

- In developing its plan, each state will have the flexibility to select the measures it prefers in order to achieve the CO_2 emission performance rates for its affected plants or meet the equivalent statewide rate- or mass-based CO_2 goal. States will also have the ability to shape their own emissions reduction pathways over the 2022-29 period.

- The final rule also gives states the option to work with other states on multi-state approaches, including emissions trading, that allow their power plants to integrate their interconnected operations within their operating systems and their opportunities to address carbon pollution.

- The flexibility of the rule allows states to reduce costs to consumers, minimize stranded assets and spur private investments in renewable energy and energy efficiency technologies and businesses.

- States can tailor their plans to meet their respective energy, environmental and economic needs and goals, and those of their local communities by:

    - relying on a diverse set of energy resources;

    - protecting electric system reliability;

    - providing affordable electricity; and

    - recognizing investments that states and power companies are already making.

EMISSIONS TRADING

- One cost-effective way that states can meet their goals is emissions trading, through which affected power plants may meet their emission standards via emission rate credits (for a rate-based standard) or allowances (for a mass-based standard).

- Trading is a proven approach to address pollution and provides states and affected plants with another mechanism to achieve their emission standards. Emission trading is a market-based policy tool that creates a financial incentive to reduce emissions where the costs of doing so are the lowest and clean energy investment enjoys the highest leverage.

- Market-based approaches are generally recognized as having the following benefits:

    - Reduce the cost of compliance

    - Create incentives for early reduction

    - Create incentives for emission reductions beyond those required

    - Promote innovation, and

    - Increase flexibility and ensure reliability

- In addition to including mass-based state goals to clear the path for mass-based trading plans, the final rule gives states the opportunity to design state rate-based or mass-based plans that will make their units "trading ready," allowing individual power plants to use out-of-state reductions – in the form of credits or allowances, depending on the plan type – to achieve required CO_2 reductions, without the need for up-front interstate agreements.

- EPA is committed to supporting states in the tracking of emissions, as well as tracking allowances and credits, to help implement multi-state trading or other approaches.

RELIABILITY ASSURANCE

- The final rule has several features that reflect EPA's commitment to ensuring that compliance with the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply:

    - A long compliance period, and phased-in reduction requirements, providing sufficient time and flexibility for the planning and investment needed to maintain system reliability.

    - A basic design that allows states and affected EGUs flexibility to include a large variety of approaches and measures to achieve the environmental goals in a way that is tailored to each state's and utility's energy resources and policies, including trading within and between states, and other multi-state approaches that support electric system reliability.

    - A requirement that each state demonstrate in its final plan that it has considered reliability issues in developing its plan.

    - A mechanism for a state to seek a revision to its plan in case unanticipated or significant reliability challenges arise.

- A reliability safety valve to address situations where, in the wake of an unanticipated event or other extraordinary circumstances, an affected power plant must provide reliability-critical generation notwithstanding CO_2 emissions constraints that would otherwise apply.

- In addition to the measures outlined in the rule EPA, the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) are coordinating efforts to monitor the implementation of the final rule to help preserve continued reliable electricity generation and transmission.

STATE PLAN TIMING

- States will be required to submit a final plan, or an initial submittal with an extension request, by September 6, 2016.

- Final complete state plans must be submitted no later than September 6, 2018.

- The final rule provides 15 years for full implementation of all emission reduction measures, with incremental steps for planning and demonstration that will ensure progress is being made in achieving CO_2 emission reductions.

- Each state plan must include provisions that will allow the state to demonstrate that the plan is making progress toward meeting the 2030 goal. The Clean Power Plan offers several options for states to show their progress for meeting interim CO_2 emission performance rates or state CO_2 emission interim step goals.

- In addition to offering three multi-year "step down" goals within the interim period, the final rule also allows states to apply measures in a gradual way that that they determine is the most cost-effective and feasible.

- During the interim period states are required periodically to compare emission levels achieved by their affected power plants with emission levels projected in the state plan and report results to EPA.

HELPING COMMUNITIES BENEFIT FROM CLEAN ENERGY

- The Clean Power Plan gives states the opportunity to ensure that communities share in the benefits of a clean energy economy, including energy efficiency and renewable energy.

- EPA is creating a Clean Energy Incentive Program (CEIP) to reward early investments in wind and solar generation, as well as demand-side energy efficiency programs implemented in low-income communities, that deliver results during 2020 and/or 2021.

- Through this program, EPA intends to make allowances or emission rate credits (ERCs) available to states that incentivize these investments. EPA is providing additional incentives to encourage energy efficiency investments in low-income communities.

COMMUNITY INVOLVEMENT AND ENVIRONMENTAL JUSTICE

- The final rule reflects two years of unprecedented outreach and engagement with stakeholders and the public, and incorporates changes directly responsive to stakeholders' critical concerns and priorities.

- Public engagement was essential throughout the development of the Clean Power Plan, and EPA will continue to engage with communities and the public now that the rule is final.

- To ensure opportunities for communities – particularly low-income communities, minority communities and tribal communities – to continue to participate in decision making, EPA is requiring that states demonstrate how they are actively engaging with communities as part of their public participation process in the formulation of state plans.

- The requirement for meaningful engagement within state plans will provide an avenue for all communities to both hear from the state about strategies that might work best to tackle climate pollution, and to provide input on where possible impacts to low-income communities, minority communities, and tribal communities could occur along with strategies to mitigate those impacts.

- The final rule includes information on communities living near power plants, and EPA will provide additional information to facilitate engagement between communities and states as implementation of the Clean Power Plan moves forward. For example, the agency will provide guidance on strategies states can use to meaningfully engage with communities, along with other resources and information, on a portal web page the agency will develop for communities' use.

- As implementation of the Clean Power Plan goes forward, the agency will conduct air quality evaluations to determine impacts that state plans may have on vulnerable communities. EPA encourages states to conduct analyses to help states, communities and utilities understand the potential localized and community impacts of state plans.

- To help with these analyses, EPA will ensure emissions data is available and easily accessed through the Clean Power Plan Communities Portal web page. The agency also will provide demographic information and other data, along with examples analyses that states have conducted to assess the impact of other rules.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA-HQ-OAR-2015-0199; FRL_XXXX-X]

RIN 2060-AS47

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

AGENCY: Environmental Protection Agency.

ACTION: Proposed Rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing a federal plan to implement the greenhouse gas (GHG) emission guidelines (EGs) for existing fossil fuel-fired electric generating units (EGUs) under the Clean Air Act (CAA). The EGs were proposed in June 2014 and finalized on August 3, 2015 as the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (also known as the Clean Power Plan or EGs). This proposal presents two approaches to a federal plan for states and other jurisdictions that do not submit an approvable plan to the EPA: a rate-based emission trading program and a mass-based emission

trading program. These proposals also constitute proposed model trading rules that states can adopt or tailor for implementation of the final EGs. The federal plan is an important measure to ensure that congressionally mandated emission standards under the authority of the CAA are implemented. The proposed federal plan is related to but separate from the final EGs. The final EGs establish the best system of emission reduction (BSER) for applicable fossil fuel-fired EGUs in the form of a carbon dioxide (CO_2) emission performance rate for steam-fired EGUs and a CO_2 emission performance rate for natural gas-fired combined cycle units, and provide guidance and criteria for the development of approvable state plans. The purpose of the proposed federal plan is to establish requirements directly applicable to a state’s affected EGUs that meet these emission performance levels, or the equivalent statewide goal, in order to achieve reductions in CO_2 emissions in the case where a state or other jurisdiction does not submit an approvable plan. The stringency of the emission performance levels established in the final EGs will be the same whether implemented through a state plan or a federal plan. The EPA is also proposing enhancements to the CAA section 111(d) framework regulations related to the process and timing for state plan submissions and EPA actions. The EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016.

DATES: Comments. Comments must be received on or before [**insert date 90 days after date of publication in the Federal Register**].

Public Hearing. The EPA will be holding **[insert number of hearings here]** public hearings on the proposed federal plan. The hearings will be held to accept oral comments on the proposed federal plan. The hearings will be held **[insert number, days of and locations of hearings here]**. The hearings will begin at 9:00 a.m. (local time) and will conclude at 8:00 p.m. (local time).

ADDRESSES: Submit your comments on the federal plan requirements proposed rule, identified by Docket ID No. EPA-HQ-OAR-2015-0199, by one of the following methods:

- Federal Rulemaking Portal http://www.regulations.gov: Follow the online instructions for submitting comments.
- Email: Send your comments via electronic mail to A-and-R-Docket@epa.gov, Attention Docket ID No. EPA-HQ-OAR-2015-0199.
- Facsimile: Fax your comments to (202) 566-9744, Attention Docket ID No. EPA-HQ-OAR-2015-0199.
- Mail: Send your comments to: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mailcode: 28221T, 1200 Pennsylvania Ave., NW, Washington, DC 20460, Attention Docket ID No. EPA-HQ-OAR-2015-0199. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attn: Desk Officer for EPA, 725 17th Street NW., Washington, DC 20503.
- Hand Delivery: Deliver your comments to: EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave., NW, Washington, DC, 20004, Attention Docket ID No. EPA-HQ-OAR-2015-0199. Such deliveries are accepted only during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays) and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments on the federal plan requirements proposed rule to Docket ID No. EPA-HQ-OAR-2015-0199. The EPA's policy is that all comments received will be included in the public docket and may be made available online at http://www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through http://www.regulations.gov or email. The http://www.regulations.gov Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through http://www.regulations.gov, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Public Hearing: **[insert number of hearings here]** public hearings will be held to accept oral comments on the proposed federal plan. The hearings will be held on **[insert number of, dates and locations of hearings here].** The hearings will begin at 9:00 a.m. (local time) and will conclude at 8:00 p.m. (local time). There will be a lunch break from 12:00 p.m. to 1:00 p.m. and a dinner break from 5:00 p.m. to 6:00 p.m. To register to speak at a hearing, please use the online registration form available at: http://www.epa.gov/cleanpowerplan. For questions regarding registration, please contact **[insert name]** at (919) 541**–[insert number]**. The last day to pre-register to speak at the hearings will be **[insert date]**, 2015. Additionally, requests to speak will be taken the day of each hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. Please note that registration requests received before each hearing will be confirmed by the EPA via email. We cannot guarantee that we can accommodate all timing requests and will provide requestors with the next available speaking time, in the event that their requested time is taken. Please note that the time outlined in the confirmation email received will be the time the one will be scheduled to speak. Again, depending on the flow of the day, times may fluctuate. If you require the service of a translator or special accommodations such as audio description, we ask that you pre-register for the hearings by **[insert date]**, 2015, as we may not be able to arrange such accommodations without advance notice. Please note that any updates made to any aspect of the hearings will be posted online at http://www.epa.gov/cleanpowerplan. While the EPA expects the hearings to go forward as set forth above, we ask that you monitor our Web site or contact **[insert name]** at (919) 541–**[insert number]** to determine if there are any updates to the information on the hearings. The EPA does not intend to publish a notice in the Federal Register announcing any such updates. The hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Verbatim transcripts of the hearing and written statements will be included in the docket for the rulemaking. The EPA plans for the hearings to run on schedule; however, due to on-site schedule fluctuations, actual speaking times may shift slightly.

Because these hearings are being held at United States (U.S.) government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver’s license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma, or the state of Washington, you must present an additional form of identification to enter the federal building. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver’s licenses, and military identification cards. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building, and demonstrations will not be allowed on federal property for security reasons.

Attendees will be asked to go through metal detectors. To help facilitate this process, please be advised that you will be asked to remove all items from all pockets and place in provided bins for screening; remove laptops, phones, or other electronic devices from their carrying case and place in provided bins for screening; avoid shoes with metal shanks, toe guards, or supports as a part of their construction; remove any metal belts, metal belt buckles, large jewelry, watches; and follow the instructions of the guard if identified for secondary screening. Additionally, no weapons (e.g., pocket knives) or drugs or drug paraphernalia (e.g., marijuana) will be allowed in the building. We recommend that you arrive 20 minutes in advance of your speaking time to allow time to go through security and to check in with the registration desk.

Docket: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2015-0199. The EPA has previously established a docket for the January 8, 2014, Clean Power Plan proposal under Docket ID No. EPA-HQ-OAR-2009-0559. All documents in the docket are listed in the http://www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically at http://www.regulations.gov or in hard copy at the EPA Docket Center EPA/DC, EPA WJC West

Building, Room 3334, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Ms. Toni Jones, Fuels and Incineration Group, Sector Policies and Programs Division (E143-05), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-0316; fax number: (919) 541-3470; email address: jones.toni@epa.gov.

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ANSI	American National Standards Institute
ARP	Acid Rain Program
BSER	Best system of emission reduction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CBI	Confidential Business Information
CEMS	Continuous emissions monitoring system
CFCs	Chlorofluorocarbons
CISWI	Commercial Industrial Solid Waste Incinerators
CFR	Code of Federal Regulations
CHP	Combined heat and power
CO_2	Carbon dioxide
CO_2	Carbon dioxide equivalent
CSAPR	Cross-state Air Pollution Rule
DOE	Department of Energy
EE	Energy efficiency
EGs	Emission Guidelines
EGU	Electric generating unit
EIA	Energy Information Administration
EJ	Environmental justice

EM&V	Evaluation, measurement, and verification
EPA	Environmental Protection Agency
EO	Executive Order
FERC	Federal Energy Regulatory Commission
FIP	Federal implementation plan
FR	Federal Register
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GJ/h	Gigajoule per hour
HAP	Hazardous air pollutants
ICR	Information collection request
IGCC	Integrated gasification combined cycle unit
IPM	Integrated Planning Model
IPCC	Intergovernmental Panel on Climate Change
ISO/RTO	Independent System Operator/Regional Transmission Organization
lbs	Pounds
LML	Lowest measured $PM_{2.5}$ levels
MATS	Mercury and Air Toxics Standards
M&V	Measurement and verification
MMBtu/h	Million British Thermal units per hour
MSW	Municipal solid waste
MW	Megawatts
MWh	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industrial Classification System
NERC	North American Electric Reliability Corporation
NSPS	New source performance standards
NSR	New Source Review
NTTAA	National Technology Transfer and Advancement Act
NO_X	Nitrogen oxides
OAP	Office of Atmospheric Programs
OAQPS	Office of Air Quality Planning and Standards
PRA	Paperwork Reduction Act
PUC	Public Utility Commission
RE	Renewable energy
REC	Renewable Energy Certificate
RFA	Regulatory Flexibility Act
RGGI	Regional Greenhouse Gas Initiative
RIA	Regulatory impact analysis
SCT	Stationary combustion turbine
SGU	Steam generating unit
SIP	State implementation plan
SO_2	Sulfur dioxide
TSD	Technical support document
The Court	U.S. Court of Appeals for the District of Columbia Circuit

TTN	Technology Transfer Network
UMRA	Unfunded Mandates Reform Act
UNFCCC	United Nations Framework Convention on Climate Change
U.S.	United States
WWW	World Wide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Executive Summary

In the CAA, Congress created a partnership between the EPA and the states. Under section 111(d) of the CAA, the EPA establishes emission performance levels based on its determination of the BSER for existing sources of air pollution and provides guidelines for state plans to apply standards of performance to their sources that meet the BSER level of performance. The EPA promulgated EGs under CAA section 111(d) which set source-level CO_2 emission performance rates for the EGUs at certain large fossil fuel-fired power plants ("affected EGUs"). States then apply these EGs to their sources in developing state plans to achieve these emission performance levels for EPA approval, or initial submittals, by September 6, 2016. The amount of reductions in CO_2 that the EPA determined to be achievable for these sources is based on its determination of what constitutes the BSER. This determination is finalized in the EGs, which are designed to maximize the flexibility of both states and affected EGUs in meeting CO_2 emissions performance rates. While states may impose the emission rates directly on their affected EGUs, states also have the option of submitting more tailored plans that meet state-specific emissions goals. The EGs also provide flexibility by allowing for emissions trading and multi-state compliance options.

While it has been the EPA’s longstanding view that the statute identifies states as the preferred implementers of CAA programs, the agency makes clear in the EGs that states cannot and will not be penalized for failing to participate in this program. However, if a state does not submit an approvable plan under section 111(d) of the CAA, the EPA will develop, implement, and enforce a federal plan to reduce CO_2 from the fossil fuel-fired power plants in that state. This is wholly consistent with the “cooperative federalism” structure of the CAA and many of our nation’s other environmental laws. In addition, we have heard from states and other stakeholders that it would be helpful for the agency to present model designs for state plans, and a federal plan would be an appropriate means of doing that.

Accordingly, the EPA proposes a federal plan under section 111(d) of the CAA for the control of CO_2, a GHG pollutant, from certain emitting fossil fuel-fired power plants, in the event that some states do not adopt their own plans. Specifically, the EPA is proposing approaches in the form of mass- and rate-based trading options that provide flexibility in implementing emission standards for a state's affected EGUs. Both proposed approaches to the federal plan would require affected EGUs to meet emission standards set using the CO_2 emission performance rates in the EGs. The federal plan will achieve the same levels of emissions performance as required of state plans under the EGs. The EPA will promulgate a final federal plan for only the affected EGUs in states that the EPA determines did not submit an approvable plan.

At the same time, these two proposed options offer states model trading rules that the states can follow in developing their own plans in order to capitalize on the flexibility built into the final EGs. Thus, this document proposes four discrete actions: (1) A rate-based federal plan for each state with affected EGUs; (2) a mass-based federal plan for each state with affected EGUs; (3) a rate-based model trading rule for potential use by any state; and (4) a mass-based model trading rule for potential use by any state. The regulatory text of each federal plan and corresponding model trading rule is identical, except as indicated otherwise within the text of the model rule (for instance, the EPA is providing model rule text for states to use related to the crediting of a broader set of clean energy resources than is being proposed in the federal plan).

The EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016. The EPA will finalize a federal plan for only a given state in the event that the state does not submit an approvable plan by the deadlines specified in the final EGs and the EPA takes action finding that the state has failed to submit a plan, or disapproving a submitted plan because it does not meet the requirements of the EGs.[1] Indeed, states may simply choose to accept a federal plan for their sources rather than undertake the development of a plan of their own by not submitting a state plan. Under this proposed rule, a federal plan promulgated for a particular state would take the form of either the mass-based model trading rule

[1] For simplicity, at times this document may refer to the co-proposed federal plans as “the federal plan.” (It may refer to the model trading rules in the singular as well.) Even though the singular is used, this term is meant to encompass both the rate-based approach and the mass-based approach. The use of the singular when referring to this proposed federal plan also is intended to encompass all state-specific federal plans. In other words, the EPA intends to finalize “the federal plan” as a series of state-specific “federal plans.” This is consistent with the agency’s prior practice in other multi-state trading programs such as the NOx Budget Trading Program, the Clean Air Interstate Rule (CAIR), and the Cross-State Air Pollution Rule (CSAPR), where a single rule promulgated multiple FIPs.

or the rate-based model trading rule. The EPA currently intends to finalize a single approach (i.e., either the mass-based or rate-based approach) for every state in which it promulgates a federal plan, given the benefits of a broad trading program, as discussed in the following section of this preamble. We invite comment on which approach, i.e., either mass-based or rate-based trading, should be selected if we opt to finalize a single approach.

It is the EPA’s intention to give the states as much opportunity as possible to set their own course for carrying out the EGs. Even where a federal plan is put in place for a particular state, that state will still be able to submit a plan, which, upon approval, will allow the state and its sources to exit the federal plan. In addition, as discussed in section VI.A of this preamble, states may take delegation of administrative aspects of the federal plan in order to become the primary implementers. And as discussed in sections V.E and VII.A of this preamble, states may submit partial state plans in order to take over the implementation of a portion of a federal plan. For instance, in a mass-based trading program, the agency proposes to allow states to submit partial state plans to replace the federal plan allowance-distribution provisions with their own allowance-distribution provisions, similar to the approach we have taken in prior trading programs. Finally, even in states in which the affected EGUs are operating under a federal plan, the agency recognizes that states may adopt complementary measures outside of CAA programming to facilitate compliance and lower costs that could benefit power generators and consumers, directly or indirectly.

A state program that adheres to the model trading rule provisions specified in this rulemaking would be presumptively approvable. States may submit means of meeting the EGs' requirements that differ from the model trading rule provisions, so long as the state demonstrates to the EPA's satisfaction in the state plan submittal that such alternative means of addressing requirements are at least as stringent as the presumptively approvable approach described here.[2] Additionally, there are stand-alone portions of the model trading rules, such as the evaluation, measurement, and verification (EM&V) procedures, that would be approvable even if a state adopted an approach that differs from the federal plan. The model trading rules serve as a mechanism to facilitate larger trading markets since consistency with the federal plan allows trading across both the state and federal programs. The EPA expects a larger

[2] For example, in the context of a mass- or rate-based trading program, a state may submit a plan with alternative components other than those described, so long as the program includes each of the requirements and the state satisfactorily demonstrates in the state plan submittal that such alternative means of addressing the requirements are as stringent as the presumptively approvable approach as described, and therefore provide for the implementation of the state plan's emission standards.

trading region is likely to result in lower overall costs. These and other aspects of the model trading rules and federal plan provide additional support for this rule as proposed. Thus, the proposed rule would ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented, either by the states in the first instance, or by the EPA where needed.

The agency is proposing a finding that it is necessary or appropriate to implement a CAA section 111(d) federal plan for the affected EGUs located in Indian country. CO_2 emission performance rates for these facilities were finalized in the EGs. Tribes generally may seek “treatment as a state” (TAS) and submit a tribal plan to implement CAA programs, including programs under CAA section 111(d), and this proposed finding does not preclude tribes from doing that. However, tribes are not subject to the deadlines applicable to state action under the EGs and in the absence of a federal plan, CO_2 emissions from these EGUs could go unregulated. Therefore, as discussed in section VI.D of this preamble, we are proposing a necessary or appropriate finding.

This document also proposes certain enhancements to the process and timing for state submittals and EPA action in the CAA section 111(d) framework regulations of 40 CFR part 60, subpart B (these proposals are not a part of the federal plan or model trading rules). These changes, if finalized, would be applicable under the Clean Power Plan and other CAA section 111(d) rules. These changes clarify the availability of certain procedural mechanisms similar to those available under CAA section 110 (such as calls for plan revisions and the availability of “conditional approvals,” etc.). They also extend the deadlines for EPA action, in part to conform with the timelines in the EGs. These changes do not alter the timelines for state action under the EGs and do not alter the submission requirements established in the EGs. Finally, the agency proposes to clarify and request comment on an interpretive issue raised in the Clean Power Plan proposal regarding whether a reconstruction or modification that is subject to a CAA section 111(b) standard moves an existing source out of a CAA section 111(d) program. These proposed changes are discussed in section VII of this preamble. The agency intends to finalize these changes earlier than the finalization of the model trading rules.

In proposing a federal plan, the EPA considered a variety of potential impacts that its action might have on the environment, on businesses, particularly in the energy sector, and on the reliability of the electrical grid. The agency gave extensive consideration to impacts on vulnerable communities, particularly low-income communities, communities of color, and indigenous communities. These considerations are discussed in sections III, VIII, IX, and X of this preamble.

The agency convened a Small Business Advocacy Review Panel under the Regulatory Flexibility Act and has completed an Initial Regulatory Flexibility Analysis (IRFA). Various recommendations from the Panel are found reflected throughout this proposal. In section X of this preamble, the agency explains how it has conducted or intends to conduct all other statutory or executive order (EO) reviews that apply to this proposed action. The EPA also explains in this document how it proposes to take into consideration the “remaining useful lives” of affected EGUs in the design of the proposed federal plan, as discussed below in section III.G of this preamble.

The agency considered the impacts this action could have on the electricity grid and developed options for compliance that are cost-effective and that provide substantial flexibility for the affected EGUs that will accommodate the parties charged with maintaining the reliability of electrical power. A key feature of the proposed federal plan and model trading rule is that the flexibility inherent in both of the two approaches (i.e., rate-based or mass-based trading) enables the EPA and the states to create a level of flexibility for affected EGUs that allows owners and operators to determine the best way to achieve emissions reductions, at the EGU-, state-, multi-state-, regional-, or national level. As a result, compliance strategies can mirror, or be integrated with, the ongoing operations of the current electricity grid as it continues to serve its primary critical function of ensuring an uninterrupted supply of affordable and reliable electricity. This flexibility is especially valuable whenever the need to address specific reliability concerns arises. It allows owners and operators of reliability-critical EGUs to continue to meet their compliance obligations while operating to maintain electric reliability.

The EPA outlined and initiated the Clean Energy Incentive Program (CEIP) in the final EGs (see section VIII of the final EGs). The program is designed to incentivize investment in certain types of renewable energy (RE) projects, as well as demand-side energy efficiency (EE) projects implemented in low-income communities, that generate MWh or reduce end-use energy demand during 2020 and/or 2021. The EPA proposes to apply the CEIP in all states subject to either a rate-based or mass-based federal plan.

We also reviewed impacts that this action could have on the environment and the need to ensure environmental integrity of the program as well as avoid unintended environmental impacts. We took measures to ensure that the reductions in carbon emissions this plan will achieve are real, and not just apparent. As in the EGs, in both the rate- and mass-based approaches, the EPA has incorporated components to address the concern that the dynamics of either a rate- or mass-based trading program could incentivize shifting generation from existing units in ways that would result in more CO_2 emissions than would otherwise be expected, or that undermine the purpose of the CAA section 111(d) program.

We considered whether compliance choices under a federal plan could lead to an unintended concentration of other air pollutants in certain overburdened communities, particularly low-income communities and communities of color. As discussed below, our analysis shows why we do not expect this to occur at any significant level. In general, as in the EGs, we anticipate that the federal plan will result in overall reductions of co-pollutants, in addition to reductions in CO_2, with corresponding co-benefits to public health. We also reviewed whether this action could trigger an obligation to consult with other agencies responsible for implementing the Endangered Species Act, and propose to conclude that it will not.

In the final emission guidelines, the EPA emphasized the importance of state actions to ensure that in developing their respective compliance plans the states addressed the concerns and priorities of vulnerable communities. In the process of developing a final federal plan, the EPA will also take actions to address those concerns as well. In addition to the public hearings that the EPA will be holding for all members of the American public on this proposed rulemaking, we will also be conducting a national webinar and outreach meeting(s) in all ten regions on this proposed rulemaking for communities. The goal of these outreach activities is to provide communities with the information they need to understand how the proposed rulemaking will potentially impact their respective communities. At the same time, this information will be useful in helping communities engage the EPA during our comment period, as well as with their states during the state plan development process. We will also be providing other outreach and support activities for vulnerable communities, which are outlined in the community and environmental justice (EJ) considerations in section IX.B of this preamble.

B. Organization and Approach for this Proposed Rule

In this action, the EPA is proposing a federal plan to implement the Clean Power Plan EGs for affected fossil fuel-fired EGUs operating in states that do not have approved state plans. Specifically, the EPA is co-proposing two different approaches to a federal plan to implement the Clean Power Plan EGs – a rate-based trading approach and a mass-based trading approach. While establishing emission standards for affected EGUs that would be directly enforceable against the owners and operators of the source, both approaches would grant EGUs substantial flexibility in meeting their compliance obligations. For this reason, among others, these proposed approaches also serve as two proposed model trading rules that states may adopt or tailor in designing their own plans.

The EGs provide that states have until September 6, 2016 (or upon making an initial submittal, until September 6, 2018) to submit state plans, and the EPA does not intend to finalize and implement the federal plan for any states prior to the agency's action of determining a failure to submit a state plan or disapproving a state plan. At the same time, in order to support states' consideration of adoption of one of the model trading rules as an approvable state plan, the agency intends to finalize either or both model rule options presented in this proposed rule by summer 2016, prior to the deadline for state submittals.

The EPA currently intends to finalize a single approach – i.e., either a rate-based or a mass-based approach – in all promulgated federal plans for particular states in order to enhance the consistency of the federal trading program, achieve economies of scale through a single, broad trading program, ensure efficient administration of the program, and simplify compliance options for affected EGUs. The EPA recognizes that the mass-based trading approach would be more straightforward to implement compared to the rate-based trading approach, both for industry and for the implementing agency. The EPA, industry, and many state agencies have extensive knowledge of and experience with mass-based trading programs. The EPA has more than two decades of experience implementing federally-administered mass-based emissions budget trading programs including the Acid Rain Program (ARP) sulfur dioxide (SO_2) trading program, the Nitrogen Oxides (NO_X) Budget Trading Program, CAIR, and CSAPR. The tracking system infrastructure exists and is proven effective for implementing such programs. The EPA requests comment on which approach – mass-based or rate-based trading – is preferred for the federal plan. Some stakeholders have suggested there could be utility in the availability of both approaches based on the unique circumstances of particular states. The EPA recognizes that it remains potentially possible to finalize a different approach to a federal plan in some circumstances, but believes that in general, and consistent with prior federal trading programs such as CSAPR, creating a single, broad program has the most advantages.

The stringency of the proposed federal plan is the same as the CO_2 emission performance rates established for affected EGUs in the EGs. As explained in the final EGs, the EPA determined the CO_2 emission performance rates through the application of the BSER. In the EGs, the EPA has taken final action on the BSER for CO_2 emissions from existing fossil fuel-fired EGUs. Any comments on this proposed rule relating to the BSER, its stringency, rationale, or legal basis, will not be considered as, by definition, they will be beyond the scope of this action.[3]

1. The Rate-based Approach

In the first approach, the EPA would implement a rate-based emissions trading program. In a rate-based program, affected EGUs must meet an emission standard, derived from the EGs, expressed as a rate of pounds of CO_2 per megawatt hour (lbs/MWh). If sources emit above their assigned rate, they must acquire a sufficient number of emission rate credits (ERC), each representing a zero-emitting megawatt hour (MWh), to bring their rate of emissions into compliance. ERCs may be generated by affected EGUs or by other entities that supply zero- or low-emitting electricity resources to the grid through an approval and recognition process that the EPA will administer. ERCs may be bought and sold, or banked for use in later years. The rate-based approach is explained in greater detail in section IV of this preamble.

2. The Mass-based Approach

[3] The agency recognizes that the "remaining useful lives" of facilities subject to a CAA section 111(d) federal plan is a factor that it must consider at the time it implements the federal plan. This factor, and how the agency proposes to consider it, is discussed in section III.G of this preamble below.

The second approach to a federal plan that the EPA is proposing in this action is a mass-based trading program. In a mass-based program, the EPA would create a state emissions budget equal to the total tons of CO_2 allowed to be emitted by the affected EGUs in each state, consistent with the mass goals established in the EGs. The EPA would initially distribute the allowances within each state budget – less three proposed allowance set-asides – to the affected EGUs based on their historical generation. Allowances may then be transferred, bought, and sold on the open market, or banked for future use. The compliance obligation on each of the affected EGUs is to surrender the number of allowances sufficient to cover the EGU’s respective emissions at the end of a given compliance period. The EPA is also proposing as a part of the mass-based approach three set-asides of allowances: (1) For a Clean Energy Incentive Program; (2) to support RE projects; and (3) to allocate allowances based on an updating measurement of affected-EGU generation. The EPA is also proposing that a jurisdiction may choose to replace the federal-plan allocation provisions with its own allowance allocation provisions. The mass-based approach is explained in greater detail in section V of this preamble.

3. Other Proposed Actions

The EPA is proposing in this action a finding that it is necessary or appropriate to regulate affected EGUs in certain parts of Indian country via a federal plan. This is discussed in section VI.D of this preamble.

In this action, the EPA is also proposing a number of changes to the framework CAA section 111(d) regulations of 40 CFR part 60, subpart B. These changes generally are intended to provide enhancements to the process for state plan submissions and the timing of EPA actions related to state plans and the federal plan. Specifically, the EPA proposes six changes, to include: (1) Partial approval/disapproval mechanisms similar to CAA section 110(k)(3); (2) a conditional approval mechanism similar to CAA section 110(k)(4); (3) a mechanism for the EPA to make calls for plan revisions similar to the "SIP-call" provisions of CAA section 110(k)(5); (4) an error correction mechanism similar to CAA section 110(k)(6); (5) completeness criteria and a process for determining completeness of state plans and submittals similar to CAA section 110(k)(1) and (2); and (6) updates to the deadlines for EPA action. These proposed changes are explained in greater detail in section VII of this preamble. They are not a component of the proposed federal plan, or changes in the EGs. If these changes are finalized, they will be applicable to other CAA section 111(d) rules. The EPA intends to finalize these changes earlier than the finalization of the model trading rules.

C. Who Does the Proposed Action Apply to?

Regulated Entities. Existing fossil fuel-fired EGUs (or affected EGUs) covered by the final Clean Power Plan that are located in a state that does not have an EPA-approved state plan are potentially subject to this proposed action Affected EGUs are those that were in operation, or had commenced construction, on or before January 8, 2014[4]. The following North American Industrial Classification System (NAICS) codes apply as shown in Table 1 of this preamble:

Table 1. Examples of Potentially Regulated Entities[a]

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112[a]	Fossil fuel electric power generating units
State/Local Government	221112[b]	Fossil fuel electric power generating units owned by municipalities

[a] Includes NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a general guide for identifying entities likely to be affected by the proposed action. Whether an affected EGU is affected by this action is described in the applicability criteria in 40 CFR 60.5845 and 60.5850 of subpart UUUU. Questions regarding the applicability of this action to a

[4] An affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an “existing source” for purposes of CAA section 111, but in all other respects would meet the applicability criteria for coverage under the GHG standards for new fossil fuel-fired EGUs.

particular entity should be directed to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

1. What is an Affected Electric Utility Generating Unit?

For the federal plan, the definition of an affected EGU is identical to the definition in the final Clean Power Plan. Additionally, the applicability of the federal plan is consistent with the EGs, where an affected EGU subject to the federal plan is any steam generating unit (SGU), integrated gasification combined cycle unit (IGCC), or stationary combustion turbine (SCT) that was in operation or had commenced construction as of January 8, 2014,[5] and that meets certain criteria, which differ depending on the type of unit. The criteria to be an affected EGU are as follows: A unit, if it is a SGU or IGCC, must serve a generator capable of selling greater than 25 MW (Megawatts) to a utility power distribution system, have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel), and historically have supplied more than 1/3 of its potential electric output and 219,000 MWh as net-electric sales on any 3 calendar year basis. If a unit is a SCC, the unit must meet the definition of a combined cycle or combined heat and

[5] January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the Federal Register (79 FR 1430).

power (CHP) combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, have a base load rating of greater than 260 GJ/h (250 MMBtu/h), and historically have combusted more than 90 percent natural gas on a heat input basis on an annual basis.

2. How to Determine if a Unit is Covered by an Approved and Effective State Plan

Section 111(d) of the CAA, as amended, 42 U.S.C. 7411(d), authorizes the EPA to develop and implement a federal plan for affected EGUs upon the EPA's action finding a failure to submit or disapproving a state plan.[6] The affected EGUs covered in EPA-approved state plans are not subject to the federal plan. If the federal plan has been put in place in a state, but is later replaced by an EPA-approved state plan, the affected EGUs would become subject to the state plan as of the effective date specified in a Federal Register notice regarding the EPA's approval of the state plan. The EPA is not expecting state plans to be submitted by the states that submit negative declarations. However, in the event that there are later determined to be affected EGUs located in these states, the final federal plan

[6] In this Preamble, the term "state" generally encompasses the 50 states and the District of Columbia, U.S. territories, and any Indian Tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan. However, the federal plan is not proposed for affected EGUs in certain states or territories where the EGs did not finalize emission performance rates.

would be applied to such EGUs through a future action. Part 62 of title 40 of the CFR identifies the status of approval and promulgation of CAA section 111(d) state plans for designated facilities in each state. Recognizing the urgent need for actions to reduce GHG emissions, and in accordance with the Presidential Memorandum[7], as well as the benefit of providing states with model trading rule options to consider as they prepare their state plans, the EPA is proposing this rulemaking concurrently with the Administrator's signing and promulgation of the final Clean Power Plan EGs. 40 CFR part 62 is updated only once per year. Thus, if 40 CFR part 62 does not indicate that your state has an approved and effective plan after the compliance date has passed requiring state plan submittal, you should contact your state environmental agency's Air Director or your EPA Regional Office (see Table 2 in section II.B of this preamble) to determine if approval occurred since publication of the most recent version of 40 CFR part 62.

D. What Should I Consider as I Prepare my Comments?

Do not submit information that you consider to be CBI electronically through http://www.regulations.gov or email. Send or deliver information identified as CBI to only the following

[7] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

address: OAQPS Document Control Officer (Room C404-02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA-HQ-OAR-2015-0199. Clearly mark the part or all of the information that you claim to be CBI. For CBI on a disk or CD-ROM that you mail to the EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

Docket. The docket number for the proposed action (40 CFR part 62, subpart MMM) is Docket ID No. EPA-HQ-OAR-2015-0199.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the proposed action is available on the Internet through the EPA's Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air pollution control. Following signature by the EPA Administrator, the EPA will post a copy of the proposed action at http://www2.epa.gov/cleanpowerplan/regulatory-actions#regulations. Following publication in the Federal Register (FR), the EPA will post the FR version of the proposed rule and key technical documents on the same Web site.

II. Background Information

A. What is the Regulatory Development Background for this Proposed Rule?

On August 3, 2015, the EPA finalized the Clean Power Plan EGs for existing fossil fuel-fired EGUs (40 CFR part 60, subpart UUUU) under authority of section 111 of the CAA (79 FR 34950). The Guidelines apply to existing fossil fuel-fired EGUs, i.e., those that were in operation or had commenced construction before January 8, 2014. States with existing EGUs subject to the guidelines are required to submit to the EPA by September 6, 2016, a state plan that implements the EGs. States may also make initial plan submittals in lieu of a complete state plan, in which case extensions will be granted until September 6, 2018 (40 CFR part 60, subpart UUUU).[8] As discussed in section VI.D of this preamble, Indian Tribes may, but are not required to,

[8] See Section VII of this preamble for additional information on proposed changes to 40 CFR 60.27 to provide enhancements and flexibilities to the agency's process for review and action on state plans and promulgation of federal plans.

submit tribal plans. Once the EPA finds that a state has failed to submit a plan, or disapproves a state plan,[9] section 111 of the CAA and 40 CFR 60.27 require the EPA to develop, implement, and enforce a federal plan for existing EGUs located in that state. In addition, CAA section 301(d)(2) authorizes the Administrator to treat an Indian Tribe in the same manner as a state for this EGU requirement. See 40 CFR 49.3; see also "Indian Tribes: Air Quality Planning and Management," hereafter "Tribal Authority Rule," (63 FR 7254, February 12, 1998). As discussed in section VI.D of this preamble, the agency in this action is proposing a necessary or appropriate finding for the affected EGUs in several areas of Indian country and is proposing the federal plan for these affected EGUs.

The agency believes it is appropriate to propose the federal plan at this time for any states that may ultimately be found to have failed to submit a plan, or had their plan disapproved by the EPA. For some states in this situation, the federal plan may be no more than an interim measure to ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented until they can get an approved plan in place. Other states may choose to rely on the

[9] If a state has submitted a complete plan, then the EPA will go through a public notice and comment process to fully or partially approve or disapprove the state plan.

federal plan and would not need to develop their own plan. This proposal also serves as two proposed model trading rules which states can adopt or tailor for adoption as their state plan. The role of the model rules is discussed in the following section.

In this proposal, the EPA is soliciting public comment only on the proposed approaches for a federal plan and model trading rule for the implementation of the Clean Power Plan EGs. Comments on the underlying Clean Power Plan rule will be considered outside the scope for this proposed rule.

B. What is the Purpose of this Proposed Rule?

The purpose of this action is two-fold: (1) To co-propose two approaches to a federal plan to implement the Clean Power Plan EGs for affected EGUs operating in any state lacking an approved state plan by the relevant deadlines; and (2) to propose these same approaches as model trading rules for states to consider in developing their own plans.

1. Federal plan

Section 111 of the CAA and 40 CFR 60.27 require the EPA to develop, implement and enforce a federal plan to cover existing EGUs located in states that do not have an approved plan. Section 111(d) of the CAA relies upon states as the preferred implementers of EGs for existing EGUs. States with affected EGUs are to submit state plans or make initial submittals to the EPA by September 6, 2016 pursuant to the EGs.[10] States without any existing EGUs are directed to submit to the Administrator a letter of negative declaration certifying that there are no affected EGUs in the state. No plan is required for states that do not have any affected EGUs. Affected EGUs located in states that mistakenly submit a letter of negative declaration will become subject to the federal plan until a state plan covering those EGUs becomes approved. The EPA intends to finalize the federal plan only for those states that the EPA finds failed to submit plans or whose plans the EPA disapproves. For more information on the timing and mechanics of EPA action on state plans and finalization of this federal plan, see section II.D of this preamble below.

2. Model Trading Rule

The EPA is also proposing the federal plan approaches as two forms of a model trading rule (mass-based and rate-based), which states can adopt or tailor for implementation as a state plan under the EGs. The EPA intends to finalize the model trading rules earlier than it promulgates a federal plan for a state. When the EPA finalizes one or both of its proposed approaches as a final model trading rule, and a state adopts a

[10] States may request extensions of up to two years as part of a complete initial CAA section 111(d) submission.

final model trading rule in its entirety as its state plan, it would be presumptively approvable.

The EPA has designed these rules so that they meet the requirements of the final EGs. If one of the model rules is adopted by a state without any change, it would be presumptively approvable. We use the term “presumptively” in recognition that a state plan submission must be accompanied by other materials in addition to the regulatory provisions. These requirements are set forth in the final Clean Power Plan and framework regulations of 40 CFR part 60, subpart B. For instance, they include a formal letter of submittal from the Governor or his or her designee, evidence that the rule has been adopted into state law and that the state has necessary legal authority to implement and enforce the rule, and evidence that procedural requirements, including public participation under 40 CFR 60.23, have been met.

In further support of state use of the model rules, we are drafting the model trading rule so that it can be adopted or incorporated by reference with a minimum of changes that would be necessary to make the rule appropriate for use by states. This way, a state may incorporate by reference the model rule as the state plan, or as the backstop to a state measures plan with few if any adjustments. States may make changes to the model trading rule, so long as they still meet the requirements of the

EGs. If the state chooses to tailor or modify the model trading rule such as by expanding the scope of eligibility of projects that may generate ERCs in a rate-based trading program, the EPA may still approve the plan, but the EPA would conduct appropriate review of such provisions for consistency with the EGs and the state would have to demonstrate to the EPA's satisfaction that its alternative provisions are as stringent as the presumptively approvable approach described. We note here, and as a "note" in the regulatory text of the model trading rule, that the scope of eligibility of proposed "ERC resources" for the federal plan is different than the scope of eligibility provided for in the model rule. Thus, all of the language and provisions in the regulatory text relevant to these other ERC resources is relevant only to the proposed model trading rule and not to the federal plan as such (i.e., those ERC resources discussed in section IV.C.3 of this preamble are applicable to the model rule and only metered RE and applicable nuclear are applicable to the federal plan).

The EPA's approval of a state plan, including a plan that adopts the model trading rule, will be the result of an independent notice-and-comment rulemaking process. Without prejudging the outcome of that process, the EPA recognizes that it may be able to approve or "conditionally approve" state plans that are substantially similar, but not identical to, the final model trading rules. Ultimately, state plans must meet the requirements of the EGs for approvability. Thus, a conditional approval would be based on a condition that the state take such actions as may be necessary by a date certain to meet the requirements of the EGs. (The EPA is proposing to explicitly provide for conditional approvals in the CAA section 111(d) framework regulations. See section VII.B of this preamble.)

In accordance with the EGs, the process for review and approval (or disapproval) of state plans, whether based on the model trading rules or otherwise, would occur once the states have made their submissions by September 6, 2016. As provided in the EGs, states have the option of not submitting a full state plan, but rather making an initial submittal, in order to obtain an extension of 2 years before submitting a full state plan for EPA approval. It could be beneficial for coordination purposes if a state that is interested in adopting one of the model trading rules but intends to make an initial submittal next year were to indicate which model trading rule they intend to adopt. This is not an additional requirement beyond what the EGs require for initial submittals, however.

The EPA strongly encourages states to consider adopting one of the model trading rules, which are designed to be referenced by states in their rulemakings. Use of the model trading rules by states would help to ensure consistency between and among the state programs, which is useful for the potential operation of a broad trading program that spans multi-state regions or operates on a national scale. As discussed at length in the EGs, EGUs operate less as individual, isolated entities and more as multiple components of a large interconnected system designed to integrate a range of functions that ensure an uninterrupted supply of affordable and reliable electricity while also, for the past several decades, maintaining compliance with air pollution control programs. Since, as a practical matter under both the EGs and any federal plan, emissions reductions must occur at the affected EGUs, a broad-scale emissions trading program would be particularly effective in allowing EGUs to operate in a way that achieves pollution control without disturbing the overall system of which they are a part and the critical functions that this system performs. In addition, consistency of requirements benefits the affected EGUs, as well as the states and the EPA in their roles as administrators and implementers of a trading program. States of course remain free to develop a plan of their own choosing to submit to the EPA for approval following the criteria set out in the final Clean Power Plan EGs.

The EPA believes there are compelling policy reasons that support the provision of a proposed model trading rule at this time. The EPA has heard from multiple stakeholders and in public comments submitted on the proposed EGs that there is a strong interest in seeing a model state plan or trading rule prior to the deadline for state submittals under the EGs. According to these stakeholders, model rules can provide predictability for planning purposes, both among states and affected EGUs. In addition, some states have indicated that they may prefer to rely on a federal plan, either temporarily or permanently, rather than develop a plan of their own. This proposal of a model trading rule addresses these policy interests.

The approach of proposing model trading rules that are identical in all key respects to proposed federal plans that may be promulgated later, is consistent with prior CAA section 111(d) and CAA section 110 rulemakings. For example, the NO_x state implementation plan (SIP) Call model rule at 40 CFR part 96 (63 FR 57356; Oct. 27, 1998) was identical in all meaningful respects with the Federal NO_x Budget Trading Program at 40 CFR part 97 (65 FR 2674; Jan. 18, 2000). And the CAIR model rule in 40 CFR part 96 (70 FR 25339; May 12, 2005) was identical in all meaningful respects with the federal CAIR in 40 CFR part 97 (71 FR 25396; April 28, 2006).[11] While these identical programs for model rules and Federal Implementation Plans (FIPs) were

[11] We also note that historically under the CAA section 111(d)/129 rules, the content of EGs and their corresponding federal plans have had significant overlap.

finalized in separate parts of the CFR, the EPA does not see any reason that it could not just as easily propose the federal plan as the model trading rule in the same section of the CFR.[12] If a federal plan were to be finalized for a given state at a later time, this would be reflected in 40 CFR part 62 by cross-reference, along with any modifications or adjustments that may be appropriate at the time of actual promulgation of a federal plan.

Table 2. Regional Office Contacts

Region	Regional contact	Phone	States and protectorates
Region I	Shutsu Wong wong.shutsu@epa.gov	617-918-1078	Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, Vermont
Region II	Gavin Lau lau.gavin@epa.gov	212-637-3708	New York, New Jersey, Puerto Rico, Virgin Islands
Region III	Mike Gordon gordon.mike@epa.gov	215-814-2039	Virginia, Delaware, District of Columbia, Maryland, Pennsylvania, West Virginia
Region IV	Ken Mitchell mitchell.ken@epa.gov	404-562-9065	Florida, Georgia, North Carolina, Alabama, Kentucky, Mississippi, South Carolina, Tennessee
Region V	Alexis Cain cain.alexis@epa.gov	312-886-7018	Minnesota, Wisconsin, Illinois, Indiana, Michigan, Ohio

[12] We propose to include a note in the regulatory text explaining where aspects of the proposed subpart relevant to states as part of the model trading rule are not applicable

Region	Regional contact	Phone	States and protectorates
Region VI	Rob Lawrence lawrence.rob@epa.gov	214-665-6580	Arkansas, Louisiana, New Mexico, Oklahoma, Texas
Region VII	Ward Burns burns.ward@epa.gov	913-551-7960	Iowa, Kansas, Missouri, Nebraska
Region VIII	Laura Farris farris.laura@epa.gov	303-312-6388	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
Region IX	Ray Saracino saracino.ray@epa.gov	415-972-3361	Arizona, California, Hawaii, Nevada, American Samoa, Guam, Northern Mariana Islands
Region X	Madonna Narvaez narvaez.madonna@epa.gov	206-553-2117	Alaska, Idaho, Oregon, Washington

C. Legal Authority

Section 111(d)(2) of the CAA, 42 U.S.C. 7411(d)(2) provides the EPA the same authority to prescribe a plan for a state in cases where the state fails to submit a satisfactory plan as the agency would have under CAA section 110(c) in the case of failure to submit an implementation plan. In addition, the EPA has authority under CAA section 111(d)(1) to prescribe regulations that establish procedures similar to CAA section 110 with respect to the submission of state plans, and the EPA also has general rulemaking authority as necessary to implement the CAA under CAA section 301. A federal plan under CAA section 111(d) applies, implements and enforces standards of performance for affected EGUs. Under the Clean Power Plan EGs, state plans will be due on September 6, 2016, but states are also allowed to seek a 2-year extension for a final plan submittal, upon a satisfactory initial plan submittal by the same deadline. See 40 CFR 60.5755, 60.5760(b). If a state does not submit a final state plan or initial plan submittal,[13] or if either a final state plan or an initial plan submittal does not meet the requirements of the EG, the agency will take the appropriate steps to finalize and implement a federal plan for that state's EGUs.

Further, states will remain free, and indeed are strongly encouraged, to submit an approvable state plan even after promulgation of the federal plan for their jurisdictions. Upon approval of the state plan by the EPA, the federal plan will no longer apply to the affected EGUs covered by the state plan. See 40 CFR 60.5720.

D. Timing of EPA Actions on the Model Trading Rules, Federal Plan, and other Proposed Actions

[13] Indeed, states may simply choose to accept a federal plan in lieu of undertaking to develop a state plan at all. While the statute uses the phrase "fails to submit a satisfactory plan," the EPA does not believe this should carry any pejorative connotation. While Congress identified states and local governments as having "primary responsibility" for air pollution prevention and control, CAA section 101(a)(3), states are in no way penalized for not submitting a plan under CAA section 111(d). Rather, the EPA steps into the shoes of the state to carry out the CAA section 111(d) program in its stead. To the extent states may be interested in accepting a federal plan, the EPA would be interested in hearing that through the comment process on this proposal.

This action co-proposes two approaches to the federal plan, both of which also constitute proposed model trading rules that states could adopt as state plans for EPA approval. The EPA currently intends to finalize one or both of the model trading rules by next summer so that they may be available to states as soon as possible to help inform their state plan development efforts prior to the initial submittal deadline of September 6, 2016, and 2 years before the states' final plan deadline of September 6, 2018.[14] If the EPA finalizes the model trading rules in that timeframe, the only direct consequence will be to provide the states certainty as to one or two particular approaches to the design of their state plan that the EPA will approve if adopted in full. The finalization of a model trading rule will not constitute a final action with respect to a federal plan for the affected EGUs in any state. Rather, the proposed federal plan will remain just that, a proposal. The EPA will promulgate a final federal plan for any state only after it has made a finding on a state's failure to submit a plan, or fully or partially disapproved a submitted state plan. The EPA will go through a public notice and comment process before disapproving a submitted and complete state plan, in whole or

[14] We anticipate that the model rules' text could be finalized either in a new subpart or subparts of 40 CFR part 62 of title 40 of the CFR as proposed, or in a final document that is not published in the CFR.

part. The EPA invites comments on this staged approach to finalizing one or more model trading rules on the one hand (which we currently intend to do in summer 2016), and finalizing federal plans on the other (which we currently intend to do state-by-state upon our taking predicate action on states' plans).

In this action, the EPA is also proposing enhancements to the process for agency action on state submittals and promulgation of a federal plan under CAA section 111(d). For more detailed discussion of these changes, see section VII of this preamble. This aspect of this proposal is separate from the federal plan and the model trading rules. The EPA intends to finalize these changes on a timeline earlier than both a model trading rule and the federal plan.

Under the framework regulations and the final EGs, at 40 CFR 60.27 and 60.5715 and 5760, respectively, the initial timelines for EPA action on state submittals and, potentially, the promulgation of a federal plan will be as follows: the EPA will have 12 months from the date of a state's submission to approve or disapprove that state's plan. The EPA will have 12 months from the date of its action on a state submission to promulgate the federal plan for the EGUs in that state. The EPA will have 6 months from the date of a state's submission to notify a state that its submittal does not meet completeness criteria and constitutes a failure to submit a plan. In the case of initial submittals under 60.5765, the EPA will have 60 days from September 6, 2016 to notify a state that its initial submittal does not meet the requirements of 60.5760(a). As with state plans, the EPA will have 12 months to promulgate a federal plan from the date of its finding that a state failed to submit a complete and approvable initial submittal. (Formally, such a finding would be that the state failed to submit a state plan.)

The timeframes stated in the previous paragraph reflect the maximum time allowed for EPA action. We note that under CAA section 111(d)(2) and CAA section 110(c), the EPA may promulgate a final federal plan for a state immediately upon making a finding of failure to submit a state plan or initial submittal, or upon making a finding of final disapproval of a state plan. Congress gave the EPA authority in CAA section 111(d)(2), as it did in CAA section 110(c), to promulgate a federal plan at any time after it disapproves or finds a failure to submit a state plan. The Supreme Court has recognized that under this authority, the EPA may promulgate a FIP "at any time" within the 2-year limit of CAA section 110(c) "that begins the moment EPA determines a SIP to be inadequate." EME Homer City v. EPA, 134 S. Ct. 1584, 1601 (2014). "EPA is not obliged to wait two years or postpone its action even a single day . . . ." Id. It is essential to implement plans for the control of emissions of CO_2

expeditiously and avoid unnecessary delay. Among other reasons, this will provide affected EGUs regulatory certainty and will assist the regulated entities as well as those authorities with responsibility for ensuring grid reliability to have as much time as possible to plan for the 2022 compliance start date set in the EGs. Thus, it is reasonable to propose this federal plan now so that federal plans will be ready to be promulgated quickly in cases where states have failed to submit a plan or their plans are found unsatisfactory.

It is the agency’s intention to promulgate federal plans promptly for states who do not submit plans or initial submittals by September 6, 2016. However, the effect of putting the federal plan in place at that time would ultimately be limited in impact upon states. Because the EPA would implement the federal plan, its promulgation does not obligate state officials to take any actions themselves. Further, states remain free - and the EPA in fact encourages states - to submit state plans that can replace the federal plan. States can do so in advance of the beginning of the performance period in 2022, or may transfer to a state plan after that date. However, in doing so, the agency and states should be mindful of the goals of regulatory certainty discussed in the prior paragraph.

Because we are proposing a federal plan that would apply emission standards to affected EGUs in all states that the agency determines not to have an approvable plan, the EPA invites comment from all persons with concerns about or comments on the proposed federal plan as it may apply in any state, whether or not that state has submitted, or intends to submit, its own plan on which the EPA has yet to take action.

In this document, the EPA is proposing regulatory text setting out the substantive provisions for both of the proposed federal plans/model trading rules. The EPA is not providing specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied.[15] We currently envision that this language would be in the form of a new section to the state-specific subparts of part 62 and would be ministerial in nature. It would likely provide that the affected EGUs in each such state are subject to a federal plan and would then cross-reference or incorporate by reference the substantive provisions of one of the two subparts proposed in this action (if finalized), along with any applicable modifications or adjustments as may be necessary, either based on new information or in response to comments regarding the application of the federal plan to that particular state. This text may appear

[15] The minimum contents of a notice of proposed rulemaking under the CAA are set forth at CAA section 307(d)(3) and 5 U.S.C. 553(b).

similar to the FIP language found in the final CSAPR rule (76 FR 48208, 48361-78; August 8, 2011).

E. Use of the Model Trading Rule as a Backstop

As discussed in the final EGs, the EPA believes that either a mass-based or rate-based model trading rule could function well as the federally enforceable "backstop" that the EGs require to be included in "state measures" type state plans.[16] (The proposed federal plan does not itself require a "backstop" because it relies on an "emission standards" approach, rather than a "state measures" approach, as delineated in the final EGs.) The conditions and requirements for the federally enforceable backstop in a state measures approach are discussed in detail in the final EGs. See sections VIII.C.3.b and VIII.C.6.c of the final EGs. To summarize those provisions, without reopening them for comment, the federally enforceable backstop must fully achieve the CO_2 emission performance rates or the state's interim and final CO_2 emission goal if the state plan fails to achieve the intended level of CO_2 emission performance. The state plan submittal must identify the federally enforceable emission standards for affected EGUs that would be used in the

[16] We are aware of at least one case in which a court has upheld the use of a trading program as a backstop to ensure CAA requirements are met. See WildEarth Guardians v. U.S. EPA, No. 12-9596 (10th Cir. filed Oct. 21, 2014) (upholding use of backstop cap-and-trade program under 40 CFR 41.309 of the Regional Haze Rule).

backstop, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the EGs, and identify all necessary state administrative and technical procedures for implementing the backstop (e.g., how and when the state would notify affected EGUs that the backstop has been triggered). In addition, the backstop emission standards must make up for any shortfall in CO_2 emission performance during a prior plan performance period that led to triggering of the backstop.

The EGs explicitly recognized that the backstop emission standards could be based on one of the model trading rules that the EPA is proposing in this action. As discussed in section II.B of this preamble above, we are drafting the model trading rule so that it can be adopted or incorporated by reference with a minimum of changes necessary to make the rule appropriate for use by states, and this includes its use as a backstop. Instances of this approach are throughout the proposed rule text and reflect our desire to ease the use of the model rule for states, as a full state plan, or as a backstop to a “state measures” plan.

One way in which a backstop may need to differ from the model trading rules proposed in this action is the requirement to make up for a shortfall in emissions performance in a state's prior plan performance period. The model trading rules do not provide provisions that would automatically adjust the emission standards to account for any prior emission performance shortfall (which is an option states have if designing their own backstop). Thus, a state relying on the model trading rule as its backstop would likely need to submit an appropriate revision to the backstop emission standards adjusting for the shortfall through the state plan revision process. This would likely be done in conjunction with the process for putting the backstop into effect.

If a state chooses to use the model rule as its federally enforceable backstop in a state measures plan, this does not mean that the backstop is itself the federal plan. Rather, the model rule becomes adopted as a part of the state plan. Both approaches to the model trading rule are "emission standard" approaches under the EGs where an emission standard is imposed and federally enforceable on the affected EGUs: in the rate-based approach the emissions standard is an allowable rate of emissions; in the mass-based approach the emission standard is the requirement to hold allowances equal to reported emissions. The EPA may also handle the administration of the trading program for states utilizing the model trading rule. However, even though the backstop may take the form of an EPA-administered, federally-enforceable trading rule, this does not mean that a federal plan has been put into effect. The state retains all of its rights and responsibilities with respect to the implementation and enforcement of the backstop as a component of its state plan.

Applicability and Enforceability. If promulgated for the affected EGUs in a particular state, this federal plan will require affected EGUs to meet specific emission standards for CO_2 and related requirements. These enforceable compliance obligations will apply to the owners and operators of those affected EGUs. See 40 CFR 62.13. No obligation falls on states or state officials (except to the extent they may be owners and operators of affected EGUs).[17] In the event of noncompliance, the provisions in the federal plan are federally enforceable against an affected EGU, in the same manner as the provisions of an approved state plan under CAA section 111(d), and similar to a FIP or an approved SIP under CAA section 110. See CAA section 111(d)(2)(B), 42 U.S.C. 7411(d)(2)(B) (power to enforce state and federal plans), section 113(a)–(h), 42 U.S.C. 7413(a)-(h),

[17] See Reno v. Condon, 528 U.S. 141, 151 (2000). State officials responsible for developing state plans, however, should be aware of the procedural enhancements being proposed to the framework regulations of 40 CFR part 60, subpart B, in this rulemaking document. These changes are discussed in section VII of this preamble below. These changes are not a component of the proposed federal plan or the EGs. Although these changes do not alter the deadlines or submission obligations provided in the Clean Power Plan Emission Guidelines, state officials and other interested parties are encouraged to review and comment on these changes.

and section 304, 42 U.S.C. 7604. This means that the Administrator has the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h), and states and other third parties maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA section 304.

III. Federal Plan Structure to Achieve Reductions

A. Overview

1. Interactions with State Plans and scope of trading

The EPA intends to set up and administer a program to track trading programs – both rate-based and mass-based – that will be available for all states that choose it. The EPA proposes that affected EGUs in any state covered by a federal plan could trade compliance instruments with affected EGUs in any other state covered by a federal plan or a state plan meeting the conditions for linkage to the federal plan. In the proposed mass-based federal-plan trading program, this would mean that affected EGUs in a state covered by the federal plan or a state meeting the conditions for linkage to the federal plan could use, as a compliance instrument, an allowance distributed in any other state covered by the federal plan or a state meeting the conditions for linkage to the federal plan. Similarly, in the proposed rate-based federal-plan trading program approach, this would mean that affected EGUs in a state covered by the federal plan or a state meeting the conditions for linkage to the federal plan could use, as a compliance instrument, an ERC issued in any other state covered by the federal plan or a state meeting the conditions for linkage to the federal plan. We propose that an affected EGU in a state covered by the mass-based trading federal plan must use allowances for compliance (not ERCs). Similarly, an affected EGU in a state covered by the rate-based trading federal plan must use ERCS for compliance (not allowances).

The agency promulgated provisions for “ready-for-interstate-trading” plans in the EGs. The EPA is proposing the federal plans as ready-for-interstate-trading plans. States plans that adopt the model rule are also considered ready-for-interstate-trading. The EPA proposes to allow interstate trading between affected EGUs in states covered by the proposed federal plans and affected EGUs in states covered by state plans (referred to below as “linking” states, or “linkages”) under the following conditions, which are discussed further below the list:

- The state plan must be approved.
- The state plan must implement the same type of trading program as the federal plan trading program in order to be linked for interstate trading, i.e., mass-based trading programs can link to mass-based trading programs only, and rate-based trading programs can link to rate-based trading programs only.

- The state plan must use the identical compliance instrument as the federal plan (this requirement is detailed below).
- The state plan must be approved as a ready-for-interstate-trading plan.
- The state plan must use an EPA-administered tracking system (we are also requesting comment on expanding this to include a state plan that uses an EPA-designated tracking system that is interoperable with an EPA-administered system, as detailed below).

The EPA proposes that interstate ERC trading could occur both 1) from affected EGUs in states covered by the rate-based trading federal plan to affected EGUs in states with approved rate-based trading state plans meeting the proposed conditions for linkages (including the conditions for being “ready-for-interstate-trading” that were finalized in the EG), and 2) from affected EGUs in such state-plan-covered states to affected EGUs in federal-plan-covered states. The EPA also requests comment on expanding the scope of interstate trading to include linking states covered by the rate-based trading federal plan with any state that has an approved rate-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated ERC tracking system that is interoperable with an EPA-administered ERC tracking system. The EPA also takes comment on allowing a state that has an approved rate-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated ERC tracking system to register with the EPA, and after registration, to link with states covered by the rate-based trading federal plan. There are multiple benefits to a registration requirement, which include ensuring that the tracking systems are functionally interoperable.

For the mass-based federal plan, the EPA proposes that interstate allowance trading could occur in both directions, i.e., from affected EGUs in states covered by the mass-based trading federal plan to affected EGUs in states with approved mass-based trading state plans meeting the proposed conditions for linkages, and from affected EGUs in such state-plan-covered states to sources in federal-plan-covered states.

The EPA proposes that a condition of linkage between a state plan and the federal plan is the use of an identical compliance instrument. In the mass-based federal plan the EPA proposes to issue allowances in short tons; as a result, the EPA is proposing in this rule that linkage for the mass-based federal plan is limited to state plans that issue allowances in short tons. The agency also requests comment on whether to extend linkage to state plans that issue allowances in metric tons and on what provisions would be necessary to implement such linkages. The EPA believes that considerations for linkages to state plans that use metric tons may include tracking system design, and stipulation of which parties convert state plan allowances denominated in metric tons to allowances denominated in short tons and at what stage of compliance operations the conversion occurs. The agency requests comment on these and any other considerations for linkages between the federal plan and state plans that issue allowances in metric tons.[18]

The EPA also requests comment on expanding the scope of interstate trading to include linking states covered by the mass-based trading federal plan with any state that has an approved mass-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated allowance tracking system that is interoperable with an EPA-administered allowance tracking system. The EPA also takes comment on allowing a state that has an approved mass-based trading state plan meeting the proposed conditions for linkages and that uses an EPA-designated allowance tracking system to register with the EPA, and after registration, to link with states covered by the mass-based trading federal plan.

In the Clean Power Plan EGs, the EPA promulgated requirements that apply to an emissions budget trading state plan that includes non-affected EGU emission sources, to provide the opportunity for such a state plan to be potentially approvable for linking to other state plans (see Clean Power Plan EGs, section VIII). In this proposed rule, the proposed approach to link from the mass-based trading federal plan to

[18] In this preamble all references to “tons” are short tons, unless otherwise noted.

state plans could result in linking of the federal plan to state plans that include non-affected emission sources. The EPA requests comment on this proposed approach.

The EPA believes that a broad trading region provides greater opportunities for cost-effective implementation of reductions compared to trading limited to a smaller region. The proposed approach to interstate trading is intended to strike a reasonable balance between providing the opportunity for a wide interstate trading system while maintaining the integrity of the linked programs. The agency requests comment on the proposed approach to interstate trading linkages in the federal plans.

Whether the EPA ultimately finalizes rate-based or mass-based federal plans, the agency believes that the ERC market and the allowance market would be competitive. The opportunities for interstate trading detailed above would reduce any potential for firms to exercise market power in the ERC market or allowance market. The EPA requests comment on this expectation of a competitive ERC market and a competitive allowance market, and comment on potential program design choices that could address any identified market power concern. The EPA intends to provide information to the market and the public, consistent with other trading programs that the agency administers, as detailed in sections IV and V of this preamble, for the rate-based and mass-based approaches, respectively.

A transparent and well-functioning allowance or ERC market is an important element of a mass-based or rate-based trading program. The EPA has over 20 years of experience implementing emissions trading programs for the power sector and based on that experience, believes the potential or likelihood of market manipulation is fairly low. Nonetheless, the EPA is evaluating the options for providing oversight of the allowance or ERC markets that may be established through the final EGs and federal plans. This could include engaging with other federal and state agencies as appropriate, and potentially with third parties, in conducting market oversight. The agency requests comment on appropriate market monitoring activities, which may include tracking ownership of allowances or ERCs, oversight of the creation and verification of credits, and tracking market activity (e.g., transaction volumes and prices).

2. Addressing Potential Leakage and Interstate Effects

The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs as the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the

BSER. The final EGs specified that mass-based plan approaches must address leakage, because the form of the mass goals may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether the mass goal implements or is consistent with the BSER and overall emissions from the sector. These circumstances are much less likely to be present under a rate-based plan approach, where the form of the goal ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates. By requiring mass-based plan components that address leakage, the final EGs ensure that mass goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. Section VII.D of the final EGs details the requirement for addressing leakage and why it is needed, and section VIII.J of the final EGs specifies options for mass-based state plan components that address leakage. We are proposing, as part of the mass-based approach under the federal plan and model rule, to implement allowance allocation approaches to address leakage, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE. These proposed strategies are detailed in section V.D of this preamble.

In the final EGs, the EPA also discussed the concern that CO_2 emissions reductions would be eroded in situations where an affected EGU in a rate-based state counts the MWh from measures located in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state. The proposed rate-based approach, in accordance with the final guidelines, restricts ERC issuance for any emission reduction measures located in a mass-based state, except for RE. RE measures located in a state with a mass-based state plan can only be approved for ERC issuance for use by a state under a rate-based federal plan if it can be demonstrated that that load-serving entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state. As part of this federal plan, we are proposing that this can be demonstrated through the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question and providing documentation that the electricity was treated as comparable to a generation resource used to serve regional load that included the rate-based state. This demonstration must be included as part of the project application for ERC issuance to the EPA or its agent from the RE provider in the mass-based state. Once the project is approved, subsequent applications for issuance of credit to the EPA will need to reference that the MWh submitted are associated with that contractual arrangement with the mass-based RE provider. The EPA requests comment on this approach. It should also be noted that we are proposing that under the proposed mass-based approach, if RE located in a mass-based state receives mass-based set-aside allowances for any generation, that generation is not eligible to be issued ERCs in a rate-based state.

The EPA requests comment on the proposed treatment of leakage and of interstate effects under both the proposed rate-based federal plan approach and the proposed mass-based federal plan approach, and as part of the corresponding proposed model rules.

3. Provisions to Encourage Early Action

The EPA outlined and initiated the Clean Energy Incentive Program (CEIP) in the final EGs (see section VIII.B.2 of the final EGs). The program is designed to incentivize investment in certain types of RE projects, as well as demand-side energy efficiency (EE) projects implemented in low-income communities. These RE projects must commence construction, and these EE projects must commence implementation after the date of submission of a final plan to the EPA by the state they are located on or benefitting, or after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan, and will receive incentives for the MWh they generate or the end-use energy demand reductions they achieve during 2020 and/or 2021. The CEIP also provides an additional incentive to drive investment in demand-side EE projects implemented in low-income communities. The EPA proposes to apply the CEIP in all states subject to either a rate-based or mass-based federal plan. The EPA's proposed approaches to implementing the program in the rate-based and mass-based federal plans are detailed in sections IV and V of this preamble, respectively.

B. Inventory of Emissions

Fossil fuel-fired EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2, and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks[19] (the U.S. GHG Inventory).

[19] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015.
http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program[20] (GHGRP) that requires emitting facilities over threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 of this preamble, which presents total U.S. anthropogenic emissions and sinks[21] of GHGs, including CO_2 emissions, for the years 1990, 2005, and 2013.

[20] U.S. EPA Greenhouse Gas Reporting Program Dataset, see http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html

[21] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of CO_2.

Table 3. U.S. GHG Emissions and Sinks by Sector (Million Metric Tons Carbon Dioxide Equivalent (MMT CO_2 Eq.))[22]

SECTOR	1990	2005	2013
Energy[23]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[24] In 2013, fossil fuel combustion by the utility power sector –- entities that burn fossil fuel and whose primary business is the generation of electricity –- accounted for 38.3 percent of all energy-related CO_2 emissions.[25] Table 4

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[22] From Table ES-4 of “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013”, Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015.

http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[23] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities, including fuel combustion and fugitive fuel emissions.

[24] From Table ES-2 “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013”, Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015.

http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[25] From Table 3-1 “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013”, Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15, 2015.

of this preamble presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

Table 4. U.S. GHG Emissions from Generation of Electricity from Combustion of Fossil Fuels (MMT CO_2)[26]

GHG EMISSIONS	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
- from coal	1,547.6	1,983.8	1,575.0
- from natural gas	175.3	318.8	441.9
- from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory, which represents comprehensive total U.S. GHG emissions and complies with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its GHGRP. Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 of this preamble presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5 of this preamble, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported

http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[26] From Table 3-5 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013", Report EPA 430-R-15-004, United States Environmental Protection Agency, April 15 2015.

http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

Table 5. Direct GHG Emissions Reported to GHGRP by Largest Emitting Industrial Sectors (MMT CO_2e)[27]

Industrial sector	**2013**
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

C. Affected EGUs

For the Clean Power Plan and this federal plan, an affected EGU is any SGU, IGCC, or stationary combustion turbine that was in operation or had commenced construction as of January 8, 2014,[28] and that meets the following criteria, which differ depending on the type of unit. To be an affected EGU, such a unit, if it is SGU or IGCC, must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250

[27] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. http://ghgdata.epa.gov/ghgp/main.do.

[28] Under section 111(a) of the CAA, determination of affected sources is based on the date that the EPA proposes action on such sources. January 8, 2014 is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the Federal Register (79 FR 1430).

MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a SCT, the unit must meet the definition of a combined cycle or CHP combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, and have a base load rating of greater than 260 GJ/h (250 MMBtu/h).

When considering and understanding applicability, the following definitions may be helpful. Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself. Combined cycle combustion turbine means any SCT which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used to create additional electric power output in a steam turbine. CHP combustion turbine means any SCT which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generates steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

We note that certain affected EGUs are exempt from inclusion in a state plan and this federal plan. Affected EGUs that may be excluded under the EGs are those that (1) Are subject to subpart 40 CFR part 60, subpart TTTT as a result of commencing modification or reconstruction; (2) are SGUs or IGCC units that are currently and always have been subject to a federally enforceable permit limiting net-electric sales to one-third or less of its potential electric output or 219,000 MWh or less on an annual basis; (3) are non-fossil units (i.e., units that are capable of combusting 50 percent or more non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) are stationary combustion turbines that are not capable of combusting natural gas (i.e., not connected to a natural gas pipeline); (5) are CHP units that are subject to a federally enforceable permit limiting, or have historically limited, annual net electric sales to a utility power distribution system to the product of the design efficiency and the potential electric output or 219,000 MWh (whichever is greater) or less; (6) serve a generator along with other SGU(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each SGU, IGCC, or stationary combustion turbine) is 25 MW or less; (7) are a municipal waste combustor unit subject to subpart Eb of 40 CFR part 60; or (8) are a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of 40 CFR part 60.[29]

The EPA is also taking comment on an alternative compliance pathway that could be available to units under a mass based approach. The ways that the approach could be implemented are further outlined in the Alternative Compliance Pathway for Units that Agree to Retire Before a Certain Date TSD. Under this approach, two basic requirements would need to be met. The first is that the unit would have to take a commitment that it would retire on a date on or before December 31, 2029. The second is that the unit would have to demonstrate that it will take an enforceable emission limitation that would assure that the overall state emission goal is met. The TSD explores ways that this approach could be implemented, including ways that the enforceable emission limitation could be calculated and implemented. The EPA requests comment on whether this approach should be available for all units or limited to small units (e.g. less than 100 MW nameplate capacity). EPA is also taking

[29] We had proposed in the CPP EGs that affected EGUs were those existing source fossil fuel-fired EGUs that met the applicability criteria for coverage under the final GHG standards for new fossil fuel-fired EGUs being promulgated under CAA section 111(b). However, we are finalizing in the EGs that states need not include certain units that would otherwise meet the CAA section 111(b) applicability in this CAA section 111(d) EGs. These include simple cycle turbines, certain non-fossil units, and certain CHP units. The final CAA section 111(b) standards include applicability criteria for simple cycle combustion turbines, for reasons relating to implementation and minimizing emissions from all future combustion turbines.

comment on whether and how such an approach could be included under a rate-based approach.

The applicability of this proposed federal plan follows the same applicability criteria as the final EGs. The rationale for these criteria is provided in section IV.D of the Clean Power Plan. We are not reopening the criteria or rationale here.

In the federal plan Affected EGU Technical Support Document (TSD), the EPA lists all applicable affected EGUs according to our records from the National Electric Energy Data System (NEEDS), Energy Information Administration (EIA), and comments from the CPP. In this TSD, each affected EGU is assigned its proposed applicable standards if a federal plan were to be promulgated for that affected EGU at any time. The EPA requests comments and updates to this list of affected units. Section VI.C of the final EGs describes the data used in setting the standards and how an inventory of affected units has been compiled.

D. Compliance Schedule

In accordance with the schedule set out in the EGs, the federal plan is proposed to be implemented in a phased approach. The first period, corresponding to the Interim Period in the EG, is proposed to run from beginning of calendar year 2022 until end of calendar year 2029 (January 1, 2022 to December 31, 2029). The Final Period would run from beginning of calendar year 2030 (January 1, 2030) indefinitely into the future. The first period is proposed to be comprised of three “compliance periods,” set by calendar year. The first compliance period will be from January 1, 2022 to midnight, December 31, 2024 (3 calendar years). The second compliance period will be from January 1, 2025 to midnight, December 31, 2027 (3 calendar years). The third compliance period will be from January 1, 2028 to midnight, December 31, 2029 (2 calendar years).

Under the EGs, midnight, December 31, 2029 marks the end of the Interim Period, and the beginning of the Final Period. The EPA proposes that the compliance periods in the Final Period will each be 2 calendar years. Thus, the first compliance period after 2030 would be from January 1, 2030 to midnight, December 31, 2031. The second compliance period would be from January 1, 2032 to midnight, December 31, 2033. This would repeat accordingly unless changed by the EPA through a revision to the federal plan or other action.[30]

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, “[t]he time over which [the compliance standards] extend should be as short term as possible and should

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[30] This schedule would be the same under either a rate- or mass-based approach.

generally not exceed one month." See e.g., June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and §112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

Prior to the beginning of the first compliance period in 2022, the agency intends to establish the infrastructure for operating a federal trading program and to work closely with affected EGUs in the states where the federal plan is promulgated prior to the start of the first compliance period in 2022. We request comment on whether it would be possible to grant, on a case-by-case basis, certain affected EGUs, particularly small entities, additional time to come into compliance, and to request additional input from the public as to the design of such flexibility that would be compatible with the EGs and a federal plan that implements a trading system.

The EPA recognizes that it is important to ensure a degree of liquidity in compliance instruments in either of the proposed trading approaches, while also maintaining the stringency required by the final EGs. A number of aspects of the rate-based and mass-based programs would assist with this, including allocation methods or rules, mechanisms to place allowances or credits into the market relatively early, requirements for public transparency of information related to allowance, or credit issuance, tracking, transfers and holdings. The EPA solicits comment on other approaches to ensure market liquidity while continuing to meet the stringency of the final EGs.

E. Addressing Reliability Concerns

The proposed federal plan has been designed to ensure that, to the greatest extent possible, implementation would not interfere with the power sector's ability to maintain electric reliability.[31] Like the EGs, the federal plan provides a long planning horizon and implementation period. In addition the federal plan allows affected EGUs to obtain tradable allowances and credits to meet obligations which assures that reliability can be maintained without disruption to the electricity system.

There are many features of the electricity system that ensure that electric system reliability will be maintained. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards

[31] The EPA evaluated certain aspects of electric reliability in the context of modeling projections for the final Clean Power Plan, and that evaluation is described in the "Resource Adequacy and Reliability Analysis TSD" for that rulemaking, a copy of which is also included in the docket for this rulemaking.

mandatory and enforceable by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, Department of Energy (DOE), state public utility commissions (PUCs), independent system operators and regional transmission organizations (ISOs/RTOs), and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry’s efforts regarding electric system reliability have become multidimensional, comprehensive and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[32] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[33] Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain and implement a set of plans to mitigate operating emergencies.[34]

The EPA's approach in this proposed federal plan builds on the foundation provided in the EG's determination of BSER to ensure that the final federal plan, like the final EG, does not interfere with the industry's ability to maintain reliability of the nation's electricity supply. First, the federal plan, like the EG, provides more than 6 years before reductions are required and an 8-year period from 2022 to 2029 to meet interim

[32] Casazza, J. and Delea, F., Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations, IEEE Press, at 160 (2010).

[33] Id.

[34] NERC Reliability Standard EOP-001-2.1b – Emergency Operations Planning, available at http://www.nerc.net/standardsreports/standardssummary.aspx.

goals. This allows time for planning and steady, measured implementation.

Second, the federal plan is a market-based trading program which will allow affected EGUs the opportunity to buy and sell emissions credits or allowances as well as bank them. The EPA's proposed federal plan includes two alternative approaches: a mass-based trading program and a rate-based trading program. Trading programs of both types have many positive attributes. Among them is that they help to ensure that imposition of the federal plan will not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Such a program does not restrict unit-level operational decision-making beyond requiring units to hold a sufficient number of tradable permits (e.g., allowances or ERCs) to cover emissions. It, therefore, inherently allows for unit level operational flexibility to facilitate the maintenance of reliability and makes the program enormously resilient. If a unit finds it needs to run more than anticipated, the market-based compliance system provides a way for the EGU to meet its generation needs while it maintains compliance with the federal plan.

Third, just as we have required the states to do in developing state plans, the EPA is considering reliability as a part of developing this federal plan. For example, the EPA will consult with planning authorities. The EPA will work with the ISO/RTO Council to convene a face-to-face meeting for planning authorities with the EPA during the comment period to discuss any concerns or other feedback on the federal plan from those entities. This meeting will help to ensure that the EPA is taking into consideration any concerns about the relationship of this rulemaking to the ability of the industry to maintain electric reliability across the country as we finalize the federal plan. It will give the planning authorities an opportunity to hear directly from the EPA how the federal plan is designed and gives the planning authorities an opportunity to voice concerns and ask questions. This will help inform comments that planning authorities may submit to the docket.

In the final CPP EGs, the EPA laid out the availability of a reliability safety valve that could be used if an unanticipated catastrophic emergency caused a conflict between maintenance of electric reliability and inflexible requirements that a state plan might impose on an affected EGU or EGUs. Under the federal plan, inflexible requirements are not imposed on specific plants. Rather as explained earlier, the very nature of the federal plan, in which affected EGUs can obtain allowances or credits if needed, supports reliability. Therefore, a reliability safety valve for the federal plan is not needed. The

EPA invites comments on this aspect of the proposed federal plan.

The EPA, Department of Energy (DOE) and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final EGs and the final federal plan in any state that does not have an approved state plan. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor implementation. The three agencies will work together to monitor implementation, share information and resolve any difficulties that may be encountered.

The EPA is not proposing to include an allowance set-aside, or similar mechanism in a rate-based approach, to address reliability issues in the federal plan; however, we request comment on including such a set-aside in the context of a mass-based approach. The EPA requests comment specifically on creation of an allowance set-aside for the purpose of making allowances available in emergency circumstances in which an affected EGU was compelled to provide reliability critical generation and demonstrated that a supply of allowance needed to offset its emissions was not available.

The set-aside would be in addition to the proposed set-asides that are detailed in section V.D in this preamble. The

EPA would set aside allowances in each state under the mass-based federal plan, and if a reliability issue is perceived by the EPA, DOE and FERC coordinated monitoring process discussed above, the EPA would distribute allowances from the set-aside to support affected EGUs during or after an unforeseen, emergency reliability event. If there were unused allowances remaining in the set-aside, then the EPA would distribute them to affected EGUs pro rata based on the allocation approach that is detailed in section V.D of this preamble. The EPA requests comment on all elements of such an approach, including what events would trigger the need for allowances from the reliability set-aside; eligibility criteria to receive the set-aside allowances; the size of the set-aside; and the timing of distribution of allowances from the reliability set-aside. Additionally, the EPA requests comment on how a reliability “set-aside” approach could be implemented in the rate-based federal plan.

As detailed later in this preamble, the EPA proposes in the federal plan to implement a CEIP, which was established in the EGs to reward investment in certain clean energy projects that achieve MWh results during 2020 and 2021 (see sections IV and V of this preamble for the proposed approach to implement this incentive program in the rate-based and mass-based federal plans, respectively). Implementation of the Clean Energy Incentive Program in the federal plans would create ERCs and allowances before 2022, allowing for creation of banks that could be used in the event of an unforeseen, emergency reliability issue. The EPA requests comment on the potential for these banks of ERCs and allowances to support reliable electricity generation and transmission to be utilized in the event of this kind of reliability emergency.

F. Worker Certification

In the EGs, the EPA suggested that to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. The EPA asks for comments as to whether the federal plan should encourage EGUs to ask for a demonstration that the work undertaken under a federal plan is performed by a proficient workforce. A good way to ensure such a workforce is to require that workers have been certified by: (1) An apprenticeship program that is registered with the U.S. DOL, Office of Apprenticeship or a state apprenticeship program approved by the DOL; (2) a skill certification aligned with the U.S. DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or (3) other skill certification validated by a third party accrediting body.

G. Remaining Useful Lives and Potential for “Stranded Assets”

Section 111(d)(2) of the CAA provides, “In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.” 42 U.S.C. 7411(d)(2). This language tracks similar language in CAA section 111(d)(1) with respect to state plans. In the final EGs, we explained how the Guidelines permit states in applying a standard of performance in their state plans to consider the remaining useful life of a facility. We determined that it was appropriate to specify that the general variance provisions in 40 CFR 60.24(f) should not apply to the class of affected facilities covered by these Guidelines. We concluded that facility-specific factors and in particular, remaining useful life, do not justify a state making further adjustments to the performance rates or aggregate emission goal that the Guidelines define for affected EGUs in a state and that must be achieved by the state plan.

Because the Guidelines do not allow for states to deviate from state goals based on remaining useful life, the EPA does not believe such goal adjustments are necessary or appropriate in the federal plan either. Nonetheless, this does not obviate the requirement that the EPA itself, in the design of its federal plan, consider, among other factors, the remaining useful lives of the affected facilities. The agency therefore proposes the following analysis of this factor.[35]

Congress added the “remaining useful lives” factor to CAA section 111(d)(2) in the 1977 CAA Amendments. Congress did not provide in the statute any direction on how or to what degree “remaining useful lives” of facilities subject to a section 111(d) federal plan is to be considered. As discussed in the preamble to the final EGs, Congress’ intent in enacting the provision was to allow for older facilties with short remaining useful lives to not be required to install capital-intensive pollution control devices to meet emission standards that would only be used for a short period of time before a plant ceased operation. A House of Representatives report on a predecessor bill to the enacted statute stated, “Older plants with relatively short remaining useful lives might have chosen to cease operation if the only means of emission limitation available to meet emission limits were pollution control technology.” H. Report 94-1175, at 159 (1976) (emphasis added).

[35] We note that the preamble and supporting materials for the EGs discuss a related concern raised by some stakeholders, which is whether the EGs could result in widespread “stranded assets” as a direct result of the rule. As explained there, we believe this concern is distinct from the “remaining useful lives” factor in CAA section 111(d)(1), and for the same reasons, believe it is distinct from the factor Congress directed the agency to consider in CAA section 111(d)(2). Nonetheless, we undertook analysis in the final EGs of whether and to what extent there may be a “stranded asset” concern. See memorandum to Clean Power Plan Docket EPA-HQ-OAR-2013-0602 titled “Stranded Assets Analysis” dated July 2015. We believe that analysis demonstrates that this is not likely to be a widespread issue under the federal plan either.

This language is probative of the fact that Congress viewed "remaining useful lives" as a consideration for facilities with relatively little remaining useful life. We are confident the proposed federal plan will not force costly pollution control investments at older plants with short remaining useful lives.

Further, the statute provides that this factor is one "among other factors" that the agency is to consider in promulgating a standard of performance. Congress provided no guidance in the statute as to what those other factors could be. The inclusion of unspecified factors that the agency may determine for itself to consider, along with the use of the term "consider," highlights that Congress intended to give the agency a substantial degree of discretion in determining how the "remaining useful lives" factor is considered. The statute does not require, and Congress did not intend, that this consideration mandate the agency to prevent all premature retirements of affected EGUs, to impose no emission requirements on older affected EGUs, or to ensure that profitability is maintained at all times for all affected EGUs. Congress knew how to explicitly exempt older plants from CAA requirements at the time of the 1977 Amendments. For example, Congress excluded plants in existence before August 7, 1977 from the preconstruction requirements of the PSD/non-attainment new source review (NSR) program, see CAA section 165(a). And in CAA section 169A related to visibility impairment in federal class I areas, Congress excluded from applicability units that began operation before August 7, 1962. 42 U.S.C. 7491(b)(2)(A). In CAA section 111(d) Congress did not set any such specific criteria. Rather it directed the agency to "consider" the remaining useful lives of facilities, among other factors.

This view also accords with past agency practice in implementing a similar provision. In the 1977 Amendments, Congress listed "remaining useful life" as a factor for consideration in the visibility program under section 169A. 42 USC 7491. The "remaining useful life of the source" is one of several enumerated factors that the state or the EPA is to consider in determining the best available retrofit technology (BART) for a particular source. Consistent with congressional purpose, the EPA has implemented this factor in the regional haze program for many years through the BART guidelines, in appendix Y to 40 CFR part 51. The BART Guidelines provide:

> The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. … If the remaining useful life will clearly exceed th[e] time period [for amortization based on the type of control], the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculation.

40 CFR part 51, appendix Y, section IV.D.4.k. In the agency's view, this approach to "remaining useful life" aligns

with congressional intent and informs our view of how the “remaining useful lives” factor should be considered under this CAA section 111(d) federal plan. The key consideration is whether the time period associated with amortizable costs of compliance will exceed the remaining useful lives of the sources in question.

Consistent with legislative intent and past agency practice, we propose that the federal Plan adequately considers ”remaining useful lives” of affected EGUs by providing for trading and other flexibilities authorized in the EGs. To summarize, these include: relatively long periods for affected EGUs to come into compliance, the ability to credit early action, the use of emissions trading, the use of multi-year compliance periods, and the ability to link to other federal or state plans to create larger emissions markets. The federal plan is proposed to include a Clean Energy Incentive Program as provided for in the EGs, which will credit early action and ease compliance in the initial years of the program. These tools will create economic incentives that reward over-performance of some affected EGUs, and allow others to simply acquire credits or allowances to comply with their emission standard, thereby avoiding the need for installation of costly pollution controls at sources with a short remaining life.

Thus, the proposed federal plan is designed in such a way that it adequately, and inherently, takes into account the remaining useful lives of affected EGUs. It provides substantial compliance flexibility, including means of avoiding the need to make extensive capital investments in control technologies that could not be recouped during the remaining useful lives of a facility.[36] The design of the federal plan as a form of emission trading provides individual affected EGUs the flexibility to make cost-conscious compliance choices. This flexibility avoids or substantially diminishes any likelihood that compliance will be a physical impossibility or result in unreasonable costs.

By relying on either rate- or mass-based emission trading, the proposed federal plan capitalizes on the inherent flexibility available through market-based techniques. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a

[36] Because we believe that this is the case for all facilities through the basic design of the federal plan, we also can confirm, in line with the EGs, that the availability of variances from the emission standards is unnecessary in the federal plan. Under the general framework regulations, facility-specific variances from an otherwise applicable standard of performance have been potentially available under the application process in 40 CFR 60.27(e)(2), which incorporates the factors provided in 40 CFR 60.24(f) for states. Consistent with our view that the federal plan adequately considers remaining useful lives, and for the same reasons, the need for facility-specific variances under the circumstances of 60.24(f) (unreasonable costs of controls, physical impossibility of installation of necessary control equipment, or other factors that make longer compliance times or less stringent standards significantly more reasonable) is not expected to arise, and thus, the agency proposes to make 40 CFR 60.27(e) inapplicable in this federal plan.

total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs or allowances than the second facility. Buying ERCs or allowances as a compliance method could avoid excessive up-front capital expenditures that might be unreasonable for facilities with short remaining useful lives, and therefore addresses the consideration of “remaining useful lives.” Buying ERCs or allowances as a compliance method also would reduce the potential for stranded assets.

In addition, the timing of the federal plan limits the immediate costs of compliance, particularly for facilities that have useful lives ending before 2022, but also for facilities that have useful lives ending before 2030. There are no compliance obligations for affected EGUs under this federal plan until 2022, when the first compliance period begins. At that point, the agency is following the glide path provided for in the EGs, which begins with relatively higher emission targets that will slowly strenghten over the interim performance period from 2022-2029 through three multi-year compliance periods. The final, most stringent, compliance obligation does not begin until 2030.

Further, unlike state plans that can be more stringent under CAA section 116, the federal plan is no more stringent than the EGs, and, as explained in the EGs, the Guidelines reflect a reasonable, rather than a maximum possible, implementation level for each building block in order to establish overall goals that are achievable. As discussed in the EG , the BSER determined an average level of emissions achievable by groups of EGUs, rather than for an individual EGU. In considering the remaining useful lives of facilities under a federal plan, the EPA believes this approach to setting the emission standards, coupled with the ability to trade, adequately accounts for remaining useful lives of facilities. In essence, it allows the facilities to comply with the federal plan through the purchase or acquisition of ERCs or allowances, and to avoid the need to make costly investments in control technology for plants that have short remaining useful lives.[37] For these reasons, the federal plan adequately considers “remaining useful lives.” We invite comment on our consideration of facilities’ “remaining useful lives” in the federal plan.

H. Implications for Other EPA Programs and Rules

1. Title V Permitting

a. Permitting Requirements

[37] In addition, the ability to generate ERCs for sale or to sell unneeded emission allowances (depending on whether in a rate- or mass-based system) may give some affected EGUs an economic incentive to take measures to reduce emissions that otherwise would have been uneconomical.

Under the proposed federal plan, title V permits for sources with affected EGUs will need to include any new applicable requirements that the plan places on the affected EGUs. The EPA, however, is not proposing any permitting requirements independent of those that would be required under title V of the CAA and the regulations implementing title V, 40 CFR parts 70 and 71.[38] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of an applicable CAA section 111(d) state plan or federal plan. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The “applicable requirements” that must be addressed in title V permits are defined in the title V regulations, and include requirements under CAA section 111(d) (40 CFR 70.2 and 71.2 (definition of “applicable requirement”)).

The EPA anticipates that, given the nature of the units covered by the proposed federal plan, most of the sources at which they are located are already or will be subject to title V permitting requirements. For sources subject to title V, the

[38] Part 70 addresses requirements for title V programs implemented by state, local, and tribal governments, and part 71 governs the title V program implemented by the EPA or delegate agencies in areas under federal jurisdiction, such as Indian country.

requirements applicable to them under the proposed federal plan will be "applicable requirements" under title V and, therefore, will need to be addressed in the title V permits. For example, requirements under the proposed federal plan concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to either meet an emission rate (including through holding ERCs (rate-based approach)), or to hold allowances covering emissions (mass-based approach) will be "applicable requirements" to be addressed in the permits.

The EPA does not believe this approach is affected by the Supreme Court's decision in Utility Air Regulatory Group v U.S. EPA, 134 S. Ct. 2427 (June 23, 2014). The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment on April 10, 2015 vacated the title V regulations under review in that case (40 CFR 70.12 and 71.13) to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of UARG v. EPA, and, if so, to undertake to make such revisions. As the agency made clear in a memorandum to Regional Administrators last year, "While the EPA will no longer apply or enforce the requirement that a source obtain a title V permit solely because it emits or has the potential to emit GHGs above major source thresholds, the agency does not read the Supreme Court decision to affect other grounds on which a title V permit may be required or the applicable requirements that must be addressed in title V permits."[39] Accordingly, while the emission of GHGs alone cannot trigger the need for a title V permit under UARG, the EPA believes a final federal plan under CAA section 111(d) will create new "applicable requirements" in the form of an emission standard (either an emission rate or an allowance system) and related requirements for GHGs (here, CO_2) on affected EGUs. See 40 CFR 70.2, 71.2 (definition of "applicable requirement" includes "any standard or other requirement under section 111 of the Act, including section 111(d)") (emphasis added). Thus, an affected EGU may be required to modify its existing title V permit, or obtain a new permit if it does not already have one, if it becomes subject to an emission standard for CO_2 under a CAA section 111(d) federal plan.

[39] Memorandum from Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, to Regional Administrators, Regions 1-10, at 5 (July 24, 2014).

The title V permits program is structured to provide flexibility for market-based approaches, such as allowance trading programs under the federal plan, including flexibility to make changes under such programs without necessarily requiring a formal permit revision. For example, the title V regulations provide that a permit issued under title V shall include, for any “approved * * * emissions trading or other similar programs or processes” applicable to the source, a provision stating that no permit revision is required “for changes that are provided for in the permit.” 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with this provision in the title V regulations, the proposed federal plan regulations include a provision stating that no permit revision shall be required for the allocation, holding, deduction, or transfer of allowances once the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit. Consistent with title V regulations, this provision should be included in each title V permit for a covered source. As a result, allowances will be able to be traded (or allocated, held, or deducted) under the federal plan without a revision of the title V permit of any of the sources involved.

As a further example of flexibility under title V, the title V regulations allow the use of the minor permit modification procedures for permit modifications “involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA.” 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). Therefore, the EPA is proposing that any changes that may be required to an operating permit with respect to a trading program under the federal plan may be made using the minor permit modification procedures of the title V rules. The EPA proposes that such changes may include the initial changes needed to the title V permit to establish the applicability of the trading program to the source, specify the covered units, and to include other permit terms that may be needed for implementation, including the general approach for monitoring and reporting. The minor permit modification procedures could also be used for any subsequent changes to permit terms that may be needed with respect to the trading program, although we expect such changes to be infrequent. As noted above, once a trading program has been established in the permit, there may be transactions, such as individual trades, that will require no formal permit modification procedures because such trading would be already addressed and allowed by the permit (“provided for in the permit”) and provided the changes do not conflict with any existing terms of the permit. If a sources wishes to make a change that would go against any express term of the permit, the permit must be revised to allow such a change before the source begins operation of the change. Under the implementation strategy described above, the EPA believes it would be unlikely that any change in trading allowances would violate a term of a permit, but this principle is important to keep in mind when deciding if a minor permit modification is appropriate with respect to operating a trading program in the context of a title V permit.

The EPA believes that the approach to permitting requirements we are proposing here, which imposes no additional permitting requirements independent of title V and provides for the use of minor permit modification procedures, will streamline the process for sources already required to be permitted under title V and for permitting authorities. If there are any sources that would become newly subject to title V as a result of the requirements of this proposed federal plan, the initial title V permit that would be issued pursuant to 40 CFR 70.7(a) or 71.7(a) would address the federal plan requirements, when finalized.

The EPA notes that the approach to title V permitting that is being proposed is somewhat similar to the approach adopted in the final CSAPR. See 76 FR 48299-30 (Aug. 8, 2011). The agency recently issued guidance to assist permitting authorities and sources subject to CSAPR in incorporating CSAPR requirements into title V permits.[40] The EPA invites comment on its proposed approach to permitting requirements for the federal plan, including whether it would be of use to develop guidance similar to the guidance developed for permitting under CSAPR. The EPA invites comment on its proposed approach to incorporating applicable requirements of the federal plan into title V permits and revising those requirements, including specifically seeking comment on whether all requirements should be eligible for incorporation into title V permits via minor modification procedures or if only a specified subset of such requirements should be eligible for such procedures.

The EPA also notes that the applicable requirements of this proposed federal plan would apply to a source and are independently enforceable regardless of whether they have yet been included in the source’s Title V permit.

2. Implications for New Source Review Program

The NSR program is a preconstruction permitting program that requires major stationary sources of air pollution to

[40] Memorandum from Anna Marie Wood, Director, Air Quality Policy Division, Office of Air Quality Planning and Standards (OAQPS), and Reid P. Harvey, Director, Clean Air Markets Division, Office of Atmospheric Programs (OAP), to Regional Air Division Directors, 1-7, regarding Title V Permit Guidance and Template for the Cross-State Air Pollution Rule (May 13, 2015).

obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific.

In the final EGs, the EPA recognized that, as part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR. We noted that while there may be instances in which an NSR permit would be required, we expect those situations to be few.

The EPA believes the analysis of NSR applicability is basically the same for sources under a CAA section 111(d) federal plan. That is, it is conceivable that a source under a federal plan may choose, as a means of compliance with either a rate-based or mass-based approach, to undertake a physical or operational change to improve an affected EGU's efficiency that results in a significant net emissions increase of a regulated NSR pollutant. This would trigger NSR. However, as with state plans, the EPA believes that these situations will be few.

After the proposal for the Clean Power Plan was published in June of 2014, the U.S. Supreme Court issued its opinion in UARG v EPA, 134 S. Ct. 2427 (June 23, 2014). The Supreme Court held that an increase in GHG emissions alone cannot by law trigger the NSR requirements of the PSD program under section 165 of the CAA. On remand from the Court, the D.C. Circuit issued an amended judgment in Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir., April 10, 2015), vacating the relevant regulations. Therefore, increases in emissions of GHGs alone, including those that may occur through actions taken at sources to comply with the proposed federal plan (such as may occur when an NGCC unit increases its operations due to generation shift from a SGU), cannot trigger NSR.

The EPA will invite comment on potential scenarios in which affected EGUs, particularly small entities, could be subject to the requirements of the NSR program as a result of taking compliance measures under the federal plan, and any ideas for harmonizing or streamlining the permitting process for such sources that are consistent with judicial precedent. However, the EPA is not proposing any changes to the NSR program in this action, and the agency is not reopening or reconsidering any prior actions or determinations related to NSR in this action. Any comments related solely to the NSR program will be considered outside the scope of this proposed rule.3. Interactions with Other EPA Rules

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other rules recently finalized or proposed by the EPA.[41] These rules include the Mercury and Air Toxics Standards (MATS) (77 FR 9304; Feb. 16, 2012);[42] the CSAPR; Requirements for Cooling Water Intake Structures at Power Plants (79 FR 48300; Aug. 15, 2014); Disposal of Coal Combustion Residuals from Electric Utilities, issued on December 19, 2014; and the proposed Steam Electric Effluent Limitation Guidelines and Standards (78 FR 34432; June 7, 2013). These rules are discussed in more detail in the final EGs along with steps the EPA is taking to enable compliance with

[41] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[42] The Supreme Court recently reversed and remanded a D.C. Circuit Court of Appeals decision that had upheld the MATS rule. Mich. v. EPA, No. 14-46 (S. Ct. filed June 29, 2015). The Court did not vacate the rule, however, and it remains in effect.

obligations under other power sector rules as efficiently as possible. We solicit comment on whether there are specific things the EPA can do in the design and implementation of the federal plan that further this objective.

I. Administrative Appeals Process

Under either a rate-based or mass-based trading program, the EPA anticipates that there may be situations in which individual parties are affected by decisions of the agency. For example, under a rate-based plan, a determination may be made that an eligibility application by an ERC provider is denied. And, for set-asides in the mass-based program, an affected EGU may believe that its allowance allocation amount was miscalculated. Similar to prior trading programs, the agency believes it would be efficient and potentially avoid the need for recourse to litigation to provide an administrative appeals process. Therefore we are proposing, and requesting comment on, the use 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 under CAA section 111(d). We also propose to revise part 78 to accommodate such appeals. The part 78 procedures cover prior CAA emission trading programs and were specifically designed with these types of disputes in mind.

The persons eligible to file such appeals would be similar to the existing definition of an “interested person” in part 78. The filing of an appeal and the exhaustion of administrative remedies under part 78 would be a prerequisite to seeking judicial review. For purposes of judicial review, final agency action would occur only when an agency decision under the federal plan listed as appealable under part 78 has been issued, and the procedures of part 78 for appealing the decision are exhausted.

The actions we propose to list as appealable under the part 78 procedures are as follows.

In the case of the rate-based federal plan: decisions on an eligibility application for ERCs; decisions regarding the number of ERCs generated; decisions on the transfer of ERCs; decisions on the disallowance of ERCs for compliance; decisions that there has been an excess of emissions requiring a 2-for-1 ERC administrative compliance penalty; decisions regarding deduction or surrender of ERCs for compliance from affected EGUs’ compliance accounts; decisions on the accreditation of independent verifiers; the use of error corrections regarding information submitted by ERC providers, affected EGUs, or other ERC account holders; and the finalization of compliance period emissions data, including retroactive adjustment based on audit or other investigation.

In the case of a mass-based federal plan: decisions on an eligibilty application for set-aside allowances; decisions regarding the allocation of allowances to affected EGUs; decisions regarding the allocation of allowances from set-asides; decisions on the transfer of allowances; decisions regarding the finalization of emissions data by affected EGUs during compliance periods; decisions making error corrections to information submitted by affected EGUs and other account holders; decisions that there has been excess emissions requiring a 2-for-1 allowance administrative compliance penalty; and decisions regarding the deduction or surrender of allowances for compliance from affected EGUs' compliance accounts.

We request comment on this list of actions for both types of approaches to the federal plan, and whether there are other decisions that may be made in the course of implementation of the federal plan that are party-specific that would be appropriate to list as appealable under part 78. We also take comment on whether it would be appropriate for the EPA to finalize an administrative appeals process that differs in any way from that offered under part 78, or in addition to that offered under part 78. If so, we request comment broadly on all aspects of the alternative or additional adminsitrative appeals process, including with respect to any structural, procedural, subtantive, and timing requirements it should include, who should have access to it and in what manner, and how it would differ from part 78. Finally, we request comment on whether, similar to other programs identified in 40 CFR 78.1(a)(1), the agency should make the procedures of part 78 available to any actions of the Administrator under the comparable state regulations approved as a part of a state plan under the EGs.

J. Consistency of Program Structure with Clean Air Act Authority

The EPA is co-proposing two distinct forms of emissions trading as the mechanism for federal implementation of standards of performance that achieve the emission performance levels by determined by application of the BSER in the Clean Power Plan EGs. Both proposals are “emission standard” approaches as defined in the EGs, and the EPA is not proposing an approach like the “state measures” approach that is also available to states in the final EGs. The EPA has legal authority to establish either of the proposed trading systems as a federal plan under CAA section 111(d)(2). We discuss this topic briefly here and invite public comment. The EGs discussed the role of emissions trading in the BSER, see, e.g., section V.A of the preamble to the final EGs. The EPA regards this to be a separate issue and is not revisiting or reopening the discussion of the BSER or the role of trading in the BSER here. The EGs recognize and provide ample opportunity for states to establish standards of performance that allow the use of emissions trading or other multi-unit compliance approaches. Here we discuss why an emissions trading program is a lawful and appropriate form of federal "implementation" of a "standard of performance" under CAA section 111(d)(2). We invite comment on this legal discussion and the agency's interpretation of its authority.

1. General Section 111(d)(2) Authority

Section 111(d)(2) provides as follows:

> The Administrator shall have the same authority—
>
> (A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title [CAA section 110(c)] in the case of failure to submit an implementation plan, and
>
> (B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title [CAA sections 113 and 114] with respect to an implementation plan.
>
> In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, the remaining useful lives of the sources in the category of sources to which such standard applies.
>
> 42 U.S.C. 7411(d)(2).[43]

The phrase "same authority to prescribe" indicates that Congress viewed the EPA's authority to issue a federal plan for designated pollutants under CAA section 111(d) as, in some sense, co-extensive with its authority to issue a FIP for National Ambient Air Quality Standards (NAAQS) pollutants under

[43] The agency's interpretation of the "remaining useful lives" provision is discussed above in section III.G of this preamble.

CAA section 110. This authority under CAA section 111, of course, must be understood in reference to the purpose of that section (i.e., to achieve emission reductions for designated pollutants from designated facilities), rather than in reference to the purpose of CAA section 110 (i.e., to attain and maintain the NAAQS). However, it has been the agency's longstanding view that, in both procedural and substantive respects, Congress intended that the CAA section 110 authority be looked to under CAA section 111(d)(2). See 40 FR 53340, at 53342 (Nov. 17, 1975) ("It is obvious that [the Administrator] could only prescribe standards on some substantive basis. The references to section 110 of the CAA suggest that (as in CAA section 110) [she] was intended to do generally what the states in such cases should have done, which in turn suggests that (as in CAA section 110) Congress intended the states to prescribe standards on some substantive basis. Thus, it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans.").

Over the several decades of implementation of the CAA, the courts, and the EPA, have addressed the nature and scope of CAA section 110 authority. See, e.g., 71 FR 25328, 25338 (May 12, 2005) (CAIR final rule). In general, the EPA has broad power under CAA section 110(c) to cure a defective SIP. Thus, in promulgating a FIP under CAA section 110, the EPA may exercise its own, independent regulatory authority in accordance with CAA section 110(c) and the CAA more broadly. When the EPA has promulgated a FIP, courts have not required explicit authority for specific measures: “We are inclined to construe Congress’ broad grant of power to the EPA as including all enforcement devices reasonably necessary to the achievement and maintenance of the goals established by the legislation.” South Terminal Corp. v. EPA, 504 F.2d 646, 669 (1st Cir. 1974). Further, the same authority that is exercised by the states under the CAA in connection with the adoption, implementation, and enforcement of a SIP may be assumed to be available to the EPA when the agency issues a FIP, after determining that a state has not adopted a satisfactory SIP. As the Ninth Circuit has held, when the EPA acts in place of the state pursuant to a FIP under CAA section 110(c), the EPA “stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to EPA.” Central Ariz. Water Conservation Dist. V. EPA, 990 F.2d 1531, 1541 (9th Cir. 1993). Accord, South Terminal, 504 F.2d at 668 (“[T]he Administrator must promulgate promptly regulations setting forth an implementation plan for a state should the state itself fail to propose a satisfactory one. The statutory scheme would be unworkable were it read as giving to the EPA when promulgating an implementation plan for a state, less than those necessary measures allowed by Congress to a state to accomplish federal clean air goals. We do not adopt any such crippling interpretation.”).

By the same token, if there are clear limits to the EPA’s CAA section 110(c) authority, those too, would arguably carry over to CAA section 111(d)(2). For instance, CAA section 110(c)(1) ties the EPA’s authority to promulgate a final FIP for a state to the EPA’s predicate action on a SIP(or lack thereof): generally, either an action disapproving a plan, or a finding that a state has failed to submit a plan. However, even here, as the Supreme Court has recognized, “the plain text of the CAA grants EPA plenary authority to issue a FIP ‘at any time’ within the 2-year period that begins the moment EPA determines a SIP to be inadequate.” EPA v. EME Homer City Generation, 134 S. Ct. 1584, 1602 n.14 (2014).

Congress gave the EPA the same authority to prescribe a plan under CAA section 111(d)(2) as it possesses under CAA section 110(c). The EPA believes this authority is the “same” in the sense described above and in the case law.[44] The scope of the

[44] We interpret the cross-reference to be to the currently enacted version of CAA section 110(c), rather than to a prior version. As discussed in section VII of this preamble, below, the current version of CAA section 110, including subsection (c), reflects changes made in the 1990 Amendments based on experience gained in the first two decades of the CAA’s implementation. The statute and legislative history do not expressly address the question,

EPA's action to undertake a FIP under CAA section 110 is informed by the scope of the state's action to undertake a SIP; likewise, the scope of the EPA's action to undertake a federal plan under CAA section 111(d) is informed by the scope of the state's action to undertake a state plan.

The agency received comments on the proposed EGs from commenters who stated that the EPA cannot require states to implement the building blocks that make up the BSER; for example, ordering re-dispatch to natural gas-fired units, or ordering the construction of RE projects. These commenters went on to say that the EPA itself would have no authority to order these types of actions under a federal plan. As we explained in the Legal Memorandum for the final EGs, and reiterate here, the premise of these comments is incorrect. The EPA is not requiring the implementation of the BSER or the building blocks in the EGs. Even where the EPA is directly implementing standards of performance in a federal plan, the agency will not, and need not, attempt to order sources to implement the measures that comprise the BSER. Rather, as set forth in the co-proposed federal plans discussed in sections IV and V of this preamble, the EPA would set emission standards for each of the affected EGUs in the federal-plan state, provide mechanisms for their

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but there is no indication Congress would have intended to prevent these improvements from being available under CAA section 111 as well.

implementation and enforcement, and otherwise leave to the owners and operators of the affected EGUs the decisions about what measures they want to take to comply with the emission standard. Though the emission standards will be federally enforceable, as under a state plan, sources may achieve them through implementation of measures in the BSER, or any other method.

Thus, the question whether the EPA would have the authority to directly order the implementation of the measures in the building blocks in this proposed federal plan is not only not relevant but represents a categorical misunderstanding of the nature of the BSER in relation to the imposition of standards of performance under a CAA section 111(d) plan. To illustrate this, by the same token the EPA could not enforce many logistical aspects of a control requirement such as a scrubber – for instance, the EPA does not need to assert the authority to order into existence companies that manufacture scrubbers, or order their construction or delivery on a certain schedule. The EPA need not in setting emission standards have before it all of the information regarding manufacturing, transportation of parts, or other logistical requirements to ensure that each scrubber gets constructed and delivered to a source. Similarly, the EPA here does not, and needs not, propose an implementation approach of directly intervening to re-dispatch certain units, construct new

RE projects, or take other measures, either included in the BSER or not. The agency determined the BSER and emission performance levels in the EGs on a reasonable assumption that all of those things can actually happen. In providing for the implementation of federally enforceable standards of performance in the federal plan proposed in this action, the agency is ensuring that these things will happen.

2. Use of Market Techniques to Implement Standards of Performance under the Clean Air Act

The use of market techniques such as emission trading is well-supported in the CAA and has many regulatory precedents. The EPA discussed this history, and the reason why trading is a supportable method of implementation of standards of performance under CAA section 111(d) in the EGs. See section V.A of the final EGs. Here we supplement that discussion with respect to the agency's own authority under CAA section 111(d)(2) to use trading as a method of implementation of a "standard of performance" in the federal plan.

The 1990 CAA Amendments added broad authorizations for the use of market techniques in several sections of the statute, including in Title I. States were provided express authority to use such approaches in their NAAQS implementation plans under CAA section 110(a)(2)(A): "Each [state] plan shall—include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights)…." 42 USC 7410(a)(2)(A). The EPA was given similar authority in the definition of a "Federal Implementation Plan" in CAA section 302: "The term 'Federal implementation plan' means a plan (or portion thereof) promulgated by the Administrator … which includes enforceable emissions limitations or other control techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard." 42 U.S.C. 7603(y). Section 111(d)(2) of the CAA provides the EPA "the same power to prescribe" a federal plan under CAA section 111 as it would have to promulgate a FIP under CAA section 110(c). Thus, the EPA believes the plain language of the statute authorizes the use of market techniques in CAA section 111(d) federal plans.

However, even if one were to view this language as not wholly unambiguous with respect to the scope of federal authority under CAA section 111, the EPA believes that CAA section 111, in conjunction with authorizations and endorsements of market techniques throughout the CAA, and other indicia of congressional intent, strongly support the view that market techniques are within the EPA's authority to promulgate a federal plan under CAA section 111(d).

Case law throughout the history of the CAA has generally confirmed the legal viability of emissions trading as an implementation measure so long as the trading ultimately achieves the emission reduction goals of the statute. See, e.g., Sierra Club v. EPA, No. 12-3169 (6th Cir. Filed March 18, 2015), Slip Op. at 11-14 (upholding EPA approval of redesignation of area to attainment on basis that reductions in emissions from cap-and-trade programs (NO_x SIP Call, CAIR, and CSAPR) are permanent and enforceable). Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837 (1984) ("Chevron"), the seminal case establishing the Supreme Court's standard of review of agency interpretations of the statutes they administer, upheld one of the EPA's early emissions trading programs, the Netting Rules of 1980 (45 FR 52676; Aug. 7, 1980), which the EPA in its discretion chose to allow states to apply in both attainment and nonattainment areas (46 FR 50766; Oct. 14, 1981). The Netting Rules allowed existing major sources to modify without triggering certain requirements of PSD or nonattainment NSR, so long as any increase in emissions associated with the modification is compensated for by a corresponding decrease in emissions elsewhere within the same facility, such that there is no significant net increase in emissions from the facility as a whole. In upholding this approach in Chevron, the Supreme Court gave deference to the EPA's definition of the term "source," finding in that term sufficient ambiguity to support the agency's reasoned application of an emissions averaging approach for total pollution emitted from the source. See EPA v. EME Homer City, 134 S. Ct. 1584, 1603 (2014) ("Because 'a full understanding of the force of the statutory policy . . . depend[s] upon more than ordinary knowledge' of the situation, the administering agency's construction is to be accorded 'controlling weight unless . . . arbitrary, capricious, or manifestly contrary to the statute.'") (quoting Chevron, 467 U.S. at 844).[45]

With the increasing recognition of the utility of trading, crediting, and averaging to meet emission reduction goals efficiently, the EPA set forth a comprehensive policy on trading in 1986. Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 FR 43814 (Dec. 4, 1986) (hereinafter "ERC Policy"). In the ERC Policy, the EPA stated that it "endorses emissions trading and encourages its sound use by states and industry to help meet the goals of the CAAt more quickly and inexpensively." At the same

[45] The EPA is not aware of any case since at least the Chevron decision in which a trading program under the CAA was invalidated simply by virtue of being a trading program. The CAIR trading program was set aside by the D.C. Circuit because the court held it did not accomplish the objective of the Good Neighbor provision of the CAA, not because it used a trading approach per se. North Carolina v. U.S. EPA, 531 F.3d 896, 921 (D.C. Cir. 2008). More recently the Supreme Court upheld key portions of the CSAPR trading program that replaced CAIR in EPA v. EME Homer City, 134 S. Ct. 1584 (2014).

time, based on lessons learned from its earlier 1982 trading policy, the EPA took steps to tighten its policies on the use of "bubbles" to ensure environmental integrity of trading, particularly in non-attainment areas. The agency emphasized the requirements of enforceability, tracking (and preventing double-counting), determining the appropriate baseline from which to measure emissions, and demonstration of actual air quality benefits.

The use of an emissions trading system for CO_2 reductions for affected EGUs under CAA section 111(d) is also analogous to the trading system for chlorofluorocarbons (CFCs) under the pre-1990 CAA provision for control of stratospheric ozone depleting substances. This program was reviewed by the Office of Legal Counsel (OLC) within the Department of Justice in 1989. See Memorandum for Alan Raul, General Counsel, Office of Management and Budget, from the Office of the Assistant Attorney General (April 14, 1989) (hereinafter "OLC Memo").[46] The OLC was asked by OMB to opine whether a general grant of regulatory authority to the EPA to "control" CFCs was sufficient to authorize an emissions fee or a cap-and-trade system, including auction, of tradable allowances. The statute authorized the EPA to issue regulations "for the control of any substance, practice,

[46] A copy of this memorandum has been placed in the docket for this rulemaking.

process, or activity (or any combination thereof) which in his judgment may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, if such effect in the stratosphere may reasonably be anticipated to endanger public health." Former CAA 157(b) (as enacted in the 1977 CAA amendments). The Office of Legal Counsel concluded that this language – which it characterized as "plain," "unambiguous," and "sweeping" – was sufficient to authorize the EPA to establish a cap-and-trade program with auction for CFCs. See id. At 7 ("It cannot seriously be argued that the use of economic incentives to regulate pollution is a novel or strange idea that could not have been anticipated by the authors of the Clean Air Act Amendments [of 1977].") (citing multiple examples from the policy literature as early as E. Mishan, The Costs of Economic Growth (1967)). The OLC noted that as of 1977, "Congress was cognizant of economic forms of regulation, did not prohibit them, but instead used general language permitting a wide scope of regulatory measures for the control of CFCs." To interpret the general authority of this section of the CAA as affirmatively prohibiting market incentives would be, in the OLC's words, to read into the statute the italicized clause "regulations for the control [of CFCs] by traditional command and control or specification standard methods," id. At 9 – a rewriting "unwarranted in any case, but especially so where

Congress was aware of economic methods of control and where such methods so ably serve the underlying purposes of the statute." Id.

By the time of the 1990 CAA Amendments, as discussed above, Congress was comfortable enough with the efficacy of market techniques that they were broadly authorized for use in SIPs and FIPs for NAAQS. See 42 U.S.C. 7410(a)(2)(A), 7602(y). In the wake of the 1990 Amendments, the EPA issued an "Implementation Strategy for the Clean Air Act Amendments of 1990."[47] This Strategy included as one of nine overarching implementation principles, "Market-based: Use of market-based approaches and other innovative strategies to creatively solve environmental problems." Further, it announced that the EPA would make "full use of innovative market-based approaches," and that the agency will supplement traditional approaches with broader use of market incentives and other innovative approaches "whenever possible." Id. At 3, 9.

Since the 1990 Amendments, the EPA has established three of its most robust trading programs – the Federal NO_X Budget Trading Program (65 FR 2674; Jan. 18, 2000), the CAIR (71 FR 25328; April 28, 2006), and the CSAPR (76 FR 48208; Aug. 8, 2011),

[47] U.S. EPA, Office of Air and Radiation, Implementation Strategy for the Clean Air Act Amendments of 1990 (Update, 1992) (July 1992), 400-K-92-004.

under CAA section 110(a)(2)(D)(i)(I), relating to air pollution that causes nonattainment or interference with maintenance of air quality standards in downwind states.[48]

As noted in the rulemaking notice for the final EGs, the EPA has instituted or authorized the use of emissions trading programs twice in the past under CAA section 111(d). The EPA authorized NO_x emissions averaging or trading within or between facilities under the Municipal Waste Combustors EGs in 1995. 60 FR 65387, 65402 (Dec. 19, 1995) (codified at 40 CFR 60.33b(d)(1) and (2)). The EPA also developed a cap-and-trade system for mercury under CAA section 111(d) in the Clean Air Mercury Rule (CAMR). 70 FR 28606 (May 18, 2005). The EPA proposed a federal plan for trading that was identical in all relevant respects to the CAMR rule. 71 FR 77100 (Dec. 22, 2006). However, CAMR was vacated by the D.C. Circuit on grounds unrelated to the establishment of a trading system for implementation before the CAMR federal plan could be finalized. New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).[49]

[48] The EPA notes that complications that arise with respect to assigning a "significant contribution" among upwind states for NAAQS pollutant levels in downwind states, and designing a trading regime that accomplishes Good Neighbor objectives, are not present with respect to CO_2, which is a global pollutant; emission reductions anywhere contribute to the environmental objective of addressing climate change.

[49] The CAMR program was vacated because the EPA had not made requisite findings under CAA section 112(c)(9) in delisting EGUs with respect to emissions of a hazardous air pollutants (HAP). No such procedural concern is present here with respect to CO_2, which is not a HAP under CAA section 112.

The agency believes these legal and administrative precedents for federal trading programs under the CAA going back decades amply support its decision to propose two forms of emission trading as the method of implementation of the Clean Power Plan EGs in the federal plan. Notably, emissions trading is particularly appropriate with respect to a global pollutant such as CO_2 that is well-mixed in the atmosphere and does not have direct, acute health impacts due to inhalation at ambient levels.[50]

Finally, the Supreme Court has affirmed the breadth of the agency's discretion under CAA section 111(d) to select the method by which it would control CO_2 emissions from existing power plants. See AEP v. Connecticut, 131 S. Ct. 2527, 2538 (2011) ("Congress delegated to EPA the decision whether and how to regulate carbon-dioxide emissions from power plants.") (emphasis added); see also id. At 2539 ("The appropriate amount of regulation in any particular GHG-producing sector cannot be prescribed in a vacuum: as with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially

[50] We recognize that some commenters on the EGs raised concerns about the localized impacts that may occur from the potential for concentrations of co-pollutants associated with CO_2 emitted from affected EGUs. We address those concerns in the communities sections of the final EGs, at section IX, and in this preamble in section IX below.

achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The CAA entrusts such complex balancing to the EPA in the first instance, in combination with state regulators.").

This proposal is guided by the relevant cases and the experiences of the agency in implementing the CAA trading programs discussed above. The EPA invites comment on this discussion and the agency's interpretation that CAA section 111(d)(2) authorizes the two approaches to a federal plan proposed here.

IV. Rate-based Implementation Approach

A. Overview

The EPA's federal plan requirements for CO_2 from affected EGUs implement the EGs as previously discussed. In this federal plan and model rule proposal the EPA is proposing, as one option, rate-based emission standards (i.e., the emission standard approach) for affected EGUs not covered by an approved state plan as specified in the Clean Power Plan. The EPA is proposing to apply the subcategorized emission rates in this federal plan proposal. These rate-based emission standards are consistent with, and would satisfy, the degree of emission limitation achieved by the BSER determination made in the final Clean Power Plan EGs, which included sub-categorized CO_2 emission performance rates for affected EGUs to meet during the plan performance periods. An affected EGU subject to this federal plan will demonstrate compliance by achieving a stack emission rate less than or equal to the rate-based emission standard or by applying ERCs, acquired by the EGU, to its measured stack emissions rate. The application of ERCs by an affected EGU to comply with an emission standard has been determined in the final Clean Power Plan as a mechanism available to affected EGUs with a CO_2 emission rate greater than its respective performance rate to meet compliance obligations, see section VIII.K of the final EGs. Under a rate-based federal plan, the EPA would act as the state described in section VIII.C.1.a of the final EGs with the EPA acting as the issuer of ERCs, and otherwise implementing and enforcing the standards of performance for affected EGUs subject to the federal plan.

This section describes the proposed rate-based federal plan and model trading rule and how each would be designed and operated, consistent with the EGs. For the federal plan, the EPA is proposing to limit the issuance of ERCs to designated categories of affected EGUs and to RE resources and nuclear generation (from new capacity and incremental capacity uprates) that are measured by a revenue quality meter, rather than the full suite of options discussed in the EGs. The EPA requests comment on whether to limit the scope of the federal plan in this manner, and if not, what other sources of low- or zero-emitting electricity in federal plan states should also be eligible to generate ERCs for compliance purposes. For both the proposed federal plan and model rule, the EPA requests comment on which EM&V plan, measurement and verification (M&V) report, and verification report requirements should apply for each eligible resource. Further discussion of non-BSER measures that may be eligible to generate ERCs can be found in the Clean Power Plan and section IV.C.3 of this preamble. (The EPA is not reopening its determination of the BSER.)

B. Rate Goals

In the Clean Power Plan the EPA identified a rate-based “emission standards” approach as an approvable method for state plans to implement the final EGs. In this approach the requirements for compliance rest solely on affected EGUs in the form of federally enforceable emission standards expressed as a rate of emissions of CO_2 per unit of energy output. In the Clean Power Plan, the EPA established, through application of the BSER, separate CO_2 emission performance rates for affected EGUs in two subcategories. The two subcategories are natural gas-fired stationary combustion turbines (i.e., natural gas combined cycle units, or NGCC units) and fossil fuel fired SGUs (i.e., utility boilers and IGCC units)[51]. The CO_2 emission performance

[51] For simplicity, affected utility boilers and IGCC units will collectively be called “steam generating units.”

rates set in the Clean Power Plan are reflected below in Table 6 of this preamble. The EPA is proposing to apply these rates in the rate-based federal plan as the emission standards for NGCC units, and SGUs, respectively. For a thorough discussion of affected EGU category-specific CO_2 emission performance rates and rationale, see section VI of the final EGs. These calculated standards and the premises that these standards are based on are not within the scope of comment in this rulemaking as they were finalized in the Clean Power Plan.

As discussed in section III.D of this preamble above, the EPA proposes to implement a compliance schedule for the rate-based federal plan with multi-year compliance periods as follows: A 3-year period (2022 through 2024), followed by a 3-year period (2025 through 2027), followed by a 2-year period (2028 and 2029), for the Interim Period; and, commencing in 2030, successive 2-year compliance periods for the Final Period. In the Clean Power Plan, the EPA established CO_2 emission performance rates for the subcategories of affected EGUs for the performance periods. The EPA proposes to use those emission performance rates promulgated in the Clean Power Plan as the emission rate standard for the respective EGUs that would become subject to this proposed federal plan if finalized. The EPA is not opening for comment the determinations made in the Clean Power Plan of each subcategorized CO_2 emission performance rates.

The emission rate standards for respective EGU types are provided for convenience in Table 6 of this preamble.

The EPA is proposing to use a glide path during the Interim Period for EGUs to provide a smooth transition to the final compliance periods after 2030. This approach is established in the final EGs. In Table 6of this preamble, the applicable standards for each interim compliance period is listed.

Table 6. Glide Path Interim Performance Rates (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs)

Technology	2022-2024 Compliance Rate	2025-2027 Compliance Rate	2028-2029 Compliance Rate	Final Rate
SGU or IGCC	1,671	1,500	1,380	1,305
Stationary combustion turbine	877	817	784	771

The EPA is using the subcategorized rates in the rate-based trading approach because it allows ERCs to be fungible across jurisdictional borders and provides an incentive structure, as compared to other rate-based approaches, that facilitates implementation of measures identified as part of the BSER. Using subcategorized rates allows for: (1) consistently applied emission rates for power plants of different types ; and (2) free trading of fungible ERCs among all affected EGUs subject to the federal plan and within the federal trading program. The EPA solicits comments on whether the subcategorized rate approach is the preferred rate-based approach for the federal plan and model trading rule.[52] If a subcategorized approach for a rate-based model rule and federal plan is not preferred by commenters, the EPA requests comment on the perceived benefits of an alternative rate or set of rates (e.g., applying a uniform rate, i.e., the state goal, to all affected units within the state as the EGUs' emission standard).

C. Crediting Mechanism

Under a rate-based emission standard approach in the federal plan, we are proposing that EGUs subject to the emission performance requirements for GHGs will either need to emit at or below their emission rate standard, or they will need to acquire ERCs to achieve compliance. An ERC is a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. These ERCs may then be used to adjust the measured and reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Under this proposed federal plan, ERCs will be issued by the EPA to three categories of entities: (1) Affected EGUs that perform at a rate below the applicable emission rate standard;

[52] Note that the values of limits and determinations made as the BSER are not open for comment.

(2) affected NGCC units for all generation (represents shifting generation from SGUs to NGCC units, as anticipated under Building Block 2); (3) new nuclear units and capacity uprates at existing nuclear units, and (4) RE providers that develop metered projects and programs whose results, in MWh, are quantified and verified according to EM&V criteria as described below in section IV.D.8 of this preamble. We are also discussing in this preamble, taking comment on for the federal plan, and proposing for the model trading rule a potential fourth category: other low- and zero-emitting non-BSER measures that are described in section IV.C.3 of this preamble. The concept of using an ERC as a crediting mechanism to meet compliance obligations is consistent with the CPP EGs and is being adopted in this federal plan.53

Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. The responsibility for the validity of the ERC rests with the affected EGU. Despite safeguards included in the structure of

[53] The use of ERCs and definition as a compliance mechanism to meet the BSER emission performance rates is established in section VIII.K of the final EGs.

ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and EPA issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the EGs. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud. The EPA requests comment on ways that the EPA could safeguard the validity of an ERC.

1. ERCs Generated and Owed Against a Standard

The number of ERCs generated or needed for surrender by an affected fossil fuel-fired EGU is based on the CO_2 emission rate of the EGU in comparison to an emission rate standard. The calculation of ERCs generated by an EGU or needed for compliance is the CO_2 stack emission rate of the EGU subtracted from the standard the EGU is subject to, and this value is subsequently divided by the standard the EGU is subject to. This value is a normalized quantity of how much better or worse the EGU is performing compared to its standard. The normalized value is weighted by multiplying the MWh electricity output from the EGU at that emission rate. This can be generically expressed as:

$$\text{ERCs} = \frac{(\text{EGU standard} - \text{EGU operating rate})}{\text{EGU standard}} * \text{EGU generation}$$

If the value calculated is positive, this indicates the number of ERCs that are being generated; conversely, a negative value indicates how many ERCs will need to be acquired to meet the unit's emission rate for that compliance period. ERCs will be issued on an annual basis to ERC providers (i.e., entities generating ERCs via the ERC approval and issuance process detailed below). Surrender of ERCs for compliance by affected EGUs will not occur until the end of the compliance period as further described in section IV.D.10 of this preamble.

As an example, assume a steam EGU operating in the second interim compliance period is subject to a rate standard of 1,500 lbs CO_2/MWh. Assume it operates at 2,000 lbs CO_2/MWh, and also assume it generates 1 million MWh over a compliance period. Its total emission rate would be 2 billion lbs CO_2 / 1 million MWh. In order to achieve the emission standard, it would need to purchase 333,334 ERCs (rounded to the nearest higher integer). In essence, this quantity of ERCs represents the quantity of MWh that need to be added to the steam EGU's denominator (i.e., generation, here, 1 million MWh), such that 2 billion pounds of CO_2 (total emissions), divided by total generation (i.e., in this case, 1,333,334 MWh) equals the emission rate for compliance (1,500 lbs/MWh).

The discussion in this subsection builds on and applies the definition, benefits, use, and determination of using ERCs from the final EGs (section VIII of the final EGs). We invite comment on use of the approach just described as a method of implementation of a federal plan and a model trading rule, and we take comment on any alternatives to this approach that still fall within the established criteria described in the CPP EGs. Comments that solely relate to determinations finalized in the EGs will be considered outside the scope of this proposed rule.

2. Incremental NGCC ERCs

Building Block 2 (BB2) of the BSER determination in the CPP EGs describes shifting generation from SGUs to NGCC units because NGCC units generate electricity at a less carbon intensive rate. BB2 describes NGCC units generating at 75 percent of the unit's annual operating capacity. This level of generation, for most NGCC units, would represent an increase in annual generation from a 2012 baseline.For every hour of electricity generated by an NGCC beyond its 2012 baseline (i.e., incremental generation), there is a corresponding emission reduction in the power system.[54] The EPA is proposing to reflect the emission reductions of BB2 by crediting all NGCC generation on a pro-rata basis that reflects expected incremental NGCC generation to 75 percent capacity. This means that for every hour that an NGCC generates electricity, it will also generate a partial credit associated with the generation shift from fossil steam to NGCC units. The NGCC will generate a partial credit

[54] It is assumed that any increase in NGCC generation above 2012 levels is displacing fossil fuel-fired steam EGU generation.

because the emission reductions associated with BB2 have been distributed on an hourly basis. A discussion on the concepts behind the distribution of emission reductions of incremental NGCC generation on an hourly basis can be found at the end of this subsection.

All affected NGCC generation will be credited, with ERCs, by a factor that represents the described emission reductions from incremental generation; ERCs credited in this way will be designated as Gas Shift ERCs (GS-ERCs) for clarity[55]. The collective sum of the GS-ERCs generated realizes the amount of emission reductions described in BB2 when 75 percent capacity is achieved. This incentive is not a requirement, however. If NGCC units do not collectively increase to 75 percent capacity or above, the lost opportunity for ERC generation simply will need to be achieved through other means (e.g., emissions performance improvements at affected EGUs or additional RE generation). The amount of GS-ERCs the EPA proposes to be generated for every MWh of NGCC operation is set at a factor relating the amount of electricity generation that NGCC units collectively would generate at the level described in BB2 (i.e., reaching 75 percent capacity) and the associated emission reductions. This

[55] A GS-ERC is treated and represents the same value as an ERC, but has a compliance restriction that it can only be used by steam generating units and not by stationary combustion turbines for compliance obligations.

means that fractional GS-ERCs are generated for every NGCC MWh and when the interconnect region collectively reaches the level that would be generated if all NGGCs in the region operated at a 75 percent capacity factor there will be an amount of GS-ERCs that correlates to the emission reductions anticipated under BB2 of the BSER. NGCC units are expected to be incentivized to reach this level of generation in part due to market demand for GS-ERCs. Thus, GS-ERCs have the potential to play an important role in the sector meeting compliance obligations.

The number of GS-ERCs that an NGCC generates is a combination of three factors. The first is the GS-ERC Emission Factor. This emission factor represents how much better an individual NGCC's emission rate is compared against the fossil steam standard. This measures the emission reductions because of the BB2 shift in generation. The SGU standard used as reference here is as described above in section IV.B of this preamble and established in the BSER determination from the EGs of the least stringent region[56] (i.e., the region with the highest calculated emission rate standard for SGUs). The GS-ERC Emission Factor is expressed by taking the complement of the ratio of the NGCC

[56] The regions that are used in the CPP EGs and for this proposal are the Eastern Interconnect, Western Interconnect, and Electric Reliability Council of Texas (ERCOT).

standard to the fossil-steam standard. It can be summarized by the following expression:

$$\text{GS-ERC Emission Factor} = 1 - \frac{\text{NGCC emission rate}}{\text{Steam Standard}}$$

The second factor is the Incremental Generation Factor. This factor represents the distribution of the increased NGCC generation across all NGCC generation. In essence, it is prorating the incremental NGCC generation over all NGCC generation. The Incremental Generation Factor is calculated by taking the number of MWh beyond the 2012 baseline needed for the corresponding region to reach 75 percent NGCC generation capacity and dividing it by the MWh that is 75 percent NGCC generation capacity, giving a factor. This factor can be summarized by the following expression:

$$\text{Incremental Generation Factor} = 1 - \frac{\text{Regional 2012 NGCC Baseline}}{\text{75 \% NGCC Regional Capacity}}$$

The Incremental Generation Factor is a factor that the EPA will calculate and will be calculated for every compliance period based on the least stingent region’s Incremental Generation Factor based on increased utilization of RE and its replacement of fossil fuel fired generation (based on Building Block 3 of the CPP EGs).[57] For the calculation of this factor the EPA is

[57] Note that per the discussion in section VI of the final EGs, if the EPA had measured incremental NGCC generation for reassignment to fossil steam rate as the difference from the post building block three levels and full utilization, the post building block three levels would be used in the

using the least stringent region for each compliance period and applying it for all GS-ERC calculations subject to the federal plan. The calculations for determinating the least stringent regional Incremental Generation Factor can be found in the GS-ERC TSD. Table 7 of this preamble presents the proposed values that would apply for all NGCC units to calculate the amount of issued GS-ERCs.

Table 7. Incremental Generation Factors for Interim and Final Compliance Periods

Corresponding Incremental Generation Factor			
Compliance Period 1 2022-2024	**Compliance Period 2 2025-2027**	**Compliance Period 3 2028-2029**	**2030-2031 and thereafter**
0.22	0.32	0.28	0.26

The third factor in calculating an NGCC's generaton of GS-ERC is the NGCC Generation. The NGCC Generation is the total net energy output generation of the affected NGCC during the year that ERCs are being calculated. The three factors combine to make the following equation:

GS-ERCs = NGCC Generation * Incremental Generation Factor * GS-ERC Emission Factor

The GS-ERC equation above gives the number of GS-ERCs that an NGCC will generate. The Incremental Generation Factor and GS-ERC Emission Factor combine to make the GS-ERC generating rate for the NGCC. This functions by the Incremental Generation Factor

numerator here, resulting in a higher "incremental generation factor" and more ERCs for the same amount of NGCC generation.

prorating all incremental NGCC generation and the GS-ERC Emission Factor designating the proportion of the incremental NGCC generation that will generate ERCs. The GS-ERC generating rate multiplied by the total NGCC Generation gives the total GS-ERCs generated by the NGCC for the year.

The EPA is proposing this approach, which provides GS-ERCs for all affected EGU NGCC generation but at a fractional, pro rated level, using the three factors above, for several reasons. This approach has the benefit of allowing NGCC units to bid into the electricity market without having to adjust bids based on a projection of whether or not the NGCC will have generation incremental to its baseline in a given year. The proposed method also promotes the best performers within the NGCC subcategory by crediting them with a higher rate of generating GS-ERCs, as shown by the calculations above. The better the emission performance of an NGCC unit, the more GS-ERCs it is capable of earning per MWh. The proposed method also promotes and incentivizes all NGCC units, regardless of historical generation, to continue to operate at a greater capacity to replace steam generation. The EPA believes that this will allow for more fluidity in the market and flexibility for greater NGCC generation.

In the Clean Power Plan the BSER determination for subcategory rates is calculated by using the least stringent region and applying the standards from that region on a national level. The determination of the BSER in the final EGs was a one-time determination and is not being altered, updated, or changed here. Rather, in this preamble the EPA is proposing to use the same regions and to apply the least stringent components to an NGCC's GS-ERC calculation at a national level (i.e., applying the GS-ERC calculation components that generate the most GS-ERCs for every MWh). The EPA solicits comment on applying the least stringent regional factor to calculate GS-ERCs for all affected NGCC units subject to the federal plan and model rule on a national level. Conversely, the EPA also requests comment on applying, for each region, its own regional GS-ERC generation rate. As proposed, the least stringent region could change from compliance period to compliance period. The EPA requests comment on whether a single "least stringent" region should be chosen and used for calculations or whether being "least stringent" should be evaluated on a compliance period by compliance period basis. The EPA also requests comment on whether "least stringent" should be evaluated on a year-to-year basis.

The EPA also requests comment on whether the GS-ERC Emission Factor should be calculated on a unit by unit basis (as currently proposed) or be calculated based on the least stringent region's baseline 2012 average emission rate. This will simplify the practice of calculating and distributing GS-

ERC generation, but would not reward the better performing NGCC units within the subcategory. In the GS-ERC TSD, the EPA used the regions' average emission rate to calculate a factor that would credit GS-ERCs to all NGCC units subject to the federal plan. For 2030 and beyond, this value is based on the Eastern Interconnect and is 0.08 GS-ERCs/MWh. So for every MWh that an NGCC generates it would be issued 0.08 GS-ERCs and, if this were the approach the EPA proposed, this would apply to every NGCC that would be subject to the federal plan.

In the GS-ERC TSD, the spreadsheet can be manipulated to show what an individual NGCC's GS-ERC Emission Factor would be in the proposed method. This is done by adjusting the cell for a year's Average GS-ERC Emission Factor to account for the individual NGCC's emission rate instead of the average NGCC emission rate.

The calculation of GS-ERCs for an NGCC is independent of the calculation of ERCs generated or owed against the NGCC standard. It is possible that an NGCC will owe ERCs against its assigned emission standard for every MWh generated, but still be generating GS-ERCs. GS-ERCs may only be used to meet steam generation units' compliance obligations.

As an example, an NGCC is connected to the grid and generates 1 million MWh of electric output for the first year of the final performance period. During this year it emits 850 million lbs of CO_2 giving it an emission rate of 850 lbs CO_2/MWh. The NGCC is subject to a Final Period emission rate limit of 771 lbs CO_2/MWh. Since the NGCC is always subject to its NGCC emission rate standard of 771 lbs/MWh and it is operating at a rate above that standard it will owe non GS-ERCs for its own compliance. The ERCs owed are calculated by solving for the number of ERC MWh the NGCC will need to adjust its rate down to its emission rate limit. This is shown in the following equation:

$$850{,}000{,}000\ \text{lbs CO\_2} \ / \ [1{,}000{,}000\ \text{MWh} + \text{ERC MWh}] \ = \ 771\ \text{lbs CO\_2/MWh}$$

When that equation is solved for the number of ERC MWh needed, the NGCC would need to acquire 102,464 ERCs to adjust its emission rate to its emission rate standard.

Additionally, the GS-ERC Emission Factor for this NGCC is calculated by using 771 lbs CO_2/MWh for the NGCC emission rate and 1,404 lbs CO_2/MWh for the SGU emission standard in the equation described above.

$$\text{GS-ERC Emission Factor } = 1 - \frac{771\ \text{lbs/MWh}}{1{,}404\ \text{lbs/MWh}}$$

This calculation results in a GS-ERC Emission Factor of 0.45. This is only an example. Because the Incremental Generation Factor is calculated by the EPA, it can be found in the GS-ERC TSD and is proposed to be 0.26. By using the GS-ERC Emission Factor and Incremental Generation Factor calculated above with the NGCC's generation for the year, the number of GS-ERCs for this NGCC can be calculated.

$$0.45 * 0.26 * 1{,}000{,}000 = \text{GS-ERC}$$

The calculation results in 117 thousand GS-ERCs being generated. Because an NGCC cannot use the GS-ERCs it generates to meet its compliance obligations, this NGCC will both generate ERCs (117,000 GS-ERCs) and owe ERCs (102,464 non-GS-ERCs against NGCC standard). This NGCC may sell (or otherwise transfer) or bank its GS-ERCs. If a GS-ERC is sold, those proceeds may, in turn, be used to acquire non-GS-ERCs to satisfy the NGCC's compliance obligations.

A GS-ERC may not be used to meet an NGCC's compliance obligation because they are generated to reflect incremental NGCC generation replacing a SGU's generation. The calculation to derive a GS-ERC represents this generation shift. If a GS-ERC were to be used for compliance for an NGCC it would represent a shift from one NGCC to another, which serves little purpose in achieving emission reductions.

The EPA requests comment on the proposed approach and requests comment and suggestions on other approaches for existing NGCC units to generate GS-ERCs at all times. The EPA is considering this methodology that GS-ERCs are generated for all NGCC generation because it ensures that all existing NGCC units are encouraged to run at a greater capacity. The EPA is requesting comment on alternative methods to account for NGCC units generating GS-ERCs. Specifically, the EPA solicits comment on NGCC units generating GS-ERCs once a threshold of electric generation for the year is exceeded. This threshold is based on 2012 as a baseline and any NGCC generation beyond this threshold would be considered incremental generation. There are two different options to evaluate against a baseline. The first is on a unit level, if an NGCC generates more than it did in 2012, all generation above the 2012 level (i.e, incremental generation) is eligible to be credited with GS-ERCs. The other threshold option is to use a percentage threshold. Evaluated on a regional level, the 2012 baseline capacity percentage for NGCC units in the least stringent region is applied to all units. Each unit is considered to be incrementally generating after it exceeds the capacity percent and will be credited with GS-ERCs accordingly. The GS-ERCs in these instances are calculated by the following equation:

$$\text{GS-ERC} = \frac{(\text{Steam standard} - \text{NGCC emission rate})}{\text{Steam standard}} * \text{ Incremental NGCC generation}$$

This equation quantifies the reductions of the generation shift from fossil steam to NGCC units by the NGCC operating rate being evaluated against the fossil steam standard. For all incremental NGCC generation the NGCC operating rate is compared against two different standards: (1) The NGCC standard against which ERC generation is evaluated; and (2) the steam standard against which GS-ERC generation is evaluated. An evaluation against each standard is independent of one another and GS-ERCs, in this situation, are only available for fossil steam compliance purposes.

While having a baseline threshold for EGU generation to credit GS-ERCs against closely resembles the EPA's BSER determination, it enables a system in which GS-ERCs can be generated by replacing NGCC generation from one unit with NGCC generation from another. In this situation there is not necessarily any additional NGCC generation as a subcategory, but a shift in which NGCC units are generating electricity and to what degree. This allows for a situation in which GS-ERCs can be generated without achieving the anticipated reductions in CO_2 emissions.

The EPA also requests comment on whether a distinct type of ERC that comes with the proposed restrictions (i.e., GS-ERCs) is necessary to maintain the integrity of the rate-based trading proposal. Comments regarding this section that solely relate to determinations finalized in the EGs will be considered outside the scope of this proposed rule.

3. Eligible Emission Reduction Measures for ERC Generation

Under the rate-based federal plan, the EPA is proposing to specify emission reductions measures used to adjust an emission rate that are eligible for ERC issuance under the federal plan. Specifically, the EPA is proposing that RE generation that meets the requirements for eligible resources in the EGs (as specified in section VIII.K of the final EGs), meets all other requirements related to ERC issuance in the EGs and this proposal, and falls into one of the following specific categories of RE resources (as specified in section V.E of the final EGs) are eligible to be issued ERCs: wind, solar, geothermal power, and hydropower.[58] Further, the EPA is proposing for the federal plan that new nuclear units and capacity uprates at existing nuclear units that meet the requirements for eligible resources in the EGs (as specified in section VIII.K of the final EGs) and all other requirements related to ERC issuance in the EGs and this proposal are eligible to generate ERCs. Further, these RE and nuclear measures must have the ability to provide data from a revenue quality meter, a requirement that is further discussed in section IV.D.8 of this preamble.

[58] This treatment for RE as an eligible measure type is also proposed for the set-aside for RE that is part of the proposed mass-based implementation approach co-proposed in section V of this preamble as the federal plan, and all proposed aspects of the eligible measure types described in this section and the requests for comment included below also apply in the mass-based set-aside context. Incremental nuclear is not eligible for the RE set-aside. The set-aside method and the use of this eligibility treatment within it are specified in section V.D.3 of this preamble.

The EPA is proposing the inclusion of these measure types in the federal plan for the following reasons. These technologies, with the exception of nuclear, are part of the quantification of RE generation potential for the BSER. Thus, they are included in the quantification of CO_2 emission performance rates and should be available to affected EGUs to meet their CO_2 emission performance rate under the federal plan. See the final EGs for details on the treatment of these measures in BSER (see section V.E of the final EGs). These technologies are also expected to be able to deploy on an economic basis during the compliance period, as discussed in the final EGs (see section V.E.6 of the final EGs). These technologies also provide the simplest and most timely path for EM&V implementation under a federal plan, because they can use their existing metering infrastructure to quantify generation and submit it for ERC issuance. A concern unique to federal plan implementation is the need for an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions in the time frame allowed by the federal plan while still assuring a rigorous EM&V process. By limiting eligibility to measures that can be directly metered, a feasible federal plan process for ERC issuance across a potentially large number of jurisdictions is ensured. This approach would allow for easier determinations of compliance with the requirements for EM&V proposed in section

IV.D.8 of this preamble below (see also section VIII.K.3 of the final EGs).

The agency requests comment on the inclusion of other emission reduction measures as eligible for ERC issuance under the rate-based federal plan. This may include other RE technologies not included above, such as distributed RE generation and various types of biomass. In this proposal, the EPA is also offering for comment treatment options for biomass fuels, if it is included as an eligible measure under the federal plan (see below).

The 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. The agency also requests comment on the inclusion of CHP as an eligible measure under the federal plan. Later in this section, the agency has provided detailed requirements for the issuance of ERCs for CHP, and we request comment on these requirements for inclusion in the federal plan.

The EPA requests comment on the inclusion as eligible for ERC issuance under the federal plan of any other emission reduction measures beyond those mentioned here, as long as they meet the eligibility requirements outlined in the final EGs for rate-based crediting. For all of the above measures on which the EPA requests comment, the agency is particularly interested in comments on how EM&V methods can be implemented for these measures across applicable jurisdictions in the timeframe provided by this proposal in a way that is rigorous, straightforward, widely demonstrated, and in accordance with the EM&V requirements in this proposal, outlined in section IV.D.8 of this preamble, and within the requirements outlined in the final guidelines (see section VIII.K.3 of the final EGs). It should also be noted that any eligible measure will be subject to the eligibility requirements outlined in this proposal and the final EGs, such as the requirement that the measure be incremental to 2012.

The EPA acknowledges that as new technologies mature, there should be an avenue to add new technologies to this specified set of eligible measures under the federal plan. The agency is requesting comment on appropriate processes through which, after the federal plan is finalized, the EPA and/or stakeholders could demonstrate the appropriateness of new measure types and the EPA could evaluate and approve the demonstration so that a new measure type could be considered eligible for ERC issuance under the federal plan.

Under the rate-based model rule, the EPA is proposing that any emission reduction measure is eligible as long as the requirements for eligible resources in the final EGs (as specified in section VIII.K of the final EGs) and all other requirements related to ERC issuance under the model rule that are specified in the EGs and this proposal. In particular, these measures should be able to meet the requirements for EM&V as finalized in the final EGs section VIII.K and those proposed for the model rule in section IV.D.8 of this proposal. In this section, the EPA is also providing detailed requirements for CHP and waste heat power (WHP), these requirements are proposed under the model rule, and we request comment on their inclusion in the federal plan. We are requesting comment on the inclusion of biomass and an option for the treatment of biomass in both the proposed rate-based federal plan and proposed rate-based model rule.

As mentioned above, the EPA is requesting comment on the inclusion of biomass as an eligible measure for rate-based crediting. The EPA is also requesting comment on the following treatment options for biomass if biomass is included as an eligible measure. In the final EGs, the EPA recognizes that the use of some biomass-derived fuels can play an important role in controlling increases of CO_2 levels in the atmosphere (see section V.A.6 of the final EGs). The use of some kinds of biomass has the potential to offer a wide range of environmental benefits, including carbon benefits. However these benefits can typically be realized only if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account. Many states have already recognized the importance of waste-derived feedstocks via mandatory and voluntary programs supporting such efforts.[59] Some states have also acknowledged the potential role of certain forestry and agricultural industrial byproducts (such as black liquor) in energy production. Many states have also recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, biomass-related RE incentives and standards, and GHG accounting procedures.[60]

In addition to acknowledging such state programs, the EPA has undertaken a technical assessment of biogenic CO_2 emissions from stationary sources associated with the production,

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[59] Types of waste-derived biogenic feedstocks may include: landfill gas generated through the decomposition of Municipal Solid Waste (MSW) in a landfill; biogas generated from the decomposition of livestock waste, biogenic MSW, and/or other food waste in an anaerobic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities (as discussed in section VIII.I.2.C of the final EGs).

[60] Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as climate change mitigation through carbon storage. Others, like California’s Forest Practice Regulations, support sustained production of high-quality timber while considering ecological, economic and social values. Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts RPS, which, among other requirements, limits old growth forest harvests.

processing and use of biomass fuels. In November 2014, the agency released a second draft of the technical report, Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources. The revised Framework, and the EPA's Science Advisory Board (SAB) peer review of the 2011 Draft Framework, concluded that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral" and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[61]The EPA is engaging in a second round of targeted peer review on the revised Framework with the SAB in 2015.[62] Information in the revised Framework and the second SAB peer review process, including stakeholder comments, will assist the EPA in assessing potential qualified biomass feedstocks in federal plan applications.

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[61]Specifically, the SAB found that "There are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality is not an appropriate a priori assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably. Of course, biogenic feedstocks that displace fossil fuels do not have to be carbon neutral to be better than fossil fuels in terms of their climate impact." http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.

[62] http://www.epa.gov/sab.

If biomass is included as an eligible measure, we are taking comment on an option for biomass treatment under the rate-based federal plan, which would also apply to eligible generation under the mass-based plan allowance set-aside and to the calculation of covered emissions for affected EGUs that are co-firing biomass.

This option offered for comment is to specify a list of pre-approved qualified biomass fuels. For example, the EPA could recognize the CO_2 and climate policy benefits of waste-derived feedstocks (e.g., landfill gas) and certain industrial byproduct feedstocks (e.g., black liquor or other forestry and agricultural industrial byproducts with no alternative markets). As another example, the EPA could also recognize biomass feedstocks from sustainably managed forests lands, provided that these feedstocks meet certain requirements such as demonstration that the feedstock is sourced from sustainably managed lands (for example, feedstocks from forest lands with sustainable practices like improved management to increase carbon sequestration benefits) and therefore helps control increases of CO_2 in the atmosphere. The pre-approved qualified biomass feedstocks list could be amended in the future as the science related to biogenic CO_2 emissions assessments evolves. The EPA asks for comment on whether to include a provision that allows sources to seek approval for other types of biomass to be added to the pre-approved list and what that process would entail. For example, this process could include consideration of the production, processing and use of forest- and agriculture-derived biomass fuels and related CO_2 benefits.

The EPA also requests comment on options for how EGUs would demonstrate that feedstocks meet the requirements to be accepted as a pre-approved qualified biomass feedstocks. These requirements could include demonstration of certification or verification of practices that are additional to other monitoring, reporting and EM&V requirements discussed in this proposal, such as provision of sufficient credible analysis of carbon benefits, third party verification and/or certification, or a determination of the net biogenic CO_2 effects related to the production, processing and use of the feedstock.

The EPA requests broad comment on the types of qualified biomass feedstocks that should be specified in the final model rule, if any. We request comment on the methods that we should specify in the final model rule for the measurement of the associated biogenic CO_2 for such feedstocks, as well as what other requirements we should specify in the final model rule related to biomass. Specifically, we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule. We request comment on any other requirements that should be included in the final model rule regarding EM&V for qualified biomass. Discussion of the biomass EM&V requirements in the rate-based model rule can be found in section IV.D.8 of this preamble below.

The eligibility requirements for ERC resources discussed in this section meet the requirements outlined in the final EGs (see section VIII.K.2 of the final EGs). The agency in this proposal is including in the regulatory text for the model rule language related to the crediting of these other potential ERC resources, even though they are not being proposed as a part of the federal plan. Our intent is to provide states further direction through the model rule on how states may include this broader set of ERC-generating resources in a rate-based plan. To reduce confusion over the applicability of these provisions, the agency has added a note in the regulatory text to clarify that these resources, and provisions throughout the proposed subpart that are related to those resources, are not applicable in the case of a federal plan. Rather they are proposed as part of the model trading rule only. However, again, the agency is requesting comment on the inclusion of these resources in the federal plan.

The EPA is proposing with respect to the rate-based model rule that CHP units are eligible to generate ERCs. With respect to the federal plan, the EPA is requesting comment on the incorporation of non-affected CHP units. Electric generation from non-affected CHP units[63] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. Electrical generation from non-affected CHP units that meet the eligibility criteria under section VIII.K.1.a of the Clean Power Plan preamble can be used to adjust the reported CO_2 emission rate of an affected EGU.

The electrical generation from a non-affected CHP unit that can be used to adjust the CO_2 emission rate of an affected EGU must be calculated in accordance with the method specified in this section. The CHP unit's electrical output is prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's "incremental CO_2 emission rate") compared to a reference CO_2 emission rate.[64] This "incremental CO_2 emission rate" related to the electric generation from the CHP unit would be relative to the applicable CO_2 emission rate standard for affected EGUs in the state and would be limited to

[63] The accounting treatment described in this section is for a "topping cycle" CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/or mechanical energy. A CHP unit can also be configured as a "bottoming cycle" unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some waste heat power (WHP) units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

[64] The applicable CO_2 emission rate standard is in Table 6. of this preamble.

values between 0 and 1. The CHP unit's electrical output is prorated as follows:

Prorated MWh = (1-incremental CHP electrical emission rate/applicable affected EGU emission rate standard)* CHP MWh output

Where the ratio is limited to values between 0 and 1.

The CHP electrical CO_2 emission rate is the net emission rate when the CHP unit's CO_2 emissions related to its thermal output are deducted from the CHP unit's total CO_2 emissions. The CHP electrical CO_2 emission rate is derived as follows:

CHP electrical CO_2 emission rate = [CHP fuel input[65] * fuel emission factor[66] – (UTO/boiler efficiency) * fuel emission factor]/CHP electrical MWh

Where UTO is the useful thermal output from a counterfactual industrial boiler that would have existed to meet thermal load in the absence of the CHP unit.

This accounting approach takes into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. To generate ERCs for CHP, the CHP Electrical CO_2 Emission Rate that is calculated (from above) is applied against the applicable affected EGU standards in the same fashion as

[65] This term generally represents the thermal energy associated with the total fuel input.

[66] The fuel emission factor can be determined through 40 CFR Part 75 Appendix G.

described in section IV.C.1 of this preamble. The low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method does not presume that emission reductions occur outside the electric power sector, but instead only accounts for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

The EPA is proposing with respect to the rate-based model rule that WHP units are eligible to generate ERCs. With respect to the federal plan, the EPA is requesting comment on the incorporation of non-affected WHP units. WHP units that meet the eligibility criteria under section VIII.K.1 of the Clean Power Plan preamble may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity.[67] There are also WHP facilities where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP facilities could be considered non-emitting, for the purposes of meeting the emission guidelines, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[68] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.[69]In addition, where fossil fuel is used to supplement waste heat in a WHP application, the EPA requests comment on what provisions to include in the final

[67] In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.

[68] This only applies where no additional fossil fuel is used to supplement the use of waste heat in a WHP facility. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

[69] This limitation prevents oversizing the thermal output of a WHP unit to exceed the useful industrial or other thermal load it is meeting, prior to generation of electricity.

model rule to prorate the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity. The EPA also solicits comments on other potential accounting mechanisms for WHP. As noted above, the EPA requests comment incorporating WHP as an ERC generating resource for the federal plan.

D. ERC Tracking and Compliance Operations

The EPA proposes that the rate-based federal trading program use the agency’s already-existing allowance tracking and compliance system (ATCS). Under the proposed rate-based trading program, the federal trading program would be maintained in the EPA’s existing data system. The ATCS would be used to track the trading of ERCs held by affected EGUs, as well as ERCs held by other entities. Specifically, the ATCS would track the generation of ERCs, holdings of ERCs in compliance accounts (i.e., accounts for affected EGUs) and general accounts (i.e., accounts for other entities and for affected EGUs, including affected EGUs that are under a ready-for-interstate-trading state plan), deduction of ERCs for compliance purposes, and transfers of ERCs between accounts. The primary role of the ATCS is to provide an efficient, automated means for covered sources to comply, and for the EPA to determine whether covered sources are complying, with the emissions rate standards. The ATCS would also provide data to the ERCs market and the public, including a record of ownership of ERCs, dates of ERC issuance, ERC transfers, buyer and seller information, serial numbers of ERCs transferred, emissions, and compliance information. This information would be publicly available on the EPA's Web site and in annual progress reports. The ATCS and the EPA provide all required elements of a qualified ERC tracking system as described in section VIII of the final EGs.

In the subsections that follow, the mechanisms by which a rate-based trading program would be implemented and administered are detailed. The EPA requests comment on each component of the trading system that is proposed in this preamble and the associated model rule, the trading program as a whole, and specifically requests comment on means to expedite the process of issuing ERCs, any minimum and maximum periods for which ERCs should be issued (e.g., monthly, quarterly, annually), and any means to ensure that the ERCs issued meet the requirements of the EGs and these proposed rules. The rate-based federal plan and model rule borrow many concepts from other successful trading programs, and the agency is interested in receiving additional information through comments on successful implementation of similar programs.

1. Designated Representatives and Alternate Designated Representatives

This section establishes the procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of the affected EGU and for changing the designated representative and alternate designated representative. These sections also describe the designated representative’s and alternate designated representative’s responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions would be patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

The designated representative would be the individual authorized to represent the owners and operators of each affected EGU in matters pertaining to the rate-based trading program. One alternate designated representative could be selected to act on behalf of, and legally bind, the designated representative and, thus, the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: specified identifying information for the covered source and covered EGUs at the source and for the designated representative and alternate; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate. All submissions (e.g., monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the ATCS for the affected EGU involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the affected EGU involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (e.g., in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative and alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative and alternate could designate agents to submit electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the rate-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the proposed rate-based trading program.

2. ERC Tracking and Compliance System

The rate-based trading program rules establish the procedures and requirements for using and operating the Allowance Tracking and Compliance System (which is the electronic data system through which the Administrator would handle ERC issuance, holding, transfer, and deduction), and for determining compliance with the ERC-holding requirements in an efficient and transparent manner. The ATCS provides a record of ownership, dates of ERC transfers, buyer and seller information, origin of ERCs, the serial numbers of ERCs transferred, and ERC type (<u>i.e</u>., if it is a GS-ERC or not). ERC price information would not be included in the ATCS. The EPA's experience is that private parties (<u>e.g</u>., brokers) are in a better position to obtain and disseminate timely, accurate price information than the EPA. For example, because not all ERC transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

3. Tracking System Requirements

This federal plan and model rule's proposed tracking system and tracking systems that will be presumptively approvable for state plans fufill the criteria set forth in the final EGs. The EPA's tracking system includes provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are "surrendered" by the owner or operator of an affected EGU and "retired" or "cancelled" by the Administrator or administering state regulatory body), to ensure they areused only once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected

EGUs,[70] and an accompanying tracking system infrastructure design. Each issued ERC will have a unique identifier (*i.e.,* serial number) and the tracking system will provide traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders on the Clean Power Planabout the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. As described above in section III.A of this preamble, the EPA is proposing, as part of both types of model trading rules, a federal trading platform that would allow state plans that are ready-for-interstate-trading to operate through a program in which the EPA provides the tracking and compliance system. This system will meet the requirements of the Clean Power Plan.

4. Compliance and General Accounts

This section describes two types of ATCS accounts: compliance accounts, which would be established by the Administrator for each affected EGU upon receipt of the certificate of representation for the source; and general

[70] "Compliance true-up" refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission limit.

accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any ERCs used by the affected EGU for compliance with the emissions limitations would have to be held until retired for compliance.

General accounts could be used by any person or group for holding or trading ERCs. However, ERCs could not be used for compliance with emissions limitations so long as the ERCs were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would be required to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format to be prescribed by the Administrator: The name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with the respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to ERCs, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates. The EPA requests comment on these compliance mechanisms.

5. Compliance Demonstration

The EPA proposes that affected EGUs subject to this federal plan are required to meet compliance obligations by November 1 of the year following the end of the compliance period. For an affected EGU to meet its compliance obligations its average stack emission rate over the compliance period must be at or below its applicable rate standard, or the affected EGU must use ERCs to adjust its average stack emission rate to be at or below its applicable rate standard. An EGU’s average emission rate over the compliance period will be calculated based on submitted data to ATCS. The compliance period average would be calculated by taking the measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU and dividing it by the total net energy output over the compliance period for that affected EGU in units of MWh.[71] This averaged emission rate will be compared to the emissions standards that the EGU is

[71] Note that these values will be the submitted values from the affected EGUs to the EPA that have gone through a transparent review process.

subject to during the corresponding compliance period. Accordingly, and if necessary, the appropriate number of ERCs will be retired from the EGU’s compliance account to adjust the emission rate of the EGU to be equal to the emission standard. The discussion of using ERCs for compliance is found in section IV.D.10 of this preamble.

6. Recordation of ERC Generation and ERC Issuance

The EPA proposes to issue ERCs for ERC generating entities once per year. Thus, in a 3-year compliance period, for instance, there would be three points at which the agency issues ERCs. After each calendar year, the EPA will calculate the ERCs generated for EGU and non-EGU ERC generators based on data submitted to the EPA through the Emissions Collection and Monitoring Plan System (ECMPS). These calculated ERC quantities will be proposed as part of a Notice of Data Availability (NODA) with a 30-day comment period. Subsequently, the EPA will finalize this NODA and issue ERCs accordingly with tracking and serial numbers. For affected EGUs with compliance accounts, the ERCs will be issued to these. For entities without compliance accounts, the EPA will issue ERCs to an entity’s general account. The timing for issuing ERCs is consistent with existing programs, and the EPA believes there is value in consistency. However, we solicit comment on the annual issuance of ERCs and whether issuance should occur at different intervals (e.g., quarterly, biannually, or other time frames). The EPA requests justification along with corresponding comments regarding ERC-issuance intervals. We request comment on how reporting and recordkeeping requirements could be minimized, particularly for small entities, to the extent possible under the statute and existing regulations.

a. Issuance of ERCs to Affected EGUs. Following the determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate[72], the EPA will issue those ERCs into the affected EGU's compliance account in ATCS. The issuance will occur annually through the NODA process. ERCs will have a unique serial number, tracking number, and will distinguish ERC type (*i.e.,* if it is BB2 or not) when issued to an affected EGU.

b. Issuance of ERCs for Measures Used to Adjust an Emission Rate. In the final EGs, the EPA has specified requirements for an ERC issuance process for the quantification and verification of measures used to adjust an emission rate that provide the necessary rigor and transparency while being efficient and streamlined. This is the intent of the federal plan as well, where there is a particular concern with implementing a

[72] As described in section IV.C.1 of this preamble.

streamlined and efficient federal process for ERC issuance across federal plan states. As required in the final EGs, we are proposing a two-step application process to the federal plan tracking systems for ERCs that allows for project approval to take place prior to the performance period, and makes the issuance of ERCs as quick and efficient as possible after generation has been quantified and verified, while still assuring a rigorous approval process. For the first step in the ERC issuance application process, the EPA proposes that RE and nuclear generation providers submit to the EPA an eligibility application for EPA approval, or its designated agent, demonstrating that the project is eligible for the issuance of credits, including an EM&V plan that meets EPA requirements. The EPA takes comment on all aspects of the proposed ERC issuance process. The EPA is also taking comment on how an ERC issuance process would apply to emission reduction measures for which we are taking comment regarding their eligibility for ERC issuance under the federal plan, including types of RE not covered by the federal plan, demand-side EE, CHP, biomass, and any other measure that could be considered eligible under the final guidelines.

The following are proposed required components of the eligibility application, as specified for these measures in the final EGs:

(1) The EPA proposes that the federal plan will require that providers must show that the generation they would be providing to the federal plan system for ERC issuance is only being credited in the federal plan, and will not be submitted for ERC issuance in any other rate-based crediting system in any other state. As discussed in section IV.C. of this preamble, we are proposing that states with rate-based emission standards plans that have eligibility and EM&V requirements compatible with the federal plan would have the opportunity to participate in the federal plan trading systems, and create a shared pool of creditable reductions, in which case credits approved by such states would be eligible for use by affected EGUs in the federal plan.

(2) The provider must show that the project is using an eligible RE or nuclear resource. Specific requirements are proposed in section IV.C of this preamble.

(3) The provider must show that the project has an EM&V plan that meets the federal plan requirements. Proposed requirements specific to the federal plan are proposed in section IV.D.6 of this preamble. As specified in section IV.D.8 of this preamble, we request comment on whether nuclear energy resources should be subject to the same EM&V requirements as RE resources, and if not, we take comment on to which EM&V requirements nuclear energy resources should be subject.

(4) There are special conditions if the provider is located in a state with a mass-based plan. For eligible RE capacity, the provider can only be credited in a rate-based state or rate-based multi-state system if the provider can demonstrate that the measure must be implemented to meet electricity load in a state with a rate-based plan. The EPA is proposing that an RE provider can make this demonstration by providing documentation of a power purchase agreement or delivery contract from the rate-based state and show that the measure was treated as a generation resource used to serve regional load that included the rate-based state. For incremental nuclear capacity, no provider in a state with a mass-based plan can be eligible for ERC issuance in a rate-based state. This requirement and the justification for its inclusion is further discussed in section III.A of

this preamble on Interstate Effects and also discussed in the Interstate Effects section of the final EGs (section VIII.L of the final EGs). The EPA is proposing that there is no other geographic limitation on the location of the providers of RE and incremental nuclear generation under the federal plan.

(5) This application must include an independent third-party verifier's review and approval of the eligibility requirements, as is reflected in EM&V requirements for the final guidelines, and specified as part of proposed federal plan EM&V requirements in section IV.D.6 of this preamble.

We request comment on each criterion of the eligibility application described herein and in the proposed model rule, for each eligible resource. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule.

ERCs will be tracked in the Allowance Tracking and Compliance System (ATCS). Additionally, the EPA is proposing that the agency will establish a complementary tracking system for the ERC issuance process. It will provide for transparent access to RE project and program eligibility applications and regulatory approvals as well as information on the activities of accredited third party verifiers (third party verifiers are further discussed in section IV.D.6 of this preamble), as well for the public to be able to generate reports based on this information.

The agency is proposing that the project eligibility applications will be accepted after the finalization of the federal plan and prior to the first compliance period, as soon as the agency is able to establish an application process, and that applications will be accepted on an annual basis. The agency requests comment on whether a quarterly or biannual application process is more appropriate. These applications will be accepted through the entirety of all compliance periods. The EPA will review and approve the project applications. It is proposed that the EPA may designate an agent to coordinate the project application process and assist with review of applications.

For the second step in the credit issuance application process, the EPA proposes that providers submit an M&V report to the EPA, or its designated agent, prior to the EPA’s issuance of ERCs. This can only occur after the approval of a project application, the RE has been generated, and necessary EM&V has been completed.

The following are proposed required components of the ERC issuance application:

(1) Documentation of completed EM&V in accordance with the EM&V plan submitted by the RE provider, including quantification of the MWh of generation to be credited and verification of their creation.

(2) Documentation that the generation has not been submitted for crediting under any other federal or state plan, including to another rate-based credit tracking system.

(3) Documentation that the MWh resulted from RE or incremental nuclear capacity eligible for crediting under the federal plan requirements and in accordance with final EGs. This documentation should note if the

MWh are from an RE project located in a state with a mass-based plan, and show if the generation is approved to be eligible for ERC issuance under the federal plan. See section IV.C.3 of this preamble for specifics on the required demonstration for this type of RE generation. As discussed in that section, this option is proposed to not be available to incremental nuclear capacity located in a state with a mass-based plan.

(4) This application must include a verification report from an independent third-party verifier, submitted after the verifier's review and approval of the eligibility application, as is reflected in EM&V requirements for the final guidelines, and specified as part of proposed federal plan EM&V requirements described below and included in detail in the proposed model rule.

If the application meets these requirements, pursuant to review by the EPA or its designated agent, ERCs will be issued to the provider by the EPA through the Allowance Tracking and Compliance System (ATCS). The specific steps of the process by which an eligible resource seeks ERCs, and by which an affected EGU may use ERCs in its compliance demonstration are laid out in the proposed model rule. One of the steps requires the proponent to register for a general account in the EPA tracking system where the ERCs would be recorded. See 40 CFR 62.16515 for the requirements to establish a general account. While EPA is proposing to allow eligible resources to use a general account to receive any ERCs issued under this section, the EPA requests comment on extending the designated representative provisions in 40 CFR 62.16485 to eligible resources instead of the general account provisions. Requiring eligible resources to submit information similar to that collected in the certificate of representation in 40 CFR 62.16500 and to appoint a designated representative to act on behalf of all owners/operators for all projects requesting ERCs may improve the EM&V process by making the eligible resources more accountable.

Because it is critical to the integrity of an ERC that it represents the actual MWh of energy generated or saved that it purports to represent, and as required in the EGs for state plans, the federal plan and model rule include provisions to address error correction (mechanisms to adjust the number of ERCs issued based on all form of errors, from clerical, to over- and under-statements, to material inconsistency with rule provisions, to fraud, etc.). In addition, the federal plan and model rule include provisions that provide that, at any time for cause, the EPA may temporarily or permanently revoke the qualification status of eligible resources (from being issued ERCs for at least the duration it does not meet the requirements for being issued ERCs) and independent verifiers (from providing verification services for at least the duration it does not meet the requirements of your state plan). For the federal plan, as discussed in section III.I of this preamble above, we propose to use the administrative appeals process set forth 40 CFR part 78 to address party-specific disputes concerning the issuance and/or validity of ERCs. States may adopt a similar procedural and substantive process at the state level to enable them to rescind or withhold approval of specific credits. We request comment on the content of each of these provisions in the model rule, and specifically seek comment on whether the model rule should include different or additional details related to either procedure or substance for error correction and the revocation of the qualification status of an eligible resource or independent verifier.

The agency is proposing that ERC eligibility applications will be accepted starting before the beginning of the first compliance period (January 1, 2022), through an application process the agency will establish and administer (unless delegated or taken over through a partial state plan), and that applications will be accepted on an annual basis. These applications will be accepted through the entirety of all compliance periods. The EPA will review and approve eligibility applications, and may designate an agent to coordinate and assist with ERC eligibility applications. The EPA is proposing that it will issue ERCs for a given year no later than 6 months after the end of the relevant year. This amount of time may be necessary to accommodate the ERC issuance process, including necessary EM&V. The overall proposed schedule for trading and true-up has been constructed to allow for this period of time for EM&V after the compliance period.

For purposes of the proposed rate-based federal plan, the EPA proposes to implement the Clean Energy Incentive Program (CEIP) on behalf of a state by issuing early action ERCs for eligible actions located in or benefitting that state that are implemented after September 6, 2018 and that generate zero-emitting MWh or reduce energy demand in 2020 and/or 2021.[73] The EPA intends to implement the program in a way that maintains the stringency of the rate-based emission standards for affected EGUs in the compliance periods established in this rule. For the purposes of the rate-based federal plan, the EPA is proposing to award early action ERCs to two types of eligible projects, as listed below. The rationale for including these projects is included in section VIII.B.2 of the final EGs.

- RE investments that generate metered MWh from any type of wind or solar resources; and
- Demand-side EE programs and measures implemented in low-income communities that result in quantified and verified electricity savings (MWh).

[73] As discussed in section VIII.B.2 of the final emission guidelines, in the case of a state that submits a final state plan including requirements for the state's participation in the CEIP, eligible RE projects may commence construction, and eligible EE projects may commence implementation, following the date of submission of a final state plan to the EPA. These projects must be implemented in or benefit the state that submitted the final state plan to the EPA, and may receive incentives for the zero-emitting MWh they generate or the end-use energy savings they achieve during 2020 and/or 2021.

The EPA proposes the following framework to implement the CEIP in the rate-based federal plan. First, the EPA proposes to implement a mechanism for issuing early action ERCs for eligible RE porjects that commence construction and eligeible EE projects that commence implementation after September 6, 2018 and that generate zero-emitting MWh or reduce end-use energy demand during 2020 and/or 2021. These projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan. The EPA proposes to design this mechanism in a manner that would have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods. The EPA requests comment on the structure of this mechanism, which could include adjusting the stringency of the emission standards during the compliance periods to account for the issuance of early action ERCs for MWh generated or avoided in 2020 and/or 2021. For example, during the interim performance period, a number of ERCs could be retired in an amount equivalent to the number of early action ERCs that were awarded for MWh generated or avoided in 2020 and/or 2021. As another option, the EPA, or a state under the model trading rule, could adjust their targets to achieve the same stringency, taking into account the additional borrowed ERCs. The EPA requests comments on all potential methods to adjust state targets, including modeling-based approaches, and on what information the state must present to demonstrate that the new targets preserve the needed stringency. More generally, the EPA requests comments on these ideas, as well as on alternatives for maintaining the stringency of a rate-based plan implementing the CEIP so as to have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods.

Second, the agency proposes to create an account of "matching" ERCs for each state participating in the CEIP – regardless of whether a state is implementing a state plan or the agency is implementing a federal plan on its behalf. This distribution would reflect each state's pro rata share – based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states – of a federal pool of additional ERCs, which would be limited to the equivalent of 300 million short tons of CO_2 emissions. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal pool upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021. The EPA intends that a portion of these matching ERCs would be reserved for eligible wind and solar projects, and a portion would be reserved for eligible EE projects implemented in low-income communities. The agency recognizes that there have been historic economic, logistical and information barriers to implementing EE programs in these communities, and therefore believes it is appropriate to reserve a portion of the federal pool to incentivize investment in these programs. The EPA is requesting comment on the size of reserve of matching ERCs for eligible low-income EE programs as well as for eligible wind and solar projects. The EPA is proposing that unused ERCs in either reserve would be redistributed among participating states. This redistribution could be executed according to the pro-rata method discussed above. Alternatively, unused matching EE or RE ERCs could be swept back into a federal pool and distributed to project providers on a first-come, first served basis. EPA requests comment on these ideas as well as alternative proposals regarding the method for redistributing matching ERCs, as well as the appropriate timing for such a redistribution.

Following the effective date of a rate-based federal plan for a state, the agency will create an account of matching ERCs for the state that reflects the pro rata share of the 300 million short ton CO_2 emissions-equivalent matching poolthat the state is eligible to receive. Any matching ERCs that remain undistributed after September 6, 2018 will be distributed to those states with approved state plans that include requirements for CEIP participation, as well as to those states on whose behalf EPA is implementing a federal plan. These ERCs will be distributed according to the pro rata method outlined above. Unused matching ERCs that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA.

7. Independent Verifiers

The EPA has determined in the final EGs that independent verification requirements are necessary to ensure the integrity of any rate-based emission trading program, given the types of eligible measures that may generate ERCs and the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for the EPA in the context of the proposed federal plan, and the states in the context of their plans, to ensure that eligibility applications and monitoring and verification reports are appropriately reviewed prior to issuance of ERCs. Inclusion of an independent verification component is also consistent with similar approaches required by state PUCs for the review of demand-side EE program results and GHG offset provisions included in state GHG emission budget trading programs.

The remainder of this section and the related language in the proposed model rule provide the proposed basis by which the EPA intends to evaluate the independence of the verifiers that it uses to provide verification reports pursuant to the federal plan. The qualifications described here and in the model rule would be presumptively approveable in the context of a state plan.

As a starting point, an independent verifier must have the necessary technical qualifications to provide verification services for the subject in question, as well as fulfill certain codes of conduct in providing verification services. Only verifiers approved or “accredited” by the EPA may provide verification services related to ERC issuance for the federal plan, in the same way that only verifiers approved by a state may be eligible to perform verification services pursuant to a state plan.[74]

In addition, verifiers must have sufficient knowledge of the rate-based emission trading program rules, technical expertise, and knowledge of auditing, accounting, and information management practices, in order to perform verifcation services related to the Clean Power Plan. Accredited verifiers must be independent. Accredited verifiers may not provide verification services for any eligible resource for

[74] In this section, the term “verifier” is used interchangeably to refer to both a “verification body” (i.e., a verification company or organization) and a “verifier,” which is an individual that is a principal or employee of a verification body.

which they have a financial, management, or other interest.[75] Such relationships constitute a conflict of interest (COI). COI situations may also arise as a result of personal relationships among individuals representing an ERC provider and an accredited verifier. A verification report will not be accepted as part of an eligibility application or M&V report where the accredited verification body or any individual verifier has a COI. Accredited verification bodies must have management protocols in place to identify and remedy any COI prior to provision of verification services. That the proposed federal plan and model rule provide that failure of an accredited verifier to identify and adequately address any COI prior to provision of verification services is grounds for revocation of

[75] Accredited verification bodies and individual verifiers may not have any direct or indirect organizational or personal relationships with an ERC provider that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report. In addition to this general requirement, the following specific requirements also apply. Accredited verifiers must have no direct or indirect financial interest in, or other financial relationships with, an ERC provider or any related program or project that seeks issuance of ERCs. Accredited verifiers must have no relationship with the implementer of a program or project that seeks the issuance of ERCs, or any related ERC provider, that would represent a COI. Accredited verifiers must have no role in the development and implementation of a program or project that seeks issuance of ERCs, beyond the provision of verification services. Accredited verifiers must not be compensated, directly or indirectly, in relation to the quantified and verified MWh in an M&V report or on the basis of program or project approval, ERC issuance, or the number of ERCs issued. Accredited verifiers may not hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that hold ERCs or other related financial derivatives. Verification reports must include an attestation by the accredited verifier that it assessed potential COI related to an ERC provider and adequately addressed any identified COI. The EPA requests comment the potential for payments to be channeled through the EPA as fees.

accreditation. The EPA will perform periodic reviews of accredited verifiers, to ensure that verifiers are maintaining necessary technical and professional qualifications and are meeting program requirements for provision of verification services. The EPA may recognize, in part, accreditation by an outside organization where such outside accreditation demonstrates that federal plan requirements are met.[76] The EPA requests comment on the proposed necessary requirements for an independent verifier to perform verification services in connection with the federal plan, including those requirements specifically detailed in this section of the preamble and the related language in the proposed model rule, and including whether there are any requirements that are not included in this proposal that should be included in the final rule. We further request comment on the level of detail that we should include in the final model rule regarding all requirements for indepenent verifiers, and all aspects of verification.

8. Evaluation, Measurement, and Verification (EM&V) Plans, Monitoring and Verification (M&V) Reports, and Verification Reports

[76] An example is American National Standards Institute (ANSI) accreditation under ISO 14065:2013 for GHG validation and verification bodies. More information is available at https://www.ansica.org/wwwversion2/outside/GHGgeneral.asp.

This section identifies and discusses the EM&V approaches used to quantify and verify MWh from RE, demand-side EE, and other eligible measures used to generate ERCs or otherwise adjust an emission rate.[77]

Only a subset of the potentially creditable ERC resources discussed in this section are actually being proposed as part of the federal plan. The remainder, and their associated requirements, are provided as part of the proposed model trading rule. Thus, all provisions of this subsection relating to such resources are presented only for the purpose of comment in the context of the federal plan, but are actually proposed for inclusion in the model trading rule. The ERC resources proposed in the federal plan must meet the following criteria: 1) they are in the following categories of measures: on-shore wind, solar, geothermal power, hydropower, new nuclear units and capacity uprates at existing nuclear units, and 2) they can provide quantified generation data from a revenue quality meter. The language pertaining to all other measures (e.g., demand-side EE) is proposed only for the model rule. While they are currently being proposed as part of the model rule and not the

[77] EM&V is defined here as the set of procedures, methods, and analytic approaches used to quantify the MWh from RE, demand-side EE, and other eligible measures and thereby ensure that the resulting savings and generation are quantifiable and verifiable. In this proposal, we are proposing EM&V for the eligible RE, and taking comment on EM&V for demand-side EE and any other measures that could be eligible.

federal plan, the EPA requests comment on the inclusion of other RE measures, demand-side EE measures, and any other measures that may be eligible under the final guidelines as eligible measures under the federal plan. For stakeholders that are submitting comments on the inclusion of such additional measures, the EPA requests comment on how the EPA could implement across applicable jurisdictions a rigorous, straightforward, and widely demonstrated set of EM&V methods, procedures, and approaches that could be implemented in the time frame allowed by the federal plan and that also meet the requirements outlined in the final guidelines. To the extent proposed for inclusion in the model trading rule, we also invite comment on these requirements in the context of state implementation as part of a state plan. Thus, commenters on this aspect of the proposal should consider whether and how these provisions could be implemented at the state level. Comments that suggest an approach not authorized by the EGs will likely be considered outside the scope of this proposed rule.

Additionally, with respect to EM&V, the EPA describes certain established industry best-practice methods, procedures, and appraoches that would be presumptively approvable if included in state plans. States wishing to adopt the model rule must submit these methods, procedures, and approaches as specified, or may submit alternative EM&V that is functionally equivalent to the industry best-practices described as presumptively approvable.[78]

As discussed in section IV.C.3 of this preamble, quantified and verified MWh of RE generation and other means of generating ERCs may be used to adjust a CO_2 emission rate when demonstrating compliance with the EGs. Providers other than affected EGUs who seek to earn ERCs must develop EM&V plans outlining how they will quantify and verify the resulting MWh from their efforts. These providers must then submit these EM&V plans as part of their application to the Administrator for project approval.[79]

a. Overall Approach and Measure-Specific Requirements. The proposed Clean Power Plan stated that the EPA would establish EM&V requirements and procedures to help states, sources, and resource providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts. This federal plan proposes those requirements that the EPA committed to establish. The Clean Power Plan proposal and

[78] The EPA recognizes that EM&V is routinely evolving to reflect changes in markets, technologies and data availability, and expects to update its EM&V guidance over time. Therefore the agency expects that alternative quantification approaches will emerge that can be approved for use, provided that such approaches are functionally equivalent to the provisions for EM&V outlined in this section.

[79] A full discussion of applicable requirements for the establishment and functioning of the rate-based trading system is provided above, in section IV.D of this preamble.

associated "State Plans Considerations" TSD[80] suggested that such EM&V requirements would leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The EPA also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh. The EPA is proposing EM&V methods, procedures, and approaches, described herein, that are intended to be consistent with and leverage prevailing industry best-practices.

In addition, the EPA's proposed EM&V methods, procedures, and approaches reflect several overarching objectives and principles offered by states, private organizations, and the public during the comment period of the CPP EGs. One of these is the importance of balancing the accuracy and reliability of

[80] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.

results with the associated costs of EM&V. Another objective for the EPA's proposed EM&V is to avoid excessive interference with existing practices that are already robust, transparent and effective.

Submittals. Applicable submittals under a rate-based emission trading program include eligibility applications (including EM&V plans), monitoring and verification reports, and verfication reports. These submittals are described in section VIII.K.3.b of the final EGs preamble and in this model rule and federal plan. At the initiation of a program or project, ERC providers develop and submit to the state or the EPA, respectively, an EM&V plan that documents how requirements for quantification and verification will be addressed as EM&V is performed over the program or project period. After implementation has occurred, the ERC provider must submit periodic monitoring and verification (M&V) reports to document and describe how each of the requirements were applied. These reports must also specify the resulting MWh savings or generation values, as determined on a retrospective (ex-post) or real-time basis. MWh values may not be determined using projections or other ex-ante quantification approaches.

Each EM&V plan submitted in support of an eligibility application must identify the eligible resource covered by the plan, and provide specific EM&V criteria that specify the manner in which the energy generated or saved by the eligible resource will be quantified, monitored and verified. The manner of quantification, monitoring and verification must meet the criteria outlined below and included in the proposed model rule, as applicable to the specific eligible resource. We take broad comment on each criteria specified below and in the proposed model rule, for each eligible resource. Specifically, we seek comment on the substantive content of the criteria, and we seek 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.

Each M&V report submitted in support of the issuance of ERCs to a specific eligible resource must include specific criteria described here and in the proposed model rule. For the first M&V report submitted, a key component is documentation that the electricity-generating resources or electricity-saving measures were installed or implemented consistent with the description in the approved eligibility application. Each following M&V report must then identify the time period covered by the M&V report, describe how the methods specified in the EM&V plan were applied during the reporting period, and document the quantify (in MWh) of energy generation and/or electricity savings quantified and verified for the period covered by the

M&V report. Any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report must also be included in the M&V report, along with the date on which the change occurred, and information sufficient to demonstrate whether the eligible resource continued to meet all eligibility requirements during the period covered by the M&V report. Any change should also be specified in the report. The EPA takes broad comment on each of these criteria, as described here and in the proposed model rule. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level 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.

Each verification report submitted by an independent verifier in support of the issuance of ERCs to a specific eligible resource must address the criteria described here and in the proposed rule text. Each verification report must set forth the findings of the verifier, based on an assessment of all relevant requirements, information and data, including an assessment of any material misstatements or data discrepancies. Any verification report included as part of an eligibility application must further describe the review conducted by the verifier and verify the following: the eligibility of the resource to be issued ERCs; that the eligible resource exists and has been, or will be, generating energy or saving electricity in the manner required; that the EM&V plan meets its requirements; and any other information required or that the verifier finds, in its professional opinion, is necessary to assess the accuracy of the subject of the verification report. Each verification report included as part of a M&V report must also describe the review conducted by the verifier and verify the following: the adequacy and validity of the information and data submitted to quantify eligible MWh of electric generation or electricity savings during the period covered by the report, as well as all supporting information and data identified in the EM&V plan and M&V report; evaluate whether all generation or savings data is within a technically feasible range for that specific eligible resource (determined through a quality assurance and quality control check of the data); that the M&V report meets its requirements; and any other information required or that the verifier finds, in its professional opinion, is necessary to assess the accuracy of the subject of the verification report. The EPA takes broad comment on each of these criteria, as described here and in the proposed model rule. Specifically, we seek comment on the substantive content of the criteria, and we seek 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.

For demand-side EE, all EM&V plans that are developed for purposes of adjusting an emission rate under this final rule are intended to leverage and closely resemble the plans already in routine use for a wide range of publicly or rate-payer funded EE programs and energy service company (ESCO) projects. For RE, EM&V plans similarly leverage resources and approaches to MWh tracking for RE that are broadly applied in the state and regions. The existing reports and documentation from existing tracking systems may serve as the substantive basis for a monitoring and verification report for RE.

b. Renewable Energy EM&V Requirements. This section describes the EM&V requirements associated with quantifying electricity generation from eligible RE and nuclear, and for documenting these requirements in EM&V plans and reports. Consistent with prevailing views expressed in public comments, the EPA’s requirements presume that the quantification of RE generation can leverage the infrastructure and documentation associated with the establishment of renewable energy certificates (RECs) and registration of such certificates in REC registries. These registries typically include well-established safeguards, documentation requirements, and procedures for registry operations intended to support the demonstration of compliance with state RPS policies. A key element of RPS compliance is that each RE generating unit must be uniquely identified and recorded in a registry to avoid the double counting of RECs.

The primary metric for all RE is electricity generation, in units of MWh. Measured output must be derived either from (1) A revenue quality meter that meets the applicable ANSI C-12 standard or equivalent, which is the typical requirement for settlements with RTO and other control-area operators; or (2) for customer-sited generators that are interconnected behind the customer meter, measurement at the AC output of an inverter, adjusted to reflect the energy delivered into either the transmission or distribution grid at the generator bus bar. Further, a RE generating facility of 10 Kilowatt capacity or less may estimate the facility’s output if the state where it is located explicitly allows estimates to be used and provides rules for when it will be allowed. In the latter case, calculations of system output must be based on the RE unit’s capacity, estimated capacity factors, and an assessment of the local conditions that affect generation levels. All such input parameters and assumptions must be clearly described and documented. For RE units that are managed by regional transmission operators or other control area operators, metered generation data should be electronically collected by the control area’s energy management system, verified through an energy accounting or settlements process, and reported by the control area operator to the REC registry at least monthly. The EPA requests comment on this proposed requirement for quantifying RE generation for the purpose of ERC issuance.

For RE units that do not go through a control area settlements process, metered data may be read and transmitted to the ERC registry by an independent third party, or may be self-reported. Third-party and self-reported generation data must be reported on an annual basis. All such data must be verified for reasonableness by the agency, state or the REC registry.

For reporting purposes, RE generation may be aggregated from multiple generators into a single MWh value for the group, provided the following requirements are met: each RE unit is uniquely identified in the federal tracking system, the nameplate capacity of each RE unit is less than 150 Kilowatt, the aggregated RE units collectively have nameplate generating capacities less than 1.0 MW, the units aggregated are located in the same state, the RE units being aggregated utilize the same technology/fuel type, and the RE unit’s generation data are based on the same metering or the same generation estimating software or algorithms. The EPA requests comment on how existing reporting systems can play a role in meeting EM&V requirements under the federal plan, particularly, in assuring that each MWh of RE generation is uniquely identified and recorded to avoid double counting.

An additional criterion that applies to distributed RE units that directly serve on-site end-use electricity loads is that avoided transmission and distribution (T&D) system losses can be considered, as is commonly practiced with demand-side EE. Such calculations must apply the requirements specified for demand-side EE as described below.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection, includuing the appropriateness of their use for each type of RE resource (including the relvant size and distribution of such resource) that qualifies for issuance of ERCs for use in Clean Power Plan compliance.

For RE resources with a nameplate capacity of 10 Kilowatt or more and for RE resources with a nameplate capacity of less than 10 Kilowatt for which metered data are available, we take comment on the appropriateness of the requirement to use a revenue quality meter for monitoring generation, and we take comment on the definition of revenue quality meter. We take comment on the appropriateness of other types of meters for monitoring generation. We take comment on whether 10 Kilowatt is the appropriate threshold, under which an eligible resource can be issued ERCs for generation based on data other than metered generation, and if not, what would be the appropriate threshold.

For RE resources of all sizes and means of monitoring, we take comment on the appropriate requirements for allowing generation data to be aggregated, including comment on the provisions in the proposed model rule and any alternatives to them. We take comment on whether the all of the generating units have the same essential generation characteristics, in order for their data to be aggregated, and if so, what the appropriate content of the definition of “essential generation characteristics” (e.g., are essential generating characteristics determined on a resource by resource basis, or can generation from a group of wind turbines be aggregated with generation from a group of solar panels? We seek comment on the appropriate thresholds for the aggregated of individual units (e.g., nameplate capacity of less than 150 Kilowatt per unit and the units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, as in the proposed model rule).

For non-metered units of less than 10 Kilowatt, we take comment on whether the final model rule should specify the specific estimating software or algorithms by which generation data should be measured, and if so, we take broad comment on the appropriate estimating software or algorithms and/or the appropriate characteristics for such estimating software or algorithms.

We request comment on any other requirements that should be included in the final model rule regarding EM&V of RE resources.

For all energy generating resources (such as RE, but also including applicable resources requiring EM&V described below), we take comment on the appropriate place of measurement of the generation, including comment on whether measurement should be at the bus bar or at a different location (or in the case of meter on units of less than 10 Kilowatt, at the AC output of the inverter or elsewhere), whether measurement should be before or after parasitic load (and how to separate out parasitic load). In addition, for all energy generating resources, we take comment on whether generation data should go through a control area settlement process prior to issuance of ERCs, and if so, what level of specificity with respect to that process we should include in the final model rule. If not, or if the unit does not go through a control areas settlement process, we take comment on how the data collection should be specified in the final model rule. Finally, we take comment on the frequency with which data should be collected, for all energy generating resources, of all sizes.

c. Nuclear EM&V Requirements. The EM&V requirements associated with quantifying electricity generation from eligible nuclear, and for documenting these requirements in EM&V plans and reports are the same as the requirements for RE discussed in the preceding section.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection, includuing the appropriateness of their use for each type of nuclear energy resource (including the relvant size and distribution of such resource) that qualifies for issuance of ERCs for use in Clean Power Plan compliance. We take comment on whether nuclear energy resources should be subject to the same EM&V requirements as RE resources, and if not, we take comment on to which EM&V requirements nuclear energy resources should be subject.

d. Non-Affected Combined Heat and Power EM&V Requirements. In additon to the CHP specific EM&V requirements discussed below and in the associated provisions in the model rule, all CHP must follow the requirements for RE discussed in the preceding section, including metering requirements, special treatment for units of less than 10 Kilowatt, and how to account for T&D losses.

In order to determine the incremental CO_2 emission rate, a CHP unit would monitor requirements for CO_2 emissions and energy output.[81] The monitoring requirements are standard methods currently in use and the requirements would depend on the size of the CHP units and the fuel used in the unit.

Non-affected CHP facilities[82] with electric generating capacity greater than 25 MW would follow the same monitoring and reporting protocols for CO_2 emissions and energy output as are required for affected EGU CHP units. These requirements are discussed in section IV.D.13 of this preamble. For non-affected CHP facilities with electric generating capacity less than or equal to 25 MW, which use only natural gas and/or distillate fuel oil, the low mass emission unit CO_2 emission monitoring and reporting methodology outlined in 40 CFR part 75 is acceptable.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to CHP, including the appropriateness of their use for CHP (including with respect to the size of the CHP resource). We take comment on whether a CHP unit should be subject to the same EM&V requirements as RE resources, and we take comment on any additional EM&V requirements to which CHP units should be subject. Specifically, we take comment on

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[81] Where a CHP unit uses biomass fuel, it must report both total CO_2 emissions and biogenic CO_2 emissions. Proposed requirements for reporting biogenic CO_2 emissions are discussed below in the section titled EM&V requirements that apply to biomass RE facilities.

[82] A CHP facility may consist of one or more electric generators.

specifying in the final model rule that if a CHP unit has an electric generating capacity greater than 25 MW, its EM&V plan must specify that it will meet the requirements that apply to an affected EGU under 40 CFR 62.16540. We also take comment on specifying in the final model rule that if a CHP unit has an electric generating capacity less than or equal to 25 MW, the EM&V plan must specify that it will meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75. We take comment on any alternatives to these measurement methodologies that should be specified in the final model rule. We take comment on any other requirements that should be included in the final model rule regarding EM&V of CHP.

e. Biomass EM&V Requirements. A state plan that is adopting the rate-based model rule must propose EM&V requirements for monitoring and reporting biogenic CO_2 emissions from the use of qualified biomass at RE facilities that are eligible for adjusting a CO_2 emission rate. If a state proposes to use the monitoring and reporting requirements for biogenic CO_2 emissions in 40 CFR part 98 (40 CFR 98.3(c), 98.36(b)-(d), 98.43(b), and 98.46) in its plan submission, those requirements are presumptively approvable. An EM&V plan that addresses biomass RE must follow the requirements for monitoring and reporting biogenic CO_2 emissions from the facility that were approved by the EPA in connection with the specific state plan.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to biomass, including the appropriateness of their use for qualified biomass. We take broad comment on the types of qualifying biomass feedstocks that should be specified in the final model rule, if any. We take comment on the methods that we should specify in the final model rule for the measurement of the associated biogenic CO_2 for such feedstocks, as well as what other requirements we should specify in the final model rule related to qualfied biomass. We take comment on any other requirements that should be included in the final model rule regarding EM&V for qualified biomass. Detailed discussion on the role of qualified biomass feedstocks can be found in section IV.C.3 of this preamble.

f. Waste-to-Energy EM&V Requirements. A state plan that is adopting the rate-based model rule must propose EM&V requirements for monitoring and reporting biogenic CO_2 emissions from waste-to-energy facilities that are eligible for adjusting a CO_2 emission rate. If a state proposes to include the monitoring and reporting requirements for biogenic CO_2 emissions in 40 CFR part 98 (40 CFR 98.3(c), 98.36(b)-(d), 98.43(b), and 98.46) in its plan submission, those requirements are presumptively approvable. The EPA may approve other requirements of similar rigor, at its discretion. An EM&V plan that addresses the biogenic CO_2 emissions from a waste-to-energy facility must follow the requirements for monitoring and reporting biogenic CO_2 emissions from the facility that were approved by the EPA in connection with the specific state plan.

As discussed in the final EGs (see section VIII.K.1 of the final EGs), only the portion of electric generation at a waste-to-energy facility that is due to the biogenic content of the MSW may be used to generate ERCs or counted by a state towards its achievement of its obligations pursuant to this regulation.

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to WTE, including the appropriateness of their use for WTE. We take comment on whether a waste-to-energy resource should be subject to the same EM&V as RE resources, and we take comment on any additional EM&V requirements to which waste-to-energy resources should be subject, including comment on any specific methods for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste that the EPA should include in the final model rule.

g. <u>Demand-Side Energy Efficiency EM&V Provisions</u>. The following section proposes EM&V provisions that will be presumptively approvable if included in state regulations governing how EE is to be quantified by EE providers and verified by independent entities acting on behalf of the state. As noted above these proposed provisions apply to all demand-side EE used to adjust an emission rate if a state adopts the model rule. The EPA is soliciting comment on the incorporation of EE for the federal plan and by extension the EM&V associated with it.

For all demand-side EE used to generate ERCs, the EPA is proposing that the metric is MWh of electricity savings must be quantified on an ex-post or real-time basis and defined as a reduction in facility- or premises-level electricity consumption due to an EE program, project, or measure.

(1) Common Practice Baseline.

Based on public input and assessments of industry best-practice protocols and procedures, the EPA is proposing that it is presumptively approvable to quantify EE savings as the difference between actual metered electricity usage after an EE program, project, or measure is implemented, and a “common practice baseline” (CPB). A CPB is the equipment that would most frequently be installed at the time an existing piece of equipment fails or is replaced at the end of its effective useful life – or that a typical consumer or building owner would have continued using for the remainder of the equipment's effective useful life – in a given circumstance (i.e., a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. It defines what would commonly have happened in the absence of the EE program, project, or measure.

The applicable CPB depends on a number of factors, such as characteristics of the EE program, project, or measure, the mechanism by which electricity customers are engaged, local consumer and market characteristics, and the applicable building energy codes and product standards (C&S), including the C&S compliance rate. Examples of appropriate CPBs to apply in specific circumstances, which may be presumptively approvable, can be found in the EPA's EM&V guidance. EE providers must document the selected CPB in their EM&V plans, along with clear documentation and discussion of the rationale, applicability, and relevant data sources, protocols, and other supporting information. Monitoring and verification reports must refer to the EM&V plan and confirm that the CPB was appropriately applied.

(2) Methods Used to Quantify Savings from Energy Efficiency Programs and Projects.

This section proposes criteria that are presumptively approvable for the general types of EM&V methods that EE providers may use to quantify the MWh savings from demand-side EE programs, projects, and measures. During the CPP EG's public comment period, the EPA received input indicating that state PUCs typically allow utilities and other EE providers to use a range of EM&V methods that reflect applicable circumstances and on-the-ground conditions (versus mandating which methods must be used in a particular situation). Consistent with this approach, the EPA is proposing to offer flexibility for EE providers to select from three broad categories of EM&V methods to determine savings.

These categories include project-based M&V, deemed savings, and comparison group approaches such as randomized control trials (RCT). Regardless of the approach selected, the EPA is proposing that annual savings values must be quantified using these EM&V methods at specified time intervals (in years) on a recurring basis over the effective useful life of the EE project or measure in order to ensure accurate and reliable savings values. To be presumptivey approable, the EPA is proposing that EE providers must apply the above methods at a minimum of 4-year intervals for building energy codes and product standards; every 1, 2, or 3 years for publicly- or utility-administered EE programs, depending on the program type, magnitude of savings, and experience with the program; and annually for large individual commercial and industrial projects, unless the EE provider can credibly demonstrate why this is not possible and how the accuracy and reliability of savings values will be maintained. The EPA is further proposing that, to be presumptively approvable, the selected method, associated assumptions, and data sources must be identified and described in EM&V plans.

For comparison group approaches, the EPA is propsing that states and EE providers can refer to the EPA's draft EM&V guidance for a discussion of industry best-practice protocols and guidelines. Where feasible, the EPA is proposing to encourage the use of RCT methods, which determine savings on the basis of energy consumption differences between a treatment group and a comparison group, and therefore increase the reliability of results.

As noted above, an alternative to comparison group methods is the use of deemed savings values, which establish pre-determined annual electricity savings values for specific EE measures. The EPA is proposing that the use of deemed savings values will be presumptively approvable if those values (a) are documented in a publicly available database (also known as a Technical Reference Manual) that is accessible on a public Web site, or is otherwise readily accessible; (b) specify the conditions for which each deemed value can be applied, including but not limited to climate zone, building type, and EE implementation mechanism; and (c) are updated at a minimum of every 3 years to reflect the per-measure MWh savings documented in ex-post EM&V studies apply M&V or comparison group methods.

For M&V methods to be presumptively approvable, the EPA is proposing is that industry best-practice protocols and/or guidelines must be followed. Examples of acceptable best-practice protocols and guidelines are provided in the EPA's EM&V guidance. EE providers can consult the EM&V guidance to assess the applicability of these technical resources to the EE programs and projects generating savings, and must document how one or more best-practice protocols or guidelines will be appropriately applied in EM&V plans (along with clear documentation and discussion of the rationale, applicability, and relevant data sources, and other supporting information). The EPA is also proposing that monitoring and verification reports must refer to the EM&V plan and confirm that the relevant M&V protocol or guideline was properly applied.

(3) Quantifying Savings.

Regardless of the approach used to quantify and verify MWh savings, the EPA is proposing that EM&V plans must describe how they will address the following provisions:

- How major changes in independent variable conditions (weather, occupancy, production rates, etc.) that affect energy consumption and savings estimates will be accounted for. The EPA is proposing that the effects of these changes must be calculated using industry best-practices such as real-time conditions or normalized conditions that are reasonably expected to occur throughout the lifetime of the EE project or measure.

- How the initial installation of EE will be verified for EE program categories that involve the installation of identifiable measures (e.g., most utility consumer-funded EE programs and project-based EE are evaluated site-by-site). The EPA is proposing that verification is required within the first year of program implementation and that all verification activities must be performed using industry best-practice techniques (e.g., phone or mail surveys, document review, site inspections, spot or short-term metering). For projects implemented as part of a larger program, the EPA is proposing that verification can be performed using a sample of projects to represent the full program population.
- How avoided T&D system losses[83] will be quantified and applied to EE savings determined at the customer facility or premises. The EPA is proposing that demand-side EE programs (other than T&D efficiency measures such as CVR and volt/VAR optimization[84]) may adjust reported savings by using a T&D adder. If such an adder is applied, the presumptively approvable approach is to use the smaller of 6 percent or the calculated statewide annual average T&D loss rate (expressed as a percentage) calculated using the most recent data published by the U.S. EIA State Electricity Profile.[85]
- How the duration of EE program or project electricity savings will be determined. This must be determined using industry best-practice protocols and procedures involving annual verification assessments, industry-standard persistence studies, deemed estimates of effective useful life (EUL), or a combination of all three.

[83] T&D losses are defined as the difference between the quantified EGU generation required to serve a customer’s load (measured at the EGU bus bar) and the customer’s actual electricity consumption (measured at the customer meter).

[84] More information about these technologies is in section VIII.F.1 of the final EGs.

[85] Estimated losses in MWh, total electric supply, and direct electricity use values are available in the U.S. EIA’s State Electricity Profiles. See table on Supply and Disposition of Electricity (currently Table 10). Direct electricity use refers to the electricity generated at facilities that is not put onto the electricity grid, and therefore does not contribute to T&D losses.

- How the accuracy and reliability of quantifying MWh savings values will be assessed, and the rigor[86] of the methods used to control the types of bias or error inherent to the applied EM&V methods. Sampling of populations is appropriate, provided that the quantified MWh derived from sampling have at least 90 percent confidence intervals whose end points are no more than +/-10 percent of the estimate.
- How double counting will be avoided through the use of tracking and accounting procedures to ensure that the same MWh of electricity savings is not claimed more than one time (for example, two EGUs claiming savings from the same lighting retrofit). The types of double counting that may arise are discussed in the EPA’s draft EM&V guidance.

(4) Use of Energy Efficiency EM&V Protocols.

In the CPP EG’s public comments, the EPA heard that EM&V protocols for demand-side EE are currently in wide use, and that they should be continued and encouraged. The agency agrees with this observation and is therefore proposing the application of industry best-practice protocols and procedures for demand-side EE. In particular, the EPA is proposing that, to be presumptively approvable, EM&V plans must specify the use of best-practice protocols and procedures, and must also include a clear description and documentation of how the relevant protocols and procedures will be applied. EM&V reports must include documentation of how such protocols and procedures were actually applied. EE providers can refer to the EPA’s EM&V

[86] Rigor refers to the level of effort expended to minimize uncertainty from factors such as sampling error and bias. The higher the level of rigor, the more confident one is that the results of the EM&V activities are both accurate and precise.

guidance document for information about protocols that are considered “industry best-practice protocols and procedures.”

(5) Eligible Demand-Side Energy Efficiency Programs and Projects.

There has been stakeholder interest expressed through the CPP EGs rulemaking process in allowing states to issue ERCs for quantified and verified MWh savings from DS-EE under state plans. Consistent with these perspectives, the EPA is proposing that any demand-side EE program, project, or measure that results in MWh savings may be potentially eligible to generate ERCs, including under this proposed model trading rule, provided that they meet the presumptively approvable provisions for eligibility described in section IV.C.3 of this preamble, and that supporting EM&V is rigorous, transparent, credible, complete and fulfills the requirements provided in the EGs and the state plan. Examples of potentially eligible demand-side EE program and project types include:

- Publicly or utility-administered EE programs, including those implemented in low-income residences and facilities.
- Project-based EE evaluated site-by-site, for example those implemented by ESCOs at commercial buildings and industrial facilities.
- State and local government building energy code and compliance programs.
- State and local government incremental product energy standards.

The EPA’s EM&V guidance contains supplemental information about applicable best-practice protocols, methods, and other key considerations for quantifying and verifying savings from the above-listed EE activities in an accurate and reliable manner. The agency also recognizes that the programs and policies listed above will evolve and change over the rule period, as new technologies emerge and efficiency improves. The agency also expects that new EE program types will emerge and expand throughout the rule period, and that MWh savings resulting from any such programs can similarly be considered if they meet the requirements of the EGs.

(6) Requests for Comment on Energy Efficiency EM&V.

We take broad comment on each EE EM&V criterion described herein and in the proposed rule text, for each type of EE activity, project, program, or measure. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level detail provided regarding these criteria and whether more or less detail (and what detail) should be included in the final model rule. In addition, we seek comment on whether some of the EE EM&V criteria (and if so, which criteria) included in the draft guidance document released simultaneously with this proposed rulemaking should instead be included in the final model rule, instead of in guidance. Similarly, we seek comment on whether some of the EE EM&V

criteria (and if so, which criteria) included in the proposed model rule should instead be addressed in the final EM&V guidance. More generally, we seek comment on what EE criteria the EPA should described in guidance versus what criteria the EPA should specify in the final model, whether or not those criteria are already included in the draft guidance or draft model rule.

We take broad comment on the appropriate EE EM&V criteria for quantifying the electricity savings from every type of EE program, project, or measure. We take broad comment on what constitute EE best-practice protocols and procedures for every type of EE program, project, or measure.

We take broad 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. We also take comment on whether some alternative metric should be used in lieu of the common practice baseline and, if so, what that metric should be.

We take broad comment on the appropriateness of quantifying electricity savings by applying one or more of the following methods and comment on all aspects of each method: project-based measurement and verification (PB-MV), comparison group approaches, or deemed savings. We take further comment on circumstances in which it is appropriate (or inappropriate) to use each of these methods, including when it is appropriate to use random control trials (RCT) and quasi-experimental methods, and the circumstances in which they can be encouraged and applied in practice (e.g., when a suitable control or comparision group can be identified and applied in a cost-effective manner). In addition, we take comment on whether the general suitability and applicaton of quantification methods, such as RCT, quasi-experimental techniques or other comparison group approaches when they are available at reasonable cost for purposes of quantifying MWh savings for particular EE programs, projects, or measures.

If deemed savings are to be used in quantifying electricity savings from an EE program, project, or measure, we take comment on the appropriate characteristics and presumptively approvable provisions for their use in generating qualifying ERCs, including the basis and frequency for their determination, and the appropriateness of their application to particular EE programs, projects or measures in particular states or regions. We further take comment on the presumptively approvable provision for public access and input to the development of the TRMs used to house the applicable deemed savings values.

We take comment on the minimum and maximum intervals (in years) over which electricity savings must be quantified, including those time intervals specified in the proposed model rule, and we take comment on any factors that must be taken into consideration when determining the appropriate time interval for specific EE programs, projects, or measures.

Because many states have different EE programs in place today, and we would expect them to leverage these programs if they incorporated EE into a rate-based trading scheme with ERCs, it is theoretically possible that an ERC could be issued in one state that would not have been issued in another, even if both states have rate-based programs in place that meet all of the EGs. The EPA takes comment on what criteria it should include in the final model rule, and what level of details with respect to those criteria that it should include, in order to ensure that an ERC issued for an EE program, project, or measure in one state reflects the same MWh of energy or electricity saved in another state. We further take comment on whether there are provisions that the EPA should include in the final model rule that would prevent an entity seeking to be issued an ERC (whether from EE or energy generation) from forum shopping, in an effort to find a state with standards for ERC issuance that it deems more lenient or less burdensome than those in another state.

We take comment on how to appropriately consider factors that affect energy savings in the quantification and verification process, including those identified in the proposed model rule, and we take comment on whether these factors should be addressed in every plan or just certain types of plans. Such factors may include the effect of changes in independent factors, effective useful life (and its basis), and interactive effects of EE programs, projects, and measures.

We take comment on the circumstances and frequency in which savings verification must occur to ensure that EE measures have been installed, are functioning, and have the potential to save energy.

We take comment on the appropriate steps for avoiding double counting, and how such steps should be documented in an EM&V plan. In particular, we take comment on the circumstances and conditions in which double counting is most likely to occur (including those identified in this section), and the presumptively approvable provisions that must be adopted in state plans for avoiding and mitigating double counting.

We take comment on the appropriate means by which an EM&V plan can ensure the accuracy and reliability of electricity savings estimates, including the necessary rigor of the methods selected to evaluate the electricity savings, the methods used to control all relevant types of bias and to minimize the potential for systematic and random error, and the potential effects of such bias and error. We further take comment on the presumptively approvable provision that samples taken to quantify EE program savings must achieve 90/10 confidence and precision.

We take comment on the presumptively approvable approach to quantifying the electricity savings that result from avoiding a transmission and distribution system loss, including the provisions in the proposed model rule, which specify that each EM&V plan must quantify the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity comsumption measured at the end use meter or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the U.S. EIA State Electricity Profile. We take comment on the appropriateness of including a restriction in the final model rule that no other transmission and distribution loss factors may be used in calculating the electricity savings.

We take comment on any additional criteria that we should include in the final model rule regarding EE EM&V.

h. Skill Certification Standards. Using a skilled workforce to implement demand-side EE and RE projects and other measures intended to reduce CO_2 emissions, and to evaluate, measure and verify the savings associated with EE projects or the additional generation from performance improvements at existing EGU's are both important. Several commenters pointed out that skill certification standards can help to assure quality and credibility of demand-side EE,RE and other carbon emission reduction projects. The EPA also recognizes that a skilled workforce performing the EM&V is important to substantiate the authenticity of emissions reductions.

The EPA agrees that in conjunction with other EM&V measures discussed in this section, and in the context of the model trading rules although this is not an aspect needed for presumptive approvability, states are encouraged to include in their plan a description of how states will ensure that workers installing demand side EE and RE projects, or other measures intended to reduce CO_2 emissions, as well as workers who perform the EM&V of demand side EE and existing EGU performance will be certified by a third party entity that:

- Develops a training or competency based program aligned with a job task analysis and/or certification scheme;
- Engages with subject matter experts in the development of the job task analysis and/or certification schemes that represent appropriate qualifications, categories of the jobs, and levels of experience;
- Has clearly documented the process used to develop the job task analysis and/or certification schemes, covering such elements as the job description, knowledge, skills, and abilities;
- Has pursued third-party accreditation aligned with consensus-based standards, for example ISO/IEC 17024 or IREC 14732.

Examples of such entities include: parties aligned with the DOE’s Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or parties aligned with an apprenticeship program that is registered with the federal Department of Labor (DOL), Office of Apprenticeship; or with a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body can help to substantiate the authenticity of emission reductions due to demand-side EE and RE and other carbon emission reduction measures.

9. ERC Transfers and Trading

All affected EGUs that may be subject to this proposed federal plan would be required to be a part of the allowance tracking and compliance system (ATCS) that the EPA runs, although the affected EGUs that are regulated under the rate-based federal plan would use ERCs as a compliance instrument, not allowances. To register to participate in the ATCS an affected EGU must submit designated representative information. More information on the designated representatives is described above in section IV.D.1 of this preamble. Non-EGUs who wish to participate (e.g., RE sources) may submit registration criteria to participate in the ATCS. The ATCS will allow the trading and holding of ERCs that qualify for CPP compliance in a system that also will be used to determine compliance. Quarterly, an affected EGU under the federal plan must submit information and data consistent with part 75.[87] These quarterly submission dates are the 30th of April, July, October and January corresponding with the quarterly data ending the month previous the submission deadline (e.g., an April 30, 2024 submission would include data from January through March of 2024). The data that are posted online would be publicly available.

Non-EGU ERC generating sources are required to submit generation data annually (see section IV.C.3 of this preamble for a comprehensive discussion of non-EGU ERC generating sources). The data must follow the EM&V procedures delineated in section IV.D.8 of this preamble. Because of the required rigor of the EM&V process, the EPA provides a time frame of January 1 to June 1 of the year that follows the data's inception to complete all EM&V processes (e.g, 2024 RE data must go through the EM&V process and be submitted to the EPA no later than June 1, 2025). After receiving all emission and generation data from ERC generating sources and affected EGUs, the EPA will issue ERCs through a NODA as described in section IV.D.6 of this preamble. The EPA is proposing to issue ERCs annually. ERCs are acquired and traded throughout the compliance period. An affected EGU is responsible to hold sufficient ERCs that qualify for CPP compliance in its ATCS compliance account by November 1

[87] See section IV.D.11 of this preamble for more information.

at midnight of the year following the conclusion of the compliance period.[88]

The process for transferring ERCs from one account to another is quite simple. A transfer would be submitted providing, in a format prescribed by the agency, the account numbers of the accounts involved, the serial numbers of the ERCs involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information were submitted to the EPA and, when the Administrator attempted to record the transfer, the transferor account included the ERCs identified in the form, the Administrator would record the transfer by moving the ERCs from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

10. Compliance with Emissions Standards

Once the compliance period has ended, affected EGUs would have a window of opportunity to evaluate their reported emissions and obtain any ERCs that they might need to cover their emissions during the compliance period. The agency proposes to require sources to demonstrate compliance, i.e., ERC true-up, on November 1 of the year after the last year in the

[88] This true-up process is further described in section IV.D.8 of this preamble.

compliance period. For example, if the first compliance period comprises the three years 2022, 2023, and 2024, then the ERC transfer deadline[89] for that first compliance period (after which point the EPA would evaluate compliance) would be on November 1, 2025. The agency also requests comment on an earlier ERC transfer deadline, such as June 1 or March 1, of the year after the last year in the compliance period. Each ERC issued in the proposed rate-based trading program would, if applied, be averaged into the compliance rate as one MWh of energy with zero CO_2 emissions deemed associated with it for the compliance period that includes the year for which the ERC was issued or be averaged into a later compliance period. Consequently, each affected EGU would need, as of the ERC transfer deadline, to have in its compliance account enough ERCs usable for its compliance obligations for the compliance period. The authorized account representative could identify specific ERCs to be applied, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. The ERCs that are used to meet compliance obligations are moved from the compliance account to the EPA’s retirement account. ERCs that are deducted for

[89] The “ERC transfer deadline” is the deadline for transferring allowances that can be used for compliance in the previous compliance period to a source’s compliance account.

compliance will remain in the system in an EPA account, which ensures they will not be used again.

The EPA will use the submitted generation, CO_2 emissions and ERCs in the affected EGU's compliance account to calculate an average emission rate for the EGU. It is the responsibility of an affected EGU to calculate the number of ERCs that will need to be held in a compliance account to meet the EGU's compliance obligations. The method for determining the quantity of ERCs needed to meet compliance obligations has been discussed previously in an example. To reiterate the process, the affected EGU would need to solve for the number of zero-emitting MWh (i.e., ERCs) that would need to be added to the total MWh of the EGU to make the adjusted emission rate equal to the emission standard.

$$\text{Adjusted Emission Rate} = \frac{\text{Mass of CO2 emitted (lbs)}}{\text{Generation (MWh)} + \text{MWh ERCs}}$$

This equation can be rearranged to:

$$\text{MWh ERCs} = \frac{\text{ass of CO2 emitted (lbs)}}{\text{Adjusted Emission Rate }(\frac{\text{lbs}}{\text{MWh}})} - \text{Generation (MWh)}$$

If an affected EGU fails to hold sufficient ERCs to comply with its emission standard then, upon notification of the deficiency, the owners and operators of the affected EGU must provide, for deduction by the Administrator, two ERCs as soon as available for every ERC that the owners and operators failed to hold as required to cover emissions, in addition to the ERCs owed for compliance in that next period. The owed ERCs will be deducted from the EGU’s compliance account as soon as they are available in this account; the Administrator will not wait until the next true-up date to make this deduction. The two ERCs owed for each ERC needed for compliance is in addition to any other recourse provided in sections 113 (a)–(h) or section 304 of the CAA. This requirement to surrender two times the ERCs needed to make up the shortfall for the prior period is an ongoing obligation until compliance is achieved, and there is an ongoing obligation to comply in the current period. Failure to surrender these replacement ERCs is an additional violation that may be subject to federal enforcement. The EPA solicits comment on sources owing two ERCs to make up for each insufficient ERC in previous compliance periods and whether two for one is the proper make-up rate or whether there should be a stricter or a more lenient ratio.

The EPA believes that it is important to include a requirement for an automatic deduction of ERCs. The deduction of one ERC per ERC that the owners and operators failed to hold would offset this failure. The deduction of another ERC per ERC that the owners and operators failed to hold provides a strong incentive for compliance with the ERC-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance. This is consistent with other existing trading programs.

11. Other ERC Tracking and Compliance Operations Provisions

These sections also would provide that the Administrator could, at his or her discretion and on his or her own motion and consistent with existing federal trading programs, correct any type of error that he or she finds in an account in the ATCS. In addition, the Administrator could review any submission under the rate-based trading program, make adjustments to the information in the submission, and deduct or transfer ERCs based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA including the ARP and Cross State Air Pollution Rule (see, e.g., 40 CFR 72.96, 73.37, 97.427, and 97.428). The EPA solicits comment on potential alternatives for error correction that is simpler or more efficient.

12. Banking of ERCs

The EPA is proposing to allow unlimited banking or ERCs within and between the interim and final compliance periods. This means that if an affected EGU has more ERCs than are necessary during true-up, it may save (i.e., bank) those ERCs for application during a future compliance period. The EPA requests comment on whether there should be a quantitative limit or cap on the number of ERCs that can be banked. The EPA also requests comment on whether an ERC should be eligible to be banked between the interim and final compliance periods. The EPA is also proposing that ERCs will not expire after any duration of time. Other trading rules that the EPA has instituted (e.g., CSAPR) do not have expiration on the tradable properties. The EPA requests comment on the shelf-life of an ERC.

ERC “borrowing” is a flexibility that the EPA is not proposing, but is soliciting comment on. ERC borrowing is the concept that an affected EGU may use an ERC that the EGU will acquire in a future compliance period to meet its current compliance obligations. The EPA requests comment on a methodology that would allow ERC borrowing while maintaining the integrity of the compliance obligations. The EPA also has reservations due to the fact that future ERC generation is not guaranteed.

13. Emissions Monitoring and Reporting

The EPA would require that emission and generation data be reported to the EPA quarterly starting on April 30, 2022, and continuing every 3 months thereafter (i.e., the 30th of April, July, October, and January). The EPA proposes that affected EGUs subject to the rate-based federal plan trading program would monitor and report CO_2 emissions in accordance with 40 CFR part 75. The EPA is proposing to require affected EGUs in all states covered by the rate-based federal plan trading program to monitor and report CO_2 emissions by and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many affected EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 (approximately 10 of these affected EGUs are coal fired with the remainder being gas and oil fired that will qualify for an excepted monitoring methodology) affected EGUs, that would not otherwise be subject to the ARP, will have to purchase and install additional continuous emissions monitoring system (CEMS) and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program. Several of the affected EGUs not otherwise subject to the ARP are subject to the MATS program and therefore will have already installed stack flow rate and/or CO_2 monitors in order to comply with the MATS rule which are also necessary to comply with this rule. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2

and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. The Regional Greenhouse Gas Initiative (RGGI), ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality ensured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs. The majority of the affected EGUs covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

The EPA also requests comment on requiring monitoring and reporting of CO_2 mass and net generation for the year before the initial compliance period begins, i.e., to commence January 1, 2021. Only monitoring and reporting would be required in 2021 – compliance with an enforceable emission standard would commence on the compliance period schedule that is detailed in section III.D of this preamble.

E. Federal Plan and State Plan Interactions

1. Interstate Trading

The EPA proposes that all affected EGUs within states that are covered by the federal plan, if a rate-based federal plan is finalized for two or more states, would be allowed to trade with one another since there will be an assured commonality in the ERC currency and criteria surrounding the trading program. In addition, the EPA proposes, consistent with the provision for “ready-for-interstate-trading” plans in the EGs that affected EGUs located in states with approved ready-for-interstate-trading state plans using the sub-categorized uniform rate standards, and a common credit currency (i.e., ERCs representing one zero-emitting MWh) may trade with affected EGUs operating under the federal trading program established in this federal plan.

Rate-based EGUs subject to the federal plan and rate-based EGUs in ready-for-interstate-trading state plans will be able to trade ERCs seamlessly across jurisdictional borders because of the assurances of being presumptively approvable. Ready-for-interstate-trading states must submit information that lists all affected EGUs and the EGU type to the Administrator to be able to trade within the federal trading program. To be able to trade in the federal trading program an affected EGU that is subject to a ready-for-interstate-trading state plan must: (1) Certify and authorize a designated representative per section IV.D.1 of this preamble; and (2) register a general account in the federal trading program, ATCS, in order to have a means of transferring ERCs with entities operating in the federal trading program. An affected EGU under a state plan will not register a compliance account in the federal system because it will not be demonstrating compliance under the federal plan. Compliance will be achieved in the EGU’s corresponding state plan. Affected EGUs under a state plan have the ability to acquire ERCs through the federal trading program. These ERCs will be stored in the EGU’s general account in the federal trading program. To use these ERCs for compliance purposes, the ERCs must be transferred to the EGU’s compliance account in the state’s program. The EPA proposes to provide software to states to maintain a state’s compliance and tracking program. A state’s program will have the capability to interact with the federal trading program and software, ATCS, for transferring ERCs if the state is ready-for-interstate-trading. A state’s program can be tailored to meet its needs while still providing a platform for a state to be transferring ERCs between the state’s system and the federal trading program. ERCs can flow between a state system and the federal trading program bilaterally. The EPA acknowledges that states may have additional criteria for generating ERCs that are not outlined as part of the federal plan, but because the EPA will have vetted these criteria through a state plan approval these ERCs will be able to be traded within the federal trading program.

2. Treatment of States Entering or Exiting the Trading Program.

The EPA proposes that a rate-based trading federal plan may be replaced by a state plan for a future compliance period. The EPA is proposing that a state must transition to a state plan at the conclusion of a federal plan compliance period. The EPA requests comment on whether there are reasons that a state should be allowed to transition from a federal plan to a state plan in the middle of a compliance period and if so what requirements should be put in place to do so while ensuring the integrity of both the federal plan and the state plan and while enabling the affected EGUs covered by the plans to understand and meet their compliance requirements. If a state subject to the federal plan transitions to a state plan, any affected EGU impacted by the change remains responsible for meeting any outstanding obligations under the federal plan. To make the transition to a state plan, a state must have an approved state plan as laid out in sections VIII.D and VIII.E of the final EGs.

V. Mass-based Implementation Approach

A. Trading Program Overview

In addition to the rate-based implementation approach discussed above, the EPA is proposing a mass-based implementation approach for the federal plan. As with the rate-based approach, this proposed federal plan is also a proposed model trading rule that states can adopt. The mass-based approach that the agency proposes to implement is a mass-based trading program (i.e., an emissions budget trading program, also referred to as an "allowance system"). This section provides a brief overview of the proposed mass-based trading program. The next sections describe the various elements of the proposed trading program in further detail.

A mass-based trading program establishes an "aggregate emissions limit" that specifies the maximum amount of emissions authorized from affected EGUs included in the program, and creates allowances that authorize a specific quantity of emissions. The total number of allowances created are equal to, and constitute, the emissions budget or the aggregated emissions limit expressed in terms of short tons of emissions. The EPA is proposing that allowances be issued in short tons for the federal plan.

Each facility with affected EGUs in the program must surrender allowances equal in number to the quantity of the emissions of its affected EGUs during the compliance period. A facility with affected EGUs may buy allowances from, or transfer or sell allowances to, other affected EGUs or other entities that participate in the market. A mass-based trading program provides sources with great flexibility in choosing compliance strategies.

In the proposed mass-based trading program for the federal plan, the aggregate emissions limit for a state is its statewide mass-based emission goal (or “mass goal”) as finalized in the Clean Power Plan EGs. The proposed approach to linking states for interstate allowance trading is detailed in section III.A.1 of this preamble; in an interstate trading program the aggregate emissions limit is the sum of the mass goals for the covered states.

The EPA believes that a broad trading region provides greater opportunities for cost-effective implementation of controls compared to a smaller region. Therefore, the agency proposes that an affected EGU in any state covered by the proposed mass-based trading federal plan may use for compliance an allowance distributed in any other state covered by the mass-based trading federal plan. The EPA also proposes to provide for allowance trading between affected EGUs and other entities in states with approved mass-based-trading state plans that meet the conditions specified in section III.A.1 of this preamble, above, and affected EGUs and other entities in any state covered by the federal plan mass-based trading program.

A mass-based trading program can provide environmental certainty at lower cost than other policy mechanisms, because it assures the specified emissions outcome while maximizing compliance flexibility available to individual affected EGUs. Further, allowance banking in such a program creates an incentive to make reductions earlier than required. Mass-based trading programs are relatively simple to operate, which reduces administrative time and cost. Additionally, to inform the mass-based trading approach proposed here, the EPA draws upon more than two decades of experience implementing federally-administered mass-based emissions budget trading programs including the ARP SO_2 trading program, the NO_X Budget Trading Program, CAIR, and CSAPR.

In the proposed mass-based trading program federal plans, the emissions limits in each state would be the mass goals that the EPA promulgated in the Clean Power Plan EGs (if there is interstate trading then the sum of the mass goals for the states in the trading program would constitute the aggregate emissions limit). The total amount of allowances distributed in each state for each year would sum to the state’s mass goal for that year. As detailed in section V.E of this preamble, the EPA is proposing that a state covered by the federal plan can determine its own approach to distribute allowances, and believes that state allocation has important merits. The EPA would distribute allowances in a state if the state does not choose to do so, as detailed below.

Each allowance would authorize the emission of one short ton of CO_2 during the compliance period applicable to the allowance's vintage year or a later compliance period. The proposed approach to distribute allowances, including three types of allowance set-asides, is discussed in section V.D of this preamble, below.

After each compliance period, an affected EGU would surrender for compliance an amount of allowances equal to its emissions during the course of the compliance period. See section V.C of this preamble for the proposed length of the multi-year compliance periods. Allowances could be transferred, bought, sold, or banked (carried over for future use) and any party could participate in the allowance market. The EPA is not proposing allowance "borrowing" (i.e., the bringing forward of future-period allowances for use in an earlier period); the multi-year compliance periods inherently provide the flexibility to schedule relatively greater emission reductions for later years within each period, as discussed further in section V.C of this preamble. In the proposed mass-based trading program, the emission standard applied to individual affected EGUs is the requirement to surrender emission allowances equal to reported emissions for each compliance period.

The EPA also proposes that a state may choose to replace the federal-plan allowance-distribution provisions with its own allowance-distribution provisions (i.e., to determine the distribution of allowances for its EGUs or other entities) using a state allowance-distribution methodology. State allowance distribution can have important advantages, because it allows a state to design and shape allowance allocation to its specific goals and characteristics, and because states may have additional flexibility on allocation approaches, including auctions. See section V.E of this preamble for further discussion of the proposed approach for state-determined allowance-distribution methodologies.

This proposed requirement to hold and surrender allowances equal to emissions for each compliance period would apply to all reported emissions from a facility's affected EGUs including any emissions from co-fired biomass if biomass is included as an eligible measure. Section IV.C.3 of this preamble discusses an approach on which the EPA requests comment on the inclusion of biomass as an eligible measure and on a proposed option where the agency would identify qualified biomass feedstocks (i.e., biomass feedstocks that are demonstrated to be a method to control increases of CO_2 levels in the atmosphere) and potential methods for demonstrating compliance, and thus reduce the mass emissions attributed to a biomass co-fired affected EGU. If the EPA took such an approach, then for 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. The EPA requests comment on this approach.

B. Statewide Mass-based Emissions Goals

In the Clean Power Plan EGs the EPA established statewide mass-based emission goals (“mass goals”) for all states that are equivalent to the rate-based goals. As discussed in section V.C of this preamble, below, the EPA proposes to implement the mass-based trading program with multi-year compliance periods that are consistent with the compliance timing provisions in the Clean Power Plan EGs, i.e., two 3-year compliance periods followed by a 2-year compliance period in the Interim Period, and successive 2-year periods in the Final Period. In the Clean Power Plan EGs, the EPA established mass goals for all states for this pattern of compliance periods. The EPA proposes to use those mass goals promulgated in the Clean Power Plan EGs as the mass limits (i.e., emissions budgets) for any state covered by the mass-based trading program (or, if implementing interstate trading, then the EPA would use the sum of a covered group of states’ mass goals as the aggregate mass limit). The EPA is not opening for comment the determinations, made in the Clean Power

Plan EGs, of each state’s mass goals. The mass goals are provided for convenience in Table 8of this preamble.

Table 8. Statewide Mass-Based Emission Goals (“Mass Goals”) (Short Tons)

State	Interim period			Final period
	Step 1 2022-2024	Step 2 2025-2027	Step 3 2028-2029	2030-2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337

Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

C. Compliance Timing and Allowance Banking

The EPA proposes to evaluate compliance (i.e., compare emissions from affected EGUs to allowances held by facilities) in multi-year periods. A multi-year compliance period provides greater flexibility to affected EGUs and reduces administrative burden, compared to a single-year compliance period. The EPA seeks to strike a reasonable balance between providing flexibility and reducing burden while assuring that any noncompliance can be addressed in a timely fashion.

The compliance periods in the proposed mass-based trading program would be the same as promulgated in the Clean Power Plan EGs, i.e., the Interim Period would be divided into three compliance periods: a 3-year compliance period (2022 through 2024), a second 3-year compliance period (2025 through 2027), and then a 2-year compliance period (2028 and 2029), for the Interim Period. As in the EGs, the Final Period would be divided into successive 2-year compliance periods commencing in 2030. The EPA would evaluate compliance only after the end of a compliance period in the mass-based trading federal plan, e.g., if a compliance period is 3 years long, the agency would evaluate compliance only after the end of the third year in the period. The EPA is not reopening for comment the compliance periods promulgated in the Clean Power Plan EGs.

Some existing GHG mass-based trading programs (i.e., emissions budget trading programs) use multi-year compliance periods. The RGGI uses 3-year compliance periods, along with intervening compliance requirements. The RGGI intervening compliance requirement is that sources must hold allowances to cover 50 percent of emissions for the first two calendar years of each 3-year compliance period; at the end of each 3-year compliance period sources must hold allowances to cover 100 percent of emissions for the period and allowances already deducted for the intervening requirement are subtracted from the 3-year obligation.[90] The California Air Resources Board (CARB) Cap-and-Trade Program also uses 3-year compliance periods, along with intervening compliance requirements. The CARB intervening requirement is to evaluate compliance on 30 percent of each source’s previous year’s emissions every year, and evaluate compliance for the remainder of emissions every 3 years.[91] The EPA proposes to evaluate compliance after each multi-year compliance period and is not proposing to implement intervening compliance requirements such as those in the RGGI or CARB programs, however, the agency requests comment on the inclusion of such requirements.

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, “[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.” See e.g., June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting

[90] RGGI, Summary of RGGI Model Rule changes: February 2013. http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_Summary.pdf Accessed June 9, 2015.

[91]Overview of ARB Emissions Trading Program. http://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf. Accessed June 9, 2015.

and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and §112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

The EPA proposes that allowances may be banked for use in any future compliance period, with no restriction on the use of banked allowances, including from the Interim Period (2022 through 2029) into the Final Period (2030 and thereafter). The agency requests comment on the proposal to provide for unlimited allowance banking including the banking of Interim-Period allowances for use during the Final Period.

Allowance “borrowing” is a type of timing flexibility wherein allowances from a future compliance period may be “brought forward” and used for compliance in an earlier compliance period (thus reducing the amount of allowances available for the future period). The EPA notes that the proposed multi-year compliance periods inherently provide the flexibility to emit at relatively higher amounts in earlier years of a given compliance period by using allowances from future years within each compliance period (e.g., if the first compliance period covers years 2022 through 2024, a vintage 2024 allowance could be used to cover a ton emitted in 2022). The EPA is not proposing to allow allowance borrowing across compliance periods in the mass-based trading federal plans; however the agency is requesting comment on the use of borrowing across compliance periods.

Allowance borrowing across compliance periods would increase the complexity of the proposed mass-based trading program and reduce the flexibility for states to replace the federal plan with an approved state plan. First, in order for borrowing to occur, the EPA would have to make allowances from future compliance periods available early so that sources could use these future allowances in earlier compliance periods. The EPA proposes to record allowances in source accounts for one compliance period at a time in order to maximize the opportunities for a state to replace the federal plan (or replace the allowance-distribution provisions of the federal plan) with an approved state plan (or approved state allowance-distribution methodology). The EPA proposes to allow a state to replace the mass-based trading federal plan (or the federal-plan allowance-distribution provisions) with a state plan (or state allowance-distribution methodology) for a compliance period for which the agency has not yet recorded allowances in source accounts. Recording allowances for multiple compliance periods at once – in order to make future-period allowances available for borrowing – would therefore limit these opportunities for states to take over implementation (or implementation of the allowance-distribution).

If allowance borrowing from a future compliance period were allowed, and the EPA provided the opportunity for a state to replace the federal plan for a year for which allowances had already been borrowed and retired for compliance in an earlier period, those borrowed allowances would constitute additional emissions beyond the levels specified in the Clean Power Plan EGs. In that event, the EPA would then need to address whether and how to remove allowances from circulation to prevent inflation of the allowable emissions at affected EGUs in the remaining states subject to the federal plans (to "repay" the borrowed allowances). To avoid disruption to sources already subject to the mass-based trading federal plan, the EPA is not proposing to allow allowance borrowing across compliance periods.

Although not proposing to provide for allowance borrowing across compliance periods, the agency requests comment on the potential inclusion of allowance borrowing in the proposed mass-based trading federal plans, including from how far into the future to allow allowances to be borrowed, how inclusion of borrowing would affect opportunities for states to take over implementation of the EGs (or implementation of the allowance-distribution provisions in the mass-based trading federal plan), how to address removing the extra allowances from circulation that would result if borrowed allowances originate in a state that subsequently withdraws from the mass-based trading program, and on other complexities that borrowing across compliance periods would introduce.

The agency proposes to require sources to demonstrate compliance, i.e., allowance true-up, on May 1 of the year after the last year in the compliance period. For example, if the first compliance period comprises the three years 2022, 2023, and 2024, then the allowance transfer deadline[92] for that first compliance period (after which point the EPA would evaluate compliance) would be on May 1, 2025. The agency also requests comment on an earlier or later allowance transfer deadline.

The EPA proposes to evaluate compliance (i.e., allowance true-up) at the facility level, not at the individual affected-EGU level, in the mass-based trading program. Facility-level compliance may ease implementation compared to unit-level compliance; each facility has a single compliance account in which to hold allowances to cover emissions from all its

[92] The "allowance transfer deadline" is the deadline for transferring allowances that can be used for compliance in the previous compliance period to a source's compliance account. For further information see section V.G of this preamble.

affected EGUs rather than having individual unit-level compliance accounts. Fewer accounts may make it easier for the designated representatives to manage their allowances. The EPA has adopted facility-level compliance in previous emissions budget-trading programs including the ARP (70 FR 25162), the CAIR (70 FR 25162), and the CSAPR (76 FR 48208). The EPA would continue to track unit-level emissions – while evaluating compliance at the facility level – allowing us to track increases and decreases of pollutants at individual EGUs.

D. Initial Distribution of Allowances

Establishing a mass-based trading program requires that policymakers establish an approach for the initial distribution of allowances, historically referred to as “allowance allocation.” The EPA believes that states may be well positioned to design their own allowance distribution approach because they can take into account a wide range of considerations and tailor decisions to the particular characteristics and preferences of their state. The EPA proposes that states have the flexibility to determine their own approach for distributing allowances in the federal plan, through a process that is detailed in section V.E of this preamble. The EPA believes that states should have the opportunity to make decisions about allowance distribution and that they may have additional flexibility on approaches, including allowance auctions. The EPA is also proposing an allocation approach that we intend to use in the event we implement the federal plan in a state that does not choose to determine its own allowance-distribution approach. The EPA is requesting comment on all of these, and any other, approaches to distribute allowances.

The initial allowance allocation approach that is based on historical data does not affect the environmental results of the program or generation patterns; regardless of the manner in which allowances are initially distributed, the finite total number of allowances limits allowable emissions across all affected EGUs. Allowance allocations also are not intended to prescribe or suggest any unit-level compliance requirements nor do they limit unit-level operational flexibility, because a mass-based trading program provides operators of affected EGUs with the flexibility to buy, sell, or bank allowances. Allowance allocation is simply a procedure by which allowances are distributed into the marketplace so that they may be available for affected EGUs to acquire as desired to authorize emissions under the program. However, because these allowances are finite in number and thus a limited resource, they have value, and as a result, initial allowance allocations may raise issues of equity among recipients.

Thus the agency recognizes that its choice of allocation methodology is important from the perspective of distributional effects, and the importance of selecting an approach that is fair and reasonable in light of this consideration and the overall purpose of CAA section 111 informs the agency's thinking in this proposal. We also invite comment on these considerations, and on any other factors or considerations which commenters believe should inform the allocation method.

The EPA believes that the most reasonable basis for an initial allowance allocation procedure is an approach that uses historical data reported by the affected EGUs subject to the requirement to hold allowances under this program. This approach relies on known data rather than future projections. The EPA believes this approach is preferable because any approach tied to future indicators (e.g., the expected future EGU-level pattern of emissions or the ultimate use of allowances) would depend on future outcomes that the EPA cannot project with perfect certainty in advance. Basing allocation on historical data is also consistent with the EPA's approach to initial allowance allocation under previously established mass-based trading programs.

The EPA proposes to allocate most CO_2 emission allowances to existing affected EGUs in each state covered by a final mass-based trading federal plan, with set-asides for a portion of allowances (discussed in more detail below). For each compliance period, the agency would distribute CO_2 allowances in each covered state in the amount of the state's CO_2 "mass goal" (i.e., the state's CO_2 statewide mass-based emission goal as promulgated in the Clean Power Plan EGs) for that compliance period. For example, if a compliance period is 3 years long, the EPA would aggregate and distribute allowances for all 3 years at the same time. The agency is not proposing to allocate allowances to new EGUs, which do not have a compliance obligation under this proposed federal plan. For each year of the program, the agency proposes to allocate most of the allowances directly to affected EGUs using a historic-generation based approach. The EPA is also proposing three set-asides of allowances, which are detailed below.

Although the EPA cannot anticipate the future EGU-level pattern of emissions, it is possible to consider potential future emission patterns at the source subcategory level. In developing the Clean Power Plan EGs, the agency conducted analysis of emission reduction potential in the two affected EGU source subcategories, i.e., electric utility steam generating units (steam generating units) and NGCC units. With that analysis as a basis, the EPA is requesting comment on an alternative allocation approach that would first divide the total number of allowances from each state's mass goal into source subcategories based on analysis done in developing the source category-specific CO_2 emissions performance rates promulgated in the EGs and then allocate to affected EGUs within each category based on shares of historic generation. This alternative is described later in this section.

The EPA recognizes that states may prefer different approaches to distribute CO_2 allowances from the EPA's approach and that there may be advantages in having states tailor and apply their own allocation approach. Therefore, the agency is proposing that a state may choose to replace the federal-plan allowance-distribution provisions with its own allowance-distribution provisions, using any approach to distribute allowances that the state chooses, including methods that the EPA is not proposing here, provided that the state's approach addresses emissions leakage and includes a Clean Energy Incentive Program. The proposed requirements for addressing leakage, as well as how the EPA proposes to implement the Clean Energy Incentive Program for the mass-based federal plan, are detailed in sections V.E and V.D.4 of this preamble, respectively.[93]. The EPA proposes that a state could choose its own method for distributing allowances for any compliance period including the first period that would commence in 2022. The proposed process for a state to replace federal-plan allowance-

[93] As detailed in section V.E in this preamble, a state that chooses to determine its own allowance-distribution approach under the proposed federal plan may do so through its allocation strategy (such as the set-aside approaches in section V.D.3) or may make a justification regarding leakage as detailed in section V.E.

distribution provisions with its own allowance-distribution provisions is detailed in section V.E of this preamble.

The following sections discuss and request comment on the EPA's proposed approach to allocate CO_2 allowances to affected EGUs based on shares of historic generation, the proposed timing of allowance recordation, three proposed allowance set-asides, allocations to units that change status, and the proposed approach for states to replace federal-plan allocation provisions with their own allowance-distribution approaches. In addition, we request comment on alternative allowance distribution approaches – such as auctioning or allocations to load-serving entities – that the EPA or states might adopt. The EPA requests comment on all of these aspects of allowance distribution.

1. Proposed Allocation Approach and Alternatives

The EPA proposes to allocate most of the CO_2 allowances in the mass-based trading program to affected EGUs based on historic generation (output) data. The EPA also proposes three allowance set-asides. The first would set aside a portion of allowances in each state from the first compliance period only; this set-aside is for a proposed Clean Energy Incentive Program that is detailed in section V.D.4 of this preamble. The second would set aside a portion of allowances in each compliance period except for the first period; the EPA proposes to distribute allowances from this set-aside to affected EGUs via an updating output-based approach as detailed in section V.D.3 of this preamble). The third would set aside 5 percent of allowances in each state, in all compliance periods, to be distributed to RE projects as detailed in section V.D.3 of this preamble. In summary, the proposed set-asides include:

(1) Clean Energy Incentive Program. This set-aside would be of first compliance period allowances only.

(2) Output-based allocation set-aside. This set-aside would start in the second compliance period and continue for each compliance period.

(3) Renewable energy set-aside. This set-aside would be implemented in all compliance periods.

This section describes the proposed historic-generation-based approach that the agency would use to allocate all allowances except for the set-aside allowances. The EPA is proposing affected-EGU-level allocations (based on available data) in every state. Further detail on this proposed allocation approach is provided in the Allowance Allocation Proposed Rule TSD in the docket. The affected-EGU-level allocations resulting from this proposed historic-generation-based approach are provided in the docket in an appendix to the TSD. The agency requests comment on the proposed historic-generation based allocation approach and on other allocation approaches.

The EPA proposes to allocate the historic-generation-based portion of the allowances (i.e., the mass goal minus the set-asides[94]) to individual affected EGUs based on each affected EGU's share of the state's historic generation, using 2010 through 2012 data. The calculation steps for this proposed historic-generation–based allocation approach are as follows:

> (1) For each unit in the list of likely affected EGUs in each state, identify annual net generation values for the historic period of 2010 through 2012 (reflecting affected-EGU-specific generation assumptions incorporated in the data adjustments, e.g., assumed capacity factor for "under construction" units). For a year for which an affected EGU has no generation data (e.g., a year before the year when a unit started operating), assign the affected EGU a value of zero.[95] (See step 2, below, for how zero values would be treated in the calculations.)
> The EPA proposes to use a 3-year historic period (i.e., 2010 through 2012) to reflect unit-level operations over time. In the Clean Power Plan EGs, the EPA identified a reasonable basis for using aggregate data at the regional level largely based on the most recent data year (in that case, 2012) to inform the establishment of category-wide EGs (as opposed to individual, unit-specific parameters). As a distinct matter, in this context the EPA is considering data at the unit level to inform unit-specific initial allowance allocations; notwithstanding that these allowance allocations do not impose any unit-level compliance requirements in and of themselves, the EPA finds it reasonable to consider a multi-year data period to inform unit-level initial allocations in

[94] In the first compliance period this would be the mass goal minus the Clean Energy Incentive Program set-aside and the RE set-aside. In all other compliance periods this would be the mass goal minus the output-based allocation set-aside and the RE set-aside.

[95] The EPA proposes that for affected EGUs that were under construction and began operation during 2012 or after 2012 (and thus don't have a full year of generation data from the 2010 through 2012 period), the allocation calculations be based on the same 2012 generation estimate as the agency used in the Clean Power Plan EGs for the goal-setting calculations. That is, the EPA proposes to estimate 2012 generation for such units based on a unit's net summer capacity and assuming a 55 percent capacity factor for gas units and a 60 percent capacity factor for steam units.

order to consider a broader range of unit-specific operations over time.

(2) Determine each affected EGU's average generation value by averaging all (non-zero) 2010 through 2012 annual generation values for the unit. The proposed approach would use only non-zero values in calculating a unit's average generation. For example, if generation data for a unit were available for only 2011 and 2012 then the EPA would only use the 2011 and 2012 values to determine the unit's unadjusted average generation value. The EPA included generation from all units in the historic data set in the proposed allowance calculations and calculated allowances for all such units; the agency requests comment on the treatment of generation from and allocations to units that operated in the historic data set but retire before the start of the program.

(3) In each state, sum the average generation values from all affected EGUs to obtain that state's "total average historic generation."

(4) Divide each affected EGU's average generation value by the state's total average historic generation to determine that affected EGU's share of the state's total average historic generation.

(5) Multiply each affected EGU's share of the state's total average historic generation by the historic-generation-allocation portion of the state's mass goal (i.e., the state's mass goal minus the set-asides) to determine that affected EGU's allocation.

The agency believes that this proposed historic-generation-based allocation approach is a reasonable approach for several reasons:

- The agency believes that the proposed historic-generation-based approach maximizes transparency and clarity of allowance allocations. The EPA has placed in the docket the historic generation data and the calculations used to determine the proposed affected-EGU-level allocations. The agency also placed the proposed affected-EGU-level allocations, resulting from these calculations, into the docket. These calculations can be relatively easily replicated.

- To calculate allocations, the EPA proposes to use historic affected-EGU-level net generation data compiled using a methodology similar to the Emissions & Generation Resource Integrated Database methodology. The proposed calculation approach is described further below and in the Allowance Allocation Proposed Rule TSD in the docket. The historic-data methodology is described in the CO_2 Emission Performance Rate and Goal Computation TSD for CPP Final Rule. The majority of the generation-unit-level data in this approach are from reports that emissions sources submit to the EPA under 40 CFR part 75 and to the EIA on forms EIA-860 and EIA-923. The EPA believes these are the best data available to the agency at the time of this proposed rule for calculating affected-EGU-level allocations.
- Allocating based on historic data (as opposed to data not yet reported) allows for the distribution of allowances prior to the start of the program, which can facilitate compliance planning.

The proposed approach is transparent, based on reliable data, and, like the approaches used in the NO_X SIP Call, the ARP, and CSAPR, based on historic data. For all these reasons, the agency believes that it is appropriate to use a historic-generation-based allocation methodology in this proposed rule. The EPA also requests comment on a historic-data approach based on historic emissions.

The proposed historic-data-based allocations approach would not generally affect the ultimate pattern of generation across individual power plants, as compared to other methods of allocation. The combination of plants, and their contributing generation, that will be used to meet a particular demand for electric power will be based on the relative efficiency (cost of production) of available plants. The relevant measure of this efficiency is the marginal cost of generation, which for a particular power plant would be the sum of the cost of additional fuel to generate an additional MWh, additional maintenance costs to increase output by an additional MWh, and costs associated with the additional emissions that result from generating an additional MWh. In a mass-based trading program, additional emissions must be covered by additional allowances, so the cost of emitting is the price of the allowances that must be consumed to authorize those emissions. These emissions-related costs of electricity production are the same regardless of whether the allowances used to cover those emissions were initially allocated to the user or whether they were acquired subsequently in the marketplace.

The same concept applies to any other cost of electricity production. For example, a coal-fired EGUs operator would account for the cost of consuming coal to produce generation whether or not the coal was discovered already on-site, given to the unit at “no charge”, or purchased from the marketplace; in all cases, the combustion of that coal consumes its value (i.e., it can no longer be sold). Similarly, the approach taken to distribute allowances does not affect the cost accounting for emissions at units because the use of any tradable allowance has an opportunity cost – a firm loses the opportunity of selling an unneeded allowance when it emits an additional ton. Because a firm loses the opportunity of selling an unneeded allowance when it emits an additional ton, even the emission of a ton covered by a “free” allowance causes the generator to incur the cost of emissions based on the market price of allowances the owner must forgo by emitting that ton and using that allowance.

The proposed historic-data based allocation approach would not be expected to have any effect on freely competitive electricity markets, because the marginal cost of emitting under the mass-based trading program is determined by the level of the overarching mass goals and is not affected by the distribution of the underlying allowances. This marginal cost of emitting is what will inform prices, outputs, and competition among power plants. While cost-of-service markets are structured differently from competitive markets, the regulated utility still makes the dispatch decision on the basis of marginal costs among the units in its fleet, which is not affected by the amount of allowances that any particular unit in that fleet was initially allocated (assuming a competitive allowance market).

The EPA recognizes that some stakeholders are concerned about the potential future distribution of emissions at the facility level, and possible effects on communities. However, for the reasons discussed in the above paragraphs, allowance allocations that do not change based on future activity (such as allocations under the proposed historic-generation based approach) do not affect the distribution of emissions under the program. This proposed rule is expected to achieve significant emission reductions across the electric power sector; see section IX of this preamble for discussion of anticipated broad benefits to communities.

In addition to the proposed historic-data-based allocations approach, the EPA also requests comment on other allocation approaches. One alternative approach on which the agency requests comment is similar to the proposed approach in that it allocates allowances based on historic generation. However, this alternative approach would divide the total number of allowances from a state's mass goal (minus the set-asides) into affected EGU source categories – based on analysis done in developing the source category-specific CO_2 emissions performance rates promulgated in the Clean Power Plan EGs – before determining unit-level allocations. The EPA requests comment on this alternative approach because dividing the allowances in a state by source category in this manner may result in an initial distribution of allowances that would be closer at the source-category level to the future category-level pattern of emissions, and thus to allowances ultimately used, than the proposed approach. To the extent that this category-level division of allowances is a reasonable proxy for the future category-level emissions pattern under the program, this approach may reduce wealth transfer between parties that occurs as a consequence of a less-anticipatory initial allocation procedure. The EPA cannot observe in advance the future affected-EGU-level pattern of emissions.

In this alternative approach, for each state the EPA would multiply historic steam-generating-unit generation by the steam-generating-unit source category-specific CO_2 emissions performance rate, and multiply historic NGCC-unit generation by the NGCC-unit source category-specific CO_2 emissions performance rate. The EPA would do these calculations for each of the compliance periods in the Interim Period using the glide path interim performance rates, and for the Final Period using the final performance rates. These performance rates are shown in Table 6 in section IV.B of this preamble, above. The EPA established the source category-specific emissions performance rates in the Clean Power Plan EGs (see section VI of the final EGs); these rates are not within the scope of this proposed federal plan rulemaking. Next, for each compliance period the EPA would split the total number of allowances from the state's mass goal (minus the set-asides) into affected-EGU source categories in proportion to the values resulting from the above calculation. The EPA would then allocate the steam–generating-unit portion of the allowances to individual SGUs using the same historic-generation based approach described above, and would also allocate the NGCC-unit portion of the allowances to individual NGCC units using the historic-generation based approach.

The EPA notes that there are multiple approaches that policymakers may use to distribute allowances, beyond the proposed or alternative allocation approaches we included in this proposed rule. Examples of other allocation approaches include allocating based on historic heat input (fuel) or historic emissions data, rather than historic generation data. The choice to use historic data for allocation (e.g., generation, heat input, or emissions) means that the distribution of allowance value will be based on past behavior. For example, allocations based on historic emissions would benefit those that have historically been the largest emitters, whereas allocations based on historic heat input or generation (output) would benefit those that have historically used the most fuel or generated the most electricity.[96] Alternatively, allocations could be distributed based on projected or observed future activity (e.g., generation, heat input, or emissions).

[96] Tools of the Trade, A Guide to Designing and Operating a Cap and Trade Program for Pollution Control, EPA, 2003.

The proposed and alternative allocation approaches would determine most of the allocations before the start of the program. Other potential allocation approaches would change allocations for future compliance periods based on future activity – referred to as “updating” allocations. This proposed rule includes an updating-allocation component, as we are proposing to set aside a portion of the allowances in each state for distribution using an updating output-based approach as detailed in section V.D.3 of this preamble. The EPA requests comment on the use of other updating allocation approaches.

Another allowance allocation approach that could minimize the difference between the initial allowance allocation and the ultimate distributional pattern of allowance use for compliance is to conduct an auction, a process whose express intent is to align the allocation of a scarce good (in this case, the limited authorization to emit CO_2) with the parties most willing to pay for its use. Many ascribe benefits, in terms of economic efficiency, to the use of auctioning as a means of allocating allowances. The EPA notes that some states (e.g., RGGI participating states) have used auctions to distribute allowances and have used auction revenues for a variety of purposes, including the implementation of demand-side EE measures intended to help reduce electricity rate impacts and overall program costs, as well as targeted investments in low-income communities. The EPA believes that if it conducted allowance auctions, any revenue from such auctions received by the agency must be deposited in the U.S. Treasury under federal law.[97] As a result, the EPA notes that states implementing state plans may have greater flexibility than the federal government would to direct auction funds for particular activities. The agency requests comment on the idea of auctioning all, or a portion of, each state's allowances in the proposed federal plan, on how much of each state's allowances to auction if not the entire amount, on the frequency (e.g., yearly or every few years), design of auctions (e.g., spot or advance; first, second-price or other) and who may participate in the auction.

The EPA requests comment on an alternative approach, which is allocating a portion of the allowances to load-serving entities (LSEs) rather than to affected EGUs. LSEs are the entities responsible for delivering power to retail consumers.

Allocation to LSEs can help mitigate bill impacts on electricity consumers when applied in concert with certain additional design features. In particular, if LSEs commit and/or are required to pass through to ratepayers the value from their

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[97] The EPA believes authority to conduct auctions is located in CAA section 111 alone, as well as by its reference to CAA section 110(c) FIPs. The statutory definition of a FIP authorizes "techniques (including economic incentives, such as marketable permits or auctions of emissions allowances)." 42 U.S.C. 7602(y).

selling of the allocated allowances, this approach can mitigate the impact of electricity bill increases on consumers that might otherwise result from application of the federal plan. As described in the Allowance Allocation TSD, this type of approach can also help to avoid or mitigate the potential for windfall profits for affected EGUs. The EPA could apply this approach by conditioning the receipt of allowances by LSEs on the pass through to consumers of any allowance value if necessary.

The EPA requests comment on the design and utility of allocating allowances to LSEs to help mitigate electricity price impacts. In particular, the EPA requests comment on options to establish conditions requiring pass through of allowance value and verification of such pass-through, whether it would be appropriate to identify any conditions related to equitable distribution of allowance value among ratepayer categories, as well as the EPA's legal authority to apply any such conditions.

The EPA requests comment on the additional design aspects of any potential allocation to LSEs, including but not limited to the following questions: In particular, what metric should provide the basis for LSE allocation, e.g., electricity demand served by the LSE, population served by the LSE, emissions associated with generation serving the LSE, or some other metric. If emissions are used as the basis for such allocation, what approach should be taken: on a historic basis or a continually updated basis, on the basis of estimated emissions for the relevant region or some other basis, and using what data to calculate such emissions. Also, the EPA requests comment on the form by which LSEs may distribute the allowance value to rate-payers, e.g. as a fixed amount, through reduced rates, etc. Finally, the EPA requests comment on what share of the total number of allowances should be distributed to LSEs and what monitoring and reporting requirements may be necessary to support an effective program.

The EPA requests comment on the proposed historic-generation based allocation approach, the alternative approach that divides total allowances from a mass goal into source subcategories before allocating to individual affected EGUs within each source category based on historic generation, and on the other alternative approaches described in this section. The EPA also requests comment on allocating allowances to all generation in a state (including non-emitting generation) using a historic-generation based approach. The agency also requests comment on the proposed allowance set-asides, which are detailed below. The agency requests comment on allocation approaches that may minimize the impact of this proposed rule on small entities. The EPA also requests comment on any other approaches to distribute allowances. The agency notes that we propose to provide that any state may choose to replace the federal-plan allocation provisions with an allocation approach of its choosing as discussed below. Finally, with regard to alternative allocation methodologies (either those specifically mentioned in this proposal or other allocation methodologies), the EPA requests comment on how those alternatives would satisfy the requirement that in a mass-based program where new sources are not included as part of the program, the allocation methodology must address leakage to new fossil fuel-fired sources.

2. Timing of Allowance Recordation

The proposed historic-data-based allocation approach – which the EPA proposes to use to allocate all of the allowances in each state except for the set-aside allowances – is a one-time determination that is not updated. The allocations resulting from this approach would be determined prior to the start of the program. The EPA proposes to record the historic-data based allowances for each compliance period in source accounts prior to the start of each compliance period, and to record allowances for one compliance period at a time. Recording allowances prior to the start of a compliance period provides certainty to affected EGUs of their allocations in advance of when the allowances are needed for compliance and can facilitate long-term planning. Recording allowances for one compliance period at a time provides flexibility for a state to replace the federal plan with its own plan in a timely way. As discussed in section V.F of this preamble, the EPA proposes to allow a state to replace the federal plan with its own approved state plan, for a compliance period for which allowances have not yet been recorded (the proposed schedule for allowance recordation is detailed below). The EPA also proposes that a state could choose to replace the federal-plan allocations to its affected EGUs (and other entities) with its own allocations approach, for a compliance period for which allowances have not yet been recorded as detailed in section V.E of this preamble.

The agency proposes to record allowances for the mass-based trading program in accounts of affected EGUs 7 months prior to the start of each compliance period. For example, if compliance periods are 3 years long and the first compliance period comprises the years 2022, 2023, and 2024, the EPA would record allowances for 2022, 2023, and 2024 by June 1, 2021. The EPA requests comment on the proposed approach of recording allowances 7 months prior to the start of each compliance period, and on an alternative of recording allowances 13 months prior to the start of each compliance period. See section V.D.3 of this preamble for timing of recordation of allowances from the proposed set-asides.

3. Allowance Set-asides to Address Leakage to New Sources

In addition to the general allocation method proposed above, the EPA is proposing two additional components of allowance allocation under a mass-based federal plan. These two set-asides are being proposed to satisfy the requirement in the final guidelines that mass-based plans demonstrate that they have addressed the risk of leakage to new unaffected units, as specified below.[98]

The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs preamble as the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. The final EGs specified that mass-based plan approaches must address leakage, because the form of the mass goals may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether the mass goal implements or is consistent with the BSER and overall emissions from the sector. These circumstances are much less likely to be present under a rate-based plan approach, where the form of the goal ensures sufficient

[98] The EPA is also proposing a third set-aside, for a Clean Energy Incentive Program, which is detailed in section V.D.4 of this preamble, below.

incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates. By requiring mass-based plan components that address leakage, the final EGs ensure that mass goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. Section VII.D of the final EGs details the requirement for addressing leakage and why it is needed, and section VIII.J of the final EGs specifies options for mass-based state plan components that address leakage. We are proposing, as part of the mass-based approach under the federal plan and model rule, to implement allowance allocation approaches to address leakage, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE.

As noted in the EG, if a state were to adopt allowance set-aside provisions exactly as they are outlined in this model rule once it is finalized, the requirement for that state plan to address leakage would be considered presumptively approvable.

Section VIII.J of the final EGs provides a discussion of how set-asides can effectively address leakage in a mass-based plan approach. That section of the final EGs also describes why the allowance allocation alternative for addressing leakage must be chosen for the federal plan and model rule proposal instead of the option to regulate new non-affected fossil fuel-fired

EGUs. This is because the EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include new sources under a federal mass-based plan approach.

The set-asides we are proposing – described in detail below - would establish a pool of allowances that would be allocated to affected EGUS or other entities based upon criteria designed to address leakage.

These set-asides are essentially a type of “economic incentive” authorized by the CAA as a means of pollution prevention and control, and the expected benefits of this particular type of economic incentive to address leakage make it appropriate here.[99] The EPA believes these set-aside programs are both authorized and consistent with the purpose of the Clean Power Plan under CAA section 111(d) and the specific requirements specified in the final guidelines. They do not have the effect of increasing the stringency of the federal plan because the overall budget of allowances (representing allowable emissions) remains the same.

The EPA is aware of the successful use of set-asides and similar programs in other emissions trading programs. The

[99] In designing a federal plan under CAA section 111(d), the EPA recognizes its authority as being, in some sense, the same as that available under CAA section 110(c), where the use of economic incentives is authorized. See 42 USC 7602(y) (authorizing use of “economic incentives” in FIPs).

following are examples of set-asides and similar programs used in other federal air quality rules, and in state-based GHG regulatory programs.

The EPA has previously established set-asides of emissions allowances in FIPs under CAA section 110. For example, in the CSAPR, the EPA used a 5 percent set-aside for new units, because we believed it was "important to have a small new unit set-aside in each state to cover new units within the budget that was set aside in order to address the state's significant contribution and interference with maintenance." (75 FR 45310; Aug. 2, 2010). This was important, in the EPA's view, because it allowed for growth in the electric utility sector consistent with the EPA's modeling, where new units showed up in the modeling output as surrogate facilities representing potential new EGUs that come online in future years in response to demand increases or other market drivers.[100] As between a choice of requiring these new units to purchase their allowance on the open market, versus being treated in the same manner as existing – and generally understood to be less efficient and more polluting – units, i.e., by being eligible to receive an initial allowance allocation out of the new unit set-aside, the EPA chose the latter.

[100] See also EPA, Allowance Allocation Final Rule TSD, EPA-HQ-OAR-2009-0491, at 3-4 (June 2011).

As part of the ARP under Title IV of the 1990 CAA Amendments, Congress established a “conservation and renewable energy reserve” account. CAA section 404(f), 42 U.S.C. 7651c(f). This is in essence a set-aside account of SO_2 allowances which the regulated utilities could earn by undertaking “qualified energy conservation measures” and “qualified renewable energy” projects. The size of the reserve was set at 300,000 allowances, and utilities could earn one SO_2 allowance for every 500 MWh of energy saved through DS-EE savings or RE generation. In the first years of the program, utilities received bonus allowances equivalent to close to 3,000 tons of avoided SO_2 emissions, while achieving co-benefits from reductions in other pollutants, and, in the words of one industry representative, “creating a culture change where utilities are looking for opportunities everywhere.”[101] The reserve program was nonetheless undersubscribed, and the EPA and other parties have learned from this case and made adjustments to similar programs to promote participation. This proposal seeks to minimize the administrative burden associated with participation in this rule’s proposed set-asides.

In the NO_X SIP Call, the EPA encouraged states to “consider including energy efficiency and renewables as a strategy in

[101] U.S. EPA, Acid Rain Program, Conservation and Renewable Energy Reserve, EPA 430-R-94-010 (Nov. 1994).

meeting their [emission] budgets. One way to achieve this goal is including a provision with a state's NO_x Budget Trading Rule that allocates a portion of a state's trading program budget to implementers of energy efficiency and renewable energy projects that reduce energy-related NO_x emissions during the ozone season." See 63 FR 57356, 57438 (Oct. 27, 1998). A number of states created RE and demand-side EE set-asides in their SIPs in response, and later, for the implementation of CAIR. A "roundtable" meeting with 25 states in 2006 indicated that states that had established these programs were generally having success with them, and provided a forum for exchanges of ideas on how to handle a variety of implementation issues, such as over- and under-subscription, application issues, compliance and verification, the appropriate size of a set-aside account, how to garner public input on which projects are selected, and other issues.[102] In general, the EPA believes its experience and those of the states with these set-aside programs support the view that they are an effective means to spur clean energy projects,

[102] U.S. EPA, State Clean Energy-Environment Technical Forum Roundtable on State NOx Allowance EE/RE Set Aside Programs, Call Summary (June 6, 2006), available at http://www.epa.gov/statelocalclimate/documents/pdf/summary_paper_nox_allowance_6-6-2006.pdf.

which in turn we believe can help to reduce the risk of leakage in this instance.[103]

Below, the EPA describes two potential allowance set-asides. First, the EPA proposes a set-aside for allowances distributed to existing NGCC units based on output (i.e., output-based allocation) to mitigate emission leakage to new sources. Second, the EPA proposes a set-aside for electricity generation from qualifying renewables. This set-aside also addresses the potential for leakage to new sources, as increased RE capacity can serve electricity demand in place of new sources. The EPA also solicits comment on other set-aside options that could address leakage, including a set-aside that provides an incentive for demand-side EE. The EPA seeks comment on all aspects of the set-aside options specified in this section. This includes the inclusion of a set-aside, the method for allocation of allowances to set-asides, the size of the set-asides, the requirements for the process of distribution,

[103] The agency has extensive experience in the design and establishment of set-aside programs. See, e.g., Guidance on Establishing an Energy Efficiency and Renewable Energy (EE/RE) Set-Aside in the NOx Budget Trading Program (March 1999), available at http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol1.pdf; Creating an EE and RE Set-aside in the NOx Budget Trading Program: Designing the Administrative and Quantitative Elements (April 2000), available at http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol2.pdf; Creating an EE and RE Set-aside in the NOx Budget Trading Program: Evaluation, Measurement, and Verification of Electricity Savings for Determining Emission Reductions from Energy Efficiency and Renewable Energy Actions (July 2007), available at http://www.epa.gov/statelocalclimate/documents/pdf/ee-re_set-asides_vol3.pdf.

eligibility requirements for receiving set-aside allowances, the proposed process for redistribution of undistributed allowances from each set-aside, and any other appropriate set-asides.

a. Set-asides for Output-based Allocation

The EPA is proposing a set-aside approach referred to as output-based allocation, which provides targeted allocations of a limited portion of allowances to existing NGCC units as a means of mitigating leakage. The EPA believes that this proposed set-aside would reduce incentives for generation to shift away from EGUs covered under mass-based plans to new unaffected EGUs. We seek comment on all aspects of this proposal and its underlying rationale.

Under the output-based allocation approach we are proposing, beginning with the second compliance period, a portion of the total allowances within each mass-based federal plan state would be allocated to existing NGCC units based, in part, on their level of electricity generation in the previous compliance period. Each eligible EGU would get a larger allowance allocation from this set-aside if it generates more, such that owner/operators of eligible EGUs will have an incentive to generate more in order to receive more allowances. Because the total number of allowances is limited, this allocation approach will not exceed the overall emission goal. Instead, it merely modifies the distribution of allowances in a manner designed to align the generation incentives for eligible EGUs in mass-based states with new emitting EGUs that are not subject to a mass-based limit, mitigating emissions leakage.

The EPA is inviting comment on key parameters for the appropriate design of the output-based allocation approach used for this proposed set-aside. Key parameters to be identified under the output-based allocation approach include which affected EGUs receive the allocation, the timing of the set-aside's allocation procedure, the allocation rate(s), and the size of the set-aside. The EPA also invites comment on what other parameters may be relevant for design of an appropriate output-based set-aside.

The EPA first solicits comment on which EGUs should be eligible to receive output-based allocation from the set-aside. The EPA proposes that only NGCC units subject to the final EGs receive output-based allocation from the set-aside. The EPA recognizes that performance of output-based allocation may be improved by targeting which units receive this additional incentive. In particular, this approach can most effectively address emission leakage if targeted to those affected EGUs subject to a mass goal that face the greatest difference in their incentive to generate relative to otherwise similar EGUs that are not subject to a mass goal. As noted in the discussion of the allocation rate below, new combustion turbines (i.e., NGCC units and simple cycle combustion turbines) would be expected to generate more absent this set-aside. Therefore, the difference in generation incentives between affected stationary combustion turbines subject to a mass goal and otherwise similar new stationary combustion turbines that are not subject to a mass goal is likely one of the most salient deviations in production incentives to address.

The EPA also requests comment on extending output-based allocation from this set-aside to affected SGUs. Output-based allocation for SGUs may increase generation subject to the mass limit, leading to reduced generation and emissions from new emitting sources. However, the EPA does not propose this approach because it is not as effective as output-based allocation to NGCC units. This is because output-based allocation to SGUs would incentivize generation from relatively high-emitting EGUs, which would likely increase allowance prices as other emission reductions are made to respect the overarching mass limit. This approach would thus strongly counteract the intended effect of lowering the production cost from sources subject to the proposed mass-based federal plan (compared to emitting sources not subject to the plan). The EPA also requests comment on extending output-based allocation from this set-aside to zero-emitting generators (including both renewable and nuclear generation), and how the design of the OBA set-aside for such generators would differ relative to the NGCC approach (e.g., the amount of allowances earned per MWh, the capacity-factor threshold, the size of the total set-aside).

The EPA also proposes that this approach be targeted towards marginal generation that may not have otherwise occurred absent this set-aside, by providing allocations under this set-aside only to eligible EGUs that exceed a 50 percent capacity factor on a net basis over the compliance period, and only for the portion of their generation that exceeds that capacity factor.[104]

The EPA also solicits comment on the timing of the OBA set-aside’s allocation procedure, which involves the relationship between the time at which eligible generation occurs and the vintage year(s) of the allowances allocated from this set-aside to recognize that generation. The EPA is proposing a lagged accounting procedure for this set-aside, where eligible generation that occurs during a given compliance period would receive allowances through this set-aside taken from vintage years in the subsequent compliance period. In keeping with this lagged accounting procedure, the EPA is proposing not to reserve any allowances of vintage years during the first compliance period (2022-2024) for allocation through this set-aside;

[104] Effectively, the allocation rate (defined below) of output-based allocation is zero up until this average capacity factor.

eligible generation that occurs during the first compliance period would be recognized through this set-aside with allowances of vintage years from the second compliance period (2025-2027).

The EPA is proposing this lagged accounting procedure because the amount and location of eligible generation in any given compliance period remains uncertain until the compliance period has ended and the relevant data has been reported and verified. Without this lagged accounting procedure, the EPA would have to withhold an amount of allowances for this set-aside from certain vintage years even as the corresponding compliance period was already underway. Given the size of this proposed OBA set-aside in certain states, the EPA believes it would be more advantageous for affected EGUs to know in advance how many allowances they will be allocated in a given period, inclusive of allowances allocated through this OBA set-aside.[105]

The EPA requests comment on options for the allocation rate under this approach. The allocation rate is the number of allowances, in an amount equal to a specific amount of emissions, that the affected EGU receives per one net MWh of generation eligible for the set-aside. The EPA proposes to set

[105] The EPA recognizes that under this lagged accounting procedure, if the federal plan is replaced by a state plan in a future compliance period, the incentive to create eligible generation in the last compliance period subject to the federal plan is potentially diminished.

the allocation rate equal to the emission rate standard (on a net basis) for new NGCC units under 111(b), in order to align the generation incentives across EGUs eligible for the set-aside and the type of new emitting source that would generate more absent this set-aside. Specifically, an additional MWh of eligible generation would earn the affected EGU allowances equal to the level of emissions permitted per MWh of net generation under the 111(b) new source standard, which is 1,030 lbs/MWh-net (Carbon Pollution Standards for new, modified, and reconstructed EGUs). The EPA requests comments on other values for the allocation rate. For example the allocation rate may be the expected net emissions rate of newly constructed NGCC units, the historic average emissions rate from NGCC units, or the NGCC or fossil steam source category-specific emissions performance rates promulgated in the Clean Power Plan EGs (see section VI of the final EGs).

The EPA proposes to calculate an NGCC unit’s capacity factor based on the previous compliance period’s net generation and the net summer capacity of the unit. The EPA is proposing to require affected EGUs to report net generation to the agency.[106] The EPA proposes to use net summer capacity as reported to EIA.

[106] See section V.H of this preamble for proposed monitoring and reporting requirements. The EPA proposes to make the reported generation data available to the public on the agency’s Web site.

In the alternative, the EPA proposes to require that NGCC units report net summer capacity directly to the EPA by adding it as a required data field in the certificate of registration that a unit's owner or operator would submit to the agency (see section V.H of this preamble). The EPA notes that the EIA net summer capacity data is reported at the generator level; if we add this data point to the certificate of registration it would be reported at the affected-EGU level, which would facilitate calculation of capacity factors. The EPA also requests comment on whether the "maximum load value," which is a parameter that EGUs report to the EPA in their monitoring plans, is a reasonable proxy for EGU-level net summer capacity for these calculations. The EPA also requests comment on an alternative approach of basing the capacity-factor calculation on nameplate capacity instead of net summer capacity, or other approaches to the calculation.

The EPA proposes to determine the size of the output-based set-aside once, before the start of the program, and not to change the size thereafter. The EPA proposes to determine the size of the set-aside assuming that it would incentivize existing NGCC to increase utilization to a 60 percent capacity factor. The assumed 60 percent capacity factor offers a way to limit the size of this set-aside, which allows the remainder of the allowances in a given compliance period to be allocated through the historic-generation approach (as detailed above) and the other proposed set-asides (as detailed below). Furthermore, limiting the size of the set-aside avoids the risk of incentivizing too much generation from eligible sources, as discussed further in the Allowance Allocation Proposed Rule TSD.

The EPA proposes to determine the size of the output-based set-aside using 2012 baseline data from the Clean Power Plan EGs.[107] The EPA would calculate the size of the set-aside as 10 percent of the NGCC capacity in the state[108] multiplied by the hours in a year multiplied by the allocation rate for the set-aside. The EPA takes comment on the proposed capacity data used as the basis for determining the size of the output-based set-aside, and alternative sources of capacity data that may be used for determining its size.

The set-asides resulting from this proposed approach are shown in Table 9 of this preamble. The set-asides in the table would apply to every compliance period except for the first compliance period for which there would be no output-based set-aside. Although the size of the set-aside would remain the same for each compliance period, as the mass goals decrease with each

[107] CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule.

[108] The sum of net summer capacity for affected NGCC units in the 2012 baseline for the Clean Power Plan EGs (CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule).

step in the Interim Period and to the Final Period, the set-asides would constitute an increasing share of a state’s mass goal. The Allowance Allocation Proposed Rule TSD further details the proposed approach to determine the size of the set-aside. The EPA requests comment on a potential limit for the size of the set-aside in a compliance period based on a percentage of the state’s total allowances for the compliance period.

Table 9. Proposed Size of Output-Based Set-Aside for the Second Compliance Period and Later(Short Tons)

State	Allowances in output-based set-aside
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671

Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167
Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

Given the proposed limit on the total size of the set-aside, and the amount of potential generation eligible for the set-aside, there may be fewer allowances available in the set-aside than can be earned at the allocation rate. The EPA proposes that, if the amount of total generation eligible for the set-aside multiplied by the allocation rate exceeds the size of this set-aside, then the allowances in this set-aside would be allocated to eligible generation on a pro-rata basis.

The EPA proposes that if the number of allowances allocated from the set-aside is less than the size of this set-aside, then the remaining allowances would be distributed to all affected EGUs using the historic-generation based-approach described above.

The EPA proposes to provide notice of the capacity and generation data used to calculate allocations from the set-aside, and the resulting allocations, by August 1 of the first year in each compliance period, e.g., by August 1, 2025 for the compliance period that commences in 2025 (and based on the data from the prior compliance period). The agency proposes to provide 30 days for comment on the data and allocations, until August 31, and to provide notice of the final set-aside allocations by November 1 of the same year and record the allocations in the source accounts at that time. The EPA requests comment on other approaches to providing notice of the data and allocations.

The EPA requests comment on all aspects of the proposed approach to calculate output-based set-aside allocations. Further details are in the Allowance Allocation Proposed Rule TSD in the docket.

b. Set-asides for Renewable Energy Projects

The EPA proposes to provide a set-aside of allowances for distribution to RE in each state covered by the proposed mass-based federal plan, and is also proposed for the mass-based model rule. The agency is also taking comment on whether distribution should extend to demand-side energy efficiency (DS-EE) and CHP projects. Under this program, the EPA would reserve a percentage of each state's allowances in a set-aside account for each state. Developers of RE projects could apply to receive set-aside allowances based on the projected generation from eligible RE capacity.

This set-aside is expected to address concerns regarding leakage by lowering the marginal cost of production of the incented clean energy technologies within the state. This will make RE more competitive against new sources, reducing the potential for leakage to new sources. While the proposed set-asides would provide additional incentive for the creation of additional RE capacity, it should also be noted that the proposed mass-based trading program itself would provide incentive for new and existing low and zero-emitting generation.

In the context of the proposed federal plan, the EPA is proposing that it would create a unique set-aside for each state covered by a mass-based federal plan. Under a model rule, the state would create this set-aside. The allowances in each set-aside would be reserved from each vintage of the assigned mass goal to that state prior to allocation of allowances to sources. The EPA is proposing that 5 percent of allowances will be reserved from the allocation for each state for the purpose of the set-aside. We are also requesting comment on options for a percentage of allowances to be reserved ranging from 1 to 10 percent of total allowances in each state. The proposed percentage has been determined to provide a meaningful additional incentive for RE activities in each state, while assuring that the vast majority of allowances are freely allocated to affected EGUs. The EPA made this conclusion based upon determining an appropriate volume of set-aside resources that, at a range of possible allowance prices, are projected to incent the development of additional RE projects. The analysis is provided in the docket as part of the Allowance Allocation Proposed Rule TSD. We note that, under the proposed framework, these allowances would be available to affected EGUs either in the marketplace or through subsequent distribution of unclaimed set-aside allowances, and thus the provision of these set-asides does not affect the overall stringency of the program.

In section V.D.5 of this preamble, below, the EPA is proposing that the size of the RE set-asides may grow over time as certain units shift out of the program.

We are proposing, as part of the mass-based federal plan and model rule, that a project is eligible to receive set-aside allowances if it is RE that meets the eligibility requirements for rate-based ERC issuance as specified in section IV.C of this preamble and section VIII.K of the final EGs. This includes, for example, the requirement that only capacity incremental to 2012 is eligible for the set-aside. The agency is requesting comment on an additional potential condition that would limit eligibility to project providers that are also the owners or operators of affected EGUs. This approach has precedent in the eligibility requirements for the ARP set-aside, and would limit the entities eligible to receive set-aside allowances to those that are subject to the federal plan.

The EPA is proposing that eligible RE capacity must meet the following conditions regarding geographic eligibility for both the federal plan and model rule. Eligible RE projects must be located in the mass-based state for which the set-aside has been designated. The agency invites comment on whether capacity outside the state should be recognized, and how that could be implemented. The EPA also proposes that the generation for which an entity receives allowances from the set-aside would not be eligible for ERC issuance in rate-based states.

As specified in section IV.C of this preamble, the EPA is proposing that the same RE measures are eligible to receive set-aside allowances under a mass-based federal plan as would be eligible for ERC issuance under a rate-based federal plan and the model rule. Specifically, the following RE measures are eligible: on-shore wind, solar, geothermal power, and hydropower. The RE measure must also have the capacity to provide data quantified by a revenue-quality meter, a requirement that is further discussed in section IV.D.8 of this preamble. New nuclear units and capacity uprates at existing nuclear units are not proposed to be eligible to receive set-aside allowances, as we do not think a set-aside used as an incentive for incremental nuclear capacity is a useful way to address leakage to new sources during the performance period, due to unique costs and development timelines for incremental nuclear power. All other proposed aspects of the RE eligible measure types described in section IV.C of this preamble and the requests for comment included within that section also apply in the mass-based set-aside context for both the proposed mass-based federal plan and the proposed mass-based model rule. For example, we are requesting comment on the inclusion of other RE measures, incremental nuclear, demand-side EE measures, CHP and any other emission reduction measures beyond those mentioned here, as long as they meet the eligibility requirements outlined in the final EGs for rate-based crediting, as eligible measures to receive set-aside allowances. We particularly request comment on how a set-aside to provide an incentive from these particular measures will serve to address leakage to new sources. We also request comment on the implications of the inclusion of such technologies for the streamlined implementation of projection-based EM&V requirements of the set-aside specified below in a federal plan context across the applicable jurisdictions, while still maintaining necessary rigor. We request comment on the appropriateness of the biomass treatment requirements offered for comment in section IV.C.3 of this preamble in the context of a mass-based set-aside. We request comment on requirements for the treatment of CHP and WHP, in the context of the mass-based set-aside. We also request comment on appropriate processes through which, after the federal plan is finalized, the EPA and/or stakeholders could make a demonstration of the appropriateness of new measure types and the EPA could evaluate and approve the demonstration so that a new measure type can be considered eligible for the set-aside.

To demonstrate that an RE project meets the requirements proposed above, in the context of a mass-based federal plan, it is proposed that the project proponent must provide the following: documentation of the nature of the project and that it meets eligibility requirements, documentation that it will be located within the state in question, and a projection of expected annual MWh generation for an RE project. The EPA must approve the documentation of eligibility and the projection of MWh before the project becomes eligible for a distribution of the set-aside allowances. In addition, the proponent must register for a general account in the EPA tracking system where the allowances would be recorded. See 40 CFR 62.16320 for the requirements to establish a general account. While the EPA is proposing to allow eligible resources to use a general account to receive any allowances allocated under this section, the EPA requests comment on extending the designated representative provisions in 40 CFR 62.16290 to eligible resources instead of the general account provisions. Requiring eligible resources to submit information similar to that collected in the certificate of representation in 40 CFR 62.16305 and to appoint a designated representative to act on behalf of all owners/operators for all projects requesting allowances may improve the EM &V process by making the eligible resources more accountable. The EPA requests comment on what documentation would be required if other measure types were considered eligible to receive set-aside allowances. We propose that the same process for approval of projects be applied in a model rule, with the state taking the approving role instead of EPA.

The EM&V requirements for the mass-based set-aside differ from those for rate-based ERC issuance, particularly because it is based upon projections provided prior to generation rather metered data provided after the generation occurs (though we are proposing that the projections will be checked against ex-post metered data). The projection method enables the distribution of set-aside allowances prior to the year during which the generation occurs. The EPA feels this still provides sufficient rigor because the set-aside does not directly affect program stringency. The reason that stringency is not affected is because of key differences between issuance of credits and distribution of set-aside allowances. Under rate-based implementation, each decision to issue an ERC based on a quantification of RE generation affects the ultimate amount of allowable CO_2 emissions, because the number of ERCs is determined by the amount of MWhs approved as eligible for ERC issuance and the ERC does not exist until the issuance decision is made. Thus the amount of ERCs that are issued can affect the stringency of the rule. As a result, the EPA has laid out specific requirements (including EM&V procedures) in the final CPP, and in this proposed federal plan and model rule, to assure the environmental reliability of measures qualifying for ERC recognition under rate-based implementation. In contrast, any decision to recognize RE with set-aside allowance allocations under a mass-based approach does not affect the validity of the allowance itself and does not affect the CO_2 emissions outcome because the ultimate amount of allowable CO_2 emissions is determined by the total number of allowances initially created (regardless of how they are distributed). As a result, while the EPA believes it is reasonable to consider a minimum set of qualifications for recognizing RE through these allowance set-asides to assure that the RE generation that is incented is actually produced, the EPA does not believe the overall integrity of mass-based implementation is significantly affected by the robustness of whatever eligibility requirements the EPA ultimately sets for RE recognition through allocation from these set-asides. This being said, the agency is proposing to require robust demonstrations of the eligibility and EM&V projections for RE generation submitted for the set-aside, demonstrations that are based in the best practices of existing programs. This is necessary to assure the delivery of RE as a result of the set-aside.

The EPA proposes that the projections of MWh provided will be the basis of the distribution of set-aside allowances. A satisfactory demonstration of the future RE generation from an eligible project must use technically sound quantification methods that are reliable, replicable, and accompanied by underlying analytical assumptions and verifiable data sources used to demonstrate future performance. These methods, assumptions and data sources must be specified in documentation accompanying the projections. These projections and supporting documentation should all be provided in the set-aside project application, and that application must be approved by a third-party verifier. The EPA invites comment on these proposed requirements for projections. We also take comment on whether set-asides should be distributed proportional to actual MWh provided by the installation in a prior year or compliance period, or another form of historical generation data. This type of allocation method could also be similar to the structure proposed for the OBA set-aside. We propose that the same projection-based distribution basis be applied in a model rule, with the state taking the approving role instead of EPA.

The EPA is proposing the following process for distribution of RE set-aside allowances. Starting prior to the compliance period, and going forward through the compliance period, RE providers in each state will have an opportunity to apply to the EPA or a designated agent to be approved as eligible to receive set-aside allowances in their state. This application must include all the requirements outlined above, including projections of expected MWh of generation. The EPA is proposing to accept RE set-aside project applications up to a deadline of June 1 in the year prior to the year during which the RE generation occurs (the “generation year”). The EPA or its agent will review and approve the project as eligible and it will be entered into the pool of projects that will receive set-asides in any compliance period. If approved, the number of projected MWh in each generation year will be the basis of the number of allowances the provider will receive, as an input to the methodology specified below. The providers will have an opportunity to update projections for future generation years, these projections must be received by June 1 of the year prior to the generation year in question.

On December 1 of the year prior to each year of the compliance period in question, the EPA is proposing to distribute allowances from the set-aside to approved providers. The agency is proposing to distribute set-aside allowances to approved RE providers pro-rata, with the number of allowances distributed to each provider according to the percentage of total approved RE MWh for that state that the approved MWHs from their project represent. This method is proposed because it treats all eligible RE projects equally in the distribution of set-aside allowance. It also inherently provides a more significant incentive in states with less eligible RE generation, but will become less significant as RE generation increases. We would also like to take comment on whether to restrict projects to a maximum number of allowances they can receive per MWh of generation, such as 1 allowance per MWh.

After each generation year, RE providers receiving allowances will have to provide an M&V report with the MWh of RE generation actually produced, to assure that they have met the projected level of generation. These M&V reports need to document that the generation was by an approved project, and the report should be approved by a third party verifier. As discussed in the rate-based approach EM&V section above, these data should be readily available from existing metering. The EPA requests comment on the process for submitting M&V reports with actual generation.

If the project or program does not reach the MWh projected in a particular generation year, the unfulfilled MWh will be subtracted from that RE provider's MWh eligible for the set-aside in the next generation year, or multiple years if the deficit exceeds the MWhs projected for the upcoming year. If this deficit is greater than 10 percent in a particular year, the provider will need to provide an explanation of the deficit and will be required to reevaluate their projections for future years. If such deficits continue through all 3 years of the any performance period in which they participate, the provider will be disqualified from receiving future set-asides for the following compliance period. We also take comment on whether a provider with continuing deficits should also be disqualified from receiving ERCs for some or all of the remaining performance periods. The agency requests comment on all of the specified aspects of this distribution process.

The EPA is proposing that once allowances have been distributed to all approved providers, any remaining allowances in the set-aside, such as set-aside allowances designated for projects that no longer exist, will be redistributed to affected

EGUs in the state in a pro rata fashion on the same distribution basis as their initial allocations were made. It is proposed that this will occur immediately after the distribution of set-aside allowances to eligible RE providers on December 1 of the year prior to the generation year in question. The EPA requests comment on this approach.

We propose that the same distribution process as outlined above be applied in a model rule, with the state taking the approving role instead of EPA.

The EPA is also seeking comment, in the context of the proposed rate-based federal plan and model rule, on whether a portion of this set-aside should be targeted to RE projects that benefit low-income communities. This benefit could be in the form of MWh provided to the low-income community, financial proceeds from the project primarily benefiting the low-income community, or the project lowering utility costs of low-income rate-payers. The EPA seeks comment on how a low-income community should be defined as eligible under this set-aside. We seek comment on how much of the set-aside should be designated as targeted at low-income communities. We also request comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ from the methods that are proposed to apply to other RE projects.

The EPA seeks comment, in the context of the proposed rate-based federal plan and model rule, on all aspects of this proposed RE allowance set-aside program, including whether it should be included as part of a mass-based federal plan, the structure of the set-aside reserve, eligibility requirements for receiving set-aside allowances, demonstration of eligibility, and the process for distribution of allowances.

4. Provisions to Encourage Early Action

For purposes of the proposed mass-based federal plan, the EPA proposes to implement the Clean Energy Incentive Program (CEIP) on behalf of a state by issuing early action allowances for eligible actions located in or benefitting the state. Eligible projects must commence construction in the case of RE or commence operations in the case of low-income EE after September 6, 2018, and will receive incentives based on the zero-emitting MWh they generate, or the energy savings they achieve,during 2020 and/or 2021.[109] These early action allowances would be drawn from a third set-aside of allowances from the

[109] As discussed in section VIII.B.2 of the final emission guidelines, in the case of a state that submits a final state plan including requirements for the state's participation in the CEIP, eligible RE projects may commence construction, and eligible EE projects may commence implementation, following the date of submission of a final state plan to the EPA. These projects must be implemented in or benefit the state that submitted the final state plan to the EPA, and may receive awards for the zero-emitting MWh they generate or the end-use energy savings they achieve during 2020 and/or 2021.

general distribution methodology. The EPA believes it is reasonable to establish the total amount of the early action-set aside in an amount equal to the pool of matching allowances. Thus, the EPA proposes that the total early action set-aside would be of an amount equal to the pool of matching allowances: no more than 300 million CO_2 allowances, depending on how many states are subject to a federal plan.

The EPA proposes to distribute the 300 million early action set-aside allowances among the states based upon the amount of the reductions from 2012 levels each state must achieve relative to that of the other participating states. The EPA proposes to calculate these values as each state's proportional share of the total difference between the 2012 baseline and the 2030 mass goals.[110] See Table 10 of this preamble for the proposed set-asides for each state under the mass-based federal plan. The agency proposes to set aside 100 million early action allowances from each of the 3 years in the first compliance period (2022, 2023, and 2024) for a total of 300 million allowances to be set aside. While the table shows set-asides for every state, the EPA proposes to implement this set-aside, according to the amounts listed in Table 10, only for those states for whom the EPA is

[110] The 2012 baseline is from the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. Where a state's relative share of the reductions from 2012 levels would yield a set-aside of less than zero, the EPA proposes to assign such a state a set-aside equal to one percent of the state's 2030 mass goal and adjust the remaining state set-asides accordingly.

implementing the mass-based federal plan. The EPA also requests comment on other approaches for determining the size of this set-aside in the mass-based federal plan.

For the purposes of the mass-based federal plan, the EPA is proposing to award early action allowances to two types of eligible projects that are located in or benefit the state for which the EPA is implementing a federal plan:

- RE investments that generate metered MWh from any type of wind or solar resources; and
- Demand-side EE programs and measures implemented in low-income communities that result in quantified and verified electricity savings (MWh).

Eligible RE projects must commence construction, and eligible EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. These projects will receive incentives for the MWh they generate or the end-use energy demand reductions they achieve during 2020 and/or 2021.

The EPA proposes the following framework to implement the CEIP in the mass-based federal plan. First, the EPA proposes to create a set-aside of early action allowances for all federal-plan states, as described above. Second, the agency proposes to create an account of “matching” allowances for each state participating in the CEIP – regardless of whether a state is implementing a state plan or the agency is implementing a federal plan on its behalf. This distribution would reflect each state’s pro rata share of a federal pool of additional ERCs – based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states[111] – which would be limited to the equivalent of 300 million short tons of CO_2 emissions. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal allocation upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021. The EPA intends that a portion of these matching allowances would be reserved for eligible wind and solar projects, and a portion would be reserved for eligible EE projects implemented in low-income communities. The agency recognizes that there have been historic economic, logistical and information barriers to implementing EE programs in these communities, and therefore believes it is appropriate to reserve a portion of the federal pool to incentivize investment in these programs. The EPA is requesting comment on the size of reserve of matching allowances for eligible low-income EE programs as well as for eligible wind and solar projects. The EPA is proposing that unused allowances in either reserve would be redistributed among participating

[111] This is the same distribution method proposed above for the allocation of early action set-aside allowances to mass-based federal plan states.

states. This redistribution could be executed according to the pro-rata method discussed above. Alternatively, unused matching EE or RE allowances could be swept back into a federal pool and distributed to project providers on a first-come, first served basis. EPA requests comment on these ideas as well as alternative proposals regarding the method for redistributing matching ERCs, as well as the appropriate timing for such a redistribution.

Following the effective date of a federal plan for a state, the agency will create an account of matching allowances for the state that reflects the pro rata share of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Any matching allowances that remain undistributed after September 6, 2018[112] will be distributed to those states with approved state plans that include requirements for CEIP participation, as well as to those states on whose behalf EPA is implementing a federal plan. These allowances will be distributed according to the pro rata method outlined above. Unused matching allowances that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA. The EPA seeks comment on whether the number of matching allowances available to a state under the mass-based federal

[112] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

plan should be limited to a number equal to the number of early action allowances included in each federal plan state’s early action set-aside.

Third, for any state subject to a federal plan, the EPA proposes to award early action allowances and matching allowances to eligible projects as follows, based upon the quantified and verified MWh of generation or savings achieved by the projects in 2020 and/or 2021:

- For RE projects that generate metered MWh from any type of wind or solar resources: for every two MWh generated, the project will receive a number of allowances equivalent to one MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to one MWh from the EPA.
- For EE projects implemented in low-income communities: for every two MWh in end-use demand savings achieved, the project will receive a number of allowances equivalent to two MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to two MWh from the EPA.

The EPA will address implementation details of the CEIP in a subsequent action. Allowances awarded by the EPA pursuant to the CEIP may be used for compliance by an affected EGU with its emission standards in any compliance period and are fully transferrable prior to such use. The EPA proposes to distribute any remaining early action set-aside allowances in a state – after distribution to all eligible projects in the state – to the affected EGUs in the state on a pro-rata basis in proportion to the initial allocations made to those EGUs under the mass-based federal plan.

As discussed in section V.E of this preamble, the EPA proposes to allow any state where a federal plan is being implemented to take responsibility for distributing allowances to affected sources. This will allow a state to tailor its allowance-distribution approach to the characteristics and preferences of the state. The EPA proposes that a state that chooses to replace the federal-plan allocations with a state-determined approach must include a CEIP set-aside, as authorized in section VIII.B.2 of the final EGs. The EPA intends that such a state would have the same flexibilities as a state implementing a full state plan with respect to implementation of the CEIP. That is, the state would not be required to implement a set-aside of the same size as proposed in Table 10 of this preamble, but rather could choose how many of its allowances to set-aside for the CEIP.

The EPA requests comment on all aspects of implementing the CEIP under a mass-based federal plan approach, including (1) The size of the early action allowance set-aside; (2) the approach for distributing the early action allowance set-aside among states; (3) the timing of distribution of set-aside and matching allowances; (4) the amount of allowances awarded per eligible MWh generated or avoided; (5) the criteria for eligible projects, including criteria for awards to EE projects implemented in low-income communities; (6) the mechanism for reviewing project submittals and issuing early action allowances; (7) EM&V requirements for eligible projects; and, (8) the number of early action and matching allowances that should be awarded for each ton of emissions reduced from eligible generation or low-income efficiency projects to ensure a robust response to the program. The EPA also seeks comment on how states, tribes and territories for whom goals have not yet been established in the final EGs may be able to participate in the CEIP in the future.

The EPA also requests comment on the proposed approach of requiring states to implement this program as a condition of a state choosing to determine its own allocation approach via a partial state plan or a delegation of the federal plan.

Table 10. Proposed Clean Energy Incentive Program Early Action Allowance Set-Aside in the Mass-Based Federal Plan (Short Tons)

State	**Set-Aside 2022 through 2024**
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929

Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183
Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

5. Allocations to Units that Change Status

Units that retire. The EPA proposes that, if an affected EGU does not operate for 2 consecutive calendar years, the unit would continue to receive allocations for a limited number of years after it ceases operation, after which the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside for the state in which the retired unit is located.[113] Continuing allocations to non-operating units for a period of time reduces the incentive to keep a unit operating simply to avoid losing the allowance allocations for that unit (e.g., a unit that would otherwise be retired due to age and inefficiency). On the other hand, non-operating units are no longer emitting and so do not need allowances. The EPA believes that the proposed approach of allocating allowances for a specified, but limited, period after a unit ceases operating is a reasonable middle ground approach. The proposed approach also allows the RE set-asides to grow over time.

The EPA proposes to record allowances for each year of a multi-year compliance period at once, 7 months prior to the start of each compliance period, as discussed above. The agency proposes that, if an affected EGU does not operate for 2 full

[113] This is similar to the approach taken in CSAPR of continuing allocations to retired units for four years and then allocating the allowances to a set-aside; in CSAPR the set-aside is for new units.

calendar years, then starting with the next compliance period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. As a result, the number of years of non-operation for which a retired unit would receive allocations would vary depending on when a unit retires. For example, if an affected EGU does not operate for the first two calendar years of a 3-year compliance period, then starting with the next compliance period the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside – in other words the unit would receive allocations for 3 years of non-operation. As a further example, if an affected EGU does not operate for both calendar years of a 2-year compliance period, then starting with the compliance period after the next compliance period the allowances would be allocated to the RE set-aside – in other words the unit would receive allocations for 4 years of non-operation.

The agency requests comment on this approach for treatment of allocations to affected EGUs that retire, including on the number of years of non-operation for which a unit would continue to receive allocations. The EPA also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state’s RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the retired units. The EPA also requests comment on treatment of allocations to units that are in long-term cold storage.

Units that are modified or reconstructed. Similar to the approach for an affected EGU that retires, the EPA proposes that, if a unit is modified or reconstructed such that it is no longer an affected EGU, then starting with the next compliance period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. The EPA requests comment on this proposed approach, including on the number of years for which a unit would continue to receive allocations. The agency also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state’s RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the modified or reconstructed units.

D. State-determined Allowance Distribution

The EPA proposes to allow any state to replace the EPA-determined federal-plan allowance-distribution provisions in the mass-based trading program with state-developed allowance-distribution provisions. In this way, a state could choose how to distribute initial allowance allocations among its affected EGUs (and other entities).

The EPA believes that this option may offer significant appeal, because it will allow a state to tailor its allocation approach to the characteristics and preferences of the state. A state would be able to design its allocation approach to address its particular state priorities, whether they are protecting low-income consumers, supporting local industries, or other goals. The EPA anticipates that a state would have great flexibility in its allowance distribution approach and could take advantage of allocation options discussed in this proposal as well as other allocation options a state might prefer. States could auction allowances and rebate the revenue to consumers, or allocate all allowances to load-serving entities, while mandating that the value be passed through to vulnerable consumers. The EPA believes that the state-determined allocation approach offers significant advantages and solicits comment on how to ease its application by states. This is similar to the approach taken in CSAPR and CAIR where the EPA adopted rules allowing states to submit SIPs with provisions replacing the allowance-distribution provisions in the CSAPR or CAIR FIPs, respectively, while remaining in the trading programs under those FIPs (76 FR 48208; August 8, 2011, 71 FR 25328; April 28, 2006). In both CSAPR and CAIR, some states have chosen to determine their own allocations under the FIPs. This form of SIP that can replace the allowance-distribution provisions in CSAPR or CAIR is termed an “abbreviated SIP revision.” In this proposed mass-based trading federal plan, the EPA proposes that a state may choose to submit a “state allowance-distribution methodology” (analogous to an abbreviated SIP revision) to replace the federal-plan allowance-distribution provisions with allowance-distribution provisions of its choosing.

The mechanism the agency envisions is in the nature of a partial state plan or (for any future changes in a state’s allocation methodology) a partial state plan revision. (We request comment below on the advantages and disadvantages of allowing a state to handle allocations via a delegation of federal plan authority.) In general, under the proposed approach, the procedural requirements states and the agency must follow, including public notice requirements, for the submission and approval of state plans, would be required here.

The EPA intends to provide the states with substantial flexibility in choosing approaches to distribute their allowances in a state allowance-distribution methodology. The

EPA proposes that a state may choose any approach, including auctions or other methods the EPA is not proposing here, provided the state's approach addresses leakage and also implements the Clean Energy Incentive Program. The EPA is also requesting comment on any other appropriate constraints to impose on state allowance-distribution methodologies.

The Clean Power Plan EGs require mass-based state plans to include a demonstration that they have addressed the risk of leakage, and the EGs provide several options for doing so (see sections VII.D and VIII.J of the final EGs). One of the options provided in the EGs is to address leakage through an allowance distribution approach that provides incentive to counteract leakage. In the mass-based trading federal plan, the EPA's proposed approach to allocate allowances would address leakage using two allowance set-asides, one for output based allocation and one for RE projects, as detailed in section V.D.3 of this preamble. The EPA believes that a state allowance-distribution methodology, which would replace the federal-plan allocation provisions, must also address leakage. The EPA proposes that a state allowance-distribution methodology must address leakage by providing incentive to counteract leakage, e.g., by including allowance set-asides like the output-based allocation and RE set-asides detailed in section V.D.3 of this preamble, or other allocation approaches designed to counteract leakage. The EPA requests comment on this proposed approach for addressing leakage in a state allowance-distribution methodology and on any other approaches for doing so. The EGs provide an additional option for state plans to address leakage, where a state would provide a demonstration that leakage will not occur (without implementing any of the strategies specified in the EGs) due to specified characteristics of the state (section VIII.J of the final EGs). In this federal plan proposal, the EPA requests comment on an alternative option where a state that chooses to submit a state allowance-distribution methodology could provide a demonstration that leakage will not occur (without implementing the allocation strategies specified here) due to specific characteristics of the state; the EPA proposes that such demonstration must meet the requirements in the final EGs, including support by credible analysis, for such a demonstration (see final EGs section VII.D). The EPA notes that a state's allowance-distribution methodology may also include other set-aside approaches that are not designed to counteract leakage.

The Clean Power Plan EGs established a Clean Energy Incentive Program (section VIII of the final EGs). The EPA proposes that a state allowance-distribution methodology, which would replace the federal-plan allocation provisions, must also include a Clean Energy Incentive Program, as detailed in section V.D.4 of this preamble.

Under the proposed approach of providing for states to determine their allowance distribution approaches in the federal plan mass-based trading program, the affected EGUs in a state that submitted a state allowance-distribution methodology, which the EPA approved, would participate in the federal plan mass-based trading program, but with allowance distribution determined by the state instead of by the EPA.

The EPA proposes that a state must submit to the Administrator tables specifying the unit-level allowances in an electronic format specified by the Administrator and by the specified deadlines applicable to each compliance period (see Table 11 of this preamble for proposed submission deadlines).

The EPA proposes that a state may submit a state allocation methodology for any compliance period, including the first compliance period, which would comprise the years 2022, 2023, and 2024. The EPA proposes that a state submitting a state allowance-distribution methodology to modify the federal plan allowance-distribution provisions must do so for all years within a compliance period (e.g., for all 3 years in a 3-year compliance period).

The EPA proposes that, if the state's allowance-distribution provisions meet certain requirements and the state allowance-distribution methodology does not change any other provisions in the proposed mass-based trading program, then the agency would likely approve the state allowance-distribution methodology. In the state allowance distribution methodology, the state could distribute allowances to affected EGUs or other entities (such as RE facilities) or could auction some or all of the allowances. The agency proposes that for EPA approval, the state allowance-distribution methodology provisions would have to meet the following requirements. The provisions would have to address leakage as discussed above. The provisions would have to provide that, for each year for which the state allowance-distribution provisions would apply, the total amount of allowances distributed could not exceed the applicable mass goal for that state for that year. A state's methodology under this proposed approach could provide that the total amount of allowances distributed is less than the applicable mass goal.[114] The EPA proposes that a state's allowance-distribution provisions would replace the EPA's allocation provisions completely – a state would not have the option of implementing only a portion of its allocations (e.g., only set-asides) and having the EPA implement the remainder of its allocations. Additionally, the EPA proposes that a state allowance-

[114] A state allowance-distribution methodology under this proposed approach, which is analogous to an abbreviated SIP revision, could provide that the total amount of allowances distributed is less than the applicable mass goal, pursuant to the reserved authority to states to set emission standards more stringent than federal standards under CAA section 116.

distribution methodology must provide for allowances to be issued in short tons.

The allocation (or auction) of allowances would be final and could not be subject to modification. Additionally, the state's provisions could not change any other provisions of the proposed mass-based trading program with regard to the allowances (e.g., the deadlines for allocation recordation, or requirements for transfer or use of allowances) or any other aspect of such trading programs.

In order for a state allowance-distribution methodology's provisions to replace the EPA's allowance-distribution provisions for a given compliance period, a state would have to submit the state allowance-distribution methodology by a deadline that would provide the agency sufficient time to review and approve it, and to submit the allowance table meeting the specified electronic format by a deadline that would provide sufficient time to record the unit-by-unit allowances in source accounts. The EPA believes that about 12 months – starting from the date of receipt of a state allowance-distribution methodology – is sufficient to complete the agency's review and approval process, which would have to provide an opportunity for public comment on the approval (or disapproval) action. Thus, the EPA proposes the following deadlines, in Table 11 of this preamble, for submission to the agency of state allowance-distribution methodologies and unit-level allowances, and for the EPA's recordation of allowances, for each compliance period. The EPA would review and approve state allowance-distribution methodologies in the 12 months between the proposed deadline for states to submit their methodologies and the proposed deadline for states to submit unit-level allowance tables. The proposed deadline for submission of allowance tables is 3 months before the proposed deadline for the agency to record allowances in source accounts. The EPA proposes to record allowances in source accounts by the recordation deadlines.

Table 11. Proposed Deadlines for Submission of State Allowance-Distribution Methodologies and Unit-Level Allowances and for Recordation

First compliance period for which allowances would be distributed	Deadline for submittal of state allowance-distribution methodologies	Deadline for submittal of unit-level allowance table	Deadline for the EPA to record allowances
2022, 2023, 2024	March 1, 2020	March 1, 2021	June 1, 2021
2025, 2026, 2027	March 1, 2023	March 1, 2024	June 1, 2024
2028, 2029	March 1, 2026	March 1, 2027	June 1, 2027
2030, 2031*	March 1, 2028*	March 1, 2029*	June 1, 2029*

*This pattern of deadlines would hold for successive 2-year compliance periods.

The proposed deadlines for submission of state allowance-distribution methodologies are later than the state plan submission deadlines promulgated in the Clean Power Plan EGs. The agency anticipates that it can complete the approval process relatively quickly for a state allowance-distribution methodology due to its narrow scope.

The agency proposes to record the EPA-determined federal plan allocations only in the absence of an approved state plan or approved state allowance-distribution methodology. The EPA proposes to record in source accounts allowances that are determined by any state as soon as feasible after approval of a state allowance-distribution methodology and submission of the unit-level allowance table, and not to wait until the allowance recordation deadline to do so.

In section V.D.2 of this preamble, the EPA proposes the allowance recordation deadline 7 months prior to the start of the compliance period (i.e., June 1 of the prior year) and also requests comment on a recordation deadline 13 months prior to the start of the compliance period (i.e., December 1 of the year 2 years before the compliance period starts). If the EPA adopted the earlier recordation deadline on which it requests comment or any other deadline, then we would adjust the deadlines for submission of state allowance-distribution methodologies and submission of unit-level allowance tables accordingly.

The EPA proposes that a state may not replace EPA-determined allocations for a compliance period for which federal plan allocations have already been recorded, for the same reasons that the agency proposes that a state may not replace a mass-based trading federal plan with a state plan for a future compliance period for which allowances have already been recorded, as discussed below in section V.F of this preamble.

The agency requests comment on the proposed approach to allow states to determine allocations via state allowance-distribution methodologies and replace the federal-plan allowance-distribution provisions. The EPA requests comment on the proposed schedule for submitting state allowance distribution methodologies to the agency, for submitting the resulting unit-level allowance tables to the agency, and for the agency to record allowances. The EPA requests comment on its proposed approach of not replacing EPA-determined allocations for a compliance period for which allowances have already been recorded. The agency also requests comment on an alternative approach where a state could notify the EPA of its intent to submit a state allowance-distribution methodology in advance, in which case the agency would hold off on recording EPA-determined allocations to allow more time for state-determined allowances to be recorded, similar to the alternative timing approach discussed in section V.F of this preamble.

The EPA is also requesting comment on an alternative approach to provide the opportunity for a state to determine its allowance-distribution provisions in the federal plan mass-based trading program. The alternative approach on which the agency requests comment is to provide for a partial delegation of the federal plan – limited to the allowance-distribution provisions – to a state that wishes to determine its allowance-distribution provisions. The EPA requests comment on the relative efficiency and ease of implementation of the two approaches (the state allowance-distribution methodology described above, or the partial delegation). The agency requests comment on whether the partial delegation approach would provide sufficient flexibility for a state to choose any method to distribute its allowances including approaches that the EPA is not proposing here. See further discussion of delegations in section VI of this preamble.

E. Treatment of States Entering or Exiting the Trading Program

If the EPA implements a mass-based trading program federal plan for any state, the agency will work with a state that wishes to replace the federal plan with an approved state plan to provide a smooth transition. The EPA proposes that a mass-based trading federal plan could only be replaced by a state plan for a future compliance period for which allowances have not yet been recorded. For example, if a 3-year compliance period comprises 2022, 2023, and 2024, the EPA would record allowances in source accounts for 2022, 2023, and 2024 prior to 2022. Once 2022, 2023, and 2024 allowances had been recorded, the first compliance period for which a state could replace the federal plan with its own plan would be for the period commencing in 2025. The EPA is proposing this stipulation for the timing of replacing a federal plan with a state plan due to the need to avoid disruption to sources already subject to the mass-based trading federal plan. Without this stipulation, a state might withdraw from the mass-based trading program in the middle of a compliance period even though allowances that authorize emissions throughout that entire compliance period would already be in circulation. In that circumstance, the EPA would then need to address whether and how to remove those allowances from circulation to prevent inflation of the allowable emissions at affected EGUs in the remaining states subject to the federal plans beyond the levels specified in the Clean Power Plan EGs. The EPA believes it is more reasonable to avoid this potential disruption by requiring that the replacement of a federal plan with a state plan be scheduled to coincide with the conclusion of the last compliance period for which allowances under the federal plan have already been recorded for that state. The EPA requests comment on other approaches to provide a smooth transition from federal-plan implementation to implementation by state plans, and on its proposed approach of not replacing a federal plan for any compliance period for which allowances were already recorded.

The agency requests comment on an alternative of providing for a state to give notice to the EPA of its intent to submit a state plan to replace the federal plan (or a state allowance-distribution methodology to replace federal-plan allocations), and for the agency to delay recording federal-plan allocations for sources in that state until a later date than proposed. The EPA requests comment on whether this alternative would help smooth the transition from federal-plan implementation to state-plan implementation, and on the trade-off between recording allowances in a timely way and providing this increased timing flexibility.

F. Allowance Tracking, Compliance Operations, and Penalties

The EPA proposes that the mass-based trading program use an allowance tracking and compliance system (ATCS) operated essentially the same way as the existing systems that are currently in use for CSAPR and the ARP under Title IV. Under the proposed mass-based trading program, the CO_2 program would be a separate trading program maintained in the EPA's existing data system. ATCS would be used to track the trading of CO_2 allowances held by covered affected EGUs in facility level compliance accounts, as well as such allowances held by other entities or individuals. Specifically, ATCS would track the allocation of all CO_2 allowances, holdings of CO_2 allowances in compliance accounts (i.e., a facility level account for all affected EGUs at the facility) and general accounts (i.e., accounts for other entities such as companies and brokers), deduction of CO_2 allowances for compliance purposes, and transfers of allowances between accounts. The primary role of ATCS is to provide an efficient, automated means for affected EGUs to comply, and for the EPA to determine whether affected EGUs are complying, with the emissions limitations and any other requirements of the mass-based trading program. ATCS would also provide data to the allowance market and the public, including a record of ownership of allowances, dates of allowance allocations, allowance transfers, buyer and seller information, serial numbers of allowances transferred, emissions, and compliance information. This information would be publicly available on the EPA’s Web site and in annual progress reports.

1. Designated Representatives and Alternate Designated Representatives

The EPA proposes to establish procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of an affected EGU and for changing the designated representative and alternate designated representative. These sections would also describe the designated representative’s and alternate designated representative’s responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions would be patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

The designated representative would be the individual authorized to represent the owners and operators of each affected EGU in matters pertaining to the mass-based trading program. One alternate designated representative could also be selected to act on behalf of, and legally bind, the designated representative and thus the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: specified identifying information for the affected EGU and for the designated representative and alternate; the name of every owner and operator of the affected EGU; and certification language and signatures of the designated representative and alternate. All submissions (e.g., monitoring plans, monitoring system certifications, and allowance transfers) for an affected EGU would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the ATCS for each facility with an affected EGU involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the affected EGU involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (e.g., in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative and alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative and alternate could designate agents to submit electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the mass-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the proposed mass-based trading program.

2. Allowance Tracking and Compliance System

The mass-based trading program rules would establish the procedures and requirements for using and operating the Allowance Tracking and Compliance System (which is the electronic data system through which the Administrator would handle allowance allocation, holding, transfer, and deduction), and for determining compliance with the allowance-holding requirements in an efficient and transparent manner. The ATCS would also provide the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Consistent with the approach in prior EPA-administered trading programs, allowance price information would not be included in the ATCS. The EPA’s experience is that private parties (e.g., brokers) are in a better position to obtain and disseminate timely, accurate allowance price information than is the EPA. For example, because not all allowance transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

3. Compliance and General Accounts

This section describes two types of Allowance Tracking and Compliance system accounts: Compliance accounts, one of which the Administrator would establish for each facility with an affected EGU upon receipt of the certificate of representation for the facility; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any allowances used by an affected EGU for compliance with the emissions limitations would have to be held. The designated representative and alternate for the affected EGU would also be the authorized account representative and alternate for the compliance account. Using facility-level, rather than EGU-level accounts, would provide owners and operators more flexibility in managing their allowances for compliance, without jeopardizing the environmental goals of the mass-based trading program, because the facility-level approach would avoid situations where an EGU would hold insufficient allowances and would be in violation of allowance-holding requirements even though EGUs at the same facility had more than enough allowances to meet these requirements for the entire facility. Facility-level compliance would also be consistent with other EPA-administered mass-based trading programs.

General accounts could be used by any person or group for holding or trading allowances. However, allowances could not be used for compliance with emissions limitations so long as the allowances were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would have to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format prescribed by the Administrator: the name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to allowances, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates.

4. Recordation of Allowance Allocations and Transfers

By June 1, 2021, the Administrator would record allowance allocations for EGUs for 2022 through 2024. Then, by June 1 of the year prior to the beginning of each compliance period, the Administrator would record the allowance allocations for the proposed mass-based trading program for each year within that next compliance period, e.g., for 2025, 2026, and 2027 by June 1, 2024. Recording these allowance allocations in advance of the first year for which they could be used for compliance would facilitate compliance planning by owners and operators and promote robust allowance markets, including futures markets for allowances.

The process for transferring allowances from one account to another would be quite simple. A transfer would be submitted providing, in a format prescribed by the Administrator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information were submitted to the Administrator and, when the Administrator attempted to record the transfer, the transferor account included the allowances identified in the form, the

Administrator would record the transfer by moving the allowances from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

5. Compliance with Emissions Limitations

Once the compliance period has ended (e.g., at midnight on December 31, 2024 for the first compliance period), facilities with affected EGUs would have a window of opportunity following the compliance period to evaluate their reported emissions and obtain any allowances that they might need to cover their emissions during the compliance period. For example, the allowance transfer deadline for the first compliance period would be midnight on May 1, 2025 (the EPA is also requesting comment on earlier or later allowance transfer deadlines). Each allowance issued in the proposed mass-based trading program would authorize emission of one ton of CO_2 and so would be usable for compliance, for the compliance period that includes the year for which the allowance was allocated or a later compliance period. Consequently, each affected EGU would need, as of the allowance transfer deadline, to have in its facility compliance account, or to have a properly submitted transfer that would move into its compliance account, enough allowances usable for compliance to authorize its total emissions for the compliance period. The authorized account representative could identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. Deducting allowances may have tax and accounting implications, so having a default deduction method provides the representatives with certainty regarding which allowances will be deducted for compliance. Allowances that are deducted for compliance will remain in the system in an EPA account, which ensures they will not be used again. If a facility were to fail to hold sufficient allowances for compliance by all affected EGUs at the facility, then the owners and operators of the facility and each affected EGU at the facility would have to provide, for deduction by the Administrator, two allowances allocated for the compliance period in the next year for every allowance that the owners and operators failed to hold as required to cover emissions. This submittal of two times the allowances required for the prior period is an ongoing obligation until compliance is achieved, and there is an ongoing obligation to comply in the current period. In addition, these owners and operators would be subject to civil penalties for each violation in accordance with the CAA, with each ton of unauthorized emissions and each day of the compliance period involved constituting a violation of the CAA.

The EPA believes that it is important to include a requirement for an automatic deduction of allowances. The deduction of one allowance per allowance that the owners and operators failed to hold would offset this failure. The automatic deduction of another allowance per allowance that the owners and operators failed to hold that could not be avoided, regardless of any explanation provided by the owners and operators for their failure, would provide a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance. Such automatic deductions have been successfully used in prior programs including the CAIR, achieving compliance rates close to 100 percent.

6. Other Allowance Tracking and Compliance Operations Provisions

These sections also would provide that the Administrator could, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the Allowance Tracking and Compliance System. In addition, the Administrator could review any submission under the mass-based trading program, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA including the ARP and Cross State Air Pollution Rule (see 40 CFR 72.96, 73.37, 97.427, and 97.428).

G. Emissions Monitoring and Reporting Requirements

The EPA proposes that units subject to the mass-based federal plan trading program would monitor and report CO_2 mass emissions in accordance with 40 CFR part 75.

The EPA is proposing to require affected EGUs in all states covered by the mass-based federal plan trading program to monitor and report CO_2 emissions and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 affected EGUs that would not otherwise be subject to the ARP will have to purchase and install additional CEMS and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program (the EPA anticipates approximately 10 coal fired units and approximately 40 gas and oil fired units will qualify for an excepted monitoring methodology). Several of the units not otherwise subject to the ARP are subject to the MATS program and, therefore, will have already installed stack flow rate and/or CO_2 monitors necessary to comply with this rule in order to comply with the MATS. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. RGGI, ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality ensured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

The majority of the units covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

The EPA also requests comment on requiring monitoring and reporting of CO_2 mass and net generation for the year before the initial compliance period begins, i.e., to commence January 1, 2021. Only the monitoring and reporting would be required in

2021 — compliance with the requirement to hold allowances would commence on the compliance period schedule that is detailed in section V.C of this preamble.

VI. Implementation of the Federal Plan and Delegation

Under section 111(d) of the CAA, the EPA adopts EGs that are then implemented when the EPA approves a state or tribal[115] plan or promulgates a federal plan that implements and enforces the EGs for affected EGUS in states or areas of Indian country[116] without an approved state or tribal plan. Congress has determined that the primary responsibility for air pollution prevention and control rests with state and local agencies, while also recognizing that "Federal … leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution." (See section 101(a)(3) and (4) of the CAA.) Congress has also provided for Indian Tribes meeting specified eligibility criteria to implement the CAA within the exterior boundaries of their reservations or other areas within the tribe's jurisdiction. (See section 301(d)(1) and (2) of the CAA.) Even

[115] AS discussed in (citation) tribes with EGU in their areas of Indian country can apply for TAS for the purpose of developing and seeking EPA approval of a tribal implementation plan (TIP) implementing the EG, but are not required to do so.

[116] As discussed in detail in (citation), in adopting a federal plan implementing the EGs in areas of Indian country containing EGU, the EPA must determine that such a plan is "necessary or appropriate" to protect air quality. See, 40 CFR 49.11(a).

in the event that it becomes necessary for the EPA to directly regulate affected EGUS under CAA section 111(d), states and eligible tribes may still seek a delegation of authority from the EPA to implement a federal plan, similar to the ability to take delegated authority under other CAA programs. The EPA encourages states and eligible tribes that do not submit approvable plans to request delegation of the federal plan if they wish to have primary responsibility for implementing the EG. Approved and effective state or tribal plans or delegation of the federal plan is the EPA's preferred outcome in many circumstances where the EPA believes that state and local, or tribal, agencies have practical knowledge and enforcement resources critical to achieving the highest rate of compliance. Legally, delegation of a standard or requirement means that obligations a source may have to the EPA under a federally promulgated standard become obligations to a state or tribe (except for functions that the EPA retains for itself) upon delegation.[117] [118]

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[117] If the Administrator chooses to retain certain authorities under a standard, those authorities cannot be delegated, e.g., the authority to allow alternative methods of demonstrating compliance.

[118] We note that issuance of a title V permit is not equivalent to the approval of a state plan or delegation of a federal plan. This has been discussed in prior rulemakings, see, e.g., Proposed Federal Plan for Commercial Industrial Solid Waste Incinerators (CISWI) (67 FR 70640, 70652; Nov. 25, 2002); Final Federal Plan for CISWI (68 FR 57518, 57535; Oct. 3, 2003).

A. Delegation of the Federal Plan and Retained Authorities

If a state or tribe[119] intends to take delegation of the federal plan, the state or tribe should submit to the appropriate EPA Regional Office a written request for delegation of authority. The state or tribe should explain how it meets the criteria for delegation. See generally "Good Practices Manual for Delegation of NSPS and NESHAP" (EPA, February 1983). The letter requesting delegation of authority to implement the federal plan should: (1) Demonstrate that the state or tribe has adequate resources, as well as the legal and enforcement authority to administer and enforce the program, (2) include an inventory of affected EGUs, which includes those that have ceased operation but have not been dismantled, include an inventory of the affected units' air emissions and a provision for state or tribal progress reports to the EPA, (3) certify that a public hearing has been held on the state or tribal delegation request, and (4) include a memorandum of agreement between the state or tribe and the EPA that sets forth the terms and conditions of the delegation, the effective date of the agreement and the mechanism to transfer authority. Upon signature of the agreement, the appropriate EPA Regional Office

[119] A tribe interested in taking delegation of the federal plan must also apply, and be approved by the EPA, for TAS eligibility for that purpose. 40 CFR part 49.

would publish an approval notice in the Federal Register, thereby incorporating the delegation of authority into the appropriate subpart of 40 CFR part 62. See also EPA's Delegations Manual, Delegation 7-139, "Implementation and Enforcement of 111(d)(2) and 111(d)(2)/129(b)(3) federal plans." (A copy of this delegation manual has been placed in the docket for this action.)

If authority is not delegated to a state or tribe, the EPA will implement the federal plan. Also, if a state or tribe fails to properly implement a delegated portion of the federal plan, the EPA will assume direct implementation and enforcement of that portion. The EPA will continue to hold inspection, information gathering, enforcement, and other parallel authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. In all cases where the federal plan is delegated, the EPA may retain and not transfer authority to a state or tribe to approve certain items promulgated in the 2015 CAA section 111(d) Clean Power Plan.

This proposed federal plan also specifies that EGU owners or operators who wish to petition the agency for any alternative requirement should submit a request to the Regional Administrator with a copy set to the appropriate state.

B. Mechanisms for Transferring Authority

There are two mechanisms for transferring implementation authority to state and local agencies and tribes: (1) The EPA approval of a state or tribal plan after the federal plan is in effect; and (2) if a state or tribe does not submit or obtain approval of its own plan, the EPA delegation to a state or tribe of the authority to implement certain portions of this federal plan to the extent appropriate and if allowed by state or tribal law. Both of these options are described in more detail below.

1. Federal Plan Becomes Effective Prior to Approval of a State or Tribal Plan

After EGUs in a state or area of Indian country become subject to the federal plan, the state or local agency or tribe may still adopt and submit a plan to the EPA. If the EPA determines that the state or tribal plan is satisfactory and approvable pursuant to the EG, the EPA will approve the state or tribal plan. If the EPA, on review of the submitted state or tribal plan, determines that this is not the case, the EPA will disapprove the plan and the EGUs covered in the state or tribal plan would remain subject to the federal plan until a state or tribal plan covering those EGU is approved and effective. Prior to disapproval, the EPA will work with states and eligible tribes to attempt to reconcile areas of the plan that are unapprovable.

Upon the effective date of an approved state or tribal plan, the federal plan would no longer apply to EGUs covered by such a plan and the state or local agency, or the tribe, would implement and enforce the state or tribal plan in lieu of the federal plan. The timing of effectiveness of an approved state or tribal plan in this circumstance may depend in part on the need to ensure a smooth transition and maintain regulatory certainty. Thus, for example, under a mass-based federal plan, we propose to handle these transitions so that they coincide with the compliance periods. The approval of a state or tribal plan would also involve a public comment process, which would give interested stakeholders including any affected EGUs, the opportunity to comment. This will assist in ensuring that compliance, program integrity, electric reliability, and other critical factors are maintained. When an EPA Regional Office approves a state or tribal plan, it will amend the appropriate subpart of 40 CFR part 62 or 40 CFR part 49, respectively, to indicate such approval, as well as the timing of its effectiveness.

As discussed elsewhere in this document, the EPA may also in certain circumstances approve a partial state or tribal plan (sometimes called an “abbreviated state plan”) that may modify certain limited provisions in the federal plan trading program. For example, this could occur if a state or tribe wishes to handle the initial allocation of allowances in a mass-based trading program, as discussed in section V.E of this preamble. The partial state or tribal plan would allow for the state or tribe to assume direct authority for administering and implementing this aspect of the trading program, while the remainder of the federal plan remains in place. The procedural and submission requirements set forth in the framework regulations of 40 CFR part 60, subpart B and the EGs would generally apply to a partial state or tribal plan, just as they would a full state or tribal plan. The scope of the requirement, however, would be commensurate with the scope of the partial plan. For instance, if a state or tribe seeks approval of a partial plan solely to handle allowance allocations, then the required statement of legal authority would be limited to those legal authorities the state or tribe must have to implement and enforce this component of the trading program.

2. State or Tribe Takes Delegation of the Federal Flan

The EPA, in its discretion, may delegate to state or tribal air agencies the authority to implement this federal plan. As discussed above, the EPA believes that it is advantageous and the best use of resources for state or local agencies or tribes to agree to undertake, on the EPA’s behalf, administrative and substantive roles in implementing the federal plan to the extent appropriate and where authorized by state or tribal law. If a state or tribe requests delegation, the EPA will generally delegate the entire federal plan to the state or tribal agency, thereby providing authority to the state or tribe for things such as administration and oversight of compliance reporting and recordkeeping requirements, inspections of its affected EGUs, and enforcement. The EPA will continue to hold inspection, information gathering, enforcement, and other authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. The delegation will not include any authorities retained by the EPA.

C. Implementing Authority

The EPA Regional Administrators have been delegated the authority for implementing the federal plan. All reports required by the federal plan should be submitted to the appropriate Regional Administrator. Section II.B of this preamble includes Table 2 of this preamble that lists names and addresses of the EPA Regional Office contacts and the states they cover.

With respect to the administration of a federal trading program in any final federal plan for a state or tribe, group of states or combined group of states and tribes, the Office of Air and Radiation within the Headquarters of the EPA is proposed to be the primary office within the agency with delegated CAA section 111(d)(2) authority. See Delegation 7-139, section 3(c).

D. Necessary or Appropriate Finding for Affected EGUs in Indian Country

Indian Tribes may, but are not required to, submit tribal plans to implement the EGs. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (TAS) for purposes of developing and implementing a tribal plan implementing the EG. See 40 CFR 49.3; see also “Indian Tribes: Air Quality Planning and Management,” hereafter “Tribal Authority Rule,” (63 FR 7254, February 12, 1998). We invite tribes with EGU in their area of Indian country to comment on the level of their interest, if any, in developing their own plans.

The EPA is proposing in this action to find that it is necessary or appropriate to regulate affected EGUs in each of the three areas of Indian country that have affected EGUs under the proposed federal plan. The EPA is authorized to directly implement the EGs in Indian country when it finds, consistent with the authority of CAA section 301 which the EPA has exercised in 40 CFR 49.11, that it is necessary or appropriate to do so. In the final EGs, the EPA establishes emission performance rates for the four EGUs located in Indian country and mass and rate-based emission goals for each of the three affected areas of Indian country. These areas include lands of the Navajo Nation’s reservation, lands of the Ute Tribe of the

Uintah and Ouray Reservation, and lands of the Fort Mojave Tribe's reservation. The EPA proposed carbon pollution EGs for EGUs in these areas and U.S. Territories in a Supplemental Notice of Proposed Rulemaking. See 79 FR 65482 (Nov. 4, 2014). The four facilities with affected EGUs located in Indian country that the EPA identified in the Supplemental Notice are: the South Point Energy Center, on the Fort Mojave Reservation geographically located within Arizona; the Navajo Generating Station, on the Navajo Indian Reservation geographically located within Arizona; the Four Corners Power Plant, on the Navajo Indian Reservation geographically located within New Mexico; and the Bonanza Power Plant, on the Uintah and Ouray Indian Reservation geographically located within Utah. The emission performance targets for these areas were finalized along with those for EGU located in the rest of the country in the final EGs.

In this action, we are proposing to find that it is necessary or appropriate, in each of the three areas of Indian country that have affected EGUs, to establish a federal plan that applies to the four power plants located on the Navajo Nation, the Fort Mojave Indian Reservation, and the Uintah and Ouray Reservation of the Ute Tribe. The affected EGUs located on the Navajo Nation are in an area of Indian country located within the continental U.S., are interconnected with the western electricity grid, and are owned and operated by entities that generate and provide electricity to customers in several states. The affected EGU located on the Uintah and Ouray Reservation of the Ute Tribe is in an area of Indian country located within the continental U.S., is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. The affected EGU located on the Fort Mojave Indian Reservation is in an area of Indian country located within the continental U.S., is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. To date, none of the three tribes on whose areas of Indian country the four power plants are located have expressed a clear intent to develop and seek approval of a tribal implementation plan. Thus, absent a federal plan, the significant emissions from these four power plants could go unregulated by the Clean Power Plan.

Because the agency has finalized emission performance targets for these power plants in the EGs, there is, in our view, little benefit to be had by not proposing to include them in a federal plan now and a potentially significant downside to not doing so; the reductions the EPA has determined are achievable in the EGs would become more difficult and costly for these power plants to achieve if they are delayed in entering into the trading program the agency intends to establish. In order to meet the performance targets, we are anticipating that the affected EGUs may need to secure allowances or ERCs (depending on the approach ultimately finalized) during the compliance periods. They may also be able to generate and sell compliance instruments by participating in the trading program. Thus, proposing a finding that it is necessary or appropriate to establish one or more federal plans providing the ability to participate in a rate- or mass-based trading program is in the interest of these four power plants located in areas of Indian country. We believe that this together with the facts that, as indicated above, all four EGU are interconnected with the western electricity grid and are owned and operated by an entity that generates and provides electricity to customers in several states thereby making it potentially disruptive and inequitable not to include them in one or more federal plans on the same schedule as other affected EGU strongly supports proposing to find that it is necessary or appropriate to establish one or more applicable federal plans at this time.

We recognize that the governments of these tribes may still choose to seek TAS to develop a tribal plan, and this proposed determination does not preclude the tribes from taking such actions. We also note that this proposed determination does not preclude these tribes from seeking TAS and receiving delegation to administer aspects of any applicable federal plan that is ultimately promulgated. In the event a federal plan is needed, proposing a necessary or appropriate finding at this time will allow the EPA to expeditiously promulgate a final federal plan for one or all of these power plants in the future to allow trading to occur. We will continue to consult with the governments of the Navajo Nation, Fort Mojave Indian Tribe, and the Ute Tribe of the Uintah and Ouray Reservation during the comment period for this proposal, and prior to taking any action to finalize a necessary or appropriate finding and/or a federal plan. Comments on the appropriateness of the proposed finding, should be submitted within the comment period specified in the Dates section of this preamble.

VII. Amendments to Process for Submittal and Approval of State Plans and EPA Actions

As indicated in the final rulemaking notice for the CAA section 111(d) guideline, “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,” in this action, in addition to the proposed federal plans and model trading rules, the EPA is also proposing to amend the framework regulations and update the process for acting on CAA section 111(d) state plans under 40 CFR part 60, subpart B. These changes would be applicable to any future CAA section 111(d) rules going forward, not just the Clean Power

Plan EGs. The EPA proposes six changes to the CAA section 111(d) process in the framework regulations to include: (1) Partial approval/disapproval mechanisms similar to CAA section 110(k)(3); (2) a conditional approval mechanism similar to CAA section 110(k)(4); (3) a mechanism for the EPA to make calls for plan revisions similar to the "SIP-call" provisions of CAA section 110(k)(5); (4) an error correction mechanism similar to CAA section 110(k)(6); (5) completeness criteria and a process for determining completeness of state plans and submittals similar to CAA section 110(k)(1) and (2); and (6) updates to the deadlines for the EPA action. In addition, in this section, the agency is proposing an interpretation regarding the effect under section 111 if an existing facility subject to CAA section 111(d) modifies or reconstructs. We believe these changes will significantly streamline the state plan review and approval process, be more respectful of state processes, and generally enhance the administration of the 111d program.

Section 111(d)(1) provides that the EPA “shall establish a procedure similar to that provided by CAA section [110] of this title under which each state shall submit to the Administrator a [111(d)] plan . . . .” 42 U.S.C. 7411(d)(1). Thus, the CAA directs the EPA to look to the structure of the SIP program when designing the procedures the states and agency will use to develop CAA section 111(d) plans. Notably, the CAA does not require the CAA section 111(d) procedures to be identical to those the EPA uses under CAA section 110 for SIPs.[120] Therefore, the EPA interprets CAA section 111(d) to provide the EPA flexibility in designing procedures that reflect the structure of those used under CAA section 110 for implementation plans, without requiring the EPA to exactly track SIP procedures when acting on section 111(d) plans.

As a general matter these proposed changes would simply update the CAA section 111(d) framework regulations to include several new, more flexible procedural tools that Congress introduced into section 110 in the 1990 CAA Amendments. The basic procedures in the CAA section 111(d) framework regulations were promulgated in 1975 based on the structure of CAA section 110 as Congress designed it in the 1970 CAA Amendments. See 40 FR 53340-49 (Nov. 17, 1975). Over the years since 1970, the EPA and the states learned a great deal about the procedural limitations of the original SIP review process. The 1970 CAA only allowed the EPA to approve or disapprove SIP submittals. The agency struggled to deal responsively to situations where the EPA wanted to work with states to get state programs approved to the extent possible, while maintaining consistency with CAA requirements. Congress responded in 1990 and enhanced

[120] See Webster's II New Riverside University Dictionary (Riverside 1988) (defining "similar" to mean "resembling though not completely identical").

the procedural mechanisms the EPA has to act on SIPs. The EPA is proposing correspondingly to update the CAA section 111(d) regulations in a similar fashion. Currently, the EPA's framework regulations for submittal and adoption of CAA section 111(d) state plans do not explicitly provide for the EPA to use some of the same procedures for approving or disapproving state plans Congress introduced into the SIP program in the 1990 CAA Amendments. The EPA is proposing to amend the procedures for approval or disapproval of CAA section 111(d) state plans to reflect the enhancements Congress included in CAA section 110 for agency actions on SIPs. These proposed amendments are discussed in more detail below.

A. Partial Approvals/Disapprovals

First, the EPA proposes to add authority similar to that under CAA section 110(k)(3) to partially approve or disapprove a plan.[121] This is a particularly useful function when much of a state plan is approvable and the EPA and the state cannot reach resolution on only a small, severable portion of the state plan. In this case, the EPA prefers not to be in a position where it

[121] We recognize that the regulations appear to already contemplate partial approval/disapprovals to some extent. See 40 CFR 60.27(a) ("The Administrator may … extend the period for submission of any plan … or portion thereof.") (emphasis added). We note that this language only allows for extensions of time with respect to portions of state plan submissions and may not sufficiently authorize a permanent partial approval. The proposed enhancement will resolve any ambiguity that partial approvals/disapprovals are an acceptable mechanism under CAA section 111(d).

must disapprove the full plan, but rather to allow the state to move forward with those portions of the plan that are approvable. This mechanism are those situations where the state wishes to take over a discrete part of a federal plan. For instance, in this proposal, states will be able to seek approval of a partial state plan that will give them the ability to handle the allocation of allowances under a mass-based federal plan.

In cases where elements of a plan are functionally severable from each other, and one element is approvable while another is not, this provision will authorize the EPA to approve one part of a plan and disapprove the other. It will also authorize the EPA to accept and review a state plan that is only partial in nature, if identified by the state as such, so long as the other applicable submission requirements are met (such as demonstration of legal authority and completion of the public process). When the state submits what it intends to be a full state plan (rather than just a partial plan), the EPA proposes that the approvable portion of a plan must be functionally severable from the rest of the plan, and this will be the case when the following conditions are met. First, the approvable portion of the plan must not depend on the rest of the plan. In other words, the disapproval of the remaining portion of the plan must not affect the portion that is approved. Second, approval of the approvable portion must not alter the function of the submittal in a way that is contrary to the state’s intent.

The partial disapproval would be a disapproval for the purposes of CAA section 111(d)(2)(A) and would trigger the EPA’s authority to issue a federal plan for the state, at least for that part of the plan that was disapproved. Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to implement as much of its program as is consistent with a CAA section 111(d) guideline and may reduce the scope of any federal plan that would be necessary.

B. Conditional Approvals

The second mechanism is the authority under CAA section 110(k)(4) to conditionally approve a plan. Where a state has submitted a plan that substantially meets the requirements of a CAA section 111(d) emission guideline, but requires some specific amendments to make it fully approvable, this provision authorizes the EPA to conditionally approve the plan. The Governor or her designee must submit to the EPA a commitment that specifies the amendments to be adopted and submitted to the EPA by no later than 1 year from the effective date of the conditional approval. If the state fails to meet its commitment, the conditional approval is treated as a disapproval.

Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to begin to administer a substantially complete program that requires only specific changes to be fully approvable. This provision is designed to authorize a state with a substantially complete and approvable program to begin implementing it, while promptly amending the program to ensure it fully complies with CAA section 111(d).

C. Calls for Plan Revisions

CAA section 110(k)(5) authorizes the EPA to find that a SIP does not comply with the requirements of the CAA. To date, the EPA has not considered using a similar procedure pursuant to the authority under CAA section 111(d). We now propose to do so. The ability to call for plan revisions is fundamental to a program that will be implemented over many years multiple decadUnder the Clean Power Plan EGs, states have more than a decade to fully implement emissions standards or state measures in order to ensure affected EGUs achieve the emission goals of the EGs. Throughout this period, the EPA and the states will be monitoring their programs to ensure they are achieving the intended results. It is possible that design assumptions about the effect of control measures the states incorporate into their plans could prove inaccurate in retrospect and could result over time in the plan not meeting the emissions reductions required by the EGs. In that case, having a procedural mechanism available under CAA section 111(d) similar to the so-called “SIP call” mechanism in CAA section 110(k)(5) will allow the agency to initiate a process with the state to make necessary revisions to ensure the plan functions properly.

Accordingly, the EPA is proposing to amend the framework regulations to include a provision similar to CAA section 110(k)(5) under which the EPA may find that a state’s CAA section 111(d) plan is substantially inadequate to comply with the requirements of the CAA and require the state to revise the plan as necessary to correct such inadequacies. Consistent with CAA section 110(k)(5), the EPA shall notify the state of any inadequacies and establish a reasonable deadline for the state to submit required plan revisions. That deadline will not exceed 18 months after the date of the notice. The EPA will make its finding and notice to the state available to the public.[122]

The effect of such a finding is that either the state submits the program corrections by the date the EPA sets in the notice, or pursuant to CAA section 111(d)(2)(A), the EPA has authority to issue a federal plan for a state that misses its deadline to correct its plan. In effect, the finding of plan

[122] Consistent with the agency’s practice under CAA section 110(k)(5), the EPA anticipates that a call for plan revisions under CAA section 111(d) will be done via notice and comment rulemaking.

inadequacy establishes a plan submittal deadline subject to the provisions of CAA section 111(d)(2)(A). A finding of failure to meet that new deadline triggers the EPA's authority to issue a federal plan for the state. The EPA may promulgate a federal plan at any time following the state's failure to timely submit an adequate plan that addresses the EPA's finding.

While these authorities are important, the intention of having a mechanism to call for plan revisions is to have a way to initiate an orderly process to improve plans when they are not meeting program objectives. It is the EPA's hope that a call for plan revision leads to a constructive dialogue with a state or states, and ultimately, an improved and more effective CAA section 111(d) plan.

The EPA is also proposing that the agency can call for a plan revision in circumstances where a state is not implementing its approved state plan and, therefore, the state plan is substantially inadequate to provide for the implementation of CAA section 111(d) standards of performance. As discussed above, the CAA directs the EPA to develop a procedure for state plans under CAA section 111(d) similar to CAA section 110 SIP procedures. Calling a plan that is substantially inadequate to provide for implementation of standards of performance (i.e., there is a failure to implement a state plan) is one area where the EPA proposes it is appropriate to adapt the procedural mechanisms available in the SIP program to provide a similar process that assures effective state plan implementation under CAA section 111(d). Under CAA section 110(k)(5), the EPA may call for a revision of a state plan "[w]henever the Administrator finds that the . . . plan . . . is substantially inadequate to . . . comply with any requirement of [the Act]." If the state does not submit a plan revision in response to the call to cure the failure to provide for implementation, the EPA would have the authority to promulgate the federal plan being proposed.

One critical requirement of CAA section 111(d)(1)(B) is that a state must submit a plan that "provides for the *implementation and enforcement* of such standards of performance" (emphasis added). If, after the EPA has approved a plan, a state fails to implement that plan, the plan has become substantially inadequate to comply with this requirement of the CAA. Under this proposal, the EPA's remedy would be to find the plan is substantially inadequate, which triggers the state's obligation to cure, and failing that, the EPA's authority to promulgate the federal plan.

In the alternative, the EPA proposes that this authority to call a plan for failure to implement is anchored in the authority provided under CAA section 110(k)(5) to call a SIP when the agency finds that it is "substantially inadequate to attain or maintain the relevant national ambient air quality standard.” In the context of CAA section 111, this authority translates into the EPA calling a state plan when the agency finds that it is substantially inadequate to achieve the emissions reductions required under the EG. If a state has failed to implement its plan, and that failure is pervasive enough to render the requirements of the plan ineffective, it is reasonable for the EPA to find that the state plan is substantially inadequate to achieve the emissions reductions required under the EG. The state’s failure to implement has revised the effect of the plan so that it is no longer adequate to meet the CAA’s requirements.

Error Corrections

The fourth mechanism is the error correction authority under CAA section 110(k)(6). Where the EPA concludes that it has erroneously approved, disapproved, or promulgated a plan or plan revision (or part thereof), this section authorizes the agency to revise its action, in the same manner as the original action, without requiring any further submission from the state. Prior to the 1990 CAA Amendments, there was some question whether the EPA could unilaterally correct a previous action on a SIP submittal without the state having to submit a new SIP. This limitation imposed unnecessary burdens on states to fix even obvious errors, because CAA section 110(a)(2) requires the state to provide notice and a public hearing on each new SIP submittal. Incorporating this mechanism into the CAA section 111(d) framework regulations will allow the EPA to fix errors in its prior actions on state plans without imposing on the states the corresponding burden of providing notice and a public hearing as required under the CAA section 111(d) framework regulations. 40 CFR 60.23.

D. Completeness Criteria

Completeness criteria provide the agency with a means to determine whether a submission by a state includes the minimum elements that must be met before the EPA is required to act on such submission. When submittals do not contain the necessary minimum elements, then the EPA may, without further action, find that a state has failed to submit a plan. This determination is ministerial in nature and requires no exercise of discretion or judgment on the agency’s part, nor does it reflect a judgment on the sufficiency or adequacy of the submitted portions of a state plan. The task is accomplished by simply comparing the materials provided by the state as its submittal against the required criteria to determine whether the plan is complete or not. In the case of SIPs under CAA section 110(k)(1), the EPA promulgated completeness criteria in 1990 at appendix V to 40 CFR part 51 (55 FR 5830; Feb. 16, 1990). The EPA proposes to adopt criteria similar to the criteria set out at section 2.0 of

Appendix V for determining the completeness of submissions under CAA section 111(d). The completeness criteria can be grouped into: (1) Administrative materials; and (2) technical support. The EPA proposes that both groups would apply to all CAA section 111(d) rules going forward. The agency notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under the EGs.

For administrative materials, the EPA is proposing completeness criteria that mirror the existing administrative criteria for SIP submittals because the two programs have similar administrative processes. The EPA proposes that a complete final state plan submittal under CAA section 111(d) must include: (1) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof; (2) evidence that the state has adopted the plan in the state code or body of regulations (That evidence shall include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date.); (3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan; and (4) a copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal shall be a copy of the official state regulation/document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the state. The effective date of the regulation/document shall, whenever possible, be indicated in the document itself. The state’s electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal shall indicate the changes made (for example, by redline/strikethrough) to the approved plan; (5) evidence that the state followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption/issuance of the plan; (6) evidence that public notice was given of the proposed change with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice; (7) certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23; and (8) compilation of public comments and the state's response thereto.

These criteria, as proposed, are intended to be generic to all CAA section 111(d) plans going forward, with the proviso that specific EGs may provide otherwise. The technical support completeness criteria that the EPA proposes will also be generic to all CAA section 111(d) rules, with the same proviso. The EPA proposes that the technical support required for all plans must include each of the following: (1) Description of the plan approach and geographic scope;(2) identification of each designated facility, identification of emission standards for the designated facilties, and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3)identification of compliance schedules and/or increments of progress; (4) demonstration that the state plan submittal is projected to achieve emissions performance under the applicable EGs; (5) documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

The EPA proposes a process similar, though not identical, to that set forth in 40 CFR 51.103 and Appendix V to 40 CFR part 51 to make completeness determinations. Similar to CAA section 110(k)(1)(C), under this proposal, where the EPA determines that a state submission required under CAA section 111(d) does not meet the minimum completeness criteria we are proposing to establish, the state will be considered to have not made the submission. The EPA further proposes that, similar to CAA section 110(k)(1)(B), within 60 days of the EPA's receipt of a state submission, but no later than 6 months after the date, if any, by which a state is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria have been met. Any plan or plan revision that a state submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria.

As with the completeness determination process for SIP submissions, the EPA’s determination that a submittal is complete is not a finding that the submittal meets the substantive requirements of CAA section 111(d) or the guideline. That must be done via the process for approval or disapproval of a state plan, which would be done through notice and comment rulemaking. In the completeness process, the EPA will confirm that a state’s submittal appears to have addressed the criteria for a complete submittal and, therefore, the submittal is sufficient to trigger the EPA’s obligation to act on it. But in the completeness process the agency will not assess the content of those submissions to determine if they are approvable. Accordingly, even when the EPA affirmatively determines that a submittal is complete, it does not prevent the agency from later finding that the state plan does not meet the requirements of the EGs, including finding that the submittal failed to address a required element and must be disapproved.

Similarly, when a submittal is determined to be complete by operation of law after 6 months without the EPA’s affirmative determination of completeness, the only legal consequence is that the EPA now has an obligation to act on that submittal. Completeness by operation of law means that the submittal is deemed complete and requires the EPA’s review, whether or not the state has actually addressed all the required elements. Accordingly, if the agency determines that a state has failed to address a required element in its submittal once the EPA begins review of the state plan that is complete by operation of law, the agency must go through the process of disapproving (or partially disapproving or conditionally approving, as discussed below) that plan, unless the state and the EPA work together to cure the deficiency. In other words, the EPA cannot simply find the plan incomplete and return it to the state at that point. But the finding of completeness by operation of law in no way prevents the EPA from subsequently concluding that the state’s submission is missing a required element of the program and making that finding as part of a disapproval of the plan.

As described in the final rulemaking notice for the CAA section 111(d) EGs, a state will submit all CAA section 111(d) plans electronically. If the EPA determines that any submission fails to meet the completeness criteria, the agency may return the plan to the state and request corrections, identifying the components that are absent or insufficient to allow the EPA to perform a review of the plan. The state will not have met its obligation to submit a final plan until it resubmits a revised state plan or supporting materials addressing the corrections the EPA identified in its incompleteness determination.

The EPA is also proposing to include an exception to the criteria for complete administrative materials in cases where a state and the EPA are “parallel processing” the final plan. Parallel processing allows a state to submit the plan prior to final adoption by the state and provides an opportunity for the state to consider the EPA’s comments prior to submission of a final plan for final review and action. The EPA would propose to take action on a state plan based on a proposed state regulation. The EPA would only finalize the action if the state adopts a final plan that is legally effective under state law. The EPA would only approve the plan if the state addressed any corrections that the EPA identified in its proposed action on the state plan without any other material change to the plan. Note that a plan submitted for parallel processing must still meet all the criteria for technical completeness so that the EPA and the public have a sufficient basis on which to evaluate and comment on the EPA’s proposed action.

E. Update to Deadlines for EPA Actions

The EPA proposes to update the deadlines for acting on state submittals and promulgating a federal plan under 40 CFR 60.27(b), (c), and (d) to more closely track the current versions of CAA section 110(c) and 110(k) adopted in 1990. The framework regulations for CAA section 111(d) state plans currently are parallel to the prior version of CAA section 110. They require the EPA to act on a state plan or plan revision submittal within 4 months after the date required for submission of a plan or plan revision. 40 CFR 60.27(b). The regulations then require the EPA to issue a proposed federal plan in certain circumstances after consideration of any state hearing record, 40 CFR 60.27(c), and require the EPA to promulgate the proposed federal plan within 6 months after the date required for plan submissions, id. 60.27(d).

The final CO_2 EG for EGUs have already adjusted the deadline in 60.27(b) to require the EPA to act on a state plan under those EGs within 12 months (rather than 4 months) after the date required for submission of a plan. See 40 CFR 60.5715. However, the Clean Power Plan EGs did not modify the 6 month deadline for a federal plan in 60.27(d).

The EPA is proposing to amend 40 CFR 60.27(b) to allow the EPA 12 months to approve or disapprove submittals of all plans or plan revisions under CAA section 111(d), not just those related to the Clean Power Plan under 60.5715. This change would provide the EPA with sufficient time for the steps required to approve or disapprove the submittal, which include proposing the EPA's approval or disapproval of the plan or plan revision, a public comment period on the EPA's proposal, time for the EPA to review and respond to public comments, and the issuance of a final rule approving or disapproving the plan or plan revision.

The EPA is also proposing to amend 40 CFR 60.27(b) to specify that the deadline for the EPA to act on a plan or plan revision is 12 months after receipt of a complete plan or plan revision, rather than 12 months after the deadline for submittal of a plan or plan revision. This amendment will allow the EPA to have the full 12 months to act on submittals of complete plans or plan revisions.

The EPA also proposes slight modifications to the provision related to issuing a proposed federal plan in 60.27(c); changing the 6 month deadline for issuing a final federal plan in 60.27(d) to 1 year[123]; and, similar to the change in timing for 60.27(b) above, setting the deadline for promulgation of a federal plan to run from the date of the EPA's action on a state

[123] As under CAA section 110, the EPA believes that, should it fail for whatever reason to meet a deadline by which it was to take action, such as issue a federal plan, under CAA section 111(d), that failure does not thereby obviate or in any way remove the EPA's authority or obligation to take that action. See Oklahoma v. U.S. EPA, 723 F.3d 1201, 1224 (10th Cir. 2013) ("Although the statute undoubtedly requires that the EPA promulgate a FIP within two years, it does not stand to reason that it loses its ability to do so after this two-year period expires. Rather, the appropriate remedy when the EPA violates the statute is an order compelling agency action.").

submittal, rather than from the original deadline for a state submittal.

The EPA believes it is appropriate to modify these timing requirements for several reasons. First, the EPA notes that under CAA section 111(d)(2), Congress gave the EPA the "same" authority to prescribe a federal plan under CAA section 111(d) as it would have under CAA section 110(c) in the case of a state failure to submit a SIP. The term "same" stands in contrast to the term "similar" in CAA section 111(d)(1) (discussed above). As with the use of the term “similar,” the EPA believes it is authorized by this language to follow the timing provisions of CAA section 110(c) as currently enacted. Second, as a general matter, the timing requirements of current 60.27(c) and (d), which effectively require the EPA to propose and finalize a federal plan within 6 months of the deadline for state submittals, may be outdated and unrealistic with respect to the timelines for review of state plans and the time periods for action, particularly as informed by the agency's experience with CAA section 110 SIPs (which led to the extension of the timelines and other changes to CAA section 110 in the 1990 Amendments discussed above). Third, in the CPP Emission Guideline, the EPA has finalized a timing requirement that gives the agency a year to approve or disapprove a state plan or revision. The existing requirement in 60.27(d) that the EPA must promulgate a federal plan within 6 months of the initial deadline for state plans is therefore inconsistent with this provision. Fourth, existing 60.27(c) tracks the prior version of CAA section 110(c) with respect to the issuance of a proposed federal plan. This relatively prescriptive language is no longer present in CAA section 110(c). The procedural requirements for rulemakings under both CAA section 110 and 111(d) are set out in section 307(d) of the CAA, and the EPA believes those provisions are appropriate and adequate to guide its rulemaking process for CAA section 111(d) federal plans.

The EPA invites comment on all of these proposed changes to the framework regulations. The EPA notes that the addition of these mechanisms to the framework regulations will make them available for all CAA section 111(d) regulations, not just those under the Clean Power Plan at 40 CFR part 60, subpart UUUU.

F. Proposed Interpretation regarding Existing Sources that Modify or Reconstruct

In the proposed rulemaking for the CPP, the EPA proposed the interpretation that if an existing source is subject to a CAA section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. 79 FR 34830, 34903–4. The EPA did not finalize a position on this issue in the final EGs rule, but indicated that it would re-propose and take comment on this issue through this federal plan rulemaking. The EPA also stated deferral of action on this issue does not impact states’ and affected EGUs’ pending obligations under this final rule relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source has already become subject to the requirements of a state plan. The EPA intends to finalize its position on this issue through this rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

We noted in the Clean Power Plan proposal that CAA section 111(d) is arguably silent as to this issue. Thus, we took this to grant the agency the authority to provide a reasonable interpretation to fill in the gaps where the statute is silent. In the proposal for the CPP, we proposed to disallow existing sources to leave the CAA section 111(d) program through modification or reconstruction. We did this for two reasons. First, if a source did so, that could prove disruptive to the state plan. Second, allowing sources to do so could provide them an incentive to do so that would be contrary to the purposes of CAA section 111(d). We then asked for comment on “whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute.”

We received many comments disagreeing with this approach. After reviewing these comments, the agency believes an alternative interpretation is more appropriate in the particular context here. In order to give the public an opportunity to comment on this, we are proposing this interpretation here. That is, when CAA section 111(d) EGs are initially promulgated for existing stationary sources in response to corresponding CAA section 111(b) standards of performance for the same pollutant, the statute prevents new, modified or reconstructed sources (including under those particular CAA section 111(b) standards of performance and as those terms are applied in the relevant new source performance standards (NSPS)) from simultaneously being subject to state plans under those particular CAA section 111(d) EGs. This interpretation gives meaning to the definition of “existing source” in CAA section 111(a)(6) and is consistent with the definition of “new source” in section 111(a)(2). Further, it is consistent with the historical treatment of modified and reconstructed sources in the CAA section 111 program.

The EPA notes the concerns it noted in the proposal supporting why the originally proposed interpretation was reasonable are being addressed in other ways in the final EGs, and in the proposed federal plan. In other words, there will be other ways to minimize disruption to state plans if such a modification or reconstruction were to take place. We invite comment on the agency’s proposed interpretation that when an existing source modifies or reconstructs in such a way that it meets the definition of a new source, for purposes of a particular NSPS and emission guideline, it becomes a new source under the statute and is no longer subject to the CAA section 111(d) program

G. Separate Finalization of these Changes

The agency intends to finalize these procedural changes and interpretation sooner than it finalizes the rest of this proposed action. The EPA believes these changes generally enhance and improve the framework regulations in a way that will be of benefit to the states, the EPA, and other stakeholders, and will improve the overall efficacy of the program. We believe it is important to finalize these changes to the framework regulations relatively quickly in order to provide states and other stakeholders predictability in how the EPA intends to process state plans and submissions under CAA section 111(d). If the EPA does finalize these changes sooner than the model trading rules or the federal plan, it will do so after the close of the comment period, and after consideration and response to any comments on these changes.

VIII. Impacts of this Action

A. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that “may affect” listed species or designated critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. See 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[124] Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. Id. To trigger a consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and if the effect is indirect, it must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of ESA section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are, like the EGs that it implements, positive: reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X), for EGUS that will be covered by the federal plan. However, the EPA's assessment that the rule will have an overall

[124] See Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4-25(March 1998) (providing examples of direct effects: e.g., driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in considering whether ESA consultation is required for this rule.

With respect to the projected GHG emission reductions, the EPA does not believe that such reductions trigger ESA consultation requirements under ESA section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between

GHG emissions and effects on the species in its habitat.[125] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the "may affect" test of the ESA section 7 regulations and, thus, are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2). In the final EGs, the agency noted that, although the GHG emission reductions projected for the EGs are large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012-2016 and 2017-2025. There the agency projected emission reductions over the lifetimes of the model years in question,[126] which are roughly five to six times those projected above and, based on air quality modeling of potential environmental effects, concluded that "EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas.

[125] See, e.g., 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: "Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases" (Oct. 3, 2008).

[126] See 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.” EPA, Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards, Response to Comment Document for Joint Rulemaking at 4-102 (Docket EPA-OAR-HQ-2009-4782). The EPA reached this conclusion after evaluating issues relating to potential improvements from the fuel efficiency rule relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that “any potential for a specific impact [of the specific federal action] on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).” Id. See also, e.g., Ground Zero Center for Non-Violent Action v. U.S. Dept. of Navy, 383 F. 3d 1082, 1091-92 (9th Cir. 2004). The EPA similarly proposes to determine that the likelihood of jeopardy to a species from this proposed action is extremely remote, and ESA does not require consultation). The EPA’s proposed conclusion is entirely consistent with DOI’s analysis regarding ESA requirements in the context of federal actions involving GHG emissions.

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SO_2 and NO_x as a collateral consequence of this proposal (which will be, as stated above, only a subset of the total reductions from the EGs). However, CAA section 111(d) cannot directly control emissions of criteria pollutants. And furthermore, a federal plan under CAA section 111(d)(2) does no more than prescribe emissions standards of the same stringency as the corresponding EGs. 40 CFR 60.27(e)(1). Consequently, CAA section 111(d) provides no discretion to set a standard in a federal plan based on potential impacts to endangered species of reduced criteria pollutant emissions. ESA section 7(a)(2) consultation is not required with respect to the projected reductions of criteria pollutant emissions. See 50 CFR 402.03; see also WildEarth Guardians v. U.S. Envt'l Protection Agency, 759 F.3d 1196, 1207-10 (10th Cir. 2014) (the EPA has no duty to consult under section 7 of the ESA regarding HAP controls that it did not require -- and likely lacked authority to require -- in a FIP for regional haze controls under section 169A of the CAA.).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and whether any such effects are "caused by" the rule and "reasonably certain to occur" within the meaning of the ESA regulatory definition of the effects of an action. 50 CFR 402.02. The EPA recognizes, for instance, that questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the EGs asserting that because potential increased reliance on wind or solar power may be an element of Building Block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector – including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities – or any potential alterations in the operations of any particular facility would, at the time of promulgation of a federal plan, be sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur.

Under a federal plan, it is the EPA that would implement a CAA section 111(d) plan. The EPA believes that even with this proposed federal plan, any effects on listed species or designated habitat are too uncertain to require consultation under ESA section 7. This is so for at least two reasons: (1) The EPA cannot know with any certainty at this stage which states will actually become subject to a finally promulgated federal plan. Which affected EGUs, in which states, will be covered by this Plan can only be known after states have failed to submit a plan, or have had their plans disapproved by the EPA; and (2), the federal plan as proposed will be implemented through some form of emissions trading. Emissions trading inherently provides maximum flexibility to individual affected EGUs to choose their method of compliance, including continuing to emit the relevant pollutant at historical rates so long as the affected EGU holds sufficient credits or allowances. At this point, the EPA has no meaningful information to express in any more than the broadest terms how any particular affected EGU may choose to comply with the federal plan, should it be promulgated for them based on their location in an area not covered by an approved state plan. The Services have explained that ESA section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[127] These are

[127] See 51 FR at 19933 (describing effects that are "reasonably certain to occur" in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish

precisely the types of speculative future activities and effects currently at issue here. The EPA requests comment on its proposed conclusion that ESA section 7 consultation is not required for this action. The EPA will continue to evaluate the scope and potential effects of federal planning activities for this source category to the extent federal plans are needed and implemented in specific areas and over specific sources.

B. What are the Air Impacts?

The EPA anticipates significant emission reductions under this proposed action for the utility power sector. Specifically, the EPA is proposing approaches in the form of mass- and rate-based trading options that provide flexibility in implementing emission standards for a state’s affected EGUs. Both proposed approaches to the federal plan would require affected EGUs to meet emission standards set using the CO_2 emission performance rates in the Clean Power Plan EGs.

However, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan or will adopt a model rule. Because of this lack of

& Wildlife Service and National Marine Fisheries Service at 4-30(March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors’ assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed).

information, in the Regulatory Impact Analysis (RIA) for this proposal, the EPA chose to examine a scenario where all states of the contiguous U.S. will be regulated under a federal plan or will adopt the model rule. Additionally, we examine two alternative federal plan approach scenarios. The first federal plan approach assumes all states in the contiguous U.S. are regulated under a rate-based federal plan. The second federal plan approach assumes all contiguous states are regulated under a mass-based federal plan.[128]

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The proposal is projected to result in substantial co-benefits through reductions of SO_2, NO_X and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Table 12 and Table 13 of this preamble show expected CO_2 and other air pollutant emissions in the base

[128] It is important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented may not be indicative of likely differences between the approaches. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

case and reductions under the proposal for 2020, 2025, and 2030 for both rate-based and mass-based approaches.

Table 12. Summary of CO_2 and Other Air Pollutant Emission Reductions from the Base Case under Rate-Based Federal Plan Approach

	CO_2 (millions short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Rate-based Federal Plan Approach	2,085	1,297	1,282
Emissions Reductions	69	14	50
2025			
Base Case	2,165	1,275	1,302
Rate-based Federal Plan Approach	1,933	1,097	1,138
Emissions Reductions	232	178	165
2030			
Base Case	2,227	1,314	1,293
Rate-based Federal Plan Approach	1,812	996	1,011
Emissions Reductions	415	318	282

Source: Integrated Planning Model, 2015.

Note: Emissions may not sum due to rounding.

Table 13. Summary of CO_2 and Other Air Pollutant Emission Reductions from the Base Case under Mass-Based Federal Plan Approach

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Mass-based Federal Plan Approach	2,073	1,257	1,272
Emissions Reductions	81	54	60
2025			
Base Case	2,165	1,275	1,302
Mass-based Federal Plan Approach	1,901	1,090	1,100
Emissions Reductions	265	185	203

2030			
Base Case	2,227	1,314	1,293
Mass-based Federal Plan Approach	1,814	1,034	1,015
Emissions Reductions	413	280	278

Source: Integrated Planning Model, 2015.

Note: Emissions may not sum due to rounding.

The reductions in Tables 12 and 13 of this preamble do not account for reductions in HAP that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

C. What are the Energy Impacts?

The proposed action may have important energy market implications. Table 14 of this preamble presents a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in section VIII.C of this preamble and presented in the RIA for this proposal.

Table 14. Summary Table of Important Energy Market Impacts for Rate-Based and Mass-Based Federal Plan Approaches (Percent Change from Base Case)

	Rate-Based			Mass-Based		
	2020	2025	2030	2020	2025	2030
Retail electricity prices	3%	1%	1%	3%	2%	0%
Average electricity bills	3%	-4%	-7%	2%	-3%	-8%
Price of coal at minemouth	-1%	-5%	-4%	-1%	-5%	-3%

Coal production for power sector use	-5%	-14%	-25%	-7%	-17%	-24%
Price of natural gas delivered to power sector	5%	-8%	2%	4%	-3%	-2%
Natural gas use for electricity generation	3%	-1%	-1%	5%	0%	-4%

These figures reflect the EPA's modeling that presumes policies that lead to generation shifts and growing use of DS-EE and renewable electricity generation out to 2029. If different implementation choices are made than those modelled, impacts could be different.

D. What are the Compliance Costs?

The compliance costs of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and modeled federal plan approaches described in section VIII.B in this preamble and presented in the RIA for this proposal. The incremental cost is the projected additional cost of complying with the proposed action in the year analyzed and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of DS-EE programs, and other actions associated with compliance. These important dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based federal plan approach to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030. The EPA estimates the annual incremental compliance cost for the mass-based federal plan approach to be $1.4 billion in 2020, $3.0 billion in 2025 and $5.1 billion in 2030. More detailed cost estimates are available in the RIA included in the rulemaking docket.

E. What are the Economic and Employment Impacts?

Based on the analysis presented in the RIA, the proposed action is projected to result in certain changes to power system operation as a compliance with the standards. See Table 14 of this preamble for a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in Section VIII.B in this preamble and presented in the RIA.

Changes in price or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or DS-EE as a result of states implementing the guidelines can result in shifts in production and profitability for firms that supply those goods and services.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, “our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.” (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. While the economy continues to move toward full employment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

The EPA’s employment analysis includes projected employment impacts associated with modeled federal plan approaches for the electric power industry, coal and natural gas production, and DS-EE activities. These projections are derived, in part, from a detailed model of the utility power sector used for this regulatory analysis, and U.S. government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that the proposed action could result in a net decrease of approximately 25,000 job-years in 2025 under the rate-based federal plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to DS-EE programs. Employment impacts from DS-EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the proposal.

By its nature, DS-EE reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in fossil fuel-fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the Benefits of the Proposed Action?

Implementing the proposed action will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for this proposal. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based federal plan approach to be \$3.5 to

$4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based federal plan approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 17 of this preamble.

Table 15. Summary of the Monetized Global Climate Benefits for the Proposal (Billions of 2011$)[a]

Year	Discount Rate (Statistic)	Monetized Climate Benefits		
		2020	**2025**	**2030**
Rate-based Federal Plan Approach				
CO_2 Reductions (million short tons)		69	232	415
	5 percent (average SC-CO_2)	$0.80	$3.1	$6.4
	3 percent (average SC-CO_2)	$2.8	$10	$20
	2.5 percent (average SC-CO_2)	$4.1	$15	$29
	3 percent (95th percentile SC-CO_2)	$8.2	$31	$61
Mass-based Federal Plan Approach				
CO_2 Reductions (million short tons)		81	265	413
	5 percent (average SC-CO_2)	$0.94	$3.6	$6.4
	3 percent (average SC-CO_2)	$3.3	$12	$20
	2.5 percent (average SC-CO_2)	$4.9	$17	$29
	3 percent (95th percentile SC-CO_2)	$9.7	$35	$60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of

carbon ($SC\text{-}CO_2$) estimates for the analysis years and are rounded to two significant figures.

Table 16. Summary of the Monetized Health Co-Benefits in the U.S. for the Proposal, Rate-based Federal Plan Approach (Billions of 2011$)[a]

Pollutant	National Emission Reductions (thousands of short tons)	Monetized Health Co-benefits (3 percent discount)	Monetized Health Co-benefits (7 percent discount)
Rate-based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	14	\$0.44 to \$0.99	\$0.39 to \$0.89
NO_X	50	\$0.14 to \$0.33	\$0.13 to \$0.30
Ozone precursor [c]			
NO_X (ozone season only)	19	\$0.12 to \$0.52	\$0.12 to \$0.52
Total Monetized Health Co-benefits		\$0.70 to \$1.8	\$0.64 to \$1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$3.5 to \$4.6	\$3.5 to \$4.5
Rate-based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	178	\$6.4 to \$14	\$5.7 to \$13
NO_X	165	\$0.56 to \$1.3	\$0.50 to \$1.1
Ozone precursor [c]			
NO_X (ozone season only)	70	\$0.49 to \$2.1	\$0.49 to \$2.1
Total Monetized Health Co-benefits		\$7.4 to \$18	\$6.7 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$18 to \$28	\$17 to \$26
Rate-based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	318	\$12 to \$28	\$11 to \$25

NO_X	282	\$1.0 to \$2.3	\$0.93 to \$2.1
Ozone precursor [c]			
NO_X (ozone season only)	118	\$0.86 to \$3.7	\$0.86 to \$3.7
Total Monetized Health Co-benefits		\$14 to \$34	\$13 to \$31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$34 to \$54	\$33 to \$51

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

Table 17. Summary of the Monetized Health Co-Benefits in the U.S. for the Proposal, Mass-based Federal Plan Approach (Billions of 2011$)[a]

Pollutant	National Emission Reductions (thousands of short tons)	Monetized Health Co-benefits (3 percent discount)	Monetized Health Co-benefits (7 percent discount)
Mass-based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	54	\$1.7 to \$3.8	\$1.5 to \$3.4
NO_X	60	\$0.17 to \$0.39	\$0.16 to \$0.36
Ozone precursor [c]			
NO_X (ozone season only)	23	\$0.14 to \$0.61	\$0.14 to \$0.61
Total Monetized Health Co-benefits		\$2.0 to \$4.8	\$1.8 to \$4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$5.3 to \$8.1	\$5.1 to \$7.7
Mass-based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	185	\$6.0 to \$13	\$5.4 to \$12
NO_X	203	\$0.58 to \$1.3	\$0.52 to \$1.2
Ozone precursor [c]			
NO_X (ozone season only)	88	\$0.56 to \$2.4	\$0.56 to \$2.4
Total Monetized Health Co-benefits		\$7.1 to \$17	\$6.5 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$19 to \$29	\$18 to \$27
Mass-based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	280	\$10 to \$23	\$9.0 to \$20
NO_X	278	\$0.87 to \$2.0	\$0.79 to \$1.8

Ozone precursor [c]			
NO_X (ozone season only)	121	\$0.82 to \$3.5	\$0.82 to \$3.5
Total Monetized Health Co-benefits		\$12 to \$28	\$11 to \$26
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$32 to \$48	\$31 to \$46

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SC-CO_2) estimates presented in the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015) ("current TSD") to analyze CO_2 climate impacts of this rulemaking.[129] We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC-CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models

[129] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

(IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC-CO_2 Technical Support Document (2010 TSD)[130] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[131]

OMB's Office of Information and Regulatory Affairs received comments in response to a request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG

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[130] Docket ID EPA-HQ-OAR-2009-0472-114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.

[131] The current version of the TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf, Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

continues to recommend the use of the SC-CO_2 estimates in RIA.[132] With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC-CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the

[132] See https://www.whitehouse.gov/omb/oira/social-cost-of-carbon for additional details, including the OMB Response to Comments and the SC-CO_2 TSDs.

May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC-CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's SC-CO_2 comment process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC-CO_2 estimates for purposes of RIA, including for this proceeding.

The four SC-CO_2 estimates are as follows: $12, $40, $60, and $120 per short ton of CO_2 emissions in the year 2020 (2011$).[133] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC-CO_2 value at several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an

[133] The current version of the TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The 2010 and 2013 TSDs present SC-CO_2 in 2007$ per metric ton. The estimates were adjusted to (1) Short tons for using conversion factor 0.90718474 and (2) 2011$ using GDP Implicit Price Deflator, http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.

intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from this proposal, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek independent expert advice on technical opportunities to improve the SC-CO_2 estimates from the Academies. The Academies process will help to ensure that the SC-CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions from the federal plan approaches examined in the RIA for this proposal. Unlike the global SC-CO_2 estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a “benefit-per-ton” approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, we conducted air quality modeling for an illustrative scenario reflecting the proposed Clean Power Plan EGs to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then used these air quality modeling results in BenMAP[134] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM

[134] http://www.epa.gov/airquality/benmap/index.html.

NAAQS RIA[135] and Ozone NAAQS RIAs.[136,137] The three regions were the Eastern U.S., Western U.S., and California. To calculate the co-benefits for this proposal, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed Clean Power Plan EGs standards by the corresponding regional emission reductions for this proposal.[138] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed Clean Power Plan EGs, which may not exactly match the emission reductions in this proposed rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More

[135] U.S. Environmental Protection Agency (U.S. EPA). 2012. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA-452/R-12-003, December). Available at: http://www.epa.gov/pm/2012/finalria.pdf.

[136] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA-452/R-08-003, March). Available at: <http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645>.

[137] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf.

[138] U.S. Environmental Protection Agency. 2013. Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors. Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.

information regarding the derivation of the benefit-per-ton estimates is available in the Clean Power Plan Final Rule RIA.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009)[139] and Lepeule et al. (2012)[140]. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based on the American Cancer Society cohort study (Krewski et al,

[139] Krewski D.; M. Jerrett; R. T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality. Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.

[140] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009." Environmental Health Perspective, 120(7), July, pp. 965-970.

2009) and one based on the extended Six Cities cohort study (Lepuele et al, 2012). We present the $PM_{2.5}$ co-benefits results as a range based on benefit-per-ton estimates calculated using the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008)[141] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship.

For the ozone co-benefits, we present the results as a range reflecting benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004)[142] and the upper end based on a benefit-per-ton estimate using the function from Levy et al.

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[141] Roman, H., et al. 2008. "Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S." Environmental Science & Technology, Vol. 42, No. 7, February, pp. 2268 – 2274.

[142] Bell, M.L., et al. 2004. "Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987-2000." Journal of the American Medical Association, 292(19), pp. 2372-8.

(2005).[143] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of the EPA's Integrated Science Assessment for Particulate Matter,[144] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits.

[143] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. "Ozone exposure and mortality: an empiric Bayes metaregression analysis." Epidemiology. 16(4): p. 458-68.

[144] U.S. Environmental Protection Agency. 2009. Integrated Science Assessment for Particulate Matter (Final Report). Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA-600-R-08-139F, December). Available at: http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.

Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[145] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter (μg/m^3). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 μg/m^3. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

[145] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative analysis of this proposed action under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ NAAQS RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and HAP (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for this proposal. In addition, in the RIA for this proposal, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed Clean Power Plan EGs, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.

As described in the Executive Summary, climate change is an EJ issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 section X.J of this preamble). While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, droughts, and the like are experienced in individual communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts.

The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the EGUs that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NO_x, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart or lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[146] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of federal plans will produce significant reductions in emissions of conventional pollutants, particularly in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, this proposed rule will lead to better air quality and improved health in those communities. In the comment period for the CPP, we heard from many commenters who recognize and welcome those benefits.

[146] Six Common Air Pollutants. http://www.epa.gov/oaqps001/urbanair/

There are other ways in which the actions that result from this rulemaking may affect overburdened communities in positive or potentially adverse ways and we also heard about these from commenters.

While the agency expects overall emission decreases as a result of this rulemaking, we recognize that some EGUs may operate more frequently. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units, which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_x compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point, but also the difficulty in anticipating prior to plan implementation where those impacts might occur. As described below, the EPA intends to conduct an assessment of whether and where emission increases may result from plan implementation and mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring, but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. It is important to ensure that all communities share in these benefits. And while we estimate that the benefits of this program will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking and we received many comments on the issues outlined above from community groups, EJ organizations, faith-based organizations, public health organizations, and others. This input has informed this final rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to assist states and stakeholders to consider EJ and impacts to communities in plan development and implementation.

It has also prompted us to work with our federal partners to make sure that communities have information on federal resources available to assist them. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in the development of this rulemaking. In this section, we discuss the steps that the EPA is going to be taking to assist communities in engaging with the agency throughout the comment period of this rulemaking.

A. Proximity Analysis

The EPA is committed to ensuring that there is no disproportionate, adverse impact on overburdened communities as a result of this proposed rulemaking. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this proposed rulemaking that summarizes demographic data on the communities located near power plants.[147] The EPA understands that, in order to prevent disproportionately high and adverse human health or environmental effects on these communities, both the agency and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008-2012 to conduct a proximity analysis that can

[147] The proximity analysis was conducted using the EPA’s environmental justice mapping and screening tool, EJSCREEN.

be used by communities as they engage with the agency throughout the comment period of this rulemaking. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA-HQ-OAR-2015-0199.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the U.S. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a 3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant’s air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to EJ considerations, we use the terms “vulnerable” or “overburdened” when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, that are central to our EJ and community considerations.

As stated in the Executive Order 12898 discussion located in section X.J of this preamble, the EPA believes that all communities will benefit from this proposed rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and the agency throughout the rulemaking process. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will make it publicly available on its

Clean Power Plan (CPP) Communities Portal that will be linked to this rulemaking's Web site (http://www.epa.gov/cleanpowerplan). Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/.

B. Community Engagement in This Rulemaking Process

The EPA has heard from vulnerable communities throughout the outreach process for the Clean Power Plan that it is imperative for communities to have an understanding of how rulemakings that target climate change work. They expressed a desire to know how these programs may benefit their communities and what the potential adverse impacts of the rules may be on their communities. We intend to provide communities with the information that they need to engage with the agency throughout the comment period.

We have received feedback from communities that public hearings, webinars and in-person meetings are the most effective ways to engage with them and to provide them with the information that they need to understand the rulemaking process. Therefore, for this rulemaking, in addition to conducting public hearings for all members of the American public (please see the dates section for information on the upcoming public hearings), the agency will hold a national webinar for communities in the early stages of the comment period. The goal of this webinar will be to walk communities through the highlights of the preamble, so they have an understanding of how the rulemaking may potentially affect their communities and they will have the contextual information they need to actively engage with the agency throughout the comment period.

Additionally, because we received positive feedback on the effectiveness of the face-to-face meetings conducted on the regional level, each region will be offering an outreach meeting(s) for communities. The goal of these meetings is to build a level of understanding on this rulemaking to enable vulnerable communities to actively engage with the agency throughout the comment period. Furthermore, we will follow up on common issues raised during the outreach meetings with national conference calls, specifically targeted for vulnerable communities.

C. Providing Communities with Access to Additional Resources

In section V.D of this preamble, we outline that we are seeking comment on whether a portion of this set-aside should be targeted to RE projects that benefit low-income communities. Furthermore, the EPA is seeking comment on how an low-income community should be defined as eligible under this set-aside. We also seek comment on how much of the set-aside should be designated as targeted at over-burdened communities. We also request comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ, and if so, in what manner, from the methods that are proposed to apply to other RE projects.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE, EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for low-income communities on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

Additionally, as part of the resources that we will be providing low-income communities, the EPA will provide information on the Adminstration’s Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[148]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. DOE, the U.S. Department of Housing and Urban Development, U.S. Department of Agriculture, and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not have adequate roof space to install solar systems, with a focus on low- and moderate- income communities. The Administration also set a goal to install 300 MW of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and

[148] http://www.eda.gov/power/.

create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: the DOE's Weatherization Assistance Program, Health and Human Service's Low Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

The U.S. Department of Housing and Urban Development supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites – many of which are in low-income communities – for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA’s Green Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs – savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include the U.S. Department of Housing and Urban Development, DOE, and the Department of Education’s “STEM, Energy, and Economic Development” program; DOE’s Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the Department of Labor’s Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Co-Pollutants

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[149] In the CSAPR the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final CSAPR anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the CSAPR, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO_2 and NO_x on a regional and national basis.[150] Thus, localized increases in NO_x emissions may well be more than offset by NO_x decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission standards for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs - in particular, high

[149] 76 FR 48348.

[150] 76 FR 48347.

efficiency gas-fired EGUs - with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already occur in response to energy demands and evolving energy sources, but the final CO_2 emission standards for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5}$, NO_x, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, SO_2, and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in title V operating permits, in addition to the guidelines in this final rulemaking. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected. For natural gas-fired EGUs, the EPA found that regulation of HAP emissions “is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.”[151] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal-and NGCC-fired generation, they assumed SO_2, NO_x, PM (and Hg) emissions to be “negligible.” Their studies predict NO_x emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[152] Many, although not all, NGCC units are also very well controlled for emissions of NO_x through the application of after combustion controls such as selective catalytic reduction.

F. Assessing Impacts of Federal Plan Implementation

It is important to the EPA that the implementation of federal plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of

[151] 65 FR 79831.

[152] “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity” Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL-2010/1397.

federal plans and other air quality rules are, in fact, reducing emissions and improving air quality in all areas and, or whether there are localized air quality impacts that need to be addressed under the Clean other CAA authorities.

The EPA will provide trainings for communities on resources that they can use to assess localized impacts, especially effects of co-pollutants, of plans on their communities. This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of federal plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the implementation phase of this rulemaking will enable the agency and communities to monitor any disproportionate emissions that may result in adverse impacts and address them.

G. The EPA’s Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and as they engage with the agency. The EPA, through its outreach efforts during the comment period, will continue to solicit feedback from communities on what they would like additional trainings and resources on.

As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan (CPP) Communities Portal that will be linked to this rulemaking's Web site (http://www.epa.gov/cleanpowerplan). In addition, the EPA has expanded its set of resources that are being developed to help communities understand the breadth of policy options and programs that have successfully brought EE/RE to low-income communities. The EPA is committed to continuing its engagement with communities from the comment period of this rulemaking through federal plan implementation.

The EPA consulted its May 2015, Guidance on Considering Environmental Justice During the Development of Regulatory Actions, when crafting this rulemaking.[153] A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section X.J of this preamble. A summary of the EPA's interactions with communities is in the

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[153] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf. May 2015.

EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA’s responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this proposed rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rule. The proximity analysis that the agency has conducted is a central component of this approach. Not only is the proximity analysis a useful tool to help identify communities that may be impacted by this rulemaking; it will also help communities as they engage with the EPA throughout the comment period. It will help the EPA as we help low-income communities access EE/RE and financial assistance programs. Finally, in order to continue to ensure that overburdened communities are not disproportionately impacted by this rule, the EPA will be conducting an assessment during the implementation phase of the effects of this and other rules on air quality.

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at http://www2.epa.gov/laws-regulations/laws-and-executive-orders.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the "Regulatory Impact Analysis for 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" (EPA-452/R-15-006, July 2015), is available in the docket and is briefly summarized in section VIII of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for two alternative federal plan approaches to implementing the proposed federal plan and model trading rules. The proposed action will achieve the same levels of emissions performance as required of state plans under the CAA section 111(d) EGs for the control of CO_2. Actions taken to comply with the guidelines will also reduce the emissions of directly-emitted $PM_{2.5}$, SO_2 and NO_X. The benefits associated with these $PM_{2.5}$, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The RIA for this proposal analyzed two implementation scenarios, which we term the “rate-based federal plan approach” and the “mass-based federal plan approach”. It is very important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented in the RIA may not be indicative of likely differences between the approaches if implemented by states and affected EGUs in response to the proposed rule. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

It is important to note that the potential regulatory impacts presented in the Clean Power Plan Final Rule RIA and the RIA for this proposed rule are not additive. Both RIAs present estimates of the benefits and costs of achieving the emission performance rates of the Clean Power Plan EGs. In the case of the Clean Power Plan Final Rule RIA, the illustrative analysis assumes the performance rates are met under state plans. In the case of this RIA for the proposed federal plan and model trading rules, the same performance rates are accomplished but are assumed to be achieved under the federal plan or model trading rules.

The EPA has used the social cost of carbon estimates presented in the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015) ("current TSD") to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC-CO_2 estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SC-CO_2 value deemed to be central in the current TSD: the model average at 3 percent discount rate.

The EPA estimates that, in 2020, the proposal will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be

$2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS-EE program and participant costs and MRR costs in 2020, are approximately $2.5 billion for the rate-based approach and $1.4 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) for the rate-based approach and from $3.9 billion to 6.7 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the proposal will yield monetized climate benefits (in 2011$) of approximately $10 billion for the rate-based approach and $12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.4 billion to $18 billion (2011$) for a 3 percent discount rate and $6.7 billion to $16 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.1 billion to $17 billion (2011$) for a 3 percent discount rate and $6.5 billion to $16 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS-EE program and participant costs and MRR costs in 2025, are approximately $1.0 billion for the rate-based approach and $3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the proposal will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS-EE program and participant costs and MRR costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Table 18 and Table 19 of this preamble provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the proposal for rate-based and mass-based federal plan approaches, respectively.

Table 18. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Proposal in 2020, 2025 and 2030 Under the Rate-Based Federal Plan Approach [Billions of 2011$][a]

	Rate-Based Approach					
	2020		2025		2030	
Climate Benefits[b]						
5% discount rate	$0.80		$3.1		$6.4	
3% discount rate	$2.8		$10		$20	
2.5% discount rate	$4.1		$15		$29	
95th percentile at 3% discount rate	$8.2		$31		$61	
Air Quality Co-benefits Discount Rate						
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits[c]	$0.70 to $1.8	$0.64 to $1.7	$7.4 to $18	$6.7 to $16	$14 to $34	$13 to $31
Compliance Costs[d]	$2.5		$1.0		$8.4	
Net Benefits[e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43
Non-Monetized Benefits	Non-monetized climate benefits					
	Reductions in exposure to ambient NO_2 and SO_2					
	Reductions in mercury deposition					
	Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury					
	Visibility impairment					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using the IPM for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS-EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

Table 19. Summary of the Monetized Benefits, Compliance Costs, and Net Benefits for the Proposal in 2020, 2025 and 2030 Under the Mass-Based Federal Plan Approach [Billions of 2011$][a]

	Mass-Based Approach		
	2020	**2025**	**2030**
Climate Benefits[b]			
5% discount rate	$0.9	$3.6	$6.4
3% discount rate	$3.3	$12	$20
2.5% discount rate	$4.9	$17	$29
95th percentile at 3% discount rate	$9.7	$35	$60

Air Quality Co-benefits Discount Rate						
Air Quality Health Co-benefits[c]	3%	7%	3%	7%	3%	7%
	$2.0 to $4.8	$1.8 to $4.4	$7.1 to $17	$6.5 to $16	$12 to $28	$11 to $26
Compliance Costs[d]	$1.4		$3.0		$5.1	
Net Benefits[e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits					
	Reductions in exposure to ambient NO_2 and SO_2					
	Reductions in mercury deposition					
	Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury					
	Visibility improvement					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC-CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC-CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC-CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC-CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC-CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using the Integrated Planning Model for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS-EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC-CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (e.g., nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (e.g., mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this proposed action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in the RIA for this proposal.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until approved by OMB.

This rule does not directly impose specific requirements on state and U.S. territory governments with affected EGUs. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of

Indian country. This rule does impose specific requirements on EGUs located in states, U.S. territories or areas of Indian country.

The information collection activities in this proposed rule are consistent with those activities defined under the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (**[insert FR number]**; the Clean Power Plan) finalized on August 3, 2015. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The ICR document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Aside from reading and understanding the rule, this proposed action would impose minimal new information collection burden on affected EGUs beyond what those affected EGUs would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

Although the EPA cannot determine at this time how many affected EGU respondents will submit information under the federal plan, the EPA has estimated an “upper bound” burden estimate for this ICR that estimates burden should every affected EGU read and understand the rule. This is the only potential respondent activity that would be required under the 3-year period following publication of the final federal plan, so there are no obligations to respond in this period. The results of this “upper bound” estimate of federal plan burden are presented below:

Respondents/affected entities: 1,028

Respondents’ obligation to respond: Not applicable, no responses are required during the period covered by the ICR.

Estimated number of respondents: Unknown at this time, but have assumed all affected entities are respondents for an upper bound estimate.

Frequency of response: None, no responses are required during the period covered by the ICR.

Total estimated burden: 17,133 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,706,501 (per year)

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to oria_submissions@omb.eop.gov, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than **[insert date 30 days after date of publication in**

the Federal Register]. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review within the RIA in docket EPA-HQ-OAR-2015-0199 and is summarized here.

The small entities subject to the requirements of this proposed rule may include privately-owned and publicly-owned entities, and rural electric cooperatives that are majority owners of affected EGUs. The EPA conducted this regulatory flexibility analysis at the highest level of ownership, evaluating parent entities with the largest share of ownership in at least one potentially-affected EGU included in EPA’s Base Case using the Integrated Planning Model (IPM) v.5.15, used in the RIA for this proposed rule. This analysis drew on parsed unit-level estimates using IPM results for 2030.

The EPA identified 223 potentially affected EGUs owned by 74 small entities included in 2030 projections from EPA’s IPM v.5.15. Fifty-nine of these potentially affected EGUs are projected to no longer be operating by 2030 in the Base Case of EPA’s version of IPM. Twenty-four small entities are projected to have all of their potentially affected EGUs cease operation by 2030 in this base case.

The EPA estimated net compliance costs for individual EGUs for the proposed rule using components for operating and annualized capital costs, fuel costs, demand-side energy efficiency program costs, and revenue changes. This approach is consistent with previous proposed power sector regulations, but also adds the additional component of change in demand-side energy efficiency program costs. Investment in demand-side energy efficiency results in lower electricity demand, and consequently fewer emissions as production is reduced to meet the lower demand, an important emission-reduction strategy modelled in the rate-based and mass-based federal plan approaches. For this analysis, the EPA used the parsed unit-level estimates to estimate three of the four components of the net compliance cost equation using IPM outputs: the change in operating and annualized capital costs, the change in fuel costs, and the change in revenue, where all changes are estimated as the difference between the base case and federal plan scenario. These impacts were then summed for each small entity, adjusting for ownership share. An additional analysis was performed outside of EPA’s IPM model to estimate the change in demand-side energy efficiency program costs, based largely on IPM-projected outputs.

As noted earlier, there are 74 small entities with potentially affected EGUs that are modeled in the IPM base case in 2030. Of these, 24 small entities are projected to withdraw all of their potentially affected EGUs from operation under base case conditions. This leaves 50 small entities with potentially affected EGUs that are projected to be generating electricity in 2030. Under the rate-based federal plan approach, 7 of these 50 small entities are projected to withdraw all of their potentially affected EGUs from operation by 2030. Under the mass-based federal plan approach, 5 of these 50 small entities are projected withdraw all of their potentially affected EGUs from operation by 2030.

Under the rate-based federal plan approach, 23 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 9 entities are estimated to have net compliance cost savings greater than 3 percent of their generation revenues from affected EGUs. Under the mass-based federal plan approach, 21 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 11 entities are estimated to have net compliance cost savings greater than 3 percent of generation revenues from their affected EGUs.

There are uncertainties and limitations in this analysis that may result in estimates that diverge from what we might see in reality. For example, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan. The rate-based and mass-based federal plan approaches analyzed in this IRFA are based on a scenario where all states of the contiguous U.S. will be regulated under a federal plan. Another factor to consider is that entities operating in regulated or cost-of-service markets are likely able to recover compliance costs through rate adjustments; as a result these costs can be viewed as likely being over-estimates for this set of utilities. Other uncertainties and data limitations exist and are described in the complete IRFA available for review within the RIA.

As discussed earlier in this preamble, the reporting, recordkeeping and other compliance requirements are most likely covered under Part 75 and Part 98 programs for affected EGUs. Therefore, only a marginal additional cost is expected for the monitoring, reporting and recordkeeping requirements of the proposed federal plan for affected EGUs.

Owners of affected EGUs may be subject to other related rules. For example, on September 20, 2013, the EPA proposed carbon pollution standards for new fossil fuel fired EGUs. On June 2, 2014, the EPA proposed carbon pollution standards for modified and reconstructed fossil fuel fired EGUs, in addition to the Clean Power Plan EGs, to cut carbon pollution from existing fossil fuel fired EGUs. These existing EGUs are, or will be, potentially impacted by several other recently finalized EPA rules. On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S.C. 1326(b)). This rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. On June 18, 2014 (79 FR 34830), the EPA promulgated the stream electric effluent limitation guidelines (SE ELG) rule to strengthen the controls on discharges from certain steam electric power plants. On April 17, 2015 (80 FR 21302), the EPA promulgated the coal combustion residuals (CCR) rule, which establishes technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

The EPA also considered whether the separate changes that we are proposing to make, as explained in section VII of this preamble above, to the framework regulations in subpart B of part 60 of the CAA regulations would have any impacts on small entities. Since these changes only modify and enhance the procedures that the Administrator will follow in processing state plans and promulgating a federal plan, and do not alter the rules or requirements that states or regulated entities must follow, the agency does not believe that there will be economic impacts on small entities from this portion of this proposal. After considering the economic impacts of the proposed changes to 40 CFR 60.27, I certify those changes will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531-1538, that could potentially result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. This federal plan will apply only to those EGUs located in states that do not submit approvable state plans, which is a subset of the EGUs considered in the RIA for the final EGs (see RIA for further discussion of impacts). Because it is impossible to determine at this time which states might be ultimately subject to a federal plan, the EPA cannot determine whether this final rule will be subject to UMRA. However, as noted below, the Agency has done substantial outreach to government entities as part of both the federal plan and the related CAA section 111(d) rulemaking. Further, regardless of whether the EPA does determine that this action ultimately meets the UMRA threshold, the agency intends to do additional outreach with government entities between now and the final rule. Additionally, the EPA has determined that this action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (e.g., municipal and rural electric cooperatives). In light of this interest, prior to this action, the EPA sought early input from representatives of small entities while formulating the provisions of the proposed regulation. Such outreach is also consistent with the President’s January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This outreach process has enabled the EPA to hear directly from these representatives, as the EPA developed the rule about how the EPA should approach the complex question of how to apply section 111 of the CAA to the regulation of GHGs from these source categories. We invite comments on all aspects of this proposal and its impacts, including potential adverse impacts, on small entities.

E. Executive Order 13132: Federalism

The EPA believes that this proposed rule may be of significant interest to state and local governments due to its relationship with the Clean Power Plan EGs. Therefore, the EPA has determined that consultations with state and local governments conducted during the Clean Power Plan EGs development process are also relevant to this proposed rule. Consistent with the EPA’s policy to promote communications between the EPA and state and local governments, the EPA consulted with state and local officials early in the process of developing the Clean Power Plan EGs to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final Clean Power Plan EGs, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This proposed action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The EGU potentially impacted by this proposed rulemaking located on Indian reservations are primarily owned by private entities, and in one case, partially owned by an agency of the U.S. government. As a result, the tribes on whose areas of Indian country those units are located will not be directly impacted by any costs of complying with this proposed rulemaking incurred by the owners/operators of those units. There would only be tribal implications in regards to compliance costs associated with this proposed rulemaking in the case where a tribal government has an ownership interest in a potentially affected EGU. A tribal government could also incur costs in the event that it seeks and is given delegated authority to enforce the federal plan proposed in this rulemaking. The EPA has, nevertheless, offered consultation to the tribes on whose areas of Indian country the units are located. As part of its general outreach to tribes regarding this proposed rulemaking, the EPA received feedback from a number of tribes regarding the potential overall economic impact that both the proposed Clean Power Plan and a proposed federal plan rulemaking may have on them. In these instances, the EPA has reached out to these tribes and as part of the consultation on the Clean Power Plan engaged with them on their concerns regarding a potential federal plan.

The EPA has conducted consultation with tribes on the Clean Power Plan and the Supplemental Proposal for the Clean Power Plan and will offer all tribes consultation on this proposed action. The EPA held consultations with tribes on the Clean Power Plan in the fall of 2014 before the agency issued its Supplemental Proposal for Indian Country and U.S. Territories. Additionally, the EPA held consultations for tribes shortly following the release of the supplemental proposal. The agency also held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. At the public hearing the agency received oral comments from community members representing a number of tribes and a number of tribal officials. The agency also conducted consultation with tribes in the spring and summer of 2015. An overview of the consultations provided as part of the Clean Power Plan is available in section XII.F of the final EGs.

Additionally, the EPA engaged in meaningful dialogue with tribal stakeholders to obtain their feedback in the pre-proposal stages of this rulemaking. We provided an update on this proposed rulemaking on the May 28, 2015, National Tribal Air Association and the EPA Air Policy call. Additionally, staff attended the National Tribal Forum conference on May 20, 2015 and provided an overview of the Clean Power Plan and explained that the agency would be proposing a federal plan.

Consistent with previous rulemakings impacting the power sector, there is significant tribal interest in these rulemakings because of the potential indirect impacts that rules such as the Clean Power Plan and this proposed federal plan may have on tribes. The EPA specifically solicits additional feedback from tribal officials on all aspects of this proposed rulemaking, including whether tribes whose areas of Indian country contain affected EGU(s) are interested in developing their own plan implementing the final EGs. Additionally, tribal stakeholders will be included in the outreach that the agency will be conducting with those communities already overburdened by pollution, which are often low-income communities,

communities of color, and indigenous communities. The actions that the agency will be taking are outlined in section IX of this preamble.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed guidelines, as well as substantial ozone and PM2.5 emission reductions as a cobenefit, would further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous U.S. in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed action does not involve technical standards.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on EJ. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections X.F and X.G of this preamble, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change (IPCC), and the National Research

Council of the National Academies that the potential impacts of climate change raise EJ issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the U.S.[154] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the U.S. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location), raising EJ concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses

[154] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 841 pp.

IPCC, 2014: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

particular threats to health, well-being, and ways of life of indigenous peoples in the U.S.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this proposed federal plan because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_x, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[155] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical

[155] "National Ambient Air Quality Standards for Particulate Matter, Final Rule," 78 FR 3086 (Jan. 15, 2013).

treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[156] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emissions reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and EJ considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on vulnerable communities. The EPA consulted its May 2015, Guidance on Considering Environmental Justice During the Development of Regulatory Actions, when determining what actions to take.[157] As described in the community and EJ considerations section of this preamble the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX of this

[156] U.S. Environmental Protection Agency (U.S. EPA). 2009. Integrated Science Assessment for Particulate Matter (Final Report). EPA-600-R-08-139F. National Center for Environmental Assessment – RTP Division. December. Available on the Internet at http://www.cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.

[157] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf. May 2015.

preamble. Additionally, as outlined in sections I and IX of this preamble the EPA has engaged meaningfully with communities throughout the development of the CPP and has devised a robust outreach strategy for continual engagement throughout this rulemaking.

List of Subject in 40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated:

Gina McCarthy,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, 62, and 78 of the Code of the Federal Regulations is amended as follows:

PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

2. Section 60.27 is amended by:

a. Revising paragraphs (b), (c) introductory text, and (c)(1);

b. Removing and reserving paragraph (c)(2);

c. Revising paragraphs (c)(3), (d), and (e)(1); and

d. Adding paragraphs (g) through (k).

The revisions, deletion, and additions read as follows:

§ 60.27 Actions by the Administrator.

*   *   *   *   *

(b) After receipt of a complete plan or complete plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within 12 months after the date on which the submission of a plan or plan revision is received, approve or disapprove such plan or revision, or each portion thereof.

(c) The Administrator must promulgate a federal plan within 12 months after the date the Administrator:

(1) Finds the State failed to submit a complete plan or complete plan revision within the time prescribed; or

*   *   *   *   *

(3) Disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart and the applicable emission guidelines have not been met.

(d) The Administrator will promulgate the regulations under paragraph (c) of this section for all or a portion of a federal plan, with such modifications as may be appropriate, unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator approves. After the promulgation of a federal plan, the Administrator may approve a State plan or plan revision or portion thereof and withdraw all or a portion of the federal plan.

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

*   *   *   *   *

(g) Completeness criteria.

(1) General. Within 60 days of the Administrator's receipt of a state submission, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator must determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of paragraph (g) of this section, the State will be treated as not having made the submission.

(2) Administrative criteria. In order to be complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) Technical criteria. In order to be complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each affected source, identification of emission standards for the affected sources, and monitoring, recordkeeping and reporting requirements that will determine compliance by each affected source;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

(4) Parallel processing. A State may submit a State plan prior to actual adoption by the State in order to expedite review and provide an opportunity for the State to consider EPA comments prior to submission of a final plan for final review and action. Under these circumstances, the following exceptions to the criteria in this paragraph apply to plans submitted explicitly for parallel processing:

(i) The letter required by paragraph (g)(2)(i) of this section must request that EPA propose approval of the proposed plan by parallel processing;

(ii) In lieu of paragraph (g)(2)(ii) of this section the State must submit a schedule for final adoption or issuance of the plan;

(iii) In lieu of paragraph (g)(2)(iv) of this section the plan must include a copy of the proposed/draft regulation or document, including indication of the proposed changes to be made to the existing approved plan, where applicable; and

(iv) The requirements of paragraphs (g)(2)(E) through (I) of this section do not apply to plans submitted for parallel processing. The exceptions granted in the preceding sentence apply only to EPA's determination of proposed action and all requirements of paragraph (g)(2) of this section must be met prior to publication of EPA's final determination of plan approvability.

(h) Full and partial approval and disapproval. If a portion of the plan revision meets all the applicable requirements of this chapter, the Administrator may approve the plan revision in part and disapprove the plan revision in part. The Administrator may authorize partial plan submissions in conjunction with a federal plan, where in combination, the federal and State plans constitute a complete and approvable plan meeting all of the requirements of this subpart and the applicable emissions guidelines.

(i) Conditional approval. The Administrator may approve a plan or a plan revision based on a commitment of the State, by a date certain established by the Administrator, to adopt specific enforceable measures, review and revise if appropriate State plans, or otherwise commit to making changes in the State's plan necessary to meet the requirements of the applicable emission guidelines. Any such conditional approval automatically converts to a disapproval if the State fails to comply with such commitment by the date certain established by the Administrator.

(j) Calls for plan revisions. Whenever the Administrator finds that the applicable plan is substantially inadequate to meet the requirements of the applicable emission guidelines, to provide for the implementation of such plan, or to otherwise comply with any requirement of the Clean Air Act, the Administrator must require the State to revise the plan as necessary to correct such inadequacies. The Administrator must notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions. Such findings and notice must be public. Any finding under this paragraph shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this part to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate.

(k) Error corrections. Whenever the Administrator determines that the Administrator’s action approving, disapproving, or promulgating any plan or plan revision (or portion thereof) was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public.

PART 62--APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS

3. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

4. Add subpart MMM to read as follows:

Subpart MMM: Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units that Commenced Construction on or Before January 8, 2014

Sec.

Introduction

Applicability of this Subpart

General Requirements

Emission Goals, Set-Asides, and Allowance Allocations

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

Designated Representatives

Monitoring, Recordkeeping, Reporting

Definitions

INTRODUCTION

§ 62.16205 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Mass-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) PSD and title V thresholds for greenhouse gases.

(1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” is considered to be the pollutant that otherwise is "subject to regulation" as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” is considered to be the pollutant that otherwise is "subject to regulation" as defined in § 71.2 of this chapter.

APPLICABILITY OF THIS SUBPART

§ 62.16210 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16215 What requirements apply to affected EGUs that retire??

(a) Exemption. (1) Any affected EGU that is permanently retired as defined in § 62.16375 is exempt from §§ 62.16220(c)(1) [CO_2 Emissions Requirements], 62.16340 [Compliance Requirements], 62.16345 [Monitoring], 62.16360 [Reporting], and 62.16365 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the facility that includes the unit, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Mass-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

GENERAL REQUIREMENTS

§ 62.16220 What requirements must I comply with?

(a) Designated representative requirements. The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16290 through 62.16300.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the designated representative, of each facility and each affected EGU at the facility must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16345 62.16360, and 62.16365.

(2) The emissions data determined in accordance with §§ 62.16345, 62.16360, and 62.16365 must be used to calculate allocations of CO_2 allowances under §§ 62.16240(a)and (b) and to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance must be the mass emissions amount for the monitoring location determined in accordance with § 62.16345 and rounded to the nearest ton.

(c) CO_2 emission standard requirements. (1) CO_2 emission standard. (i) As of the allowance transfer deadline for a compliance period in a given year, the owners and operators of each facility and each affected EGU at the facility with affected EGUs must hold, in the facility's compliance account, CO_2 allowances available for deduction for such compliance period under § 62.16340(a) in an amount not less than the tons of total CO_2 emissions for such compliance period from all affected EGUs at the facility.

(ii) If total CO_2 emissions during a compliance period in a given year from the affected EGUs at a facility are in excess of the CO_2 emission standard set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the facility and each affected EGU at the facility must hold the CO_2 allowances required for deduction under § 62.16340(d); and

(B) The owners and operators of the facility and each affected EGU at the facility are subject to federal enforcement pursuant to sections 113(a) through (h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its allowances) and secure appropriate corrective actions, and must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act.

(2) Compliance periods. (i) An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for

the compliance period starting on January 1, 2022 and for each compliance period thereafter.

(ii) [Reserved]

(3) Vintage of allowances held for compliance. (i) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in such compliance period or for a year in a prior compliance period.

(ii) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(ii)(A) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in a prior compliance period, or the current compliance period, or in the immediately following compliance period.

(4) Allowance Tracking and Compliance System (ATCS) requirements. Each CO_2 allowance must be held in, deducted from, or transferred into, out of, or between ATCS accounts in accordance with this subpart.

(5) Limited authorization. A CO_2 allowance is a limited authorization to emit one ton of CO_2 during the compliance period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization must only be used in accordance with the CO_2 Mass-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(6) Property right. A CO_2 allowance does not constitute a property right.

(d) Title V permit requirements. (1) Unless otherwise specified in this paragraph, all requirements of this subpart are applicable requirements that must be included in an affected EGU’s title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any allocation, holding, deduction, or transfer of CO_2 allowances in

accordance with this subpart, provided that the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit.

(e) Liability. (1) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU at a facility or the designated representative of affected EGUs at a facility will also apply to the owners and operators of such facility and of the affected EGUs at the facility.

(2) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU will also apply to the owners and operators of such affected EGU.

(f) Effect on other authorities. No provision of the CO_2 Mass-based Trading Program or exemption under § 62.16215 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16225 How should I compute time under the CO_2 Mass-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin on the occurrence of an act or event will begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Mass-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16230 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Mass-Based Trading Program are set forth in part 78 of this chapter.

§ 62.16231 How will the Clean Energy Incentive Program be administered under the federal plan?

(a) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for which this subpart is promulgated as a federal plan under section 111(d) of the Clean Air Act. The Administrator will award, on behalf of each such state, early action allowances for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE)) and demand-side energy efficiency (EE) projects:

(1) Metered wind power;

(2) Metered solar power; and

(3) Demand-side EE implemented in a low-income community.

Eligible RE projects must commence construction, and eligible demand-side EE projects must commence implementation after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action allowances will be distributed pursuant to a process to be prescribed by the Administrator, from an allowance set-aside equal to 300 million allowances for all states. This set-aside does not increase the total budget of allowances for the affected EGUs in the state subject to this subpart.

(c) The Administrator will match these early action allowances with additional matching allowances pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state’s pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: for every two MWh generated, the project will receive a number of early action allowances the Administrator determines to be equivalent to one MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to one MWh from the match under paragraph (c) of this section.

(2) For EE projects implemented in low-income communities as determined by the Administrator solely for purposes of this subpart: for every two MWh in end-use demand savings achieved, the project will receive a number of early action allowances the Administrator determines to be equivalent to two MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to two MWh from the match under paragraph (c) of this section.

EMISSION GOALS, SET-ASIDES, AND ALLOWANCE ALLOCATIONS

§ 62.16235 What are the statewide mass-based emission goals, renewable energy set-asides, output-based set-asides, and Clean Energy Incentive Program early action set-asides?

(a) The statewide mass-based emission goals with renewable energy set-asides and output-based set-asides for allocations of CO_2 allowances for the interim 3- and 2-year compliance periods in 2022 through 2029, and the final 2-year compliance periods in 2030 and thereafter are specified in Table 1 of this subpart.

Table 1 to Subpart MMM of Part 62--Statewide Mass-based Emission Goals*(short tons)

State	Interim Period			Final Period
	Compliance Period 1 2022-2024	Compliance Period 2 2025-2027	Compliance Period 3 2028-2029	Final compliance periods 2030-2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona	36,032,671	32,953,521	31,253,744	30,322,632
Arkansas	35,189,232	32,371,942	30,906,226	30,170,750
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	30,408,352	27,615,429	25,981,975	25,018,136
Illinois	1,615,518	1,522,826	1,493,052	1,492,856
Indiana	80,396,108	73,124,936	68,921,937	66,477,157
Iowa	92,010,787	83,700,336	78,901,574	76,113,835
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	13,360,735	12,511,985	12,181,628	12,104,747
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	2,251,173	2,119,865	2,076,179	2,073,942
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	67,312,915	61,158,279	57,570,942	55,462,884
Missouri	28,940,675	26,790,683	25,756,215	25,304,337

Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	60,975,831	55,749,239	52,856,495	51,266,234
Nevada	25,453,173	23,095,610	21,708,108	20,883,232
New Hampshire	22,246,365	20,192,820	18,987,285	18,272,739
New Jersey	4,461,569	4,162,981	4,037,142	3,997,579
New Mexico	18,241,502	17,107,548	16,681,949	16,599,745
New York	14,789,981	13,514,670	12,805,266	12,412,602
North Carolina	15,076,534	14,072,636	13,652,612	13,523,584
North Dakota	35,493,488	32,932,763	31,741,940	31,257,429
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	33,505,657	30,571,326	28,917,949	27,986,988
Wisconsin	62,557,024	56,762,771	53,352,666	51,325,342
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

* The values in this table are annual amounts; the mass goal for each multi-year compliance period is the annual value multiplied by the number of years in the compliance period. Each emission goal includes the renewable energy set-asides and output-based set-asides (the output-based set-asides are zero in the first compliance period).The first compliance period goals also include the early action Clean Energy Incentive Program set-aside.

(b) If implementing interstate trading, then the Administrator will use the sum of a covered group of States' mass-based emission goals as the aggregate mass-based emission goal.

(c) The renewable energy set-aside for each State covered by the federal mass-based emissions trading plan must reserve 5 percent from the State's annual allowances prior to allocation of that year's allowances to facilities. The renewable energy set-asides are specified in Table 2 of this subpart.

Table 2 to Subpart MMM of Part 62--Statewide Renewable Energy Set-aside (short tons)

State	Interim Period			Final Period
	Compliance Period 1 2022-2024	Compliance Period 2 2025-2027	Compliance Period 3 2028-2029	Final compliance periods 2030-2031 and thereafter
Alabama	3,308,224	3,045,949	2,910,799	2,844,024
Arizona	1,759,462	1,618,597	1,545,311	1,508,538
Arkansas	1,801,634	1,647,676	1,562,687	1,516,132
California	2,675,005	2,504,042	2,436,844	2,420,506
Colorado	1,789,266	1,632,724	1,544,591	1,495,020
Connecticut	377,789	355,423	347,754	347,076
Delaware	267,418	248,155	239,214	235,591
Florida	5,969,024	5,537,734	5,336,809	5,254,735
Georgia	2,712,897	2,492,754	2,376,741	2,317,342
Idaho	80,776	76,141	74,653	74,643
Illinois	4,019,805	3,656,247	3,446,097	3,323,858
Indiana	4,600,539	4,185,017	3,945,079	3,805,692
Iowa	1,520,418	1,380,771	1,299,099	1,250,907
Kansas	1,338,186	1,214,789	1,142,405	1,099,541
Kentucky	3,837,868	3,484,943	3,278,345	3,156,306
Lands of the Fort Mojave Tribe	31,844	30,017	29,430	29,426
Lands of the Navajo Nation	1,322,470	1,199,978	1,127,887	1,085,029
Lands of the Uintah and Ouray Reservation	137,937	125,161	117,642	113,172
Louisiana	2,101,760	1,923,058	1,824,835	1,771,351
Maine	112,559	105,993	103,809	103,697
Maryland	872,368	792,124	745,141	717,381
Massachusetts	668,037	625,599	609,081	605,237
Michigan	2,842,713	2,594,678	2,455,344	2,377,203
Minnesota	1,365,158	1,243,429	1,173,839	1,133,918

Mississippi	1,447,034	1,339,534	1,287,811	1,265,217
Missouri	3,365,646	3,057,914	2,878,547	2,773,144
Montana	688,830	625,028	587,479	565,155
Nebraska	1,112,318	1,009,641	949,364	913,637
Nevada	753,827	703,632	682,631	676,179
New Hampshire	223,078	208,149	201,857	199,879
New Jersey	912,075	855,377	834,097	829,987
New Mexico	739,499	675,734	640,263	620,630
New York	1,774,674	1,646,638	1,587,097	1,562,871
North Carolina	3,048,792	2,787,462	2,642,825	2,563,312
North Dakota	1,272,659	1,154,781	1,085,405	1,044,162
Ohio	4,425,616	4,035,247	3,814,008	3,688,490
Oklahoma	2,378,881	2,183,251	2,078,869	2,024,410
Oregon	454,886	423,883	410,479	405,933
Pennsylvania	5,304,138	4,860,236	4,619,604	4,491,115
Rhode Island	190,582	179,647	176,134	176,111
South Carolina	1,551,276	1,416,842	1,341,748	1,299,948
South Dakota	211,559	193,120	182,771	176,974
Tennessee	1,705,915	1,553,959	1,467,161	1,417,420
Texas	11,080,665	10,186,403	9,717,567	9,479,442
Utah	1,423,990	1,299,099	1,228,643	1,188,910
Virginia	1,564,510	1,449,550	1,394,924	1,371,656
Washington	619,785	572,057	548,179	536,959
West Virginia	3,127,851	2,838,139	2,667,633	2,566,267
Wisconsin	1,675,283	1,528,566	1,445,897	1,399,349
Wyoming	1,926,425	1,748,391	1,643,786	1,581,721

(d) The output-based set-aside for each State under this subpart, beginning in compliance period 2, must reserve a share of the State’s annual allowances prior to allocation of that year’s allowances to facilities as set forth in this paragraph (d). The output-based set-asides are specified in Table 3 of this subpart.

Table 3 to Subpart MMM of Part 62--Statewide Output-based Set-aside (short tons)

State	Allowances in Output-based Set-aside (short tons)
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671
Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167

Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

(e)(1) The Clean Energy Investment Program Set-Aside for each State covered under this subpart must contain an amount of allowances shown in Table 4 of this subpart, which must reserve a share of the State's annual allowances prior to allocation of that year's allowances to facilities as set forth in this paragraph.

Table 4 to Subpart MMM of Part 62--. Clean Energy Investment Program Early Action Set-Aside (short tons)

State	Allowances in Early Action Set-aside (short tons)
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929
Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183

Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

(2) Allowances may be distributed from the set-aside for projects meeting the criteria of paragraph (e)(3) of this

section, upon application of a project proponent that meets the requirements of 62.16245(a), except as may be prescribed by the Administrator in a future action. In order to receive a distribution, the project proponent must establish a general account in the tracking system as provided in 62.16320(c).

(3) Projects eligible for distribution of allowances from this set-aside must meet each of the criteria in paragraphs (e)(3)(i) through (iii) of this section. All categories of resources other than those listed in paragraphs (e)(3)(iii)(A) and (B) of this section, 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 Clean Air Act.

(i) The project was constructed or implemented on or after the signature date of the final rule promulgating subpart UUUU of part 60 of this chapter;

(ii) The creditable generation or energy savings from the project must occur in calendar years 2020 or 2021; and

(iii) Generation or energy savings must be from one of the following types of sources capable of revenue-quality metering:

(A) Onshore wind;

(B) Solar; or

(C) Demand-side EE.

§ 62.16240 When are allowances allocated?

(a) Allowance allocations. (1) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, CO_2 allowances will be allocated, for the multi-year compliance periods in the Interim Period beginning in 2022 and the Final Period beginning in 2030, as provided by the Administrator in a notice of data availability or through this subpart (if applicable). Providing an allocation to an entity does not constitute as an applicability determination of an affected EGU.

(2) Notwithstanding paragraph (a)(1) of this section, if an affected EGU which is provided an allocation does not operate for 2 consecutive calendar years, then such affected EGU will not be allocated the CO_2 allowances provided by the Administrator in a notice of data availability or through this subpart (if applicable) for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(3) Notwithstanding paragraph (a)(1) of this section, if an affected EGU provided an allocation issued by the Administrator in notice of data availability or through this subpart (if

applicable)is modified or reconstructed such that it is no longer subject to this subpart, then such affected EGU will not be allocated the CO_2 allowances provided for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(b) Set-asides. (1) Renewable energy set-asides. (i) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each approved Renewal Energy project in a State, in accordance with § 62.16245(a)(2) through (5), for the generation year of the applicable calculation deadline under this paragraph.

(ii) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(a)(6) and (7) for the generation year of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(2) Output-based set-asides. (i) By November 1 of the first year of each compliance period beginning in 2025, and each

compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(3), for the generation period of the applicable calculation deadline under this paragraph.

(ii) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(4) and (5) for the generation period of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(c) Affected EGUs incorrectly allocated CO_2 allowances. (1) For each compliance period in 2022 and thereafter, if the Administrator determines that CO_2 allowances were allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 62.16245(a) and (b), where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section. The situations for the Administrator to act according to the procedures in paragraphs (c)(2) through (5) are if:

(i)(A) The recipient is not actually an affected EGU under § 62.16210 as of January 1, 2022 and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1, 2022 and is allocated CO_2 allowances for such compliance period that the state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1, 2022; or

(B) The recipient is not located as of January 1 of the compliance period in the State from whose CO_2 allowances the CO_2 allowances allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, were allocated for such compliance period.

(ii) The recipient is not actually an affected EGU under § 62.16210 as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period that the a state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1 of such compliance period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CO_2 allowances under § 62.16325.

(3) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the facility that includes such recipient under § 62.16340(b) for such compliance period, then the Administrator will deduct from the account in which such CO_2 allowances were recorded an amount of CO_2 allowances allocated for the same or a prior compliance period equal to the amount of such already-recorded CO_2 allowances. The authorized account representative must ensure that there are sufficient CO_2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the facility that includes such recipient

under § 62.16340(b) for such compliance period, then the Administrator will not make any deduction to take account of such already-recorded CO_2 allowances.

(5)(i) With regard to the CO_2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period for the State from whose CO_2 allowances the CO_2 allowances were allocated; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(ii) With regard to the CO_2 allowances that were not allocated from a renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(iii) With regard to the CO_2 allowances that were allocated from the renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CO_2 allowances back to the renewable energy set-aside, or to the output-based set-aside, respectively, for such compliance period.

§ 62.16245 How are set-aside allowances allocated?

(a)(1) Renewable energy set-aside. The Administrator will establish a renewable energy set-aside as set forth in § 62.16235(c), and allocate CO_2 allowances from the set-aside for each year of a compliance period as outlined in this section.

(2) Eligible renewable energy capacity. To be eligible to receive renewable energy set-aside allowances, an eligible

resource must meet each of the requirements in paragraphs (a)(2)(i) through (v) of this section. Any resource that does not meet the requirements of paragraphs (a)(2)(i) through (v) of this section cannot receive set-aside allowances.

(i) The resource must be a renewable energy resource that falls into one of the following categories of resources: on-shore utility scale wind, solar, geothermal power, or utility scale hydropower.

(ii) The resources must only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then set-aside allowances may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. Set-aside allowances must not be issued for generation for an uprate that followed a derate that occurred on after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resources, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued set-aside allowances.

(iii) The resource must be located in the mass-based State for which the set-aside has been designated.

(iv) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(v) The resource must not have received emission rate credits (ERCs) for any period of time for which it receives set-aside allowances.

(3) Process for issuance of set-aside allowances. The process and requirements for issuance of set-aside allowances are set forth in paragraphs (a)(3)(i) through (x) of this section.

(i) Eligibility application. To receive set-aside allowances, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of paragraph (a)(2) of this section are met and, demonstrates that the following requirements are met:

(A) Identification of the authorized account representative of the eligible resource, including the authorized account representative's name, address, e-mail address, telephone number, and allowance tracking system account number; and

(B) Identification of the eligible resource(s), including the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the authorized account representative and designated representative; generator prime mover and technology type; generator nameplate capacity (if applicable); generator category (e.g., wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable) (if applicable); the control area, balancing authority, ISO conditions as defined in § 62.16375 (if applicable), or regional transmission organization in which the generator is located (if applicable); and a copy of the most recent filing of a copy of the generating facility's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA-860 (if applicable).

(ii) Renewable energy providers must open a general account per the requirements in § 62.16320(c), and submit a project application for renewable energy set-aside allowances to the Administrator by June 1 of the year prior to the generation year for which set-aside allowances are requested. Providers may update submitted projections for future generation years, these projections must be received by June 1 of the year prior to the generation year in question. The project application must contain the following information:

(A) Projection of the project's annual renewable energy generation in MWh.

(B) Documentation of the methodology, data facilities, and assumptions used to project the project's annual renewable energy generation.

(C) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-State approach where States are providing for joint issuance of allowances pursuant to the authority in their individual State plans.

(D) A evaluation, measurement, and verification (EM&V) plan.

(E) A verification report from an accredited independent verifier who meets the requirements of § 62.16275 and § 62.16280. While considered a part of the eligibility application, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(F) An authorization that provides for the following: the Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(G) The following statement, signed by the authorized account representative of the eligible resource:

(1) “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) [Reserved]

(H) Any other information required by the Administrator.

(4) Monitoring and verification. After the generation year for which a provider received set-aside allowances for an eligible resource, the authorized account representative must submit to the Administrator:

(i) A measurement and verification (M&V) report.

(ii) A verification report from an accredited independent verifier that meets the requirements of § 62.16275 and § 62.16280. While considered a part of the M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(5) Allocation of Renewable Energy Set-Aside Allowances. The Administrator will enter the projected generation from each approved project into a pool of projects for that State that will receive set-asides for a generation year.

(i) The Administrator will distribute renewable energy set-aside allowances for a generation year with the number of allowances distributed to each project prorated according to its percentage of the total approved projected MWhs for that State that the project represents.

(ii) If in the previous generation year, the project did not reach the MWhs projected, then the unfulfilled MWhs will be subtracted from that provider's projected generation eligible for the set-aside pool.

(iii) If the unfulfilled MWhs from a previous year exceed the projected hours for the generation year, then the Administrator will carry over the deficit and subtract from the projected generation in subsequent years until there is no deficit. If this deficit is greater than 10 percent in a particular year, then the provider will need to provide an explanation to the Administrator of the deficit, and will be required to reevaluate their projections for future years. If such deficits continue through all 3 years of the first or second compliance period, then the Administrator will disqualify the provider from receiving future set-asides for the following compliance period.

(6) Surplus renewable set-aside allowances. If, after completion of the procedures under paragraph (a)(5) of this section for each compliance period, any unallocated CO_2 allowances remain in the renewable energy set-aside for the State for such generation year, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(7) Notice of surplus renewable energy set-aside allowance distribution. The Administrator will make public the amount of CO_2 allowances allocated under paragraph (a)(6) of this section for such generation year period to each affected EGU eligible for such allocation.

(b)(1) Output-based set-aside. The Administrator will establish an output-based set-aside beginning in compliance period 2, and allocate CO_2 allowances from the set-aside for each year of a compliance period as set forth in § 62.16235(c).

(2) Unit eligibility. To be eligible to receive output-based set-aside allowances, affected EGUs must meet the following eligibility requirements:

(i) The affected EGU must be a natural gas combined cycle unit;

(ii) The affected EGU must be located in the mass-based State for which the set-aside has been designated; and

(iii) The affected EGU's average capacity factor in the preceding compliance period was above 50 percent based on net summer capacity and net generation.

(3) Allocation of output-based set-aside allowances. The Administrator will allocate output based set-aside allowances for each eligible EGU based on its average net generation and net summer capacity in the preceding compliance period.

(i) The Administrator will calculate the amount of allowances an eligible EGU receives from the output-based set-aside as the unit's average net generation in the preceding compliance period over 50 percent multiplied by the allocation rate of 1,030 lb/MWh-net.

(ii) If the amount of total allowances exceeds the size of the State's set-aside, then the allowances will be allocated to the State's eligible generation on a pro-rata basis.

(iii) The Administrator will provide notice of the net summer capacity and net generation data used, and the resulting allocations by August 1 of the first year of each compliance period beginning in 2025. The notice of the net summer capacity and net generation data used, and the resulting allocations, must allow 30 days for public comment on the data and allocations, until August 31 of the same year.

(iv) The Administrator will provide notice of the final set-aside allocations by November 1 of the same year.

(4) Surplus output-based set-aside allowances. If, after completion of the procedures under paragraph (b)(3) of this section for each compliance period, any unallocated CO_2 allowances remain in the out-put based set-aside for the State for such generation period, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(5) Notice of surplus output-based set-aside. The Administrator will notify the public, through the promulgation of the notices of data availability described in § 62.16240(b)(1) and (2), of the amount of CO_2 allowances allocated under paragraphs (b)(3) and (4) of this section for such

compliance period to each affected EGU eligible for such allocation.

§ 62.16250 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16260 in the CO_2 Mass-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued set-aside allowances. In addition, the provisions of § 62.16255(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or M&V report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, and any other requirements may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued set-aside allowances.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued allowances. In addition, the provisions of § 62.16255(a) through (d) may apply.

§ 62.16255 What is the process for error adjustments or misstatement, and suspension of allowance issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which set-aside allowances have been issued, the Administrator may adjust the number of set-aside allowances issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which set-aside allowances have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which set-aside allowances have been issued, the Administrator will revoke set-aside allowances from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of set-aside allowances to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of set-aside allowances necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines set-aside allowances have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which set-aside allowances have been issued. Freezing a general account will prevent transfer of allowances out of the account.

(d) If set-aside allowances are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(i) through (iii) of this section.

(i) Freeze the general account of the authorized account representative for an eligible resource, preventing any transfers of allowances out of the account.

(ii) Revoke or deduct allowances held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of allowances issued for the ineligible eligible resource.

(iii) In the event that the general account of the eligible resource holds a number of allowances less than the number of set-aside allowances issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of allowances necessary to fully account for all allowances issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of set-aside allowances for an eligible resource, for the following reasons in paragraphs (e)(i) through (iii) of this section.

(i) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which set-aside allowances have been issued, or the eligibility status of an eligible resource.

(ii) In the case of repeated error or misstatements in submitted M&V reports.

(iii) In the case of an intentional misrepresentation in a submitted M&V report.

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

§ 62.16260 What are the requirements for evaluation measurement and verification plans for eligible resources?

(a) EM&V plan requirements. Any EM&V plan submitted in support of the issuance of a set-aside allowance pursuant to this rule must meet the requirements of this section.

(b) General EM&V plan criteria. Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) Specific EM&V plan criteria. Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must

specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section must be met.

(i) The generation data is physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data is measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data was measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not and any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data is collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire set-aside allowances issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, the data may be self-reported and reported no less than annually.

(v) The generation data serves a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) Set-aside allowances shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation (“station service”) or parasitic load on the generator’s side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, set-aside allowances may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) through (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, the data may be reported no less than annually.

(v) The generation data are self-reported to distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(vi) The generation data serves a load that otherwise would have been served by the grid if not for the generator. The set-aside allowance is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vii) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraph (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock and its associated biogenic CO_2 have been met.

(4) For a waste—to-energy resource, in addition to the requirements of paragraph (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste; and

(iii) The net energy output is measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrate that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540 of this subpart.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2

emission monitoring and reporting methodology in part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided transmission and distribution (T&D) system losses can be assessed as is commonly practiced with demand-side EE.

(6) For electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity savings measured at the end use meter or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile expressed as a percentage. No other transmission and distribution loss

factors may be used in calculating the electricity savings, including measures such as conservation voltage reduction and volt/VAR optimization.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed – or that a typical consumer or building owner would have continued using – in a given circumstance (i.e., a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE project covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (e.g., installed as part of a utility EE program direct install EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: project-based measurement and verification (PB-MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: PB-MV, comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited – with adequate advance notification (via the internet and other social media) – to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience – for example, with new and innovative EE program types – necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2 or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of

EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (i.e., factors that are not directly related to the EE measure, such as weather, occupancy, and production levels.

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, is operating as intended, and therefore has the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (e.g., lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than +/-10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my

inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) [Reserved]

§ 62.16265 What are the requirements for monitoring and verification reports for eligible resources?

(a) M&V report requirements. Any M&V report that is submitted, in support of the issuance of a set-aside allowance that can be used in accordance with § 62.16240, must meet the requirements of this section.

(b) General M&V report criteria. Each M&V report must include the information in paragraphs (b)(1) and (2) of this section.

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16245(a)(3).

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (e.g., nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) [Reserved]

§ 62.16270 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(ii) [Reserved]

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued set-aside allowances pursuant to this regulation, in accordance with § 62.16245(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16245;

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan;

(3) The eligible resource exists or the operation or activity will be implemented in the manner specified in the eligibility application;

(4) That the EM&V plan meets the requirements of § 62.16260;

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (e.g., reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system); and

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its

professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of an M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the information specified in paragraphs (c)(1) through (3) of this section.

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the authorized account representative seeks issuance of set-aside allowances, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data is within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the allowance tracking system. If the data entered exceeds the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16265.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

§ 62.16275 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, resources (personnel and otherwise) to provide verification reports, including the following:

(A) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(B) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(C) Knowledge of the requirements of the Administrator's CO_2 Mass-based Trading Program regulations and related guidance;

(D) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(E) Capability to perform key verification activities, such as development of a verification report; site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification opinion, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of paragraph (c)(1) of this section. Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of **§** 62.16280(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR

part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4, of this chapter.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possess a financial strength rating in the top four categories from either Standard & Poor’s or Moody’s, specifically, AAA, AA, A or BBB for Standard & Poor’s, and Aaa, Aa, A, or Baa for Moody’s. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) Requirements for maintenance of accreditation status.

(1) Accredited independent verifiers must meet the requirements of **§** 62.16280 when providing verification services for an authorized account representative.

(2) The instances specified in section 62.16280(d) are cause for revocation of a verifier’s accreditation.

<u>§ 62.16280 What are the procedures accredited independent verifiers must follow to avoid conflict of interest?</u>

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of set-aside allowances, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, set-aside

allowance issuance, or the number of set-aside allowances issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold set-aside allowances, or other financial derivatives related to set-aside allowances, or have a financial relationship with other parties that own, buy, sell, or hold set-aside allowances or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI, which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and set-aside allowances must not be issued pursuant to it.

§ 62.16285 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16280(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of § 62.16270, § 62.16275, and § 62.16280.

(4) Intentional misrepresentation of data in a verification report.

DESIGNATED REPRESENTATIVES

§ 62.16290 How are designated representatives and alternate designated representatives authorized? What role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16300, each facility, including all affected EGUs at the facility, shall have one and only one designated representative, with regard to all matters under the CO_2 Mass-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the facility and each affected EGU at the facility in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the designated representative by the Administrator regarding the facility or any such affected EGU.

(b) Except as provided under § 62.16300, each facility may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the facility or any such affected EGU.

(c) Except in this section, § 62.16375, and §§ 62.16295 through 62.16315, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16295 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16315 concerning delegation of authority to make submissions, each submission under the CO_2 Mass-based Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each facility and affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the facility or affected EGUs for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a facility or an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16315.

§ 62.16300 What are the processes for changing designated representative, alternate designated representative, owners and operators, and affected EGUs at the facility?

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the facility and the affected EGUs at the facility.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the facility and the affected EGUs at the facility.

(c) Changes in owners and operators. (1) In the event an owner or operator of a facility or an affected EGU at the facility is not included in the list of owners and operators in the certificate of representation under § 62.16305, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a facility or an affected EGU at the facility, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16305 amending the list of owners and operators to reflect the change.

(d) Changes in affected EGUs at the facility. Within 30 days of any change in which affected EGUs are located at a facility (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16305 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the facility, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the affected EGU was purchased or

otherwise obtained, and the date on which the affected EGU became located at the facility.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, email address and facsimile number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the facility.

§ 62.16305 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the following elements in a format prescribed by the Administrator:

(1) Identification of the facility, and each affected EGU at the facility, for which the certificate of representation is submitted, including facility and affected EGU names, facility category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU,

actual or projected date of commencement of commercial operation, net summer capacity at the affect EGU, and a statement of whether such facility is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility and of each affected EGU at the facility.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility and each affected EGU at the facility”; and

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of the owners and operators of the facility and of each affected EGU at the facility and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the facility or unit.”

(iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the facility and of each affected EGU at the facility; and CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CO_2 allowances by contract, then CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16310 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16305 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16305 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

§ 62.16315 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the elements in paragraphs (c)(1) through (4) of this section.

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent").

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her.

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16315(d) shall be deemed to be an electronic submission by me"; and

(ii) "Until this notice of delegation is superseded by another notice of delegation under § 62.16315(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under **§** 62.16315 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

MONITORING, RECORDKEEPING, REPORTING

§ 62.16320 How are compliance accounts and general accounts established?

(a) Compliance accounts. Upon receipt of a complete certificate of representation under § 62.16305, the Administrator will establish a compliance account for the facility for which the certificate of representation was submitted, unless the facility already has a compliance account. The designated representative and any alternate designated representative of the facility shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) Retirement accounts. (1) A retirement account, into which allowances held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and allowances deposited into it are permanently retired. Once an allowance is retired, the allowance shall no longer be transferable to another account in that allowance tracking system or any other allowance tracking system.

(2) [Reserved]

(c) General accounts. (1) Application for a general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring CO_2 allowances, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CO_2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: “I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account"; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or

persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to CO_2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) Except in this section, whenever the term “authorized account representative” is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CO_2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one

or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or

(ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv) shall be deemed to be an electronic submission by me”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 62.16320(c)(5) is terminated.”

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted CO_2 allowance transfer under § 62.16330 for any CO_2 allowances in the account to one or more other Allowance Tracking and Compliance System accounts.

(ii) If a general account has no CO_2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CO_2 allowances, then the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CO_2 allowance transfer under § 62.16330 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) Account identification. The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 62.16295(a) and 62.16315 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 62.16325 When will CO_2 allowances be recorded in compliance accounts?

(a) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, the

Administrator will record in each facility's compliance account the CO_2 allowances allocated to the affected EGUs at the facility in accordance with § 62.16240(a), or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the upcoming compliance period.

(b) Except as specified in paragraph (a) of this section, the Administrator will record an allocation in the appropriate Allowance Tracking and Compliance System account by the date on which any allocation of CO_2 allowances to a recipient must be made by or submitted to the Administrator in accordance with either §§ 62.16240 or with state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter.

(c) When recording the allocation of CO_2 allowances to an affected EGU or other entity in an Allowance Tracking and Compliance System account, the Administrator will assign each CO_2 allowance a unique serial number that will include digits identifying the year of the compliance period for which the CO_2 allowance is allocated.

(d) By December 1, 2021 and December 1 of each year thereafter, the Administrator will record in each renewable energy project's general account, the CO_2 allowances allocated from the renewable energy set-aside to the project in accordance with § 62.16245(a), for the following year.

(e) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will record in each facility's compliance account the CO_2 allowances allocated from the output-based set-aside to the eligible EGUs at the facility in accordance with § 62.16245(b) or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the following year.

§ 62.16330 How must transfers of CO_2 allowances be submitted?

(a) An authorized account representative seeking recordation of a CO_2 allowance transfer must submit the transfer to the Administrator.

(b) A CO_2 allowance transfer must be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each CO_2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each CO_2 allowance identified by serial number in the transfer.

§ 62.16335 When will CO_2 allowance transfers be recorded?

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CO_2 allowance transfer that is correctly submitted under § 62.16330, the Administrator will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CO_2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any CO_2 allowances allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16340 for the compliance period immediately before such allowance transfer deadline.

(c) Where a CO_2 allowance transfer is not correctly submitted under § 62.16330, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a CO_2 allowance transfer under paragraphs (a) and (b) of the section, the

Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CO_2 allowance transfer that is not correctly submitted under § 62.16330, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16340 How will deductions for compliance with a CO_2 emission standard occur?

(a) Availability for deduction for compliance. CO_2 allowances are available to be deducted for compliance with a facility’s CO_2 emission standard for a compliance period only if the CO_2 allowances:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the facility's compliance account as of the allowance transfer deadline for such compliance period.

(b) Deductions for compliance. After the recordation, in accordance with § 62.16335, of CO_2 allowance transfers submitted by the allowance transfer deadline for a compliance period, the Administrator will deduct from each facility's compliance account CO_2 allowances available under paragraph (a) of this section in order to determine whether the facility meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions from all affected EGUs at the facility for such compliance period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) Identification of CO_2 allowances by serial number. The authorized account representative for a facility's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request must be submitted to the Administrator by the allowance transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the facility and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct CO_2 allowances under paragraph (b) or (d) of this section from the facility's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the

absence of such request or in the case of identification of an insufficient amount of CO_2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any CO_2 allowances that were allocated to the affected EGUs at the facility and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any CO_2 allowances that were allocated to any affected EGU or other entity and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the facility has excess emissions, the Administrator will deduct from the facility's compliance account an amount of CO_2 allowances, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the facility's excess emissions.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 62.16345 What monitoring requirements must I comply with?

(a) The owner or operator of an affected EGU must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter. You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(4) or (5) of this section, except that a complete data record is required, i.e., CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV must be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No.

C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(6)(i)(A) and (B) of this section.

(4) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(4)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(5) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (e.g., from sorbent injection), then this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (e.g., carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) Calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis). CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV must be used in the calculations.

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter, if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU uses, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(5) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(4) of this section,

determine the hourly CO_2 mass emissions according to paragraphs (a)(5)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) Determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) that were calculated according to procedures specified in paragraph (a)(5)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(6) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator

must calculate net energy output according to paragraph (a)(6)(i) of this section.

(i) For each operating hour of a compliance period that was used in paragraph (a)(4) or (5) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(6)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output must be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(6)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in

Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(ii) [Reserved]

(7) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(1) of this section share a common exhaust gas stack and are subject to the same emissions standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(8) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected

EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(b) [Reserved]

§ 62.16350 May I bank CO_2 annual allowances for future use or transfer?

(a) A CO_2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under §§ 62.16240(b), 62.16335, 62.16340, 62.16355, or 62.16370.

§ 62.16355 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Tracking and Compliance System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16360 What are my reporting, notification and submission requirements?

(a) You must prepare and submit reports according to paragraphs (a) through (e) of this section, as applicable.

(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period;

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period; and

(vi) If the report covers the final quarter or a compliance period, then you must include the CO_2 emission standard with which your affected EGU must comply, the affected EGUs calculated emission performance as a cumulative mass in units of the emission standard required, and if an affected EGU is complying with an emission standard by using allowances, then the designated representative must include in their report a list of all unique allowance serial numbers retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired. If set-aside allowances were used from an eligible resource by an affected EGU to comply with its emission standard, then the designated representative must include in their report the eligible resource identification information sufficient to demonstrates that it meets the requirements of § 62.16245 and qualifies to be issued allowance set-asides (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(b) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Mass-based Trading Program, except as provided in § 62.16315. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(c) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean

Air Markets Division in the Office of Atmospheric Programs of EPA.

(d) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(e) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of 40 CFR part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs off site.

(f) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16365 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraphs (a)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records:

(i) All emissions monitoring information, in accordance with this subpart;

(ii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU’s emission standard under § 62.16220 and any other requirements of, the CO_2 Mass-based Trading Program;

(iii) Data that is required to be recorded by 40 CFR part 75, subpart F, of this chapter; and

(iv) Data with respect to any allowances used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(2)(iv)(A) and (B) of this section.

(A) All documents related to any set-aside allowances used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific set-aside allowance, and each regulatory approval and any documentation that supports the issuance of each set-aside allowance by the Administrator.

(B) All records and reports relating to the surrender and retirement of allowances for compliance with this regulation, including the date each individual allowance with a unique serial identification number was surrendered and/or retired.

§ 62.16370 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Mass-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct CO_2 allowances from or transfer CO_2 allowances to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

DEFINITIONS

§ 62.16375 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or Affected EGU means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allocate or allocation means, with regard to CO_2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart or any state allowance-distribution methodology submitted by the State and approved by the Administrator under § 62.16245, to:

(1) An affected EGU;

(2) A renewable energy set-aside;

(3) An output-based set-aside; or

(4) Any other entity specified by the Administrator.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent state or federal CO_2 emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the affected EGU's heat rate in mmBtu/MWhr) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrator records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Mass-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Allowance transfer deadline means, for a compliance period in a given year, midnight of May 1 (if it is a business day), or midnight of the first business day thereafter (if May 1 is not a business day), immediately after such compliance period and is the deadline by which a CO_2 allowance transfer must be submitted for recordation in a facility's compliance account in order to be available for use in complying with the facility's CO_2

emission standard for such compliance period in accordance with §§ 62.16220 and 62.16340.

Alternate designated representative means, for a CO_2 Mass-based Trading Program facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Mass-based Trading Program. If the facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an affected EGU during a calendar year and the potential heat input to the affected EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CO_2 allowances held in the general account and, for a CO_2 Mass-based Trading facility's compliance account, the designated representative of the facility is the authorized account representative.

Automated data acquisition and handling system (DAHS) means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (e.g., trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or state, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

CO_2 allowance means a limited authorization issued and allocated by the Administrator under this subpart, or by a State or permitting authority under a state allowance-distribution methodology approved by the Administrator under § 60.24(x) of this chapter, to emit one ton of CO_2 during a compliance period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CO_2 Mass-Based Trading Program.

CO_2 allowance deduction or deduct CO_2 allowances means the permanent withdrawal of CO_2 allowances by the Administrator from a compliance account (e.g., in order to account for compliance with the CO_2 emission standard).

CO_2 allowances held or hold CO_2 allowances means the CO_2 allowances treated as included in an Allowance Tracking and Compliance System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but

not yet recorded, CO_2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart.

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in § 62.16235.

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the facility under § 62.16340(a) for such compliance period.

CO_2 Mass-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the Administrator under subpart UUUU of part 60 of this chapter, as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or CHP unit, (also known as "cogeneration") means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Common practice baseline (CPB) means a baseline derived 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 (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Tracking and Compliance System account, established by the Administrator for a CO_2 annual facility under this subpart, in which any CO_2 allowance allocations to the affected EGUs at the facility are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the facility's CO_2 emission standard in accordance with §§ 62.16220 and 62.16340.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16220(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1 2022 to December 31, 2024.

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027.

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) or CVR means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system (CEMS) means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 62.xx30 through 62.xx35. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

<u>Control area operator</u> means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: (a) has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure, and (b) is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand–side EE means energy efficiency activities, projects, programs or measures resulting in electricity savings.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating units capacity for planning purposes.

Designated representative means, for a CO_2 Mass-based Trading facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Mass-based Trading Program. If the CO_2 Mass-based Trading facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (e.g., electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Energy efficiency program or EE program means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by EE program.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of an EE measure.

Eligible resource means a resource that meets the requirements of § 62.16245 and has been registered with the EPA-administered ATCS or an allowance tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16260.

Emissions means air pollutants exhausted from an affected EGU or facility into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or affected EGU is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

Energy service company means a private enterprises engaged in delivering electricity savings directly for an end-use customer or as an agent of a sponsoring entity such as a utility.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating facility for generating allowances pursuant to this regulation, including the type of facility.

Excess emissions means any ton of emissions from the affected EGUs at a facility during a compliance period that exceeds the CO_2 emissions limitation for the facility for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an Allowance Tracking and Compliance System account established under this subpart that is not a compliance account.

Generation year means a calendar year for which a renewable energy project submits its projected generation to the Administrator by June 1 of the preceding year for allowances from the renewable energy set-aside.

Generation period means the compliance period from which the Administrator uses operations data of affected EGUs to calculate allowances from the output-based allocation set-aside for the following compliance period.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means "Indian country" as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or IGCC facility means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15^{o} C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16265.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected

EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (e.g., steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent

of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (e.g., steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or operation means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any person who operates, controls, or supervises an affected EGU at the facility or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such facility or affected EGU.

Owner means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the facility or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the facility or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, “owner” does not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from an affected EGU at the facility or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, an affected EGU that is unavailable for service and for which the affected EGU's owners and operators (1) have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of 62.16215, or (2) rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CO_2 allowances, the moving of CO_2 allowances by the Administrator into, out of, or between Allowance Tracking and Compliance System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25^{o} C, 77 ^{o}F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16270.

Waste-to-Energy means a process or unit (e.g., solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

§ 62.16380 Measurements, abbreviations, and acronyms.

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR-alternated designated representative

Btu—British thermal unit

CO_2—carbon dioxide

COI—conflict of interest

CPP—clean power plan

CVR-conservation voltage regulation

DR-designated representative

EE—energy efficiency

EGU-electric generating unit

EM&V-evaluation, measurement, and verification

GCV-gross calorific value

GJ-giga joule

H_2O—water

hr—hour

IGCC-integrated gasification combined cycle

kg-kilogram

kW—kilowatt electrical

kWh—kilowatt hour

lb—pound

M&V–measurement and verification

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt hour

O_2—oxygen

PB-MV-project-based measurement and verification

PSD-prevention of significant deterioration

T&D-transmission and distribution

TRM-technical reference manual

yr—year

5. Add subpart NNN to read as follows:

Subpart NNN: Greenhouse Gas Emissions Rate-based Model Trading Rule for Electric Utility Generating Units that Commenced Construction on or Before January 8, 2014

Sec.

INTRODUCTION

Applicability of this Subpart

General Requirements

Emission Rate Credit Issuance, Adjustment, and Revocation

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

Designated Representatives

INTRODUCTION

§ 62.16405 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Rate-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) of this chapter and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48) of this chapter.

(2) For the purposes of 40 CFR 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under

section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2 of this chapter.

(4) For the purposes of 40 CFR 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2 of this chapter.

APPLICABILITY OF THIS SUBPART

§ 62.16410 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator of an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16415 What are the requirements for retired affected EGUs?

(a)(1) Any affected EGU that is permanently retired as defined in § 62.16570 is exempt from §§ 62.16420(c)(1) [CO_2 Emissions Requirements], 62.16535 [Compliance Requirements], 62.16540 [Monitoring], 62.16555 [Reporting], and 62.16560 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the affected EGU, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing

by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Rate-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

GENERAL REQUIREMENTS

§ 62.16420 What emission standards and requirements must I comply with?

(a) Designated representative requirements. The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16485 through 62.16495.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the designated representative, of affected EGU must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16540, 62.16555, and 62.16560.

(2) The emissions data determined in accordance with § 62.16540 must be used to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided

that, for each monitoring location from which emissions are reported, the emission rate used in determining compliance must be the CO_2 emission rate at the monitoring location determined in accordance with paragraph (c) of this section.

(c) CO_2 emission standard requirements. (1) Each designated representative for each affected EGU must demonstrate compliance with its emission standard listed in Table 1 of this subpart, as applicable, by calculating a CO_2 emission rate by factoring stack emissions and any emission rate credits (ERCs) into the following equation:

$$\mathrm{CO_2 emission\ rate} = \frac{\sum \mathrm{M_{CO2}}}{\sum \mathrm{MWh_{op}} + \sum \mathrm{MWh}_{\mathrm{ERC}}}$$

Where:

CO_2 emission rate	=	An affected EGU's calculated CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.
M_{CO2}	=	Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.
MWh_{op}	=	Total net energy output over the compliance period for an affected EGU in units of MWh.
MWh_{ERC}	=	ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (c)(2) of this section).

(2) An emission rate credit (ERC) qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if it:

(i) Has a unique serial number;

(ii) Represents one whole MWh of actual energy generated or saved with zero associated carbon dioxide emissions;

(iii) Was issued to an eligible resource that meets the requirements of § 62.16435 or to an affected EGU that meets the requirements of § 62.16434, by the Administrator through an ERC tracking system or the Allowance Tracking and Compliance System; and

(iv) Was surrendered and retired only once for purposes of compliance with this regulation by the Administrator through an ERC tracking system or the Allowance Tracking and Compliance System.

(3) An ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of its state measures.

(4) As of the ERC transfer deadline for a compliance period, the owners and operators of each affected EGU must hold, in the affected EGU's compliance account, sufficient ERCs to demonstrate compliance with its applicable emission standard

listed in Table 1 of this subpart pursuant to the requirement of paragraph (c)(1) of this section.

(5) If an affected EGU exceeds its emission standard during a compliance period, then:

(i) The owners and operators of the affected EGU must hold ERCs required for deduction under § 62.16535(e);

(ii) The owners and operators of the affected EGU are subject to federal enforcement pursuant to sections 113(a) – (h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, or use of ERCs that meet the compliance demonstration in § 62.16420 (c)(2)) and secure appropriate corrective actions, and the owners and operators must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act;

(iii) If an affected EGU does not meet its emission standard because it did not meet the emissions standard based on its stack emissions and generation alone and it did not obtain sufficient qualifying ERCs to meet its emission standard by July 1 of the year following the relevant compliance period, then it may be subject to federal enforcement pursuant to Sections 113(a) – (h), 42 U.S.C. § 7413(a)-(h), and Section 304 of the Clean Air Act, 42 U.S.C. § 7604, and the United States, states, and other persons have the ability to enforce violations and secure corrective actions; and

(iv) If an affected EGU obtained sufficient facially valid ERCs to meet its emission standard, but those ERCs were found to be invalid, then it may be subject to federal enforcement as specified in (c)(5)(iii) of this section.

(d) Compliance periods. An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022, and for each compliance period thereafter.

(1) Vintage of ERCs held for compliance. An ERC held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period must be an ERC that was issued for a year in such compliance period or for a year in a prior compliance period.

(2) Allowance Tracking and Compliance System (ATCS). Each ERC must be held in, deducted from, transferred into, out of, or between ATCS accounts in accordance with this subpart.

(3) Limited authorization. (i) An ERC shall only be used in accordance with the CO_2 Rate-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(4) Property right. An ERC does not constitute a property right.

(e) Title V permit requirements. (1) Unless otherwise specified in this paragraph, all requirements of this subpart shall be applicable requirements that must be included in an affected EGU's title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any crediting, holding, deduction, or transfer of ERCs in accordance

with this subpart, provided that the requirements applicable to such creditings, holdings, deductions, or transfers of ERCs are already incorporated in such permit.

(f) Liability. Any provision of the CO_2 Rate-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU shall also apply to the owners and operators of such affected EGU.

(g) Effect on other authorities. No provision of the CO_2 Rate-based Trading Program or exemption under § 62.16415 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16425 How should I compute time under the CO_2 Rate-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Rate-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16430 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Rate-based Trading Program are set forth in part 78 of this chapter.

§ 62.16431 How will the Clean Energy Incentive Program be administered under the federal plan?

(a) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for whom this subpart is promulgated as a federal plan under section 111(d) of the Act. The Administrator will award, on behalf of each such state, early action emission rate credits (ERCs) for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE) and demand-side energy efficiency (EE) projects:

(1) Metered wind power;

(2) Metered solar power; and

(3) Demand-side EE implemented in a low-income community.

Eligible RE projects must commence construction, and eligible demand-side EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action ERCs will be distributed pursuant to a process to be prescribed by the Administrator, and in a manner to be demonstrated by the Administrator to have no impact on the aggregate emission performance of affected EGUs required to meet rate-based emission standards during the compliance periods.

(c) The Administrator will match these early action ERCs with additional matching ERCs pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state’s pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: for every two MWh generated, the project will receive one early action ERC under paragraph (b) of this section and one matching ERC from the match under paragraph (c) of this section; and

(2) For EE projects that benefit low-income communities as determined by the Administrator solely for purposes of this subpart: for every two MWh in end-use demand savings achieved,

the project will receive two early action ERCs under paragraph (b) of this section and two matching ERCs from the match under paragraph (c) of this section.

EMISSION RATE CREDIT ISSUANCE, ADJUSTMENT, AND REVOCATION

§ 62.16434 What affected EGUs qualify for generation of ERCs?

(a) ERCs may only be issued to affected EGUs under the conditions listed in paragraphs (b) and (c) of this section.

(b) For affected EGUs that emit below their applicable emission standard, the amount of ERCs generated must be calculated using the following equation:

$$\text{ERCs} = \frac{(\text{EGU emission standard} - \text{EGU emission rate})}{\text{EGU emission standard}} * \text{EGU generation}$$

Where:

ERCs	=	Number of emission rate credits generated by an affected EGU during an applicable compliance period (MWh).
EGU emission standard	=	The emission standard the affected EGU must comply with during the applicable compliance period according to § 62.16420 (lb/MWh).
EGU emission rate	=	The affected EGU's measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).
EGU generation	=	Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with 62.16540 (MWh).

(c) Stationary combustion turbines that meet the definition of an affected EGU may generate net energy output MWh gas shift

ERCs (GS-ERCs) for all hours of operation during a given compliance period according to paragraphs (c)(1) through (3) of this section.

(1) To calculate the number of GS-ERCs:

$$GS - ERCs = \text{EGU Generation} * \text{Incremental Generation Factor} * GS - \text{ERC Emission Factor}$$

Where:

GS-ERC	=	Net energy output MWh gas shift ERCs.
EGU generation	=	Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with 62.16540 (MWh).
Incremental Generation Factor	=	See Table 2 of this subpart for the applicable factor for each compliance period.
GS-ERC Emission Factor Rate	=	Value calculated using equation (c)(2) of this section.

(2) To calculate the GS-ERC Emission factor for your specific affected EGU you must use the following equation:

$$\text{GS-ERC Emission Factor} = 1 - \frac{\text{EGU emission rate}}{\text{Steam Turbine Emission Standard}}$$

Where:

GS-ERC Emission Factor	=	Factor to be used in the equation in paragraph (c)(1) of this section for GS-ERC calculation.
EGU emission rate	=	Affected EGU’s measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).

Steam turbine emission standard	=	Steam turbine emission standard for the corresponding compliance period as found in Table 1 of this subpart (lb/MWh).

(3) Notwithstanding any other provision of this subpart, GS-ERCs must not be used for compliance by an affected EGU that is a stationary combustion turbine. Stationary combustion turbines may use other ERCs in their compliance demonstration.

§ 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs?

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

(1) Resources qualifying for eligibility only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then ERCs may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be

issued for generation for an uprate that followed a derate that occurred on after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resources, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(3) The resource is located in a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation, unless the resource is located in a State with mass-based emission standards and the resource can demonstrate (e.g., through a power purchase agreement or contract for delivery) transmission of its generation into a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion);

(iv) Nuclear energy;

(v) A non-affected combined heat and power unit, including waste heat power; or

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex poste savings, not “projected” or “claimed” savings.

(b) Any resource that does not meet the requirements of this subpart cannot generate ERCs for use in the compliance demonstration required under § 62.16420.

(c) ERCs may not be issued to any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of part 60 of this chapter, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(2) EGUs that do not meet the applicability requirements of § 62.16410, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(3) Measures that reduce CO_2 emissions outside the electric power sector, including GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission

reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA to generate ERCs in connection with a specific State plan.

§ 62.16440 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16435 in the Rate-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued ERCs. In addition, the provisions of § 62.16450(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or monitoring and verification (M&V) report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, and any other requirements may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued ERCs.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued ERCs. In addition, the provisions of § 62.16450 (a) through (d) may apply.

§ 62.16445 What is the process for the issuance of ERCs?

The process and requirements for issuance of ERCs for affected EGUs and eligible resources are set forth in paragraphs (a) through (f) of this section.

(a) Eligibility application. To receive ERCs, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of § 62.16434 (for an affected EGU) or § 62.16435 (for an eligible resource) are met, and, in the case of an eligible resource only, demonstrates that the requirements in paragraphs (a)(1) through (9) of this section are met.

(1) Identification of the authorized account representative of the ERC resource, including the authorized account representative’s name, address, e-mail address, telephone number, and ERC tracking system account number.

(2) Identification of the eligible resource(s), including the information in paragraphs (a)(2)(i) through (v) of this section.

(i) For an eligible resource, the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the designated representative or authorized account representative; eligible resource generator prime mover and/or technology type; eligible resource nameplate capacity; eligible resource category (e.g., wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable); for eligible resource, the control area, balancing authority, ISO conditions as defined in § 62.16570, or the regional transmission organization in which the generator is located (if applicable).

(A) For an eligible resource with a nameplate capacity of1 MW or more, a copy of the most recent filing of a copy of the generating facility’s U.S. Energy Information Agency’s Annual Electric Generator Report Form EIA-860.

(B) For an electric generating resource with a nameplate capacity of less than 1 MW, the information that would be contained in U.S. Energy Information Agency’s Annual Electric Generator Report Form EIA-860, if that electric generating facility had nameplate capacity of 1 MW or more.

(ii) For an energy-saving resource that is project-based, a detailed description of the demand-side EE or electricity savings project, including: location and specifications of the building(s), facility(ies), or installations where energy-saving measures were implemented or will be implemented; owner and operator of the building(s), facility(ies), or installations where the energy-saving measures are implemented or will be implemented; the parties implementing the energy-saving project, including lead contractor(s), subcontractors, and consulting firms (if different from the authorized account representative); energy-saving measures installed and/or energy-savings practices implemented (or to be installed/implemented); specifications of equipment and materials installed, or to be installed, as part of the energy-saving project; project plans and technical schematics, as applicable.

(iii) For an energy-savings resource that involves an EE requirement or program, a description of the electricity savings program, including: overall approach or “logic” to the requirement or program, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or installations where energy-saving requirements or programs were implemented or will be implemented; electricity consuming system(s), end-use(s), building or facility type(s), or installations where the energy-saving requirements or programs are implemented or will be implemented; the parties implementing the energy-saving requirement or program, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of energy-saving equipment and/or energy-savings practices implemented (or to be installed/implemented) under the requirement or program; the delivery mechanisms of the requirement or program, which may include financial incentives or equipment rebates, dissemination of actionable information to electricity customers, on-site audits paired with technical recommendations.

(iv) For other electricity-saving resources (e.g., transmission and distribution (T&D) measures such as conservation voltage reduction (CVR)), a description of the resource, including: overall approach or “logic” to the electricity-saving resource, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or electricity transmitting and distributing systems, as applicable, where electricity-saving resources were implemented or will be implemented; electricity consuming, transmitting, or distributing system(s), building or facility type(s), or end-use(s) where the electricity-saving resource are implemented or will be implemented; the parties implementing the electricity-saving resource, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of installed equipment and/or implemented practices (or to be installed/implemented); the delivery mechanisms used to implement and propagate the electricity-saving resource, as applicable.

(v) For eligible resources with distributed locations, such as measures at multiple residential, commercial, or industrial buildings, at a minimum, aggregated information about the location of measures that constitute an eligible resource, provided that the accredited independent verifier and the Administrator have the ability to access information specifying the location of each discrete measure that constitutes an eligible resource.

(3) Demonstration that the eligible resource meets all applicable eligibility requirements in § 62.1435.

(4) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-state approach where States are providing for joint issuance of ERCs pursuant to the authority in their individual State plans.

(5) An evaluation measurement and verification (EM&V) plan.

(6) A verification report from an accredited independent verifier who meets the requirements of §§ 62.16470 and 62.16475.

(7) An authorization that provides for the following: the Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(8) The following statement, signed by the designated representative of the eligible resource:

(i) "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(ii) [Reserved]

(9) Any other information required by the Administrator.

(b) <u>Registration of eligible resources</u>. The Administrator must review the eligibility application to determine whether the affected EGU or eligible resource meets the requirements of § 62.16445(a), and if it determines that the requirements are met, approve the eligibility application and register the affected EGU or eligible resource in an ERC tracking system that meets the requirements of § 62.16515. Once so registered, the affected EGU or eligible resource is eligible to be issued ERCs, provided all other applicable requirements continue to be met.

(c) M&V reports. For an eligible resource, the designated representative must submit to the Administrator an M&V report prior to issuance of ERCs by the Administrator.

(d) Verification reports. For an eligible resource, the authorized account representative must submit a verification report from an accredited independent verifier that meets the requirements of § 62.16470 and § 62.16475 as part of each eligibility application and M&V report. While considered a part of the eligibility application and M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(e) Issuance of ERCs. ERCs may only be issued by the Administrator based on actual electricity generation or savings documented in an M&V report that meets the requirements of § 62.16460 and a verification report that meets the requirements of § 62.16465. Only one ERC will be issued for each verified MWh.

(f) Tracking system. ERCs may only be issued through an ERC tracking system that meets the requirements of § 62.16515.

§ 62.16450 What is the process for error adjustments or misstatement, and suspension of ERC issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which ERCs have been issued, the Administrator may adjust the number of ERCs issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which ERCs have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which ERCs have been issued, the Administrator will revoke ERCs from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of ERCs to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of ERCs necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines ERCs have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which ERCs have been issued. Freezing a general account will prevent transfer of ERCs out of the account.

(d) If ERCs are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(1) through (3) of this section.

(1) Freeze the general account for the eligible resource, preventing any transfers of ERCs out of the account.

(2) Revoke and deduct ERCs held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of ERCs issued for the ineligible eligible resource.

(3) In the event that the general account of the ERC resource holds a number of ERCs less than the number of ERCs issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of ERCs necessary to fully account for all ERCs issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of ERCs for an eligible resource, for the following reasons in paragraphs (e)(1) through (3) of this section.

(1) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which ERCs have been issued, or the eligibility status of an eligible resource.

(2) In the case of repeated error or misstatements in submitted M&V reports.

(3) In the case of an intentional misrepresentation in a submitted M&V report.

EVALUATION MEASUREMENT AND VERIFICATION PLANS, MONITORING AND VERIFICATION REPORTS, AND VERIFICATION

§ 62.16455 What are the requirements for evaluation measurement and verification plans for eligible resources?

(a) EM&V plan requirements. Any EM&V plan submitted in support of the issuance of an ERC pursuant to this rule must meet the requirements of this section.

(b) General EM&V plan criteria. Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) Specific EM&V plan criteria. Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section are met.

(i) The generation data is physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute

No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data is measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data was measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not and any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data is collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire ERCs issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, the data may be self-reported and reported no less than annually.

(v) The generation data serves a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) ERCs shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation ("station service") or parasitic load on the generator's side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, ERCs may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) though (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, the data may be reported no less than annually.

(iv) The generation data are self-reported to distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(v) The generation data serves a load that otherwise would have been served by the grid if not for the generator. The ERC is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraphs (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock and its associated biogenic CO_2 have been met.

(4) For a waste-to-energy resource, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste materials; and

(iii) The net energy output is measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrate that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540 of this subpart.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided T&D system losses can be assessed as is commonly practiced with demand-side EE.(6) For demand-side electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the facility- or premises-level electricity savings measured at the electricity customer's meter, or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile. No other transmission and distribution loss factors may be used in calculating the electricity savings.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed – or that a typical consumer or building owner would have continued using – in a given circumstance (i.e., a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE project covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (e.g., installed as part of a utility EE program direct install EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: project-based measurement and verification (PB-MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: project-based measurement and verification (PB-MV), comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited – with adequate advance notification (via the internet and other social media) – to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience – for example, with new and innovative EE program types – necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2, or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (i.e., factors that are not directly related to the EE measure, such as weather, occupancy, and production levels.

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, is operating as intended, and therefore has the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (e.g., lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than +/-10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) [Reserved]

§ 62.16460 What are the requirements for monitoring and verification reports for eligible resources?

(a) M&V report requirements. Any M&V report that is submitted, in support of the issuance of an ERC that can be used in accordance with § 62.16420, must meet the requirements of this section.

(b) General M&V report criteria. Each M&V report must include the following:

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16445(a); and

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, resource, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (e.g., nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and

information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) [Reserved]

§ 62.16465 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: “I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued ERCs pursuant to this regulation, in accordance with § 62.16435 and **§ 6**2.16445(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16435 and **§ 6**2.16445(a).

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan.

(3) The eligible resource exists or the practice or activity will be implemented in the manner specified in the eligibility application.

(4) That the EM&V plan meets the requirements of § 62.16455.

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the ERC resource (e.g., reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system).

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of a M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the following:

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the

authorized account representative seeks issuance of ERCs, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data is within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the ERC tracking system. If the data entered exceeds the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16460.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and

validity of information and data supplied by the authorized account representative.

§ 62.16470 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the Administrator's CO_2 Rate-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; performance of site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification statement, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of section § 62.16470(d)(1). Once accredited,

only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of § 62.16475(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4, of this chapter.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possess a financial strength rating in the top four categories from either Standard & Poor's or Moody's, specifically, AAA, AA, A or BBB

for Standard & Poor's, and Aaa, Aa, A, or Baa for Moody's. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) Requirements for maintenance of accreditation status, as follows:

(1) Accredited independent verifiers must meet the requirements of section 62.16475 when providing verification services for an authorized account representative; and

(2) The instances specified in section 62.16475(d) are cause for revocation of a verifier's accreditation.

§ 62.16475 What are the procedures of accredited independent verifiers must follow to avoid conflict of interest?

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal

relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of ERCs, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, ERC issuance, or the number of ERCs issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that own, buy, sell, or hold ERCs or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity

to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and ERCs must not be issued pursuant to it.

§ 62.16480 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16475(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16465, 62.16470, and 62.16475.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

DESIGNATED REPRESENTATIVES

§ 62.16485 How are designated representatives and alternate designated representatives authorized? What role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16495, each affected EGU, and each eligible resource shall have one and only one designated representative, with regard to all matters under the CO_2 Rate-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the affected EGU in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the designated representative by the Administrator regarding the affected EGU.

(b) Except as provided under § 62.16495, each affected EGU may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500,

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding any such affected EGU.

(c) Except in this section, §§ 62.16490 through 62.16510, and § 62.16570, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16490 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16510 concerning delegation of authority to make submissions, each submission under the CO_2 Rate-based Trading Program must be made, signed, and certified by the designated representative or alternate designated representative for each affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the affected EGU for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16510.

§ 62.16495 What are the processes for changing designated representative, alternate designated representative, owners and operators?

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the affected EGU.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the affected EGU.

(c) Changes in owners and operators. (1) In the event an owner or operator of an affected EGU is not included in the list of owners and operators in the certificate of representation under § 62.16500, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of affected EGU, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16500 amending the list of owners and operators to reflect the change.

(d) Changes in affected EGUs at the source. Within 30 days of any change in which affected EGUs are located at a source (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16500 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the source.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, and facsimile number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the source.

§ 62.16500 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the elements in paragraphs (a)(1) through (5) of this section in a format prescribed by the Administrator.

(1) Identification of the affected EGU for which the certificate of representation is submitted, including names, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU, net-summer capacity, actual or projected date of commencement of commercial operation, and a statement of whether such affected EGU is located in Indian Country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected EGU.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected EGU”;

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of the owners and operators of the affected EGU and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the affected EGU”; and

(iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the affected EGU ; and ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of ERCs by contract, ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program ERCs will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16505 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16500 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16500 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of ERC transfers.

§ 62.16510 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16510(d) shall be deemed to be an electronic submission by me”; and

(ii) “Until this notice of delegation is superseded by another notice of delegation under § 62.16510(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 62.16510 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

MONITORING, RECORDKEEPING, REPORTING

§ 62.16515 How are compliance accounts and general accounts established and used, and how is ERC issuance documentation accessed?

(a) Compliance accounts. (1) Upon receipt of a complete certificate of representation under § 62.16500, the Administrator will establish a compliance account for the affected EGU for which the certificate of representation was submitted, unless the affected EGU already has a compliance account. The designated representative and any alternate designated representative of an affected EGU shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(2) A compliance account will hold ERCs intended for surrender by a designated representative when demonstrating an affected EGUs compliance with a CO_2 emission standard as applicable in § 62.16420. A compliance account may be established for a facility with one or more affected EGUs, provided that the account contains subaccounts for each affected EGU within the facility.

(b) Retirement accounts. (1) A retirement account, into which ERCs held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and ERCs deposited into it are permanently retired. Once an ERC is retired, the ERC shall no longer be transferable to another account in that ERC tracking system or any other ERC tracking system.

(2) [Reserved]

(c) General accounts.

(1) Application for a general account. (i) Designated representatives of affected EGUs, authorized account representatives of eligible resources, and any other person may apply to open a general account, for the purpose of holding and transferring ERCs, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to ERCs held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the ERCs held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: “I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to ERCs held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account"; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to ERCs held in the general account in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to ERCs held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account must be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to ERCs held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the ERCs held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments.

Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the ERCs in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the ERCs in the general account.

(iii)(A) In the event a person having an ownership interest with respect to ERCs in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to ERCs in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the ERCs in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of ERCs transfers.

(5) Delegation by authorized account representative and alternate authorized account representative.

(i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16515(c)(5)(iv) shall be deemed to be an electronic submission by me”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under **§ 6**2.16515(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under **§** 62.16515(c)(5) is terminated.”

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted ERC transfer under § 62.16525 for any ERCs in the account to one or more other Allowance Tracking and Compliance System accounts.

(ii) If a general account has no ERC transfers to or from the account for a 12-month period or longer and does not contain any ERCs, then the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted ERC transfer under § 62.16525 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) Account identification. The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of ERCs in the account, only if the submission has been made, signed, and certified in accordance with § 62.16490(a) and § 62.16510 or paragraphs (c)(2)(ii) and (5) of this section.

(f) ERC identification information. The Administrator will assign to each ERC issued in the EPA ERC tracking system a unique serial identifier that beings with the two digit postal abbreviation of the State in which it was issued and includes the year it was issued, and the eligible resource category that generated it.

(g) Records supporting ERC issuance. The Administrator will maintain in the EPA ERC tracking system records of, for each ERC, all of the following:

(1) Account holder names and information;

(2) Authorized account representative name and information;

(3) Qualifying eligible resource identification number, name, State, and contact information including street address, mailing address, phone number, and email;

(4) Category of qualifying eligible resource, according to the categories specified in section § 62.16435(a)(4);

(5) The date the qualifying eligible resource commenced generation or saving of energy;

(6) Individual ERCs, each with a unique serial identifier that meets the requirements of paragraph (f) of this section;

(7) Records of ERC transfers among accounts, including the date of transfer and the accounts involved in the transfer;

(8) The date an ERC was surrendered for a compliance demonstration;

(9) Date an ERC was retired by the regulatory body; and

(10) Each eligibility application, EM&V plan, M&V report, and verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(h) Access to records supporting ERC issuance. The Administrator will provide in the EPA ERC tracking system access and functionality to allow each ERC to be traceable by the public to the records listed in § 62.16515(g). This information will be accessible via an electronic, internet-based portal in the ERC tracking system searchable by, at a minimum, each eligible resource, affected EGU, eligible resource category, and ERC.

(i) Reports. The Administrator will provide in the EPA ERC tracking system electronic, internet-based access to enable the generation of at least the following reports, [for as long as this regulation is effective] [in perpetuity]:

(1) Account Activity Reports. By each account holder, reports based on records of their account activity, including the information listed in § 62.16515(g);

(2) Public Reports. By the public, reports that include: all of the information listed in § 62.16515(g); a list of all registered account holders in the ERC tracking system, including compliance accounts and general accounts; a list of all ERC resources (including access to all documentation for such eligible resources); a list of all accredited independent verifiers; and aggregate ERC activity statistics on at least an annual basis, for at least the following: issuance of ERCs, transfers among accounts, transfers in or out of the ERC tracking system to/from another approved ERC tracking system (if relevant), and ERC retirements. The ERC tracking system shall provide this functionality for as long as this regulation is effective; and

(3) EPA reports. For the EPA and state regulators, the information listed in § 62.16515(g) and any other information regarding ERC issuance, transfer, surrender, and retirement for purpose of compliance with this regulation.

(j) Interactions with other ERC tracking systems. If approved in connection with a State plan, then an ERC tracking system may provide for transfers of ERCs to/from another ERC tracking system approved in connection with s State plan by the EPA, or provide for transfers of ERCs to/from an EPA-administered ERC tracking system used to administer a federal plan. To transfer ERCs to or from an EPA-administered ERC tracking system, the state ERC tracking system must be approved under subpart UUUU of part 60 of this chapter for such use by the EPA.

§ 62.16525 How must transfers of ERCs be submitted?

(a) An authorized account representative seeking recordation of an ERC transfer must submit the transfer to the Administrator.

(b) An ERC transfer must be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each ERC that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each ERC identified by serial number in the transfer.

§ 62.16530 When will ERC transfers be recorded?

(a) Except as provided in paragraph (b) of this section, within five business days of receiving an ERC transfer that is correctly submitted under § 62.16525, the Administrator will record an ERC transfer by moving each ERC from the transferor account to the transferee account as specified in the transfer.

(b) An ERC transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any ERCs allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16535 for the compliance period immediately before such allowance transfer deadline.

(c) Where an ERC transfer is not correctly submitted under § 62.16525, the Administrator will not record such transfer.

(d) Within five business days of recordation of an ERC transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of an ERC transfer that is not correctly submitted under § 62.16525, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16535 How will deductions for compliance with a CO_2 emission standard occur?

For affected EGUs subject to the emission standards listed in Table 1 of this subpart, the owner or operator of an affected EGU must demonstrate compliance with its CO_2 emission standard in accordance with 62.16420(c) and incorporate ERCs as listed in paragraphs (a) through (f) of this section.

(a) Availability for deduction for compliance. ERCs are available to be deducted from a compliance account and used for compliance with an affected EGU’s CO_2 emissions standard for a compliance period only if the ERCs:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the affected EGU's compliance account as of the allowance transfer deadline for such compliance period.

(b) Deductions for compliance. After the recordation, in accordance with § 62.16530, of ERC transfers submitted by the ERC transfer deadline for a compliance period, the Administrator will deduct from each affected EGU's compliance account ERCs available under paragraph (a) of this section in order to determine whether the affected EGU meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of ERCs deducted and subsequently added to the total MWh generated by the affected EGU adjusts the affected EGU’s CO_2 emission rate to equal the CO_2 emission standard for such compliance period; or

(2) If there are insufficient ERCs to complete the deductions in paragraph (b)(1) of this section, until no more ERCs available under paragraph (a) of this section remain in the compliance account.

(c) Identification of ERCs by serial number. The authorized account representative for an affected EGU's compliance account may request that specific ERCs, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (e) of this section. In order to be complete, such request must be submitted to the Administrator by the ERC transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the affected EGU and the appropriate serial numbers.

(d) First-in, first-out. The Administrator will deduct ERCs under paragraph (b) or (e) of this section from the affected

EGU's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of ERCs in such request, on a first-in, first-out accounting basis.

(e) Deductions for exceeding the emission standard. After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the affected EGU has exceeded its CO_2 emission standard, the Administrator will deduct from the affected EGU's compliance account an amount of ERCs, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of ERCs of the affected EGU's excess emissions.

(f) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (e) of this section.

§ 62.16540 What monitoring requirements must I comply with?

(a) You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) The owner of operator of an affected EGU required to meet an emission standard must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h)

of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) Each compliance period shall include only “valid operating hours” in the compliance period, i.e., operating hours for which:

(i) “Valid data” (as defined in § 62.16570) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (Note: for hours with no useful output, zero is considered to be a valid value).

(3) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vii) of this section, except as provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value

(ii) For each “valid operating hour”, calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU uses, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(vii) The owner operator of an affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected EGU; the owner or operator of an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly affected EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) For each measured hourly heat input rate, use Equation G-4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each valid operating hour (as defined in paragraph (a)(2) of this section, determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(5)(i) of this section.

(i) For each valid operating hour of a compliance period that was used in paragraph (a)(3) or (4) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(5)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, then you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net}	=	Net energy output of your affected EGU for each valid operating hour (as defined in paragraph (a)(2) of this section) in MWh.
$(Pe)_{ST}$	=	Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.
$(Pe)_{CT}$	=	Electric energy output plus mechanical energy

output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), then you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$	=	Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.
Q_m	=	Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.
H	=	Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).
CF	=	Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(C) Sum all of the values of P_{net} over the entire compliance period. Then, divide the total CO_2 mass emissions from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values to determine the CO_2 emission rate (lb/net MWh) for the compliance period.

(ii) [Reserved]

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emission standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3)(i) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), then the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emission standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) If two or more affected EGUs serve a common electric generator, then you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the affected EGUs are identical, then you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

§ 62.16545 May I bank CO_2 ERCs for future use or transfer?

(a) An ERC may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any ERC that is held in a compliance account or a general account will remain in such account unless and until the ERC is deducted or transferred under §§ 62.16530, 62.16535, 62.16550, or 62.16565.

§ 62.16550 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Tracking and Compliance System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16555 What are my reporting, notification and submission requirements?

(a) You must prepare and submit reports according to paragraphs (a) through (g) of this section, as applicable.

(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The percentage of valid operating hours in each quarter described 62.16540(a)(2) (i.e., the total number of valid operating hours) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(ii) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(iii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iv) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(v) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(vi) ERC replacement generation (if any), properly justified (see paragraph (a)(1)(viii) of this section);

(vii) The calculated CO_2 mass emission rate for the compliance period (lb/net MWh); and

(viii) If the report covers the final quarter or a compliance period, then you must include the CO_2 emission standard (as identified in Table 1 of this subpart) with which your affected EGU must comply, your CO_2 emission rate calculated according to 62.16420(c), and all if an affected EGU is complying with an emission standard by using ERCs the designated representative must include in their report a list of all unique ERC serial numbers retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrates that it meets the requirements of 62.16435 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(b) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (a) of this section, then the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in § 62.16540(a)), and shall not be used in the compliance determinations.

(c) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Rate-based Trading Program, except as provided in § 62.16510. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(d) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(e) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of 40 CFR part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an affected EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs off-site.

(g) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16560 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in (a)(1) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) Unless otherwise provided, the owner or operator of an affected EGU must maintain the following records on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance,

corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s). This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 62.16500 for the designated representative for each affected EGU and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents must be retained on site at the affected EGU beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 62.16500 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU's emission standard under § 62.16420 and any other requirements of the CO_2 Rate-based Trading Program.

(iv) Data that is required to be recorded by 40 CFR part 75, subpart F, of this chapter.

(v) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(1)(v)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(2) [Reserved]

(b) [Reserved]

§ 62.16565 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Rate-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct ERCs from or transfer ERCs to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

DEFINITIONS

§ 62.16570 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or Affected EGU means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent State or federal CO_2 emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the affected EGU's heat rate in mmBtu/MWhr) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance Tracking and Compliance System means the system by which the Administrator records allocations, deductions, and transfers of ERCs under the CO_2 Rate-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole ERCs.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Alternate designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Rate-based Trading Program. If the affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or

TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of ERCs held in the general account and, for a CO_2 Rate-based Trading Program affected EGU's, the designated representative of the affected EGU is the authorized account representative.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (e.g., trees, crops, grasses, tree litter, roots) above and belowground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the affected EGU under § 62.16535(a) for such compliance period.

CO_2 Rate-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the

Administrator under subpart UUUU of part 60 of this chapter, as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or CHP unit, (also known as "cogeneration") means an electric generating unit that use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy affected EGU.

Common practice baseline or CPB means a baseline derived 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 (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Transfer and Compliance System account, established by the Administrator for an affected EGU under this subpart, in which any ERC allocations to the affected EGUs at the affected EGU are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the affected EGU's CO_2 emission standard in accordance with §§ 62.16420 and 62.16535.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16420(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1 2022 to December 31, 2024;

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027; and

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) or CVR means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16540(a)(3). The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and

handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that (a) has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure and (b) is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand-side EE means energy efficiency activities, projects, programs or measures resulting in electricity savings.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating units capacity for planning purposes.

Designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the affected EGU, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Rate-based Trading Program. If the CO_2 Rate-based Trading affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (e.g., electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by EE program.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of demand-side EE.

Eligible resource means a resource that meets the requirements of § 62.16435 and has been registered with the EPA-administered ERC tracking system or an ERC tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16455.

Emissions means air pollutants exhausted from an affected EGU into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or affected EGU is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

ERC deduction or deduct ERCs means the permanent withdrawal of ERCs by the Administrator from a compliance account (e.g., in order to account for compliance with the applicable CO_2 emission standard).

Energy efficiency program or EE program means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

ERC held or hold ERCs means the ERCs treated as included in an Allowance Tracking and Compliance System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart.

ERC transfer deadline means, for a compliance period in a given year, midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such compliance period and is the deadline by which an ERC transfer must be submitted for recordation in a affected EGU's compliance account in order to be available for use in complying with the affected EGU's CO_2 emission standard for such compliance period in accordance with §§ 62.16420 and 62.16535.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating resource for generating ERCs pursuant to this regulation, including the type of resource.

Excess emissions means any ton of emissions from the affected EGUs at an affected EGU during a compliance period that exceeds the CO_2 emissions limitation for the affected EGU for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an Allowance Tracking and Compliance System account established under this subpart that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

GS-ERC means an ERC issued for net energy output MWh of gas shift to, but which may not be used for compliance by, an affected EGU that is a stationary combustion turbine. Aside from this restriction on use for compliance, GS-ERCs are subject to all other provisions of this subpart related to ERCs.

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means "Indian country" as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or IGCC facility means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15^{o} C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16460.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate

additional electric or mechanical output or to enhance the performance of the affected EGU (e.g., steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (e.g., steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or operation means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at a affected EGU respectively, any person who operates, controls, or supervises an affected EGU at the affected EGU or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such affected EGU or affected EGU.

Owner means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at an affected EGU respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the affected EGU or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the affected EGU or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from a affected EGU at the affected EGU or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, an affected EGU that is unavailable for service and for which the affected EGU's owners and operators (1) have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of 62.16415, or (2) rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Petroleum means the definition as defined in subpart TTTT of part 60 of this chapter.

Qualified biomass means a biomass feedstock that is demonstrated to qualify as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to ERCs, the moving of ERCs by the Administrator into, out of, or between Allowance Tracking and Compliance System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25^{o} C, 77 ^{o}F) and 100.0 kilopascals (14.504

psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions.

Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in §75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16465.

Waste to Energy means a process or unit (e.g., solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

§ 62.16575 Measurements, abbreviations, and acronyms.

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR—alternated designated representative

Btu—British thermal unit

CPP—clean power plan

CO_2—carbon dioxide

COI—conflict of interest

CVR—conservative voltage regulation

DR—designated representative

EE—energy efficiency

EGU-electric generating unit

EM&V-evaluation, measurement, and verification

GCV-gross calorific value

GJ-giga joule

H_2O—water

hr—hour

IGCC—integrated gasification combined cycle

kg—kilogram

kW—kilowatt electrical

kWh—kilowatt hour

lb—pound

M&V—measurement and verification

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt hour

T&D—transmission and distribution

O_2—oxygen

PSD-prevention of significant deterioration

yr—year

Table 1 to Subpart NNN of Part 62—CO_2 Emission Standards (Pounds of CO_2 Per Net MWh)

Compliance Period	Affected steam generating unit or integrated gasification combined cycle (IGCC) emission standards	Affected stationary combustion turbine emission standard
Compliance Period 1 (2022-2024)	1,671	877
Compliance Period 2 (2025-2027)	1,500	817
Compliance Period 3 (2028-2029)	1,380	784
Final Compliance Periods	1,305	771

Table 2 to Subpart NNN of Part 62—Incremental Generation Factor for Emission Rate Credits (dimensionless)

Compliance Period	Incremental Generation Factor
Compliance Period 1 (2022-2024)	.22
Compliance Period 2 (2025-2027)	.32
Compliance Period 3 (2028-2029)	.28
Final Compliance Periods	.26

PART 78--APPEAL PROCEDURES

6. The authority citation for Part 78 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

7. Section 78.1 is amended by revising paragraph (a)(1) and adding paragraphs (b)(18) and (b)(19) to read as follows:

§ 78.1 Purpose and scope.

(a)(1) This part shall govern appeals of any final decision of the Administrator under subparts MMM and NNN of part 62 of this chapter, part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter or State regulations approved under § 51.123(o)(1) or (2) of this chapter, subparts AAA through III of part 96 of this chapter or State regulations approved under § 51.124(o)(1) or (2) of this chapter, subparts AAAA through IIII of part 96 of this chapter or State regulations approved under § 51.123(aa)(1) or (2) of this chapter, part 97 of this chapter, or subpart RR of part 98 of this chapter; provided that matters listed in § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed. All references in paragraph (b) of this section and in § 78.3 to subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through IIII of part 96 of this chapter shall be read to include the comparable provisions in State regulations approved under § 51.123(o)(1) or (2) of this chapter, § 51.124(o)(1) or (2) of this chapter, and § 51.123(aa)(1) or (2) of this chapter, respectively.

*   *   *   *   *

(b) *   *   *

(18) Under subpart MMM of part 62 of this chapter,

(i) The decision on allocation of CO_2 allowances under § 62.16240 of this chapter.

(ii)The decision on allocation of CO_2 allowances from set-asides under § 62.16245 of this chapter.

(iii) The decision on the transfer of CO_2 allowances under § 62.16330 of this chapter.

(iv) The decision on the deduction of CO_2 allowances under § 62.16340 of this chapter.

(v) The correction of an error in an Allowance Tracking and Compliance System account under § 62.16355 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CO_2 allowances based on the information as adjusted under § 62.16370 of this chapter.

(vii) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

(19) Under subpart NNN of part 62 of this chapter,

(i) The decision on emission rate credit issuance, adjustment, and revocation under § 62.16435

(ii) The decision on qualification status of eligible resources to receive emission reduction credits under § 62.16460.

(iii) The decision on revocation of qualification status of an eligible resource under § 62.16440.

(iv) The decision on Adjustments for error or misstatement, suspension of ERC issuance under § 62.16450.

(v) The decision on accreditation of independent verifiers under § 62.16470.

(vi) The decision on revocation of accreditation status under § 62.16480.

(vii) The decision on the transfer of emission reduction credits under § 62.16530 of this chapter.

(viii) The decision on the deduction of emission reduction credits under § 62.1616535 of this chapter.

(ix) The correction of an error in an Allowance Tracking and Compliance System account under § 62.16550 of this chapter.

(x) The adjustment of information in a submission and the decision on the deduction and transfer of emission reduction credits based on the information as adjusted under § 62.16565 of this chapter.

(xi) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

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Article

THE TIPPINGPOINT OF FEDERALISM

Amy L. Stein [a1]

As the Supreme Court has noted, "it is difficult to conceive of a more basic element of interstate commerce than electric energy, a product that is used in virtually every home and every commercial or manufacturing facility. No state relies solely on its own resources in this respect." And yet, the resources used to generate this electricity (e.g., coal, natural gas, or renewables) are determined largely by state and local authorities through their exclusive authority to determine whether to approve construction of a new electricity generation facility. As the nation finds itself faced with important decisions that directly implicate the source of our electricity, including climate change and grid reliability, the proper functioning of a system of exclusive state control over the siting of electricity generation is increasingly strained.

Continued state control over the siting of electricity generation is particularly curious when viewed in relation to other infrastructure siting regimes. This Article traces the evolution of authority governing the siting of railroads, natural gas pipelines, wireless telecommunications, and electricity transmission, finding that they share many of the same federalism justifications for centralized control that exist in the siting of electricity. Yet, in every case except for electricity generation, Congress tipped the balance of power to allow for more federal authority over these siting decisions.

This Article explores this disparity between state control over the siting of electricity generation and enhanced federal control in the other siting regimes. It concludes that this disparity may be at least partially explained by more initiative on the part of relevant federal agencies. Whereas federal agencies played a minimal role in affecting the tensions caused by increasing national interests in the other infrastructure regimes, federal agencies are taking significant steps to further the national interest in the siting of electricity generation. These actions can reduce the pressure to formally alter the federalism balance through congressional action, and can play a key role in the broader federalism literature surrounding the circumstances that foster tips from state towards federal authority.

***218 Article Contents**

*219 I. Introduction

As the Supreme Court has noted, "it is difficult to conceive of a more basic element of interstate commerce than electric energy, a product used in virtually every home and every commercial or manufacturing facility. No state relies solely on its own resources in this respect."[1] And yet, the resources used to generate this electricity (e.g., coal, natural gas, or renewables) are determined largely by state and local authorities through their exclusive authority to determine whether to approve construction of a new electricity generation facility.[2]

The physical equipment of a modern electric power system is divided into three basic categories: generation, transmission, and distribution. Generation refers to the conversion of one form of energy to electric energy, a process that often occurs through the burning of fossil fuels to produce steam to spin a turbine at a power plant. Transmission refers to the transfer of electric energy over an interconnected group of lines and equipment at high voltages from its place of origin to distribution lines. Distribution refers to the final stage in delivery of low voltage electricity to the end users. For purposes of this Article, the focus is on the jurisdiction over the "siting of electricity generation," defined as the authority to determine whether to approve construction of a new electricity generation facility (often a power plant) which necessarily entails an assessment of the resources used by the facility to generate electricity, as well as determinations about location.[3]

***220** In 1935, Congress codified this state control in the amendments to the Federal Power Act (FPA). The FPA provides the states with exclusive authority to regulate all siting decisions with respect to electric energy generation facilities.[4] This places significant power with the state legislatures, whose laws govern the decision making of the state public utility commissions regarding the type of power supply approved for a given area.[5] Many states have delegated siting authority to more local levels of government, and the regulatory requirements and number of jurisdictions involved differs substantially depending on the size of the facility and the state where the generating facility is proposed.[6] As the D.C. Circuit has noted, "State and municipal authorities retain the right . . . to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the [[Federal Energy Regulatory] Commission."[7] This exclusive state authority over the siting of generation has been affirmed repeatedly by courts.[8]

***221** State or local control[9] over generation siting functioned adequately, more or less, for over seventy years. But as the nation finds itself faced with important decisions that directly implicate the source of our electricity, the proper functioning of exclusive state control over electricity siting is becoming increasingly strained. Electricity demand continues to rise. The vast majority of our electricity comes from cheap, domestic, and reliable fossil fuels, namely coal and natural gas. Combustion of these same fossil fuels are the primary contributors to the world's greenhouse gas emissions,[10] increasing the scrutiny on the nation's continued reliance on these sources of electricity generation.

Even though the legislative branch has failed to pass comprehensive legislation to address climate change, the executive and judicial branches have recognized the importance of moving towards reliance on cleaner sources of electricity generation, including renewable energy and energy efficiency. In 2007, the Supreme Court acknowledged the perils of climate change and the authority of the Environmental Protection Agency (EPA) to regulate carbon dioxide as a pollutant.[11] In 2009, the Obama Administration issued a call for renewable energy to supply twenty-five percent of the nation's electricity by 2025,[12] and in his joint address to Congress, President Obama stated that "[the U.S.] will double [the] nation's supply of renewable energy in the next three years," a prediction that has failed to be achieved.[13] As a result, complex trade-offs involving cost, reliability, national security, and the environment are infused into decisions regarding the siting of electricity generation.

At first blush, state or local control over the siting of electricity generation may not be surprising. Siting decisions, after all, are ones that require localized input and whose impacts are felt most by the immediate community. But this state or local control over the siting of electricity ***222** generation becomes a little more curious when viewed in comparison to other commonplace infrastructure siting regimes.

The siting of infrastructure in this country has experienced an evolution in its federal balance. Decisions regarding whether and where to locate railroads, natural gas pipelines, wireless telecommunications, and electricity transmission ("infrastructure regimes") were all originally committed to state or local authority. Despite their traditionally local nature, an increasing number of factors began to suggest that more centralized control was needed. In each of the siting regimes, one or more of the five traditional justifications for federal control became apparent. Some involved externalities that were caused by interstate issues, some could not function effectively without some uniform standards or harmonization, some raised concerns that states were under-regulating, some raised concerns that states were over-regulating, and some needed to pool resources to reach their full potential. Each of these infrastructure siting regimes reached a **point** where state or local control was no longer the most effective method of siting. The regimes reached a "**tippingpoint**" where the pressure **points** pushing towards more centralized control eventually coincided with the proper political atmosphere. A "**tippingpoint** of federalism" is defined for purposes of this Article as congressional action that formally shifts the balance of power from state or local control to some form of enhanced federal control.[14] In every case except for electricity generation, Congress **tipped** the balance of power to allow for more federal authority over these siting decisions.

Given this history, one might expect to see the same in the siting of electricity generation. Like the other infrastructures, the siting of electricity generation began under state or local control. And like the other infrastructures, a number of federalism pressure **points** are beginning to challenge the traditional level of governance. First, although the siting of one power plant within state lines is not as overt as an interstate issue-as compared to the siting of railroad lines, natural gas pipelines, or transmission lines that traverse through multiple states-electricity itself is an item of interstate commerce and the way that it is generated has pollution impacts with interstate implications. Second, national energy ***223** policies focused on renewable energy are conflicting with state laws providing preference for fossil fuels. This can support arguments that states are overregulating in ways that make it difficult for renewable energy to be sited within their borders. Conversely, the decision by twenty-one of our fifty states not to adopt binding renewable portfolio standards can be characterized as an example of the third justification, under-regulation, allowing fossil fuel generators to flock to the states with the least restrictive requirements or allowing states to free ride on the social benefits of renewable energy located in other states. And lastly, the potential dangers associated with a non-diversified fuel supply and accompanying threats to reliability of our national grid evoke discussions of the need to pool resources to protect national security.

Despite shared justifications for more enhanced federal authority across all the siting regimes, control over the siting of electricity generation remains firmly in the hands of the state and local authorities. This Article explores this disparity between the siting regimes to determine whether there is an explanation unique to the siting of electricity. A number of factors may exist to counter one or more of these federalism justifications in support of centralized power, including an argument that Congress would have a more difficult time asserting constitutional authority over the siting of electricity generation than it did in asserting authority over the other infrastructure regimes. Although this authority would likely stem from the Commerce Clause, defending this constitutional authority is not the purpose of this analysis.[15] Instead, this analysis assumes that Congress would have the authority to regulate the siting of electricity generation if it so chose to do so.

For purposes of this analysis, however, three counterarguments seem particularly noteworthy. First, this Article assesses whether the decentralized control over the siting of electricity generation realizes some ***224** critical federalism virtues that the other siting regimes do not. Second, it explores whether authority remains with the states and localities because electricity siting decisions are uniquely decisions of a "traditionally local nature." Lastly, it considers whether elements of public choice theory can explain why rational, self-interested federal legislators may not see fit to **tip** the balance of power of electricity siting away from the states but may see fit to do so in the other siting regimes. Although each of these theories has merit in explaining why any one infrastructure regime has **tipped**, their limits lie in their inability to inform a comparative analysis. Arguments in support of these explanations apply with similar force to the other siting regimes, rendering these explanations unsatisfactory.

Instead, this Article proposes another explanation for the disparity: the ability of federal agencies to exert their federal influence through alternative outlets. Where an agency is able to use its existing statutory authority to shape a decision that has been reserved to the state or local governments, it may reduce the pressure to formally alter the federalism balance. This Article uses electricity siting to demonstrate how federal agencies are able to exert an element of federal control over the fuel source used to generate electricity through alternative legal outlets without resorting to a formal **tip** in the actual federalism balance. By acting on the margins through existing statutory authorities, the Federal Energy Regulatory Commission, the Environmental Protection Agency, and the Department of Interior have each been able to exert a degree of influence over the siting of electricity generation that may be sufficient to counteract the justifications for a formal **tip** in the federalism balance. Such exercise of existing statutory authority by relevant agencies may play a key role in explaining the disparity in the siting regimes, as well as provide insights into the broader federalism literature surrounding the circumstances that affect **tips** from state towards federal authority.

Part II begins with an explanation into the traditional justifications for centralized federal control. These justifications are: (1) transboundary issues across state lines that create externalities; (2) the need for uniformity or harmonization; (3) under-regulation that can result in a race to the bottom between states, threatening state public safety and welfare; (4) overregulation that can result from "Not in My Backyard" ("NIMBY") scenarios threatening national public safety and welfare; and (5) the provision of public goods that require resource pooling.

Part III chronicles how control over the siting of similar commonplace infrastructure-railroads, natural gas pipelines, telecommunications, and electricity transmission-all began with a commitment to state control and later **tipped** through congressional action to some form of enhanced federal control. It highlights the federalism justifications for centralized authority that were placing pressure on the prior federalism design, as well as the limited actions of the respective federal agencies to address national ***225** interests.

Despite these tips, authority over the siting of electricity generation is resistant to this trend and remains under state and local control. Part IV applies the traditional federalism justifications for centralized authority to the siting of electricity generation. It demonstrates how the siting of electricity generation reflects many of the same federalism justifications for federal involvement as the other siting regimes, yet it yields different results.

Since all of the siting regimes share some of the traditional centralized federalism justifications for federal involvement, Part V analyzes other possible factors that may be unique to the siting of generation that may temper federalism justifications for federal involvement in deciding the source of our electricity. It looks to federalism virtues associated with decentralized state or local control, a longstanding tradition of state or local control over land use decisions, and public choice theories for guidance in explaining the disparity, ultimately finding each unsatisfying.

Part VI sets forth an alternative explanation for the disparity: the availability of alternative outlets for expressing a growing federal interest. It highlights a distinguishing feature between the federal interest in siting electricity generation and the siting of other infrastructure. Rather than a federal interest limited to ensuring the infrastructure is ultimately sited, the federal interest in the siting of electricity generation extends to the type of infrastructure being sited. This allows for slightly more flexibility in avenues by which to affect the type of electricity generation being sited without running afoul of jurisdictional boundaries. This section provides examples of the ways that the Federal Energy Regulatory Commission, the Environmental Protection Agency, and the Department of Interior may have each been able to exert a sufficient degree of influence over the type of resources used to generate electricity sited through their existing statutory authorities to alleviate the pressure to formally tip toward enhanced federal control.

The analysis ends with Part VII, which identifies continuing pressures on the proper balance of power in siting regimes and urges continued focus on the role of administrative agencies in affecting the circumstances surrounding tippingpoints of federalism.

II. Traditional Federalism Justifications for Centralized Control

Traditional discussions about allocating authority between federal and subfederal (state and local) systems typically involved taking one of two polar positions along the federalism spectrum. At one end of the spectrum lie those speaking in favor of a stronger national government and a more ***226** restrictive state and local power, often referred to as centralization [16] or federalization. [17] At the other end of the spectrum lie those arguing for greater authority in the state or local government, often evoking terms like decentralization [18] or devolution. [19] Contemporary discussions seem to place much more emphasis on the center, grouping those regimes which argue for shared power between the federal and subfederal governments into a category often referred to as "cooperative federalism." [20] To assess the normative merits of each approach, scholars and judges have coalesced around a package of abstract virtues associated with state authority (decentralized) [21] and federal authority (centralized), respectively. [22]

But the level of power for any given regime is far from static. Not only has there been an increasing volume of literature focusing on iterative or dynamic federalism, [23] which envisions a fluid back and forth between different levels of government, but there are also formal congressional tips from one level of power to another. What is it that facilitates these tips? And more importantly for purposes of this analysis, what is it that facilitates congressional tips from state and local to more enhanced federal control? One answer may lie in changes to the presence and strength of the federalism justifications associated with a given activity.

***227** Federalism scholars like Professor Robert Glicksman have identified five traditional federalism justifications for a move towards centralized control, focused primarily on collective action problems: (1) transboundary issues across state lines that create externalities; (2) the need for uniformity or harmonization; (3) under-regulation that can result in a race to the bottom between states, threatening state public safety and welfare; (4) overregulation that can result from NIMBY scenarios, threatening national public safety and welfare; and (5) the provision of public goods that require resource pooling.[24] Importantly, not all five federalism virtues need to be realized to justify a **tip** towards federal control. In fact, the presence of just one strong federalism virtue can be enough.[25] This section explains each of these justifications in more detail below.

A. Transboundary Issues

The first justification for federal involvement is its ability to better deal with externalities associated with transboundary issues. Policies adopted to maximize a state's own welfare can impose external costs on neighboring states, decreasing national efficiency.[26] State and local governments sometimes seek to shift negative regulatory byproducts or stigmas onto outsiders.[27] Exporting negative regulatory byproducts, such as pollution, is often a problem in environmental regulation.[28] For example, "a state may regulate a factory in a manner that protects its citizens, but causes pollution to be thrown off to people in bordering states."[29] Additionally, "political economists generally agree that it is appropriate for the national government to restrict regulation by the states that may impose great negative externalities on sister states."[30] ***228** Centralization can maximize efficiency by internalizing this spillover effect "through the incentives implicit within a national legislature."[31] And centralization need not **tip** all the way to federal control. For instance, states have attempted to address transboundary issues, such as management of the Great Lakes, by centralizing to a level of regional interstate compacts as opposed to federal governance.[32]

B. Uniformity or Harmonization

The second justification for centralized control is the ability to provide uniformity through single federal standards. Industry may call for federal regulation where it enables them to avoid disparate regulatory burdens across fifty states.[33] Uniform federal laws result in greater efficiency by reducing transaction costs between states.[34] Federal legislation may be warranted when businesses operating between states are encumbered by a lack of uniformity among states.[35] National policies also prevent a "piecemeal judicial approach" which undermines predictability and inhibits free trade.[36] Professor Barry Friedman touts free trade as "likely to play more of a role in the future in centralizing regulatory authority."[37] Because trade thrives on uniformity, local legislation often "runs the risk of imposing novel requirements that inhibit the easy movement of goods and ***229** people."[38] It is "almost always easier and less costly to comply with one standard than to attempt to comply with multiple standards that vary depending on the jurisdiction."[39] Therefore, businesses and free-market advocates prefer a centralized system because a uniform national policy radically simplifies operations.[40]

C. Race to the Bottom

The third justification for centralized control is the ability to protect the citizenry by preventing a race to the bottom. The race to the bottom theory suggests that decentralized competition may "lead a state to eschew policies that it truly desires for fear that they will influence a mobile citizenry and commercial-industrial base to react in ways that undermine local welfare."[41] States may have little incentive to impose more stringent regulations than other states for fear that businesses will find the more relaxed regulatory environment more favorable and shift their contribution to the tax base and local economy to the less stringent state.[42] It is particularly this type of under-regulation where enhanced federal control ***230** may be beneficial to the welfare of the citizens. A noble justification for centralization is to "guarantee a minimum level of environmental protection to citizens regardless of their place of residence . . . [that] helps guarantee that citizens can travel freely without encountering unreasonable risks to their health or welfare from environmental conditions." [43] In response, federal control can alleviate such a race to the bottom by leveling the playing field between the states. [44]

D. NIMBY

A fourth justification for centralized control is the ability to address problems of overregulation. This justification typically arises in the context of the NIMBY phenomenon. Furthermore, "[t]he NIMBY phenomenon arises when there is some undesirable but necessary activity or facility that must be located somewhere. . . . In such cases, states may impose regulatory burdens intended to drive the activity into other states." [45] In these circumstances, calls for federal action may arise to prevent the states from blocking projects that can be beneficial to the nation as a whole. The most common NIMBY example is the siting of a nuclear waste storage facility, an activity that few, if any states want to engage in, and yet is important for the benefit of the nation. [46] In the context of high-level nuclear waste, for instance, the federal government imposed the storage of high-level nuclear waste on the state of Nevada despite state efforts to block the activity. [47]

E. Public Goods

The last traditional justification for centralized authority is the ability ***231** of the federal government to provide public goods that states may be lacking incentives to provide. [48] These are often characterized by a lack of sufficient resources by any individual state, but that can be sufficient through the pooling of resources. For example, a danger to our country may present the need for a strong national defense that each individual state could not provide. Illnesses that affect all of our citizens may present a need for a scientific research broadly applicable to all of our citizens that each individual state may not have the resources to provide. In such technical fields, states "lack sufficient incentives to provide public goods, such as scientific or economic research, that would improve their decision-making capability." [49] If a state invests in a technical regulatory area, the results "will be tailored to their unique situation and not necessarily applicable in other areas of the country." [50] And public goods such as sewer systems, clean water, and clean air generate social benefits (positive externalities) that are not fully captured in their private costs, which could result in undersupply without the intervention of the federal government. [51] Poor states often lack the federal government's "technical competence" to regulate effectively. [52] While the national government also has budget constraints, it has more fiscal tools to fund regulation to address egalitarian concerns. [53]

In sum, the presence of one or more of the five traditional federalism justifications for increased centralized control can support a corresponding **tip**. The next section will evaluate the relevance of these five justifications to the **tips** that occurred in the infrastructure siting regimes.

III. TippingPoints of Siting Regimes

Siting of infrastructure in our country is rife with federalism controversies. The most high-profile federalism siting controversies involve Congress's attempts to alter the balance of power between the states and the federal government with regard to a single, high-impact siting. Two examples are the siting of a permanent repository for ***232** high-level nuclear waste at Yucca Mountain, Nevada [54] and the siting of a 1,700 mile Keystone XL oil pipeline that would run from Canada, through six states in the heartland of the nation, down to Texas. [55]

But in many ways, the more important siting decisions are those that occur on a regular basis. These decisions include the siting of railroad tracks and facilities, telecommunications towers and fiber optic cables, natural gas pipelines, electricity transmission lines, and the generators that power our electric grid. As opposed to one-time, big ticket sitings that elicit great controversy and public scrutiny, these repetitive siting decisions occur frequently, often under the media's radar, and often elicit controversy only from those living closest to the siting. Although they reflect a small sample size in the broad world of tips, the focus on siting authority can provide some useful insights into factors affecting tippingpoints for other areas. This analysis yields a number of general principles concerning the impact of the regulated community, the federal government, the states, and the affected citizenry on the political decision to tip from state to federal control.

Not surprisingly, all of the siting regimes discussed in this analysis were initially governed by state or local authority. In their most general sense, siting decisions are characterized by two elements: A governmental entity first decides (1) whether there is a "need" for the infrastructure to be sited,[56] and then decides (2) where the infrastructure should be sited. ***233** Implicit in these analyses is often a decision about the type of infrastructure to be constructed and the resources that will be used. In all cases, a state or local entity initially handled these decisions. In some situations, Congress enacted legislation to secure the role of the states over these local issues.[57] In other cases, the decentralized authority was a natural default for the manner in which this infrastructure developed. Perhaps more surprising is the fact that all of these infrastructure siting regimes, except for the siting of electricity generation, eventually tipped towards some form of enhanced federal control.[58]

This section demonstrates the historic control of the states, the presence of one or more of the traditional federalism justifications for centralized authority in each of the regimes, and the congressional action that tipped the balance of power from state towards enhanced federal control over the siting of four types of commonplace infrastructure: (1) railroads; (2) natural gas; (3) telecommunications; and (4) electricity transmission.

A. Railroad Tip

The first siting regime to tip was the railroads. From the dawn of the railroad, the decision to lay down tracks or other railroad infrastructure fell to a local level.[59] Railroad owners had largely free rein as to the creation and location of railroad infrastructure, limited only by state regulation, which had been described as "crude."[60] Since at least 1832, state railroad commissions began to take a more active role in the siting decisions.[61] For nearly half a century, railroads faced little competition from other transportation options, resulting in the "golden age" of railroads where the rail network grew from 35,000 miles of tracks to a peak of 254,000 miles ***234** in 1916, all under state control.[62]

James Ely, in chronicling the rise of federal control over the rail industry, has noted that "eminent authorities had long urged federal control of the industry."[63] But "[i]t was easier, however, to clamor for federal controls than to decide upon the appropriate type of legislation."[64] "[F]ew doubted that rail operations were within the power of Congress,"[65] and Congress enacted several statutes that strengthened the Interstate Commerce Commission ("ICC") and greatly enlarged national control of railroads.[66]

For our purposes, the relevant point in the march towards federalization was the Transportation Act of 1920 ("Transportation Act").[67] The Transportation Act amended the Interstate Commerce Act, providing the ICC with exclusive siting authority over new rail lines or facilities. It provided that no extensions or new lines could be built, nor could any portion of a line be abandoned, without a certificate of convenience and necessity from the ICC.[68] The Supreme Court affirmed this exclusive authority of the federal government to determine whether railroad infrastructure was necessary and in the public interest, rejecting attempts by a state railroad commission to do so.[69] Notably, this federal control established a presumption that rail construction projects are in the public interest unless shown otherwise.[70] Unlike in other siting regimes discussed ***235** below, even the location of the lines is subject to federal approval.[71] This federal power to issue a certificate of convenience and necessity for railroad infrastructure continues today through the ICC's successor, the Surface Transportation Board ("STB").[72]

Enhanced federal control over rail lines was prompted by a number of factors. First, in the early 1900s, the federal government faced the then-unique threat of a world war. Only three weeks before Congress declared war on Germany, the Supreme Court upheld congressional legislation that foisted an eight-hour work day upon the rail industry, reasoning that an "emergency may afford a reason for the exercise of living power already enjoyed" and paved the way for the emergency powers doctrine.[73] In 1917, the federal government seized control of the railroads for the duration of the war.[74] Following the end of World War I, President Wilson returned control to private actors, but further strengthened federal control of the railroads by vetoing a bill that would have stripped the Railroad Administration of its power over rates and schedules and returned the ICC's pre-war rate-making authority, holding that the Railroad Administration's "authority . . . was necessary to enable it promptly to meet operating emergencies."[75] Passed in 1920, the Transportation Act preserves the President's right to assert federal control over railroads and other transportation systems in times of war.[76]

Second, there was the desire to minimize inefficiencies associated with piecemeal planning. In the aftermath of mass production during wartime, the nation was left with excess supply and unnecessary and parallel lines.[77] A speech by Senator Cummins of Iowa prior to the passage of the Transportation Act of 1920 indicated that the United States railroad system was suffering as a result of the "unguided, uncontrolled right of owners to build railroads wherever they may see fit."[78] Railroad companies ***236** abandoned overbuilt lines,[79] and the courts became overcrowded with cases regarding the legal obligations associated with those abandoned railroad lands. This untenable situation demonstrated a need for federal control over the abandonment of railroad lines.[80] And as the Supreme Court has subsequently noted in other contexts, "the Federal Government has determined that a uniform regulatory scheme is necessary to the operation of the national rail system."[81]

A third catalyst for the **tip** was the infringement on fundamental rights that was occurring on some railroads under state control. Railroads were discriminating against African-Americans, and Senator Cullom proposed a bill in 1884 that would provide federal regulation to address this behavior. Senator Cullom's bill prohibited "any company engaged in transportation from one State to another from making unreasonable charges, or charging more to one person than to another for the same service, or refusing equal facilities to all."[82] As a New York Times description of the bill notes, "The public judgment is very potent for the correction of evils provided it is properly enlightened."[83] The bill also provided the proposed National Railroad Commission with federal power to investigate allegations of discrimination, and even more significantly, to report any information collected on the railroad companies to the Secretary of the Interior on an annual basis.[84] Three years later, just two months after the creation of the Interstate Commerce Commission, it found railroad companies in violation of the Interstate Commerce Act "by failing to provide African-American passengers with accommodations equal to those of whites," consequently creating "the doctrine of separate but equal almost a decade before Plessy v. Ferguson was decided."[85] Thus, the federal government justified its involvement in the railway system through various facets of discrimination. As Cass Sunstein has noted, "When a national moral commitment is involved, the case for uniformity is much stronger."[86]

In sum, authority over railroad infrastructure tipped from state control towards increased federal control in light of national security concerns, as a ***237** response to piecemeal planning and economic waste, and to provide transparency to invidious racial discrimination occurring on the railroads.

B. Natural Gas Tip

A second example of Congress altering a federalism framework from a decentralized, state-centered authority to complete preemption by the federal government is in the siting of natural gas pipelines.[87] Siting of pipelines began locally. Although one of the first natural gas pipelines ran only 5.5 miles in 1859, by 1891, pipelines had grown to 120 miles.[88] Initial distribution networks were largely within one municipality and fell under the regulatory powers of local governments.[89] But as the networks began to cross over city lines, state governments intervened.[90] And as they crossed over state lines, the federal government intervened.[91]

In 1938, Congress enacted the Natural Gas Act ("NGA") that provided the Federal Power Commission ("FPC") with jurisdiction over the pricing of natural gas in interstate commerce, as well as with exclusive siting authority over pipelines that would deliver "natural gas into a market already served by another pipeline."[92] Before that time, there is no evidence of the FPC playing any meaningful role in the siting of natural gas pipelines, as regulation occurred through municipalities and state public utility commissions.[93] This meant that in order to build an interstate pipeline, companies must first receive the approval of the FPC.[94] As a ***238** result, the NGA provides the federal government with exclusive control over siting interstate pipelines.[95] This federal power continues today through the FPC's successor, the Federal Energy Regulatory Commission ("FERC").

The initial tip towards federal control over the natural gas pipelines began not with control over the physical infrastructure, but with control over the rates charged for natural gas, a move prompted by the concerns over monopoly power.[96] This federal control over rates eventually spilled over into control over the infrastructure with Congress's passage of the NGA.[97] There, the tip from state to federal control over siting can be largely attributed to the desire to avoid piecemeal and inefficient outcomes. As technology improved, natural gas could be transported over longer distances, and soon states were regulating transport over state lines. This development, however, subjected natural gas firms to multiple regulations from multiple states, which, at times, were in conflict with each other.[98] Federal control, combined with technological advances, led to a "post-war pipeline construction boom lasted well into the '60s, and allowed for the construction of thousands of miles of pipeline in America."[99]

C. Telecommunications Tip

A third example of Congress altering the balance of power involves telecommunications infrastructure: the "cables, antennas, poles, [and] towers," and in the case of wireless/broadband facilities, fiber optic cables.[100] The tip in the telecommunications industry focuses on the siting of wireless communications towers. As with railroad infrastructure, the power to site telecommunications infrastructure initially rested with the states. After the invention of the telephone by Alexander Graham Bell, ***239** states began regulating telephone service in the early 1900s.[101] In 1934, Congress passed the Communications Act of 1934, which established a dual regulatory model for radio and wire communications.[102] It created the Federal Communications Commission ("FCC"), which was given authority over all interstate communications,[103] and left intrastate communications in the hands of the states to regulate through their PUCs.[104] Frequently described by scholars as a "natural monopoly,"[105] state governments and even the federal government embraced the idea of a telecommunications industry dominated by the Bell system and decried competition as redundant.[106]

Control over telecommunications tipped in 1996 when Congress passed the Telecommunications Act of 1996 ("Telecommunications Act").[107] This statute both deregulated the telecommunications industry and tipped the balance of power over the siting of wireless telecommunications infrastructure from complete state control towards federal control. Notably, "[b]efore adopting the statute in conference, Congress considered a bill that would have assigned the FCC broad rulemaking power over the State and local siting process."[108]

Unlike some of the other siting regimes, which involved complete ***240** federal preemption, authority over the siting of wireless communications and electricity transmission lines tipped towards federal control but stopped short of exclusive federal authority. Congress only partially preempted state siting authority over wireless telecommunications infrastructure, providing the federal government with control over the licensing of wireless infrastructure[109] and leaving control over the location specifics largely to the states.[110] But to ensure that state decisions would not hinder development of wireless telecommunications infrastructure,[111] Congress imposed three significant limitations on state regulation: (1) state regulation "shall not unreasonably discriminate among providers of functionally equivalent services";[112] (2) "state regulation shall not prohibit or have the effect of prohibiting the provision of wireless services";[113] and (3) the local government cannot regulate on the basis of the environmental effects of radio frequency emissions if those facilities comply with relevant FCC regulations.[114] Despite these federal restrictions imposed on state agencies, states have been successful in exerting their authority over siting decisions, even to the point of denying siting approval for wireless towers based on aesthetics.[115]

The tip from state control to the partial federal preemption over wireless telecommunications infrastructure is attributed to a number of factors. First, rising demand led to a national interest in growing the wireless communications industry. There was an explosion in new communication technologies, including wireless telephone use.[116] When ***241** the majority of telephone calls were intrastate, the state-controlled system worked well. Initially, ninety-eight percent of telephone calls were in-state and forty-five states had local regulatory commissions.[117] Additionally, both local and long-distance telephones were considered natural monopolies, and because of this shared assumption, the FCC and the states regulated in a similar, consistent manner with little conflict.[118] But the dynamic development surrounding the telecommunications industry began to change. By 1996, the number of cellular customers in the United States grew from zero to 44 million, with the number of cellular users having risen to over 128 million by 2001, and almost 332 million by 2011.[119] This increased demand in cellular use led to a call for more wireless communications towers. In fact, the more wireless towers that were added to the network, the more valuable the network became. These "network effects,"[120] facilitated more demand, as well as increased management and coordination needs. And as scholars have observed, "[t]hese increases in the value of network membership not only confer benefits upon existing users, but also encourage additional users to join, which in turn drives up the value of network membership even further."[121]

Second, increasing monopoly power led to calls for the federal government to deregulate the telecommunications industry in an effort to encourage competition and decrease prices.[122] In the 1950s, the FCC began to introduce competition into certain established areas of communications, and courts provided the FCC with expanded jurisdiction over new services, even if they could be characterized as intrastate communications.[123] In the 1960s and 1970s, economists and policymakers ***242** concluded that not all telecommunications were a natural monopoly, and that AT&T was exploiting its monopoly over local telephone service in order to prevent competition in other aspects of telecommunication service, such as long-distance.[124]

Finally, in 1982, the long-distance monopoly of AT&T ended, although it continued for local telephone service.[125] To add to the confusion, there was also inconsistency in court decisions concerning the boundary of FCC and state power.[126] Arguing for the passage of the Telecommunications Act of 1996, Congress referred to the telecommunications industry as an "economic apartheid" and referenced how a small number of companies commanded various sectors of the industry.[127]

Third, "the federal goals of the [Telecommunications Act of 1996] translate into a mandate for thousands of new antennas to emerge across the country, touching every community that the telecommunications industry serves."[128] Wireless telecommunication facilities were a catalyst for a wave of NIMBYism, creating obstacles to wireless providers that sought zoning board approval of siting applications.[129] Federal involvement was seen as necessary to prevent states and localities from interfering with the development of the wireless communications network.

In sum, the authority over wireless infrastructure **tipped** from state control towards increased federal control in light of an explosion in new cellular use across interstate lines, a national interest in enhancing competition by deregulating the industry, and a desire to prohibit states from imposing state regulations that limit the siting of wireless communications infrastructure.[130]

D. Electricity Transmission Tip

The last example of Congress altering the balance of power over siting rests with the siting of electricity transmission lines. As opposed to the ***243** siting of electricity generation, which involves consideration of the source of our electricity, the siting of transmission lines is about how to connect the sources of our electricity to the existing grid and transport the electricity generated to the distribution lines. Traditionally, state, rather than federal, authorities retained the power to review proposals for electric transmission lines.[131] Like the natural gas industry, the federal government became involved in the regulation of interstate pricing of the commodity. Just as it did with natural gas, in 1935, Congress amended the FPA to provide the FPC with jurisdiction over the pricing of electricity in interstate commerce.[132] But unlike the NGA, which provided the federal government with control over the siting of interstate pipelines, the FPA provides the states with sole authority over all siting decisions with respect to generation, transmission, and distribution facilities.[133] More specifically, "[s]tates have exclusive jurisdiction over transmission siting, and the FERC has no authority under the FPA to order the construction or expansion of transmission facilities, nor does it have authority to approve transmission siting."[134]

***244** As technology and the production, distribution, and consumption of electricity changed over the twentieth century, however, Congress took a step toward expanding the federal role in the siting of transmission lines. In 2005, Congress expanded FERC's jurisdiction over the siting of transmission lines in certain instances by means of Section 216 of the Energy Policy Act of 2005 ("EPAct").[135] Specifically, in areas of the country designated as high congestion areas by the Department of Energy,[136] where a state withholds approval on a transmission line, FERC may exercise federal backstop authority to approve the transmission line.[137] FERC interpreted Section 216 to mean that the federal agency may intervene in siting decisions where the state takes no action, as well as those situations where the state rejects a transmission line.[138]

This federal backstop authority has been effectively neutered by the courts. The courts have dismissed FERC's interpretation as too broad,[139] and have rejected the DOE's only two congestion designations, which are necessary preconditions to federal exercise of this backstop authority.[140] As of the time of this writing, FERC has failed to exercise this backstop authority to enable additional transmission lines to be constructed. Despite the failure to effectively enhance the federal power over transmission line siting, there was a congressional intent to do so.

Explanations for the partial tip towards federal control over transmission lines can all be traced to a growing national interest in investing in transmission infrastructure. More specifically, the tip can be ***245** attributed to a need to expedite the siting of transmission lines. House and Senate reports pointed to delays in state regulatory approval of new transmission lines and lack of siting coordination among the states as reasons for including electric transmission provisions in the EPAct.[141] Just as Congress was trying to encourage the telecommunications industry by passing the Telecommunications Act, Congress passed the EPAct in an attempt "to address the under-investment in electricity transmission infrastructure."[142]

Increased energy demand was also leading to congestion on the existing lines,[143] thereby threatening the reliability of the grid. Justifying the addition of this new Section 216 to the FPA, Congress noted that "[t]he states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities. . . . In recent times[,] increasing concerns have been expressed about the capacity and reliability of the grid."[144] A House report pointed to the August 2003 blackout that hit the Northeast and Midwest as a demonstration of the lack of reliability in the electricity transmission system, highlighting the need for legislation that addressed issues of "transmission capacity, operation, and reliability."[145] The growing gap between energy supply and demand also created concerns in Congress about national energy security.[146]

Furthermore, siting issues associated with transmission lines are particularly susceptible to interstate conflict. When the proposed transmission line will traverse multiple states, the utility company must obtain separate approvals from each state.[147] If the line is located across ***246** three states, "the states on either end can demonstrate to their constituents what the benefits of that transmission line will be, but the state in the middle has a very difficult time demonstrating the benefit. So, it's almost impossible to get the line built and approved."[148] The most famous case may be what has been referred to as the "extension cord" case, where Arizona rejected a proposal by a California utility to construct a 210-mile power line between Arizona and California.[149] One of the latest development projects, Centennial West Clean Line, is working to avoid a reprise of the extension cord case, as its proposed 900-mile transmission line is planned to extend from New Mexico through Arizona to California.[150] Some states have embarked on efforts to centralize transmission line siting up to the regional level, reflecting an understanding of some of the inefficiencies of piecemeal transmission line siting on a state level.[151]

As with telecommunications, the congressional tip consisted not of complete preemption, but a more limited form of federal control through the imposition of federal backstop authority. This may be in part because of the active involvement of the FERC to try to address some of these federal issues on the margins.[152] Siting over wireless infrastructure tipped for a number of reasons, including a furtherance of a national purpose and a desire to expedite the siting and to address potential security and reliability issues.

In sum, each of the infrastructure siting regimes discussed above involved a tippingpoint in the balance of power between the states and the federal government. Each of these commonplace infrastructure siting regimes discussed above started with state or local control. In each, the justifications for centralized authority were growing, but none of the regimes possessed all five justifications. And in each of these regimes, agency action to provide an escape valve for growing pressure on the prior ***247** state-controlled regimes was limited, resulting in formal congressional action that tipped the balance of power from state toward more enhanced federal power.

IV. No Tip in Electricity Generation Siting

Standing in stark contrast to the other infrastructure siting regimes discussed, control over the siting of electricity generation remains firmly with the states. This continued state or local control over siting of electricity generation is particularly surprising given the similarities between the siting of electricity generation and the other infrastructure siting regimes. As with railroads, natural gas, wireless, and electricity transmission, authority over the type and location of electricity generation originally rested with the states. [153] And as with the other regimes, there are a number of federalism justifications for centralized authority, many of which can be made (of varied strength) based on the traditional justifications for centralized authority. This section applies each of the five traditional justifications for centralized federal authority discussed above to the siting of electricity generation, demonstrating the similarities between the centralized justifications that resulted in enhanced federal control in the other regimes and those that apply to the siting of electricity generation: (1) transboundary issues across state lines that create externalities; (2) the need for uniformity or harmonization; (3) under-regulation that can result in a race to the bottom between states, threatening state public safety and welfare; (4) overregulation that can result from NIMBY scenarios, threatening national public safety and welfare; and (5) the provision of public goods that require resource pooling. [154]

A. Transboundary Applied to Generation Siting

In some respects, the interstate nature of railroads, pipelines, and transmission lines presents a stronger case for federal control than the intrastate siting of generation. Railroads and transmission lines are more likely to cross over state lines than a coal plant or a natural gas plant. Even the siting of wireless telecommunications towers, although purely intrastate, has network effects that could justify a federal presence. [155]

But a physical cross over interstate lines is not necessary to trigger the need for federal control. In fact, the traditional case for federal control based on transboundary issues involves an activity that exists solely ***248** intrastate but imposes externalities on other states. For example, although the choice to construct a new coal plant may be advantageous for a given state in terms of economic growth, this decision can impose external costs on the rest of the country. Differing levels of both traditional pollutants and greenhouse gases ("GHG") are associated with the different types of generation, and states that are downwind of fossil-fuel fired plants endure more externalities than states that are downwind of wind farms. In at least this respect, more centralized control over the type of electricity generated can be justified by the transboundary issues associated with differing levels of environmental externalities imposed on neighboring states. [156]

B. Uniformity Applied to Generation Siting

Although some of the regulated industries analyzed called for uniformity or harmonization as a means to address perceived obstacles caused by state regulation, this justification for centralized control does not have a lot of traction when applied to the siting of electricity generation. This section analyzes two of the primary catalysts for uniformity in the other siting regimes: (1) calls for uniformity by the regulated community; and (2) a need to assist in coordinated planning.

First, **tips** toward federal control in some of the other siting regimes were prompted by the regulated community. For instance, even after the passage of the Transportation Act, representatives of railroad companies continued to advocate for federal oversight, citing state regulation as a source of confusion and a barrier to transportation system development. [157] Similarly, developers of transmission lines began to call for increased federal siting authority. [158] Other calls for uniformity occurred in the other ***249** regimes, but not at the behest of the regulated industry. [159] One area of inconsistency that may prompt some calls for uniformity in the siting of electricity generation stems from the variety of state siting laws, many of which express different preferences for different types of generation. Some states have a direct mandate for a preference of new renewable energy sources [160] and some states have a presumption in favor of fossil fuel energy sources. [161] Although there is disparity in the state regulations that affect the type of generation built within their borders,[162] the regulatory discrepancy is not sufficient to prompt utilities to seek federal involvement. The absence of calls for federal involvement may also be attributable to the fact that the majority of utilities in the United States function within just one state. Of the more than 3,273 traditional utilities, which includes investor-owned, publicly-owned, cooperatives, and federal utilities,[163] the majority of investor-owned utilities operate in a single state.[164]

Regardless, calls for federal intervention in the electricity generation regime are few and far between.[165] Such calls may be less likely to occur ***250** within a fragmented industry such as the electricity generation industry. Even though there are trade associations that represent the utilities,[166] in the electricity generation "industry," the participating entities may be too diffuse to have common interests that align. The electricity siting "industry" is composed of a number of different entities, including coal, natural gas, nuclear, solar, and wind. Even the fossil fuel entities cannot agree on a strategy for their survival.[167] One does not expect that the renewable energy generators would be sufficiently aligned with the fossil-fuel generators to present a unified call to action. In fact, within this broad swath of "industry," some energy generators may benefit from local authority and some may benefit from more centralized authority, a fact that renders calls for uniformity extremely unlikely.

Second, many of the other siting regimes were faced with inefficiencies that could be remedied by more centralized planning or permitting. Centralized planning was seen as a remedy to railroads that were being constructed in piecemeal fashion without an eye towards efficient planning.[168] And centralized governance was seen as a remedy for transmission lines that were being constructed without sufficient regard to broader planning goals.[169]

Unlike many of the other regimes, the siting of electricity generation does not appear to have the same types of inefficiencies. Despite expected delays associated with meeting these requirements, PUCs have been found to generally act promptly on applications for certificates of need.[170] And more to the **point**, there is no indication that the federal government would be any more efficient at permitting generation than a state or local authority.

Thus far, the federalism justifications for the siting of electricity ***251** generation do not appear as strong as they were in some of the other infrastructure siting regimes. Yet the federalism literature is explicit that not all given justifications need to be present to justify a **tip**-even one would suffice.[171]

C. Race to the Bottom Applied to Generation Siting

Perhaps the best example of a potential race to the bottom with the siting of electricity can be illustrated through Renewable Portfolio Standards ("RPS"). An RPS requires utilities to obtain a certain percentage of their electricity generation from renewable energy.[172] As there is no national RPS, each state has been left to its own devices to determine whether it wants to adopt a RPS. The first RPS was adopted in 1983 in Iowa[173] and by 2010, twenty-nine states had binding RPS requirements.[174]

But what of the other twenty-one states with no RPS requirements? Eight states have nonbinding goals, but thirteen states have no such requirement.[175] One could argue that this could lead to a race to the bottom, where generators of fossil fuels flock to the states with less stringent renewable energy requirements. More empirical analysis is needed to confirm this suspicion, but of the thirteen states with no RPS requirements, a number of them reside at the bottom of the ranking for installed non-hydropower renewable energy capacity.[176] Furthermore, the thirteen states without RPS may be free-riding on the social benefits of renewable energy (e.g., abatement of GHGs and pollutants) that extend beyond the state borders of those with

RPS.[177] For many of the same reasons, scholars have criticized the decentralized, state-centered federalism that currently exists for RPS and climate change policies.[178]

*252 D. NIMBY Applied to Generation Siting

NIMBY responses can be seen in many of the historical siting regimes, as well as in the electricity generation regime. In the past, states and localities were often resistant to the sitings, and the federal government intervened to prevent the states and localities from being too stringent and creating an obstacle to the development of the relevant infrastructure. Congress partially preempted localities from preventing the siting of wireless towers and provided federal backstop authority for transmission lines if the states were dragging their feet in getting the lines sited.[179] Rising demand for wireless communications led to a national interest to promote cell tower growth.[180] Centralized permitting was seen as a remedy to eliminate state or local opposition that was standing in the way of development.[181] And rising demand for electricity led to a national interest to promote the creation of more transmission lines.[182]

Similarly, the circumstances surrounding the siting of electricity generation are drastically different today than they were in 1935, when Congress established separate spheres for federal and state governments and affirmed state control over siting of electricity infrastructure. The selection of resources used to supply the nation's electricity now has more of a national impact than was previously envisioned. For example, energy efficiency is touted as a cornerstone of national security efforts.[183] The decision to site a fossil fuel plant is not just about jobs and local air pollution anymore. The decision now has larger consequences associated with climate change, national security, and reliability of our electric grid.

In electricity siting, some states have passed siting laws that have made it much more difficult for renewable energy to be sited within its borders. This phenomenon could be characterized as a NIMBY collective action problem. For example, a utility applying for a non-coal energy facility in Pennsylvania must prove to the PUC that a coal energy generation facility is not reasonably suited for that site and that there is a strong probability that coal would be more costly.[184] West Virginia's Public Energy Authority Act states in part that “the health, happiness, safety, right of ***253** gainful employment and general welfare of the citizens of this [s]tate will be promoted by the establishment . . . of coal fired electric generating plants and transmission facilities.”[185] And Virginia law has tied the hands of the PUCs, prohibiting them from considering non-mandated environmental effects in their determination of whether a project is in the public convenience and necessity.[186] This has resulted in the rejection of projects that take environmental concerns into account that were not mandated by environmental laws.[187] The state siting processes for wind energy are similarly rife with examples of parochial tendencies. For instance, a Kansas county board of commissioners adopted a zoning ordinance that prohibited commercial wind projects.[188] And some state laws allow homeowner associations to reject solar power installations in certain circumstances.[189] If there is value in the efficiency created by the federal government stepping in to prohibit state and local authority from posing an obstacle to the siting of wireless infrastructure, then the same efficiency may be realized by the federal government stepping in to prohibit state and local authorities from posing an obstacle to the siting of renewable generation.[190] In these situations, federal intervention could be justified to remedy such parochial actions.[191]

*254 E. Public Goods Applied to Generation Siting

Since at least the Federalist Papers, danger has been a justification for federal involvement. In assuaging the fears of the anti-Federalists, James Madison explained that “[t]he operations of the federal government will be most extensive and important in times of war and danger; those of the State governments, in times of peace and security.” [192]

How one interprets “danger” alters the arguments for an enhanced federal role in the context of the siting of electricity. Where danger is narrowly interpreted to mean only that associated with war from foreign nations, the argument for enhanced federal involvement is limited. Some historians attribute the tip from state to federal control in the railroad industry to fallout from the Civil War. [193] As was noted earlier, Congress relied on emergencies resulting from the war as justifications for federal control over the railroads. [194] There was also an element of danger associated with allowing liquefied natural gas to be stored in tankers as opposed to on onshore terminals, [195] a factor that may have contributed to the complete federal preemption of the siting of liquefied natural gas terminals to receive these tankers. [196] Under this narrow construction of danger, there may be little argument that the intrusion of the federal government into the siting of electricity infrastructure is unwarranted.

But where danger is more broadly interpreted to include a range of threats to the health and happiness of the United States, [197] a number of arguments can be made to support an enhanced federal role with respect to the siting of renewable energy. First, renewable energy can be viewed as an undersupplied public good. The comparatively better environmental and health benefits associated with renewable energy as opposed to fossil fuel energy are social benefits that are not fully captured by the private costs of renewable energy. Second, renewable energy can be viewed as a good essential to grid reliability, a national need that states may not have sufficient resources to provide. The growing gap between energy supply and demand created concerns in Congress about national energy security, [198] as was evidenced by prior blackouts [199] and delays in state ***255** regulatory approval of new transmission lines. [200] Notably, even the FPA provides an exception to state control over the siting of electricity infrastructure in times of war or a shortage of generation facilities. [201]

Under this broader construction of danger, many arguments exist as to the dangers posed by climate disruption from the combustion of fossil fuels. [202] Environmental disasters have often been the impetus for calls for federal involvement, including releases of noxious fumes, [203] the Santa Barbara oil spill, [204] and coal ash waste. [205]

***256** Where the federal government can provide assurances of its commitment to renewable resources to better insulate the nation from the dangers posed by the current energy policies, consensus of the dangers may justify a tip from state to enhanced federal control over the siting of electricity generation.

In sum, while the federalism virtues in support of centralized control over the siting of electricity generation do not stack up uniformly in favor of a tip towards federal power, other infrastructure siting regimes tipped with similar justifications. This suggests that there must be some other factor at play in the siting of electricity generation that does not exist with respect to the other infrastructure siting regimes.

V. Factors Offsetting Justifications for Centralization

By no means does the mere presence of one or more of these justifications for centralized authority guarantee that a particular regime will tip from state towards federal control. There are a number of factors that may counter one or more of these federalism justifications supporting more centralized power. [206] For purposes of this analysis, three such counterarguments to centralized power seem noteworthy, particularly with an eye towards trying to explain the disparity in tips between the siting of electricity and the siting of the other infrastructure. First, this Article assesses whether electricity siting realizes competing federalism virtues supporting decentralized control that the other siting regimes do not. Second, it explores whether authority remains with the states and localities ***257** because electricity siting decisions are uniquely decisions of a "traditionally local nature." Lastly, it considers whether elements of public choice theory can explain why rational, self-interested federal legislators may not see fit to **tip** the balance of power of electricity siting away from the states but may see fit to do so in the other siting regimes. This section discusses each of these possible explanations in turn and explains why each fails to explain the resistance of the electricity siting regime to a **tip**. Although each of these theories has merit in explaining why any one infrastructure regime has **tipped**, their limits lie in their inability to inform a comparative analysis.

A. Decentralized Federalism Virtues Support State Control of the Siting of Electricity Generation

Despite the presence of centralized federalism justifications supporting federal control over the siting of electricity generation, there may be equal or stronger decentralized federalism justification supporting state or local control. A **tip** from federal to state or local authority is often justified on six grounds: (1) enhanced public participation in democracy; [207] (2) better accountability; (3) state as laboratories for experimentation; [208] (4) better protection of citizens' health, safety, and welfare; (5) enhanced cultural and local diversity; and (6) diffused power to protect liberty. [209]

Just as the federalism virtues supporting centralized authority can be used to justify enhanced federal control over the siting of electricity generation, the federalism virtues supporting decentralized authority can also be invoked to counter these arguments with support for state or local control. And just as scholars have long relied on centralized federalism ***258** virtues to advocate for increased federal control over a number of areas, including environmental pollution, [210] greenhouse gases, [211] welfare, [212] transmission lines, [213] corporate law, [214] tort law, [215] insurance, [216] medical malpractice, [217] and immigration, [218] scholars use the presence of decentralized virtues to advocate for a **tip** toward state control, including ***259** medical marijuana [219] and environmental protection. [220] This would suggest that the disparity between state control over generation siting and federal control over the other siting regimes might be explained by identifying decentralized virtues realized in electricity generation that are not realized in the other infrastructure siting regimes. Unfortunately, these virtues do not appear to be unique to the siting of electricity generation and could easily apply to other siting regimes. This section first provides some examples of the decentralized federalism virtues that can be realized by maintaining authority over the siting of electricity generation at a state and local level. [221] It then explains why use of the federalism virtues in this way have their explanatory limits, weakening their use in this type of comparative analysis.

1. Decentralized Federalism Virtues

A key benefit of decentralization is that local experts can be more flexible and adept at incorporating the area's unique "temporal and geographic information . . . to design optimal policies." [222] This virtue, often referred to as the ability to better protect the health, safety, and welfare, is particularly relevant to the decision about where to site infrastructure. All of the infrastructure analyzed involves some form of potential adverse local impacts, including aesthetic impacts, land use issues, and health issues. An increased role for the federal government runs the risk of usurping the important role of the localities in determining ***260** the type and location of the infrastructure. It is the localities that are the ones that need to adjust any decreases in property values, tax implications, loss of views, or health or environmental impacts. And it is the localities that may be able to best mitigate against such impacts. For instance, aesthetics are a primary concern of those opposed to telecommunications facilities. [223] The visual impact from towers may be minimized by disguising the towers as natural features such as trees, [224] and some municipalities have required "stealth design" within the requisite performance standards for communication facilities. [225]

An argument can be made that this need for local input is even more pronounced in the decisions about the siting of electricity generation than in decisions about the other types of infrastructure. This is because the localities may care as much, if not more, about the type of generation to be built as they care about where the generator is built. The type of generation built has a much greater diversity in impacts than the type of wireless tower or natural gas pipeline that is built. For example, one type of railroad tracks brings the same types of land use, congestion, and pollution from the locomotives as the next type of railroad tracks. And one type of telecommunications tower generally presents the same types of aesthetics, radio emissions, and environmental externalities as another.[226]

In contrast, state public utility commissions are often faced with alternatives that are rife with trade-offs that the decentralized federalism virtues suggest is best determined by a local level of authority. The generation of coal energy results in more greenhouse gas emissions than the generation of wind energy, but it is less costly and may result in less harm to endangered birds and bats.[227] Cleaner-burning natural gas ***261** generation may be able to utilize cheap domestic resources, but can have significant impacts on the water quality and supply of the area.[228] The generation of solar energy may be free from greenhouse gas emissions, but it is an intermittent resource that can affect the reliability of the grid.[229] The generation of nuclear energy may have near zero combustion emissions, but it is dependent on imported uranium and elicits public opposition because of real or perceived dangers particular to this method of generation.[230] And the generation of large-scale renewable energy may have zero combustion emissions, but it is expensive and often involves extensive land use and endangered species issues.

In fact, the unique geographic features of each state with respect to electricity generation weigh in particular favor of a decentralized framework. Each state has its own unique geographic strengths related to energy production; some have high amounts of coal, some have consistent winds, and so on. This has resulted in great variation in both the RPS adopted by the states,[231] as well as variation in siting procedures, such as different size thresholds and different criteria that must be satisfied to begin construction.[232]

A second decentralized virtue that may be realized by maintaining the current state-centered level of authority for the siting of electricity generation is the ability of state and local authorities to experiment with solutions more readily than federal authorities. Local programs are credited as being a "positive contagion," reacting faster to problems and ***262** spurring the federal government to overcome regulatory inertia.[233] When the Supreme Court held that the FPA preempted state regulation of utilities, Justice Jackson stated: "If now and then some state does not regulate its utilities according to the federal standard, it may be a small price to pay for preserving the state initiative which gave us utilities regulation far in advance of federal initiative."[234] Indeed, state legislatures can be credited with responding to proposals to impose mandates for renewable energy faster than the federal government; state legislatures have passed over thirty-seven pieces of RPS legislation over the last twenty-eight years, while the federal government has failed over twenty-five times to produce a national RPS.[235]

2. Limits of Decentralized Virtues for Explaining the Disparity

Just as the centralized federalism virtues failed to sufficiently explain the disparity in authority between the siting of electricity generation and the siting of other infrastructures, similar limitations exist with respect to the decentralized federalism virtues. Specifically, the use of these virtues to try to explain the disparity poses at least two fundamental problems, each described below.

The first problem with using federalism virtues to justify either state or federal control is that the virtues rarely line up neatly on one side of the federalism-state federalism ledger. Instead, we are often faced with an area of the law that is a kind of "hybrid," one that exhibits characteristics of both decentralized and centralized power allocations. What happens when the factors cut different ways? For instance, what is the appropriate level of government when the particular area at issue presents a need to address transboundary issues, but there is also a benefit in states serving as laboratories for experimentation? In these situations where the law can realize virtues on both sides of the ledger, there is no clear "prevailing" power level of authority and the federalism virtues lose much of their persuasive force towards either state or federal power.[236]

Each of the siting regimes discussed reflects this type of hybrid that exhibits characteristics of both decentralized and centralized authority. The siting of infrastructure clings to many historical characteristics that ***263** suggest a decentralized system is appropriate. But contemporary siting regimes also reflect many characteristics that suggest some centralized authority may be in order. There is no clear "prevailing" level of power indicated by the virtues, yet many of these regimes have **tipped** from state to enhanced federal control while the siting of generation remains in state control.

In the end, it may not be the mere presence of the virtues, but degrees that matter. Decisions about the proper balance of power may not rest with only the realization of virtues, but the degree to which each level of government can best realize the virtues. Although the localized and diverse impacts associated with the siting of electricity may suggest that decentralized authority would better further the virtues of federalism in this context, the decisions regarding the type of generation constructed also impose externalities on other states, which suggests that centralization may be appropriate, creating a type of hybrid that fails to **point** conclusively towards state or federal control. Importantly, the federalism virtues justifying decentralized control over the siting of electricity generation are no more unique than the federalism virtues justifying decentralized control over traditionally local areas. Yet the other regimes, including railroads, natural gas pipelines, wireless communications, and electricity transmission are now governed by some form of shared or overlapping federal and state authority.

Second, even if the virtues did line up neatly towards state or federal power, it is far from absolute that the presence of particular virtues renders the corresponding power allocation the best fit in all situations. In fact, although these virtues align with either state or federal authority in theory, it is unclear that they align so neatly in practice. As Barry Friedman has asserted:

> On the state side of the balance, we do not know whether retaining governmental authority at the subnational level fosters democracy, or even what we necessarily mean by this. We have not determined whether states really are laboratories for experimentation, and under what circumstances experimentation will flourish. We do not know if state governance enhances accountability. And so on.[237]

For instance, although state authority is traditionally viewed as the most effective level of power to enhance public welfare, a more centralized level of government may sometimes be in a better position to provide for the public welfare of state citizens.[238] Similarly, although the federal ***264** government is generally thought to be in a better position to provide uniformity, states can, even by loose agreement amongst themselves, realize the virtues of a centralized system without ceding power to the federal government.[239] As David Barron has noted, there is a need to "acknowledge the more complicated relationship between local autonomy and central power."[240]

A similar phenomenon can be said to exist with respect to the siting of electricity. It is unclear that state control better advances federalist values for electricity generation and that federal control best advances federalism values in the other siting regimes. For example, it is uncertain that a state and local governments are better positioned to protect their citizens' health, safety, and welfare.[241] For instance, repeated decisions by PUCs to site additional coal plants in lieu of renewable energies or demand response measures can have detrimental impacts on the amount of GHG emissions, other pollutants, and other full life-cycle environmental and health effects. West Virginia legislators, for example, are uniformly in favor of retaining coal as a dominant energy source and the state relies on coal for over 96% of its power needs.[242] Such a decision may be justified on the basis of protecting their citizens' welfare, arguing that reliance on coal provides local jobs, enhances the tax base, and otherwise helps the local economy. Yet, at least two reports on coal-dependent West Virginia and Kentucky demonstrate that coal production is a net loss to the states due to the high ***265** costs of coal-related health impacts.[243]

In the end, the federalism virtues fail to fully explain the disparity between the siting of electricity and other siting regimes.

B. Siting of Electricity Generation is Traditionally Local

Another possible explanation for disparity between the siting regimes is that siting authority for electricity generation remains with the state and local authorities because these decisions are uniquely of a "traditionally" local nature. As Professor William W. Buzbee has indicated, land use decision making remains one of the few areas of the law left overwhelmingly to state and local control, and some Supreme Court jurisprudence demonstrates a judicial reluctance to intrude upon this area.[244] The land use context is particularly prone to resolving federalism discussions in favor of the state given the inherently local nature of land use. Professors Ashira Ostrow and Uma Outka have recently focused on the crossroads of energy infrastructure siting and local land use law, with Professor Ostrow noting that despite the national impact that local siting decisions may have "scholars and policymakers often reject the notion of an expanded federal role."[245]

Nevertheless, the literature highlights a number of areas thought to be traditionally under "local control" that have **tipped** to enhanced federal control. Professor Buzbee notes that "federal environmental regulation can impinge on local and state land use regulatory choices by denying actions that might otherwise be allowed, or by imposing additional conditions on approvals."[246] Federal programs, grants, and initiatives increasingly encroach on traditionally "essential functions" of state governance such as health and family law.[247] For example, state control over family law has been usurped by federal concern over interstate child support, concerns over international human rights, and even with the administration of ***266** federal taxes and pensions.[248] Therefore, traditional classification of cases into "family law," "interstate travel," "foreign affairs," or "governmental administration" has become nearly impossible.[249]

In the area of health and environmental law, the federal government now regulates "air and water quality, food and drug safety, tobacco advertising, pesticide production and sales, consumer product safety, occupational health and safety, and medical care."[250] As the states' police power is usurped by the federal government's commerce and spending powers, the modern public health system is now "driven by national priorities in the pursuit of national health goals."[251] In the environmental realm, courts have consistently upheld federal authority to promulgate policies impacting areas traditionally controlled by the states.[252] For example, courts upheld the constitutionality of the Clean Air Act, Clean Water Act, Endangered Species Act and Comprehensive Environmental Response, Compensation, and Liability Act because these federal laws explicitly regulated industrial or commercial activity.[253] In short, traditionally local activities are not immune from federal intervention.

Similarly, the siting of all of the infrastructure discussed in this Article-railroads, natural gas, telecommunications, and electricity-were considered traditionally local activities that carried with them a presumption of decentralized control.[254] Nevertheless, for almost all of these siting regimes, this traditionally local nature of siting did not prevent the **tip** towards more federal involvement. The siting of electricity generation remains an exception despite the fact that its "traditionally" local roots are shared by all the siting regimes. Just as the traditionally local nature of these other siting regimes was not sufficient to withstand a ***267** **tip** towards federal control, the siting of electricity generation may be similarly vulnerable. At the very least, its traditionally local nature is not sufficient to explain why authority over the siting of electricity generation remains under state control.

C. Self-Interested Legislators Prefer State Control over the Siting of Electricity Generation

A final explanation for the lack of a federal tip is politics.[255] Some argue that determining when market correction is needed or when social costs should be internalized are complex issues largely resolved through the political process.[256] Indeed, lobbyists have extensive influence over the actions of legislators. One theory that captures the essence of legislators who are driven by strong lobbyists is public choice theory. Some have relied on public choice theory to suggest that "Congress will delegate to local regulators only when the political support it obtains from deferring to the states is greater than the political support it obtains from regulating itself."[257] Although this theory has some intuitive appeal, its limits lie in comparative analyses. This section explains the basic foundations of public choice theory, some generally applicable critiques, and why it has limited application to explain why the legal regime over the siting of electricity has remained under state control.

1. Public Choice Theory

Public choice is one of those terms that is used often, but rarely understood.[258] Although there are many dimensions to public choice theory, including social impact, "[t]he unifying thread of modern public choice theory is that '[w]e must always seek to understand political outcomes as a function of self-interested individual behaviors."'[259] It ***268** views the political sphere as "a market in which voters and representatives, like consumers and firms, act as if they are rational, maximizing individuals pursuing their self-interests."[260] Public choice theory "defines the legislative process as an arena for fundamentally self-serving behavior as legislators trade off votes on specific legislation to advance their prospects for reelection."[261] It applies the "rational actor model of economic theory to the realm of politics," and leads to the conclusion that systems need to be created that automatically restrain the self-serving behavior of "rent-seeking" politicians.[262] After all, politicians would not be politicians for very long if they did not care about electability.

An application of public choice theory to legislators resonates with many people. A premise that people act as rational wealth-maximizers (however wealth may be defined), has been expounded by many economists, most predominantly Judge Richard Posner.[263] A growing number of scholars across economics, political science, and law have explored the viability of public choice theory. The result is an extensive amount of empirical data that appears to support the general theory that individuals act in accordance with their own self-interest. Empirical proof has even been offered to support the allegation that self-interest drives legislators the same way as it drives individuals in a market.[264]

2. Explanatory Limits of Public Choice

Public choice theory also has its share of critics. Some argue that the theory is too simple, that the values each individual actor considers when making a choice are too varied for the actor himself to rank, let alone for outsiders to predict.[265] Others find public choice theory lacking when describing the activities of political parties as a whole, and they find unsatisfying the distillation of myriad perspectives and values into one ***269** hierarchy of values.[266] And still its view of people-both acting as individuals and in a legislative capacity-has been criticized as "ruthless" and "wealth-maximizing,"[267] as too unfair (people are capable of altruism),[268] and as too generous (people are not always rational or educated, and thus do not always act in ways that maximize their own wealth).[269] An example of this type of altruism can be found in environmental regulation. Professor Richard Stewart observes that "many Americans regard environmental quality as an important national good that transcends individual or local interests."[270] Congress reacted to strong public sentiment by passing the National Environmental Policy

Act.[271] The Act was not a result of special interest lobbying, and its continued existence "may provide evidence of the continued broad-based support for environmental protection as a national moral imperative."[272] The demand for environmental regulation "tends to increase over time as wealth, technical capability, scientific knowledge, and environmental impacts increase."[273]

Similar limitations exist in the usefulness of public choice theory to explain the disparity of control between the siting of electricity generation and other infrastructure siting regimes. Despite a number of justifications for centralized control similar to the other siting regimes, one could argue that control over electricity siting continues to rest with the states due to legislators that are not keen on rocking the boat with their respective state contingencies. Shifting power that has remained with the state for over seventy years is bound to deplete some of their political capital-a form of ***270** wealth they may be seeking to maximize-and even risk their electability, and hence another wealth index. But could not the same be said of the other siting regimes?

Although public choice provides some valuable insights, it is hard to provide specific information in any particular moment. And although the legitimacy of public choice theory as one possible explanation for behavior has been largely accepted, the foundations upon which it rests make it difficult to use as a comparative tool. First, the effects of self-interested actions apply to all legislators, rendering it difficult to isolate specific interests that resulted in continued state control over electricity generation from specific interests that resulted in **tips** towards federal control for the other siting regimes. As Professor David Skeel notes, some criticize public choice theory as excessively malleable, "lending itself to any conclusion a commentator wishes to reach."[274] Although it is plausible to suggest that the siting of electricity generation has remained under state control because rational legislators find that to be in their own self-interest, it is difficult to empirically demonstrate that this same self-interest led similarly situated rational legislators to **tip** towards federal control in all the other siting regimes.

Second, assuming that all legislators act in their own self-interest provides no consistent correlation to either state or federal power. For instance, where self-interested legislators are reluctant to act in a manner that jeopardizes their reelection, their actions may be more aligned with the protection of state sovereignty and decentralized state authority. But for legislators that are not in an election year, their self-interest may lead them in different directions. Those legislators may be more focused on obtaining necessary votes from their fellow legislators to accomplish goals, making them more reluctant to act in a manner that jeopardizes those votes for their pet projects. Their pet projects, or those of their fellow legislators, may be more aligned with national security, climate change, or other issues, suggesting an increased role for the federal government over electricity siting. As Professor Daniel Sokol notes, "An overly broad generalization about rationality has its limits. If self-interest can mean just about anything, then it is not constraining the analysis."[275] Along similar lines, self-interests do not lead legislators to act in a linear fashion that always **points** towards state control.

In sum, the prevailing theories for explaining the discrepancy between state control over electricity generation siting and enhanced federal control over the other siting regimes are unsatisfying. All of the siting regimes ***271** were traditionally local, the federalism virtues fail to conclusively **point** towards either state or federal authority for the different regimes, and a focus on self-interested legislators fails to correlate to one particular level of authority. Upon closer examination, any overarching account of these **tips** breaks down and becomes nuanced and contingent on the specifics of a dynamic and complicated balance.

VI. Alternative Outlets for Federal Involvement

If these theories do not fully explain the disparity in control between the siting of electricity generation and the siting of the other infrastructure, then what else can be weighing in favor of state control? Something must be serving as a counterbalance against the justifications for centralized control. One often overlooked answer is the presence of an alternative outlet for federal involvement.

This analysis thus far has focused on statutory tips that occur as a result of federal legislative action. As previously discussed, developing national interests in an area that is governed by state or local control can create a tension in the proper functioning of the power structure.[276] This tension can be resolved through statutory adjustments. But it can also be resolved through agency action. The ability of a federal agency to step in and address the national interest on the margins can create a release valve to reduce the pressure on Congress to act formally to tip the balance of power. Congress is less likely to find the need to endure the political costs associated with amending a statute, let alone a politically charged federalism provision of a statute, when the federal government is able to accomplish some of its federal objectives without necessitating a formal amendment.

This phenomenon plays out in the siting analysis. In the earlier siting regime tips, agency action does not appear to have played a critical role in diffusing the tensions caused by growing federal interests. There is little evidence that either the ICC or the FPC were issuing regulations that expressed a federal interest in ensuring the railroads and natural gas lines were being built prior to their respective congressional tips. On the contrary, in both the telecommunications and transmission lines siting regimes, the respective agencies, FCC[277] and FERC,[278] made some sort of ***272** effort to address national interests prior to the statutory tips. Is it a coincidence that these are the two areas where the congressional tip consisted not of complete preemption, but a more limited form of federal control through a partial preemption? This may be in part because of the active involvement of the FCC and FERC to try to address some of these federal issues on the margins.[279] Their limited success may have mitigated the need for a full preemption on these matters. Had the federal agencies not been making strides in furtherance of the national interest, Congress may have had more motivation to enact tips towards stronger federal control.

Similarly, with respect to the siting of electricity generation, an active administrative agency may be minimizing the incentives of Congress to formally tip the balance of power from state towards more federal control. Federal agencies may be better able to address the national interest in electricity siting because of the nature of the federal interest. Rather than a federal interest limited to making sure the infrastructure is ultimately sited, for instance, the federal interest in the siting of electricity generation extends to the type of infrastructure being sited (electricity generation based on renewable or coal, for instance), and perhaps more importantly, an interest in the type of fuel source relied upon by each new electric-generating facility.[280] Where the federal interest is limited to making sure the new infrastructure is constructed, as it was in so many of the other infrastructure regimes, the federal government has few options by which to ***273** directly influence a state or local decision in lieu of a formal congressional tip. But where the federal interest is in the type of the facility, the federal government has more options available to influence the type of facility constructed. Where the relevant federal agencies can address the national interest they had in siting (the type of resources used to generate electricity) through other means, it may provide an important counterbalance to the justifications for centralized control.

This section describes the efforts of three federal agencies to find alternative outlets to influence the type of electricity produced within each state: (1) FERC; (2) EPA; and (3) Department of Interior (DOI). All three have been acting within their existing statutory authorities to address the issues of current federal interest: enhanced reliance on renewables and other clean energy sources. I argue that these efforts are minimizing the strain on the existing electricity regime, providing a critical release valve on the federalism tensions. This highlights an important additional factor that may counter any federalism justifications for a formal congressional tip towards federal control.

A. FERC's Outlet on Renewables

The first example of an outlet for a growing federal interest in cleaner energy sources lies with FERC. FERC, an agency not traditionally known for its environmental values, has taken steps to advance the national interest in renewable energy. FERC's mission has been to assist consumers in "obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means."[281] But with carbon-laden fossil fuels providing 88% of the nation's electricity[282] and 79% of the nation's greenhouse gases,[283] FERC's attention has begun to shift towards climate change and renewable energy, echoing the Obama Administration's emphasis on clean energy as a national priority:

> The use of renewable energy resources to generate electricity has the potential to be a cost-effective means not only to reduce greenhouse gas emissions, but also to diversify the ***274** fuels used to generate electricity. The Commission will continue to pursue market reforms to allow all resources, including renewable energy resources, to compete in jurisdictional markets on a level playing field. . . . By implementing these or other reforms, the Commission's actions have the potential to increase the amount of electricity being produced from renewable energy resources.[284]

FERC did not stop with sweeping statements about its efforts to enhance our nation's reliance on renewable energy. FERC has also injected itself into the state and local electricity generation siting decisions in a number of ways.[285] An important method involves using FERC's broad authority under the FPA to review rates and charges to ensure that they are "just and reasonable" and not "unduly discriminatory."[286] Relying on its broad authority under these provisions, the agency also issued two recent rulemakings that seek to enable more renewable energy generation in this country. In July 2011, FERC issued Order 1000, the "Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities" that resulted in significant changes related to the construction of transmission lines in a way that allows "for reliably and cost-effectively integrating location-constrained renewable energy resources."[287] Whereas transmission line planners previously evaluated proposed transmission lines based on only two benefits-reliability and economics-FERC's new Order 1000 requires that each public utility transmission provider also provide for the consideration of "Public Policy requirements established by state or federal laws or regulations."[288] Not only does FERC specifically call out "the renewable portfolio standards ***275** adopted by many states"[289] as an example of such "Public Policy requirements," but the term is broad enough to encompass a large range of federal interests that can include environmental priorities. Again, FERC based the issuance on this order on its jurisdiction under Section 206 of the FPA to "ensure that the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential."[290]

More recently, in June of 2012, FERC issued a second relevant renewable energy rulemaking. FERC issued a final rule as a means of removing barriers to the integration of renewable energy, which it termed "variable energy resources."[291] Renewable resources present a unique challenge for grid operators and suppliers due to their intermittent nature. FERC found that the existing rules have the potential to discriminate against renewable energy generators, triggering FERC's duty to prevent "unjust or preferential rates."[292] In a statement about the proposed rulemaking, FERC Chairman Jon Wellinghoff stated that it "will help to manage the cost-effective integration of variable energy resources into the grid and to meet the future's other challenges in a way that maintains reliability."[293] Chairman Wellinghoff has stated:

> Quite frankly, FERC is sort of operating independently of the electoral process. . . . We've been acting under our statutory federal authority to move forward toward what I see as our responsibilities under the Federal Power Act, and that is to ensure rates are just and reasonable. And part of that I see as improving efficiency and competition in the markets, and incorporating new resources into the markets, including ***276** renewables and the demand side.[294]

B. EPA's Outlet on Pollution Control Limits

The second outlet for federal influence over the type of power generated is EPA's recent regulations regarding GHGs. A 2007 Supreme Court decision affirming the ability of EPA to regulate GHGs under the Clean Air Act [295] set the course for a new era of Clean Air Act regulations specific to GHGs. Over the last five years, EPA has been feeling its way through this unchartered territory, starting with key regulatory findings that GHGs endanger the public welfare with respect to mobile sources, [296] continuing with reporting regulations, [297] specially tailoring existing regulations for new source controls to account for the unique character of GHGs, [298] tightening fuel efficiency standards for the first time in 30 years, [299] and most recently, proposing New Source Performance Standards for all fossil-fuel boilers. [300]

This most recent proposal may be the most indicative of EPA's ability to exert its influence over the type of electricity generated. EPA is required to establish emissions standards for industrial categories. [301] It defined the industrial category as "fossil-fuel-fired boilers," and determined that all fossil-fuel burning plants (whether they be coal, natural gas, or oil) must meet the emissions standard established by combined cycle natural gas plants. [302] This effectively mandates that all new fossil-fuel (i.e., nonrenewable) plants that will be constructed must be natural gas, resulting in a potential phase-out of coal and oil plants. [303] Although ***277** not specifically mandating renewable energy, it reduces the likelihood that state PUCs will approve applications to construct new coal or oil power plants within their state borders.

C. Department of Interior's Outlet on Federal Lands

The third outlet for federal agency influence over the type of power generated is through the siting of renewable energy on federal lands. The Energy Policy Act of 2005 encourages agencies to site renewable energy projects on federal lands [304] and subsequent executive orders added more teeth to this encouragement. [305] As I have described elsewhere, the DOI, the agency that manages millions of acres of federal land in the United States, has taken many steps to implement these orders by fast-tracking siting of solar and wind projects on federal lands both onshore and offshore. [306] As a result, over nine solar and twenty-five wind projects have been approved in recent years, [307] with many more applications in the pipeline. [308]

In summary, although politics, special interests, moral commitments, federalism justifications, and a host of other factors contribute to these decisions, continued state control over the siting of electricity generation may be at least partially explained by the additional underappreciated variable of the availability of alternative outlets for federal control. This analysis suggests that even though there is an emerging national interest in the source of our electricity and some federalism justifications for more centralized authority, an active administrative agency is able to effect some of that national purpose on the margins through regulation.

It should be noted that such agency actions have the potential to backfire. Agency actions that affect the balance of power between the ***278** states and federal government have been under scrutiny for some time. [309] Despite mandates from the Executive Branch to carefully consider the impacts on federalism prior to rulemaking, studies have revealed agency failures to comply. [310] In fact, the Administrative Conference of the United States recently recommended a number of procedures to better ensure agency compliance with Executive Orders mandating that the agencies ensure proper respect for federalism. [311] As Professor Robert Percival has noted, "history also demonstrates that efforts to achieve federal goals will be thwarted if they are pursued without sensitivity to state and local concerns." [312]

Furthermore, greater federal involvement in renewables is dependent on the political preferences of the federal government at the time. As one scholar observed:

> The political valences of national power and state autonomy constantly have shifted back and forth throughout our history. In the Progressive Era, liberals were often based in the states and distrusted federal (particularly federal judicial) power; in the 1960s and 1970s, the opposite was more often true. Prior to the Civil War, slaveholders relied on federal authority to recover escaped slaves, while more enlightened state governments in the North sought to preserve some modicum of due process for accused escapees. It is an ahistorical mistake to take the particular political patterns of the last third of a century for immutable structural truth. One simply cannot ascribe a reliable political tendency to federalism.[313]

In much the same way, it would be a mistake to assume that federal agency actions with regard to electricity generation siting would necessarily result in the promotion of renewable energy. Just as the political valences of national power and state autonomy flip-flopped over time, the results of active federal agencies would likely flip-flop with the political parties in control of the various branches. Some have even argued that national efforts to enhance renewables can have unintended negative ***279** consequences.[314] One such consequence could be an increased reliance on cheaper fossil fuels to offset the more expensive renewables that might be required by federal mandates.

VII. Continuing Pressures on the Proper Balance in Siting Regimes

Discussions about the proper balance of power in siting and other areas of the law are sure to continue. In the two areas where Congress took small steps towards preemption or federalization, telecommunications and electricity transmission, for instance, movements to enhance federal control continue. In 2009, the FCC issued a "Shot Clock" Rule[315] that further forced the hand of the local authorities to approve requests for tower siting more swiftly.[316] And in April 2011, the FCC reopened issues surrounding the proper balance of power over siting of wireless infrastructure. The FCC issued a Notice of Inquiry that it "intended to update [the FCC's] understanding of current rights of way and wireless facilities siting policies."[317] The FCC viewed the Inquiry as "a necessary step towards determining whether there is a need for coordinated national action to improve rights of way and wireless facilities siting policies, and if so, what role the Commission should play in conjunction with other stakeholders."[318] Not surprisingly, local organizations spoke out against the expansion of the FCC's authority over broadband and wireless facilities[319] while members of the telecommunications industry fully ***280** supported the government's attempt to deploy broadband on a larger scale.[320]

On the electricity transmission side, the courts have significantly limited FERC's backstop authority.[321] In response, FERC indicated a "do it alone" attitude where it indicated that it was going to seek a delegation of authority from DOE to FERC to avoid having to engage in the legislative process.[322] For now, DOE rejected FERC's proposal to consolidate authority.[323] Additionally, the DOI has made several efforts to expedite the siting of transmission lines.[324] The National Commission on Energy Policy observed in 2006 that "energy-facility siting and permitting remains a major cross-cutting challenge for U.S. energy policy" and cited "processes in which local concerns trump broader regional or national objectives" as an obstacle to permitting and building major facilities where they are needed most.[325] If interstate controversies become more commonplace, the ***281** push towards federal intervention may grow. But if states continue to voluntarily centralize the power over siting through regional organizations, the need for federal intervention may diminish. One study, conducted by Edison Electric Institute,[326] forecasts that investor-owned utilities will invest approximately $64 billion in future transmission systems through the year 2022.[327]

And for generation, states continue to chime in when agencies seem to exert their influence too close into their realm. Where the states feel threatened by federal actions, they are more likely to dig in their heels to oppose any tip in the balance of power. For example, when FERC issued its recent Order 1000, commenters raised concerns about its federalism impacts, making a point to reiterate that "the FPA gives the Commission no authority to determine what resources should be used by load-serving entities, regardless of whether or not those resources are needed to meet public policy requirements." [328] Others commented that "the Final Rule should make explicit that any provisions do not impede or interfere with state commission authority to accept or approve integrated resource plans, make decisions about generation, demand-side resources, resource portfolios, or to modify policy based on cost thresholds." [329] States have drawn a line in the sand about the inability of the federal government to affect directly the type of generation used by the states.

VIII. Conclusion

This Article provides a number of insights for continuing discussions about tips from state to federal control. For those resistant to tips from state to federal control, they should not take comfort in the fact that the area has "traditionally" been regulated at the local level. They should not be overconfident that the historical dominance of the states will be sufficient to thwart efforts to enhance federal power. More is needed to insulate state power from a tip toward enhanced federal control. Any potential dangers to the country should be minimized. The industry should ***282** not complain about its diverse regulatory burdens. The states should collaborate to resolve any disputes. Sub-federal entities should work to streamline their permitting processes. There may even be some merit in allowing administrative agencies to exercise "creative" interpretations within their existing authority, even if they implicate the balance of power. Where these actions are taken with respect for state sovereignty, they may be able to alleviate growing tensions over national issues without warranting a congressional tip. [330] But by the same token, pro-state authority advocates should highlight callous federal actions that fail to respect state sovereignty.

For those in support of tips towards more federal power, they should not be dissuaded by the fact that the area had traditionally been under the control of the sub-federal entities. It is also not enough to point to an outdated law that fails to conform to contemporary realities. It is not even enough that the area implicates interstate issues. More is needed to elicit a tip toward enhanced federal control. Any dangers posed to the country by leaving the issue in sub-federal hands should be emphasized. The regulated industry should coordinate and determine whether there is enough common ground to present a unified front. Interstate disputes, delays, and economic inefficiencies should be highlighted. Administrative agencies should refrain from "creative" interpretations within their existing authority that unduly disrupt the balance of power, highlighting any gaps in federal control. And perhaps most important, any move toward an enhanced federal role should be respectful of state sovereignty and craft a method of tipping that preserves as much local control as possible while effecting the changes needed. [331] In the end, although all of the regimes share traditionally local roots, federalism theory justifications arguing for both centralized and decentralized control, and complicated politics, the disparity in control may be distinguished based on the lack of alternative outlets for federal agencies to affect the earlier siting decisions and the multiple avenues that federal agencies have to affect the type of electricity ***283** that is developed under state and local jurisdiction. Expanding future federalism discussions to include consideration of such variables can lead to a richer and more satisfying analysis.

Footnotes

a1 Associate Professor, Tulane University School of Law. The author thanks Washington and Lee Law School for sponsoring the 2012 conference on "Reclaiming Environmental Federalism" and her co-panelists, Bill Buzbee and Rob Glicksman for their comments. Thanks to Keith Werhan, Adam Feibelman, Claire Dickerson, Shu-yi Oei, Saru Matambanadzo, and Alfred Light for their support and thoughtful comments and to the tireless research of Emily Russell, Katy Whisenhunt, Gillian Egan, and Rick Eisenstat.

1 FERC v. Mississippi, 456 U.S. 742, 757 (1982).

2 In 1935, Congress explicitly reserved the authority over all electricity siting decisions with respect to generation, transmission, and distribution facilities to the states. Federal Power Act, 16 U.S.C. § 824(b)(1) (2012).

3 It is worth noting that jurisdiction over these three areas is complex, and any analysis depends on whether the focus is on jurisdiction over the service or the physical infrastructure. For example, FERC has jurisdiction over the rates charged to transmit electricity (the transmission service), but states retain jurisdiction over the siting of the transmission lines themselves (the physical infrastructure). For generation, the jurisdictional split is even more complex. On the service side, FERC has jurisdiction over the rates charged for electricity generated and sold for resale (wholesale rates), and states retain jurisdiction over the rates charged to end users (retail rates). On the infrastructure side, states retain jurisdiction over the siting of the electricity generation itself. Federal Power Act, 16 U.S.C. § 824(b)(1).

4 Federal Power Act, 16 U.S.C. § 824(b)(1).

5 See, e.g., Dave Markell & J.B. Ruhl, An Empirical Assessment of Climate Change in the Courts: A New Jurisprudence or Business as Usual?, 64 Fla. L. Rev. 15, 44-46 (2012) (discussing the Indiana PUC's and South Dakota PUC's approval of new coal-fired power plants and the Florida PUC's denial of two new pulverized coal generating units based on questionable cost effectiveness due to potential carbon controls).

6 See, e.g., Envtl. L. Inst., State Enabling Legislation for Commercial-Scale Wind Power Siting and the Local Government Role 1, 5-20 (2011), available at http://www.elistore.org/reports_detail.asp?ID=11410 (categorizing the fifty states into differing degrees of authority, including local authority, dual authority, and state authority over the siting of wind energy).

7 Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009).

8 Id.; see also Miss. Power & Light Co. v. Mississippi, 487 U.S. 354, 389 (1988) (Brennan, J., dissenting) ("FERC does not, after all, have any jurisdiction over a utility that simply builds its own generating facility and retails the electricity."); Transmission Access Policy Study Grp. v. FERC, 225 F.3d 667, 718 (D.C. Cir. 2000) (noting that "petitioners correctly **point** out that section 201(b) of the [FPA] denies FERC jurisdiction over 'facilities used for the generation of electric energy"' but also noting that this jurisdiction is limited by FERC's authority to "exercise jurisdiction over generation facilities to the extent necessary to regulate interstate transmission"). Federal regulation of the siting of electricity generation extends only to hydroelectric and nuclear power determinations. See Uma Outka, Siting Renewable Energy: Land Use and Regulatory Context, 37 Ecology L.Q. 1041, 1047 (2010) (noting "nuclear facilities are subject to extensive federal regulation, from siting to decommissioning, that does not apply to renewable resources"). FERC has jurisdiction over licensing of non-federal hydroelectric projects if the project meets one of four criteria. Jurisdiction Determination, FERC, http://www.ferc.gov/industries/hydropower/gen-info/comp-admin/jur-deter.asp (last visited June 23, 2012); see also 16 U.S.C. § 817(1) (requiring a federal permit to develop electric power or construct a dam in or incidental to any navigable waters of the United States).

9 Many scholars make a distinction between state and local levels of government for federalism purposes. See, e.g., Heather K. Gerken, Foreword: Federalism All the Way Down, 124 Harv. L. Rev. 4, 21-25. For purposes of this analysis, however, the key distinction is between federal and sub-federal levels of government, allowing state and local levels of government to be grouped together on the decentralized side of the federalism ledger.

10 See U.S. Envtl. Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010 ES-7 (2012), available at http:// www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf ("As the largest source of U.S. greenhouse gas emissions, CO2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2010.").

11 Massachusetts v. EPA, 549 U.S. 497, 532 (2007).

12 President Obama Calls for Greater Use of Renewable Energy, U.S. Dep't of Energy (Jan. 21, 2009), http:// www1.eere.energy.gov/femp/news/printable_versions/news_detail.html?news_ id=12194.

13 President Barack Obama, Remarks as Prepared for Delivery Address to Joint Session of Congress (Feb. 24, 2009), available at http://www.whitehouse.gov/the_press_office/Remarks-of-President-Barack-Obama-Address-to-Joint-Session-of-Congress.

14 This Article does not allege to be a comprehensive assessment of all federalism tips involving siting decisions. That assessment, which should include authority between the federal and subfederal systems specific to siting schemes such as nuclear waste disposal sites, landfills, hydroelectric (FERC-dominated), and hydrokinetic (FERC-Bureau of Energy Management cooperative) siting, as well as analyses of tips from state to federal power in other non-siting contexts, and tips from federal to state power. For example, in response to the 1973 Oil Embargo, Congress passed the 1974 Emergency Highway Energy Conservation Act that established a national speed limit only to repeal the law over twenty years later to tip power back to the states. For further discussion, see Daniel Albalate & German Bel, Speed Limits in America: Economics, Politics and Geography 5 (Institut de Recerca en Economia Aplicada Regional i Publica, Working Paper, 2010).

15 Although construction of the Commerce Clause has changed over the years that are covered in this tip analysis, a strong argument exists that even under the more constrained interpretation of the Commerce Clause that currently prevails, Congress's power to regulate purely intrastate activities that "substantially affect interstate commerce" could encompass the siting of electricity generation. See United States v. Lopez, 514 U.S. 549, 559 (1995) (providing a wide variety of examples of economic activity that has been held to substantially affect interstate commerce). Although the purely intrastate siting of electricity generation does not cross over state lines, as do railroads, natural gas pipelines, and transmission, it has at least as "substantial" of an effect on interstate commerce as the siting of intrastate wireless towers. Id. For a fuller assessment of Congress's authority over energy, see Robin Kundis Craig, Constitutional Contours for the Design and Implementation of Multistate Renewable Energy Programs and Projects, 81 U. Colo. L. Rev. 771, 780-81 (2010) (discussing the resilience of energy regulation legislation under the Commerce Clause and repeated failed challenges of the constitutionality of such legislation); Sandeep Vaheesan, Preempting Parochialism and Protectionism in Power, 49 Harv. J. Legis. 87, 128-29 (2012) (noting Congress's broad authority to regulate the electric power sector even under modern Commerce Clause jurisprudence and quoting the Supreme Court's dicta that the electric utility industry is "so fused and interdependent that the whole enterprise is within the reach of Congress" (quoting Conn. Light & Power v. Fed. Power Comm'n, 324 U.S. 515, 529-30 (1945) (internal quotation marks omitted)).

16 See Abigail R. Moncrieff & Eric Lee, The Positive Case for Centralization in Health Care Regulation: The Federalism Failures of the ACA, 20 Kan. J.L. & Pub. Pol'y 266, 266 (2011).

17 William P. Marshall, Federalization: A Critical Overview, 44 DePaul L. Rev. 719, 720 (1995); see also Abigail R. Moncrieff, Federalization Snowballs: The Need for National Action in Medical Malpractice Reform, 109 Colum. L. Rev. 844, 847 (2009) (explaining how the federal government's previous intervention in healthcare spending has necessitated federalization of medical malpractice).

18 See Mark Moller, The Rule of Law Problem: Unconstitutional Class Actions and Options for Reform, 28 Harv. J.L. & Pub. Pol'y 855, 883, 900 (2005) (discussing the merits of decentralization in the context of multidistrict litigation as one possible way to better reform class action lawsuits, noting that decentralization can reduce the cost of error by government decision makers and encourage competition between different "power centers of government").

19 See Paul E. Peterson, Devolution's Price, 14 Yale L. & Pol'y Rev. 111, 114 (1996).

20 "Decentralization is no longer an alternative to centralization. Both are needed. The complementary roles of national and subnational actors should be determined by analyzing the most effective ways and means of achieving a desired objective." Chanchal Kumar Sharma, Emerging Dimensions of Decentralization Debate in the Age of Glocalization, 1/2009 Indian J. Fed. Stud. 47, 48-49 (2009); see also Oliver A. Houck & Michael Rolland, Federalism in Wetlands Regulation: A Consideration of Delegation of Clean Water Act Section 404 and Related Programs to the States, 54 Md. L. Rev. 1242, 1244 (1995) (arguing "that the national interest in clean water and related wetlands functions merits a strong federal presence," while also acknowledging the benefits of "an active state partnership"); Philip J. Weiser, Cooperative Federalism and Its Challenges, 2003 Mich. St. DCL L. Rev. 727, 728 (2003).

21 See discussion infra Part V.A.

22 See discussion infra at Part II.

23 See, e.g., Ann E. Carlson, Iterative Federalism and Climate Change, 103 Nw. U. L. Rev. 1097 (2009) (discussing iterative federalism in the context of environmental policymaking); Kirsten H. Engel, Harnessing the Benefits of Dynamic Federalism in Environmental Law, 56 Emory L.J. 159, 175-77 (2006) (discussing dynamic federalism in the context of environmental law).

24 Robert Glicksman & Richard E. Levy, A Collective Action Perspective on Ceiling Preemption by Federal Environmental Regulation: The Case of Global Climate Change, 102 Nw. U. L. Rev. 579, 594-600 (2008).

25 See Barry Friedman, Valuing Federalism, 82 Minn. L. Rev. 317, 405-10 (1997) (providing a non-comprehensive list of common reasons for centralized national control-uniformity, race to the bottom, public goods, and externalities-and noting that there may be other reasons to exercise national authority); Richard B. Stewart, Pyramids of Sacrifice?: Problems of Federalism in Mandating State Implementation of National Environmental Policy, 86 Yale L.J. 1196, 1211-20 (1977) (identifying several justifications for the movement toward centralized federal environmental regulation).

26 Glicksman & Levy, supra note 24, at 594.

27 David B. Spence & Paula Murray, The Law, Economics, and Politics of Federal Preemption Jurisprudence: A Quantitative Analysis, 87 Calif. L. Rev. 1125, 1137 (1999).

28 See, e.g., Daniel C. Esty, Revitalizing Environmental Federalism, 95 Mich. L. Rev. 570, 601 n.101 (1996) ("[A]ir pollution is a problem that rarely falls within ready-made political boundaries. In any metropolitan area both the social costs incurred in failing to control it and the benefits to be derived from regulation within a single political subdivision inevitably spill over into other jurisdictions . . . . The necessity for . . . uniformity is rather generally agreed upon." (quoting Air Pollution, 1967 Hearings Before the Subcomm. on Air and Water Pollution of the Senate Comm. on Public Works, 90th Cong. 993 (1967) (testimony of Lewis C. Green of the Missouri Air Conservation Commission))).

29 Friedman, supra note 25, at 407.

30 Id.

31 Robert P. Inman & Daniel L. Rubinfeld, Making Sense of the Antitrust State-Action Doctrine: Balancing Political Participation and Economic Efficiency in Regulatory Federalism, 75 Tex. L. Rev. 1203, 1229 (1997). Professors Issacharoff and Sharkey explored the implications of situations when "claims of state sovereignty do pose risks to the rest of the country, when experiments of democracy within one state's borders have spillover effects that adversely affect citizens of other states," noting that this may deprive the citizens of other states "of the political means of compelling democratic accountability on economic actors shielded by other states' claims of sovereignty." Samuel Issacharoff & Catherine M. Sharkey, Backdoor Federalization, 53 UCLA L. Rev. 1353, 1355 (2006).

32 See Noah D. Hall, Toward a New Horizontal Federalism: Interstate Water Management in the Great Lakes Region, 77 U. Colo. L. Rev. 405, 406 (2006) (describing cooperative horizontal federalism as a way to utilize common minimum standards that are imposed on states by an interstate compact as opposed to the federal government).

33 Jonathan H. Adler, When Is Two a Crowd? The Impact of Federal Action on State Environmental Regulation, 31 Harv. Envtl. L. Rev. 67, 85 (2007) (discussing how federal preemption of automobile emissions standards resulted from lobbying by U.S. automakers who feared the potential for different states to adopt different emissions standards).

34 Robert M. Ackerman, Tort Law and Federalism: Whatever Happened to Devolution?, 14 Yale L. & Pol'y Rev. 429, 453 (1996).

35 Id. at 452. The Reagan Administration, for example, concluded that product liability law required federal standardization. "Implicit in this decision was a determination that conflicting state product liability laws have created such significant burdens on interstate commerce that preemptive federal legislation was necessary to provide consistent nationwide treatment of product liability disputes."

C. Boyden Gray, Regulation and Federalism, 1 Yale J. on Reg. 93, 96 (1983) (referencing the Reagan administration's support for national legislation to supplant state laws).

36 Arthur H. Harding & Paul W. Jamieson, Dismantling the Final Regulatory Entry Barriers: A Call for the FCC to Assert Its Preemptive Authority, 12 Harv. J.L. & Tech. 533, 554 (1999).

37 Friedman, supra note 25, at 375.

38 Id. at 376.

39 Thomas W. Merrill, Preemption and Institutional Choice, 102 Nw. U. L. Rev. 727, 732 (2008).

40 Id.

41 Evan H. Caminker, State Sovereignty and Subordinacy: May Congress Commandeer State Officers to Implement Federal Law?, 95 Colum. L. Rev. 1001, 1012 (1995). But see Kirsten H. Engel, State Environmental Standard-Setting: Is There a "Race" and Is It "to the Bottom"?, 48 Hastings L.J. 271, 278 (1997) (arguing that interstate competition in real world situations is in fact detrimental to social welfare despite theoretical models showing it to be beneficial); Daniel R. Fischel, The "Race to the Bottom" Revisited: Reflections on Recent Developments in Delaware's Corporation Law, 76 Nw. U. L. Rev. 913, 920 (1982) (explaining that state control over corporate law does not create a "race-to-the-bottom," but rather a "climb to the top"); Richard L. Revesz, Rehabilitating Interstate Competition: Rethinking the "Race-to-the-Bottom" Rationale for Federal Environmental Regulation, 67 N.Y.U. L. Rev. 1210, 1253 (1992) (challenging the race-to-the-bottom rationale for centralized environmental legislation and arguing that state competition is presumptively beneficial).

42 One contemporary example of the race to the bottom is the regulation of the fracking of shale formations to release natural gas. When fracking comes to town, mineral rights owners become millionaires, the unemployment rate drops, businesses prosper from the influx of developers, and the state derives tax dollars. See, e.g., Brian A. Shactman, Unemployed? Go to North Dakota, MSN Money, Oct. 5, 2011, available at http://money.msn.com/investing/unemployed-go-to-north-dakota-cnbc.aspx (attributing an influx of billions of dollars to the state economy, a jobless rate that is one-third that of the national rate, and a high demand for new housing developments to the fracking boom in North Dakota). These benefits are difficult to ignore, providing the state with a strong financial interest in luring the developers within their borders, even if it involves doing so with environmental regulation that is less restrictive than its shale-sharing neighbors. In 2010, the governor of New York imposed a moratorium on fracking until the state could complete an environmental review. See Matt Willie, Comment, Hydraulic Fracturing and "Spotty" Regulation: Why the Federal Government Should Let States Control Unconventional Onshore Drilling, 2011 BYU L. Rev. 1743, 1763 (2011) (discussing the controls New York has placed on fracking). Pennsylvania, in stark comparison to New York's strict regulatory regime, has taken a more laissez-faire approach to drilling and permitted 2,349 wells to be drilled in the Marcellus Shale between 2008 and 2010, "with 1,386 of those wells drilled in 2010 alone." Beren Argetsinger, Comment, The Marcellus Shale: Bridge to a Clean Energy Future or Bridge to Nowhere? Environmental, Energy and Climate Policy Considerations for Shale Gas Development in New York State, 29 Pace Envtl. L. Rev. 321, 326 (2011).

43 Robert V. Percival, Environmental Federalism: Historical Roots and Contemporary Models, 54 Md. L. Rev. 1141, 1171-72 (1995).

44 Id. at 1151 (noting that match companies called for federal regulation of white phosphorus where states were reluctant to adopt measures that would drive employers out of state).

45 Glicksman & Levy, supra note 24, at 600. "This scenario is essentially the flipside of a negative externality problem because the source of a NIMBY problem is a positive externality-the state that is the location of the activity bears all or most of the environmental burdens, but the economic benefits are spread to other states." Id.

46 One hundred and four nuclear reactors are currently operating in our country, storing over 60,000 tons of radioactive spent fuel across our country. Matthew McKinzie, Sixty Thousand Tons of Commercial Spent Nuclear Fuel Stored at U.S. Reactors for 60 Years?, Switchboard Natural Res. Def. Council Staff Blog (Feb. 23, 2011), http://switchboard.nrdc.org/blogs/mmckinzie/sixty_thousand_tons_of_commerc.html.

47 See Nuclear Waste Policy Amendments Act of 1987, Pub. L. No. 100-203, 101 Stat. 1330, 227-28 (codified as amended at 42 U.S.C. § 10172 (1988)) (designating Yucca Mountain, Nevada, as the sole repository site to be characterized). The storage facility was abandoned for other reasons, but only after twelve billion dollars had been spent on characterizing and initial development of the site. Hannah Northey, GAO: Death of Yucca Mountain Caused by Political Maneuvering, N.Y. Times, May 10, 2011, http://www.nytimes.com/gwire/2011/05/10/10greenwire-gao-death-of-yucca-mountain-caused-by-politica-36298.html?pagewanted=all.

48 Friedman, supra note 25, at 406-07.

49 Benjamin K. Sovacool, The Best of Both Worlds: Environmental Federalism and the Need for Federal Action on Renewable Energy and Climate Change, 27 Stan. Envtl. L.J. 397, 424 (2008).

50 Id. at 424-25.

51 Friedman, supra note 25, at 406 ("Public goods are those that would not be provided if it were not for the existence of some central authority to fund them.").

52 Sovacool, supra note 49, at 426. One argument is that "the federal government is well-equipped to provide capital-intensive services like the construction of deep salt-lined storage facilities for high-level nuclear waste, but is likely to be inept at conducting labor-intensive services like the management of public hearings to minimize public opposition to waste sites." Roderick M. Hills, Jr., The Political Economy of Cooperative Federalism: Why State Autonomy Makes Sense and "Dual Sovereignty" Doesn't, 96 Mich. L. Rev. 813, 869-70 (1998).

53 Larry Kramer, Understanding Federalism, 47 Vand. L. Rev. 1485, 1549-50 (1994).

54 After years of trying to secure a permanent repository for the nation's high-level nuclear waste, the federal government eventually decided to force over 60,000 tons of the highly radioactive substance onto the state of Nevada against its strong objections. See Nuclear Waste Policy Act of 1982, 42 U.S.C. §§ 10132, 10172 (2006) (charging DOE with the responsibility to find a site and subsequently narrowing the choices to Yucca Mountain, Nevada in 1987); see also Public Health and Environmental Radiation Protection Standards for Yucca Mountain, NV, 66 Fed. Reg. 32,081 (June 13, 2001) (discussing why Yucca Mountain was chosen). After two decades, "the Secretary of Energy has decided that a geologic repository at Yucca Mountain is not a workable option for long-term disposition of these materials." U.S. Dep't of Energy's Motion to Withdraw 1, In re U.S. Dep't of Energy (High-Level Waste Repository), No. 63-001 (N.R.C. Mar. 3, 2010), available at http:// energy.gov/sites/prod/files/edg/media/DOE_Motion_to_Withdraw.pdf.

55 Nebraska opposes the siting of this 1,700 mile pipeline through the nation's heartland, a siting decision that rests with the State Department due to its transnational effects across Canada and the U.S. In January 2012, President Obama refused to approve the pipeline under a congressionally-imposed accelerated timeframe, but would consider alternative routes that do not "risk[[] the health and safety of the American people and the environment." Statement by the President on the Keystone XL Pipeline, Jan. 18, 2012, available at http://www.whitehouse.gov/the-press-office/2012/01/18/statement-president-keystone-xl-pipeline. To counter this state interest, Congress has declared that "[t]he development and delivery of oil and gas from Canada to the United States is in the national interest of the United States in order to secure oil supplies to fill needs that are projected to otherwise be filled by increases in other foreign supplies." North American-Made Energy Security Act, H.R. 1938, 112th Cong. § 2(4) (2011).

56 Transmission lines and natural gas pipelines require a certificate of need; telecommunications infrastructure requires a certificate of necessity, and railroads require a certificate of convenience and necessity. See, e.g., infra notes 68 and 133.

57 As described supra, Congress codified state control over the siting of generation, transmission, and distribution infrastructure in the FPA.

58 For purposes of this Article, enhanced federal control includes any shift in the power balance toward a more centralized level of authority, including complete preemption, partial preemption, or some form of backstop authority.

59 Since its first use in the United States in 1827, railroads have been under state control. See Railroad Industry Overview Series-History of the Railroad Industry, IRS, http://www.irs.gov/Businesses/Railroad-Industry-Overview-Series--History-of-the-Railroad-Industry--October-2007 (last updated Sept. 27, 2012).

60 National Railroad Regulation, N.Y. Times, Dec. 3, 1885, available at http://query.nytimes.com/mem/archive-free/pdf?res=9901E1DF1F39E533A25750C0A9649D94649FD7CF.

61 Mark T. Kanazawa & Roger G. Noll, The Origins of State Railroad Regulation: The Illinois Constitution of 1870, in The Regulated Economy: A Historical Approach to Political Ecomony 13, 14 (Claudia Goldin & Gary D. Libecap eds., 1994) ("[F]or three decades before the passage of the Interstate Commerce Act, many states regulated tariffs and routes for both passengers and freight.").

62 Railroad Industry Overview Series, IRS, http:// www.irs.gov/Businesses/Railroad-Industry-Overview-SeriesHistory-of-the-Railroad-Industry October-2007 (last visited Sept. 27, 2012).

63 James W. Ely, Jr., ''The Railroad System Has Burst Through State Limits'': Railroads and Interstate Commerce, 1830-1920, 55 Ark. L. Rev. 933, 966 (2003).

64 Id. at 966.

65 Id.

66 See id. at 967 (stating that federal control began in 1862 with the Interstate Commerce Act that created the Interstate Commerce Commission and the Safety Appliance Act of 1893, but continued in quick succession with the Elkins Act of 1903, the Hepburn Act of 1906, and the Mann-Elkins Act of 1910).

67 Melvin F. Fincke, Is Competition Between Carriers To Be Considered by the Interstate Commerce Commission When Granting Certificates of Convenience and Necessity?, 25 Tex. L. Rev. 406, 406 (1947) (citing Transportation Act of 1920, Pub. L. No. 66-152, 41 Stat. 456 (1920) (codified in scattered sections of 49 U.S.C.)).

68 Rogers MacVeagh, The Transportation Act, 1920: Its Sources, History, and Text, Together With Its Amendments to the Interstate Commerce Act, Explained, Analyzed, and Compared 195 (1923). Consistent with contemporary Commerce Clause jurisprudence, Congress did not give the ICC authority over rail lines located wholly within one state. Id. at 197, 219. The Supreme Court has declared that the ICC can regulate intrastate commerce only as an incident to the control of interstate commerce. Ely, supra note 63, at 976 (noting that "calls for federal control of the rail industry steadily mounted after the Civil War").

69 R.R. Comm'n of Cal. v. S. Pac. Co., 264 U.S. 331, 347 (1924).

70 Mid States Coal. for Progress v. Surface Transp. Bd., 345 F.3d 520, 552 (8th Cir. 2003) (finding that 49 U.S.C. § 10901(c) gives rise to statutory presumption that rail construction is to be approved).

71 49 C.F.R. § 1150.4 (2011). The railroad's plan is also subject to environmental review and must meet federal and state environmental regulations. 49 C.F.R. § 1150.7 In some situations, this may indirectly give states a role in determining where a line is located.

72 49 U.S.C. § 10901 (2006) (discussing how similar to the ICC, the STB must issue a certificate authorizing construction and operation of railroad lines unless it finds that the activities are inconsistent with public convenience and necessity).

73 Michal R. Belknap, The New Deal and the Emergency Powers Doctrine, 62 Tex. L. Rev. 67, 79-81 (1983).

74 Railroad Industry Overview Series: History of the Railroad Industry, IRS, http://www.irs.gov/businesses/article/0,,id=175287,00.html (last updated Aug. 25, 2011).

75 President Vetoes Pre-war Rate Bill, N.Y. Times, Nov. 18, 1919, available at http://query.nytimes.com/mem/archive-free/pdf?res=9806E2DB153BEE32A2575AC1A9679D946896D6CF.

76 Toledo, P. & W. R.R. v. Stover, 60 F. Supp 587 (S.D. Ill. 1945) (citing Ch. 91, § 402, 41 Stat. at 457-58 (1920)).

77 MacVeagh, supra note 68, at 219.

78 Id. at 221.

79 Danaya C. Wright, The Shifting Sands of Property Rights, Federal Railroad Grants, and Economic History: Hash v. United States and the Threat to Rail-Trail Conversions, 38 Envtl. L. 711, 721 (2008).

80 See id. (showing that the current system was insufficient to address the abandonment of railroad lines).

81 United Transp. Union v. Long Island R.R., 455 U.S. 678, 688 (1982).

82 A National Railroad Commission, N.Y. Times, April 25, 1884, available at http://query.nytimes.com/mem/archive-free/pdf?res=9F01E0DB173FE533A25756C2A9629C94659FD7CF.

83 Id.

84 Id.

85 Reuel E. Schiller, Comment, The Administrative State, Front and Center: Studying Law and Administration in Postwar America, 26 L. & Hist. Rev. 415, 420-21 (2008).

86 Cass R. Sunstein, After the Rights Revolution: Reconceiving the Regulatory State 226 (1990).

87 Notably, control over the siting of onshore liquefied natural gas ("LNG") terminals (which provide the **point** of entry and departure for liquefied natural gas that has been compressed and loaded into tankers) also came under exclusive federal control, but is not included in this analysis. LNG development began after the NGA was enacted, so authority over siting was never quite clear. FERC approved construction applications on a case-by-case basis, but jurisdictional uncertainties arose concerning LNG that was to be used solely for intrastate distribution, with California challenging FERC's authority over the siting of such terminals. Fearing delays for LNG projects nationwide, FERC asked Congress to intervene and grant exclusive federal authority. Jacob Dweck, David Wochner & Michael Brooks, Liquefied Natural Gas (LNG) Litigation After the Energy Policy Act of 2005: State Powers in LNG Terminal Siting, 27 Energy L.J. 473, 480 (2006). In 2005, Congress provided FERC with express authority over applications to site, construct, expand, or operate onshore LNG terminals. Natural Gas Act, 15 U.S.C. § 717b(e)(1) (2006). Since authority for the siting of these projects was never clearly with the states, this action is not characterized as a **tip** for purposes of this analysis, but an action to clarify federal jurisdiction.

88 History, NaturalGas.org, http:// www.naturalgas.org/overview/history.asp (last visited May 28, 2012) ("One of the first lengthy pipelines was constructed in 1891. This pipeline was 120 miles long, and carried natural gas from wells in central Indiana to the city of Chicago.").

89 Id.

90 Id.

91 Id.

92 Id.; see also Carl I. Wheat, Administration by the Federal Power Commission of the Certificate Provisions of the Natural Gas Act, 14 Geo. Wash. L. Rev. 194, 196 (1945-1946) (explaining the subsequent clarification of "a market in which natural gas is already being served").

93 Id.

94 Id.

95 Natural Gas Act, 15 U.S.C. § 717b(e)(1) (2012). Although the vast majority of natural gas pipelines are interstate, more than ninety intrastate natural gas pipelines operate in the lower-forty-eight states, primarily in Texas. These are pipelines that operate totally within

one state, do not physically interconnect, and are not subject to FERC jurisdiction. About Natural Gas Pipelines, U.S. Energy Info. Admin., http://www.eia.gov/pub/oil_ gas/natural_gas/analysis_publications/ngpipeline/intrastate.html (last visited May 28, 2012).

96 Richard J. Pierce, Jr., The Evolution of Natural Gas Regulatory Policy, 10 Nat. Resources & Env't 53, 53 (1995).

97 See 15 U.S.C. §§ 717-717z.

98 Id.

99 History, NaturalGas.org, http:// www.naturalgas.org/overview/history.asp (last visited May 28, 2012) (noting welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable pipelines).

100 In the Matter of Acceleration of Broadband Deployment: Expanding the Reach and Reducing the Cost of Broadband Deployment by Improving Policies Regarding Public Rights of Way and Wireless Facilities Siting, 26 F.C.C.R. 5384, 5385 (2011).

101 Michigan, for example, began regulating in 1913. Telecommc'ns Ass'n of Mich., Michigan Telecommunications Act Handbook 2 (2003), available at www.telecommich.org/Documents/mta_handbook.pdf.

102 Communications Act of 1934, 47 U.S.C. § 154 (2012).

103 Id.

104 47 U.S.C. § 152 (2012); see also Duane McLaughlin, Note, FCC Jurisdiction over Local Telephone Under the 1996 Act: Fenced Off?, 97 Colum. L. Rev. 2210, 2213 (1997) ("[T]he 1934 Act . . . give[s] the FCC authority over all interstate communications but reserve[s] authority over intrastate communications to the states.").

105 See, e.g., John T. Soma et al., The Essential Facilities Doctrine in the Deregulated Telecommunications Industry, 13 Berkeley Tech. L.J. 565, 603 (1998) ("AT&T was a natural monopoly protected from rivalry by public restrictions on entry."); Robert B. Friedrich, Note, Regulatory and Antitrust Implications of Emerging Competition in Local Access Telecommunications: How Congress and the FCC Can Encourage Competition and Technological Progress in Telecommunications, 80 Cornell L. Rev. 646, 659 (1995) (describing local networks as "textbook examples of natural monopolies").

106 Richard A. Posner, Natural Monopoly and Its Regulation, 21 Stan. L. Rev. 548, 548 (1969); see also MCI Commc'ns Corp. v. Am. Tel. & Tel. Co., 708 F.2d 1081, 1133 (7th Cir. 1983) (explaining that Bell Systems was regarded as a natural monopoly because "it would not be economically feasible for MCI [a would-be competitor] to duplicate Bell's local distribution facilities (involving millions of miles of cable and line to individual homes and business), and regulatory authorization could not be obtained for such an uneconomical duplication").

107 47 U.S.C. § 251 (2006).

108 Matthew K. Schettenhelm, Accelerated Wireless Build-Out: Responding to DAS and "Shot Clock," 2 (Apr. 2011), http:// www.millervaneaton.com/WirelessBuildout.pdf (footnote omitted); see Gregory Tan, Note, Wading Through the Rhetoric of the Telecommunications Act of 1996: Uncertainty of Local Zoning Authority Over Wireless Telecommunications Tower Siting, 22 Vt. L. Rev. 461, 462-63 (1997) (explaining that the Telecommunications industry would have preferred to bypass local zoning authorities and that it pushed the federal government to preempt local siting authority with the Telecommunications Act of 1996).

109 FCC: Wireless Commc'n Bureau, Fact Sheet #2: National Wireless Facilities Siting Policies 4 (1996), available at http:// wireless.fcc.gov/siting/preconstruction.html.

110 The FCC encourages licensed providers to conduct research before applying for tower siting so that they may "target . . . site locations that are compatible with the proposed use, such as industrial zones, utility rights of way and pre-existing structures." Id. at 7.

111 Steven J. Eagle, Wireless Telecommunications, Infrastructure Security, and the NIMBY Problem, 54 Cath. U. L. Rev. 445, 466 (2005). In a somewhat ironic move, Congress entitled the relevant provision that partially preempted state siting authorities as "Preservation of Local Zoning Authority." 47 U.S.C. § 332(c)(7) (2006).

112 47 U.S.C. § 332(c)(7)(B)(i)(I) (2006).

113 47 U.S.C. § 332(c)(7)(B)(i)(II) (2006). “The heart of the House-Senate compromise [regarding whether FCC had total authority over tower siting], embodied in Section 704, is that states and localities can regulate the placement of wireless towers but cannot prohibit them.” Eagle, supra note 111, at 466.

114 47 U.S.C. § 332(c)(7)(B)(iv)(2006); Matthew N. McClure, Comment, Working Through the Static: Is There Anything Left to Local Control in the Siting of Cellular and PCS Towers After the Telecommunications Act of 1996?, 44 Vill. L. Rev. 781, 788 (1999).

115 Matthew K. Schettenhelm, Accelerated Wireless Build-Out: Responding to DAS and “Shot Clock,” 8 (Apr. 2011), http:// www.millervaneaton.com/WirelessBuildout.pdf (citing NextG Networks of Cal., Inc. v. City of Newport Beach, No. SACV 10-1286, 2011 WL 717388, (C.D. Cal. Feb. 18, 2011)); see infra note 223.

116 See Sara A. Evans, Note, Wireless Service Providers v. Zoning Commissions: Preservation of State and Local Zoning Authority Under the Telecommunications Act of 1996, 32 Ga. L. Rev. 965, 974 n.39 (1998) (observing that “[i]n 1981 the Federal Communications Commission [FCC] made its first invitation to telephone service providers to apply for licenses to provide cellular services in 306 metropolitan service areas and 428 rural areas” (internal quotation marks omitted)). “New innovations in cellular technology have led to the development of digital phones and combined handset technology called Personal Communications Services (PCS).” Id.

117 Daniel A. Lyons, Technology Convergence and Federalism: Who Should Decide the Future of Telecommunications Regulation?, 43 U. Mich. J.L. Reform, 383, 389 (2010).

118 McLaughlin, supra note 104, at 2221.

119 U.S. Wireless Quick Facts, CTIA, http:// www.ctia.org/advocacy/research/index.cfm/aid/10323 (last visited May 27, 2012).

120 David S. Law & Mila Versteeg, The Evolution and Ideology of Global Constitutionalism, 99 Calif. L. Rev. 1163, 1183 (2011) (an economic description of a market good that increases in value as the size of the network increases).

121 Id.

122 See Eagle, supra note 111, at 461 (noting that the TCA is “an omnibus overhaul of the federal regulation of communications companies, intended ‘to provide for a pro-competitive, deregulatory national policy framework designed to accelerate rapidly private sector deployment of advanced telecommunications and information technologies and services . . . by opening all telecommunications markets to competition”’ (quoting Sprint Spectrum, L.P. v. Willoth, 176 F.3d 630, 637 (2d Cir. 1999))); see also David W. Hughes, When NIMBYs Attack: The Heights to Which Communities Will Climb to Prevent the Siting of Wireless Towers, 23 J. Corp. L. 469, 476-77 (1998) (discussing exceptions in the Communications Act which limit local government authority). Evolving perceptions on monopolies contributed largely to states' loss of regulatory control over the industry.

123 McLaughlin, supra note 104, at 2221.

124 Lyons, supra note 117, at 389.

125 See McLaughlin, supra note 104, at 2221 (noting that “[t]hirty years of antitrust inquiries and litigation against AT&T culminated in a 1982 consent decree known as the Modification of Final Judgment (MFJ)”).

126 See id. at 2214 (“A large body of case law has developed as courts have attempted to specify the limits of federal and state power. Most disputes have been sparked by the problem noted in Louisiana PSC, namely, that the same physical equipment is used for both intrastate and interstate communications.”).

127 142 Cong. Rec. S686 (daily ed. Feb. 1, 1996) (Telecommunications Act of 1996 Conference Report).

128 Tan, supra note 108, at 466.

129 Peter M. Degnan et al., The Telecommunications Act of 1996: § 704 of the Act and Protections Afforded the Telecommunications Provider in the Facilities Siting Context, 3 Mich. Telecomm. & Tech. L. Rev. 1, 2 (1997) (noting that "this wireless telecommunications revolution has encountered significant resistance at the grassroots level . . . [leading to] a 'not in my backyard' attitude towards the infrastructural requirements associated with cellular telephone service").

130 See supra Part III.C.

131 Tara Benedetti, Running Roughshod? Extending Federal Siting Authority over Interstate Electric Transmission Lines, 47 Harv. J. Legis. 253, 253 (2010) ("While states have historically controlled the siting of interstate electric transmission lines, many federal legislators and regulators believe stronger federal authority over siting is necessary." (footnote omitted)); see also Piedmont Envtl. Council v. FERC, 558 F.3d 304, 310 (4th Cir. 2009) ("The states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities.").

132 Federal Power Act, 16 U.S.C. § 824(b)(1) (2006); see Sovacool, supra note 49, at 446.

133 Federal Power Act, 16 U.S.C. § 824(b)(1) (2006); see Sovacool, supra note 49, at 446 ("The Federal Power Act of 1935 gave the Federal Power Commission . . . jurisdiction over the interstate sale and transmission of electricity at the wholesale level, but left explicit jurisdiction of electricity transmission and sale at the retail level, creating separate roles for each level of government."). State public utility commissions generally issue the requisite certificate of need and site permit with route approvals, and address the proper allocation of costs of the new lines amongst ratepayers. See, e.g., Press Release, Great River Energy, CapX2020 Granted Certificate of Need for 345-kilovolt Projects in Minnesota (Apr. 16, 2009), available at http://www.reuters.com/article/2009/04/16/idUS206762+16-Apr-2009+BW20090416 (highlighting the Minnesota Public Utilities Commission grant of a certificate to construct electronic transmission lines in Minnesota); Press Release, Minnesota Public Utilities Commission, Minnesota Public Utilities Commission Approves Need for, and Route of, Hiawatha Transmission Lines (Jan. 12, 2012), available at http://www.puc.state.mn.us/portal/groups/public/documents/pdf_ files/013647.pdf (highlighting the Minnesota Public Utilities Commission approval of a certificate for the Hiawatha transmission lines).

134 Hoang Dang, New Power, Few New Lines: A Need for a Federal Solution, 17 J. Land Use & Envtl. L. 327, 329 (2002); see also Notice of National Transmission Grid Study 2001, 66 Fed. Reg. 47460, 47461 (Sept. 12, 2001) ("[T]he existing regime for siting and permitting of transmission facilities remains fundamentally state based. This regime may not be well adapted to reviewing proposed new transmission facilities from a regional perspective. The policy options for addressing transmission siting and permitting in a restructured electricity industry fall into three major categories: (1) Options to establish regional or federal siting institutions with authority to obtain rights-of-way for new transmission projects; (2) options to improve the existing state-based regime for transmission siting; and (3) options that could improve siting practices by government agencies and the electricity industry under any governance structure.").

135 Energy Policy Act of 2005, 16 U.S.C. § 824(a)(2) (2006).

136 Congress explicitly provided for federal authority to designate specific areas, known as national interest electric transmission corridors, as a solution to transmission congestion. Energy Policy Act of 2005, 16 U.S.C. § 824p. EPAct also grants FERC the authority to construct or modify these corridors by issuing permits and relying on the doctrine of eminent domain. See Mark A. de Figueiredo, Note, A Regulatory Framework for Investments in Electricity Transmission Infrastructure, 26 Va. Envtl. L.J. 445, 446 n.8 (2008) ("In order to issue a construction permit in a national interest corridor, FERC must find that 'a State in which the transmission facilities are to be constructed or modified does not have authority to . . . approve the siting or facilities."' (quoting 16 U.S.C. § 824p(b)(1)(A))).

137 Id.

138 See Piedmont Envtl. Council v. FERC, 558 F.3d 304, 311 (4th Cir. 2009) ("On November 16, 2006, FERC issued its final rule, which . . . interpreted the phrase to include a state's denial of a permit within the one-year statutory time frame.").

139 Id. at 309-10. The Fourth Circuit rejected FERC's interpretation, limiting their backstop authority to those cases where a state has taken no action on the siting of transmission lines and expressly rejected the idea that FERC could overrule a state's rejection of

transmission lines. Id. at 313-15. As a result, any sophisticated state could thwart federal efforts to intervene in transmission line siting decisions with a mere "no," and any attempt to increase federal involvement in the siting of transmission lines fails. Notably, there are four other ways that the federal government could exert its authority under section 216(b)(2)-(6). 16 C.F.R. § 824p(b)(2)-(6)(2006).

140 Cal. Wilderness Coal. v. U.S. Dep't of Energy, 631 F.3d 1072, 1095 (9th Cir. 2011) (vacating congestion areas on procedural grounds for a failure to properly consult with the states as required by the FPA Section 216).

141 See H.R. Rep. No. 109-215, pt. 1, at 171 (2005) (stating that "state regulatory approval delays siting of new transmission lines by many years"); S. Rep. No. 109-78, at 8 (2005) (stating that "[u]ncertainty in the marketplace about the rules and regulations that will govern generation and transmission facilities contributes to financial instability and endangers reliability of service").

142 Figueiredo, supra note 136, at 446; see also Dang, supra note 134, at 327 ("New power, few new lines. This simple statement sums up the present situation facing the electricity industry as it moves from a highly regulated, monopolistic industry towards a deregulated, competitive one.").

143 National Electric Transmission Congestion Report, 72 Fed. Reg. 56,992, 57,702-04 (Oct. 5, 2007).

144 Piedmont Envtl. Council v. FERC, 558 F.3d 304, 310 (2009) (discussing the concerns which prompted Congress to enact § 216 of the FPA).

145 H.R. Rep. No. 109-215, pt. 1, at 171 (2005); see also Carol M. Rose, Rethinking Environmental Controls: Management Strategies for Common Resources, 1991 Duke L.J. 1, 9 (1991) (discussing regulation of a resource as one way of managing congestion).

146 See S. Rep. No. 109-78, at 6 (2005) ("A combination of energy production, conservation, efficiency, and development of new technologies is the bedrock of a sound energy policy aimed at closing the supply and demand imbalance. Such a policy is necessary to ensured the country's continued growth and prosperity and to protect our national security.").

147 See, e.g., Debbie Swanstrom & Meredith M. Jolivert, DOE Transmission Corridor Designations & FERC Backstop Siting Authority: Has the Energy Policy Act of 2005 Succeeded in Stimulating the Development of New Transmission Facilities?, 30 Energy L.J. 415, 451 (2009) (explaining that the Devers PV2 project required approval from both California and Arizona).

148 Dang, supra note 134, at 339 (citations omitted).

149 In Re S. Cal. Edison Co., 2007 WL 2126365, at *1-2, *6-7 (Ariz. C.C. June 6, 2007).

150 Clean Line Energy Partners, Project Description, Centennial West Clean Line, http://www.centennialwestcleanline.com/site/page/project_ description (last visited June 23, 2012).

151 Various mechanisms exist to aid in coordination, including Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), the National Association of Regulatory Commissioners' (NARUC) affiliate groups, the North American Electric Reliability Corporation (NERC), and Interstate Compacts. Nat'l Council on Electricity Pol'y, Coordinating Interstate Electric Transmission Siting: An Introduction to the Debate 14-18 (2008); see also New England States Comm. on Electricity, Press Release: New England States Form Interstate Transmission Siting Collaborative (June 23, 2011), available at http://www.nescoe.com/uploads/Interstate_Siting_Collaborative.pdf (discussing the New England Committee on Electricity whose purpose is "to consider and to implement as appropriate means to increase coordination of states' siting processes required for interstate transmission facilities in New England").

152 See infra note 278.

153 States and localities have long controlled the source of generation within their borders, and Congress affirmed this authority in 1935 when it amended the Federal Power Act to provide the states with exclusive jurisdiction over the siting of generation. Dang, supra note 134, at 329.

154 Friedman, supra note 25, at 406.

155 See supra notes 120-21.

156 See, e.g., Clean Air Act, 42 U.S.C. § 7410(a)(2)(D)(i)(I) (2006) (noting that the "Good Neighbor Provision" gives EPA the power to cut down interstate pollution that interferes with the attainment and maintenance of the national ambient air quality standards protecting public health).

157 See Proposed Amendment to Transportation Act, 1920: Hearings Before the Committee on Interstate and Foreign Commerce of the House of Representatives on H.R. 6861 and H.R. 8131, 67th Cong., 2d Sess. 554 (1922) (statement of Howard Elliot, Chairman of Northern Pacific Railway and Member of the Executive Committee of the New York, New Haven, and Hartford Railroad) (arguing before the House of Representatives that "[t]he railroad executives as a whole . . . by force of the drift in this country toward nationalization of some of these great agencies, have practically as a unit come to the conclusion that if you are going to have a first-class, adequate transportation machine, to serve all the people of all the States, and all the United States, you have got to have somebody who is supreme in this regulatory question, and that somebody must be the Nation rather than 48 independent bodies with no head to them").

158 Nat'l Comm'n on Energy Pol'y, Siting Critical Energy Infrastructure: An Overview of Needs and Challenges 9 (2006) ("The 1992 Energy Policy Act, for example, gave FERC greater jurisdiction over energy infrastructure decisions and placed a new emphasis on interstate and regional planning approaches to identify future infrastructure needs for both natural gas pipelines and electricity transmission systems. In the past, federal agency involvement in siting projects occurred only after state and local permitting had begun, if at all. The revision of federal energy priorities to focus on interstate and regional issues, however, prompted significant shifts in jurisdiction.").

159 For instance, state railway commissioners acknowledged the need for centralized coordination. Proposed Amendment to Transportation Act, 1920, supra note 157, at 543 (statement of Mr. Howard Elliott, Chairman, Northern Pacific Railway and Member, Executive Committee of the New York, New Haven & Hartford Railroad, New York City) (testifying that a joint statement from the Interstate Commerce Commission and the National Association of Railway and Utilities Commissioners stated in part that "[t]he prime essential to [cooperation between ICC and NARUC] is realization of the nature and difficulties of the common problem . . . [and that t]he State commissions realize that the railroads form a national transportation system which is not split into parts by State lines and that the public interest demands a rate structure, State and interstate, as simple and harmonious as practicable").

160 See, e.g., Minn. Stat. § 216B.2422 (2010) (stating that Minnesota's explicit preference for renewable energy, and a non-renewable energy source may be approved only if it found that a renewable energy facility would not be in the public interest).

161 See infra notes 184-85 and accompanying text.

162 Gary D. Allison & John L. Williams, Resources for the Future: The Effects of State Laws and Regulations on the Development of Renewable Sources of Electric Energy 140-46, available at http://www.rff.org/rff/documents/rff-bck-allisonandwilliams-statelaws.pdf (describing the centralized, traditional public interest, and market approaches to the siting of generation).

163 Electric Power Industry Overview 2007, U.S. Energy Info. Admin., http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html (last visited July 1, 2012).

164 See EEI U.S. Member Company Service Territories, Edison Elec. Inst., http:// www.eei.org/whoweare/ourmembers/USElectricCompanies/Documents/EEIMemCoTerrMap.pdf (last visited Jan. 5, 2012).

165 Calls that do occur come from scholars as opposed to industry. See, e.g., Uma Outka, The Renewable Energy Footprint, 30 Stan. Envtl. L.J. 241, 257 n.73 (2011) (citing James T. Ramey & James P. Murray, Jr., Delays and Bottlenecks in the Licensing Process Affecting Utilities: The Role of Improved Procedures and Advance Planning, 1970 Duke L.J. 25, 42 (1970), A. Dan Tarlock et al., Environmental Regulation of Power Plant Siting: Existing and Proposed Institutions, 45 S. Cal. L. Rev. 502, 552 (1972)) (discussing examples of calls for federal intervention); Mason Willrich, The Energy-Environment Conflict: Siting Electric Power Facilities, 58 Va. L. Rev. 257, 334-36 (1972) (offering a conceptual framework for expediting the siting process in response to increasing demand for electricity); Gregory J. Rigano, Note, The Solution to the United States' Energy Troubles is Blowing in the Wind, 39 Hofstra L.

Rev. 201, 204 (2010) (proposing that BOEM be the lead agency with "exclusive authority to approve or deny any application for the siting, construction, expansion, or operation of an offshore wind project").

166 See, e.g., About EEI, Edison Elec. Inst., http:// www.eei.org/whoweare/abouteei/Pages/default.aspx (last visited July 1, 2012).

167 As EPA works towards more stringent controls affecting coal plants, even natural gas plants find themselves at odds with their fossil fuel competitors. See infra Part VI.B.

168 See supra notes 77-81 and accompanying text.

169 The state of Colorado, for example, has considered creating a "statewide transmission siting and permitting framework for electric transmission facilities" to combat current "inconsistent processes and requirements among local governments, unnecessary delay, increased opportunity for litigation, increased costs . . . and inconsisten[cy] with the increasingly regional nature of the modern electric industry." Dep't of Regulatory Agencies, Report of the Task Force on Statewide Transmission Siting and Permitting 3 (Dec. 1, 2011), available at http:// www.dora.state.co.us/puc/projects/TransmissionSiting/SB11-45/Report/SB11-45TF_ RptToGA_12-01-2011.pdf.

170 Swanstrom & Jolivert, supra note 147, at 418.

171 See supra note 25.

172 Lincoln L. Davies, Power Forward: The Argument for a National RPS, 42 Conn. L. Rev. 1339, 1341-42 (2010).

173 Id. at 1357.

174 Ivan Gold & Nidhi Thakar, A Survey of State Renewable Portfolio Standards: Square Pegs for Round Climate Change Holes?, 35 Wm. & Mary Envtl. L. & Pol'y Rev. 183, 189 (2010).

175 U.S. Energy Info. Admin., supra note 163, at 4, 61 tbl.1.28. The thirteen states with no RPS are Alabama, Alaska, Arkansas, Georgia, Idaho, Indiana, Kentucky, Louisiana, Mississippi, Nebraska, South Carolina, Tennessee, and Wyoming. Id.

176 Id. at 35-36 tbl. 1.15; U.S. Energy Info. Admin., Renewable Energy Annual 2009 45 tbl. 1. 20 (Jan. 2012), available at http:// www.eia.gov/electricity/annual/archive/03482009.pdf.

177 Federal involvement could also alleviate potential Dormant Commerce Clause vulnerabilities associated with an RPS that favors in-state generation. See Complaint at 27-29 North Dakota v. Swanson, No. 0:11-CV-3232, (D. Minn. 2011) (alleging a similar theory with respect to carbon reduction requirements contained in Minnesota's Next Generation Energy Act).

178 Sovacool, supra note 49, at 403-04 (explaining that decentralization facilitates interstate spillovers, provides a lack of uniformity for industry, provides no economies of scale, and promotes a race to the bottom between states).

179 See supra note 109.

180 See Eagle, supra note 111, at 447-48, 461-62 (describing the rapid increase in demand for wireless communication technology and noting that the Telecommunications Act of 1996 was "'designed to accelerate rapidly private sector deployment of advanced telecommunications and information technologies and services"' (quoting Sprint Spectrum, L.P. v. Willoth, 176 F.3d 630, 637 (2d Cir. 1999))).

181 See supra note 129 and accompanying text.

182 See supra note 143 and accompanying text.

183 Mark D. Mutschink, Facing the Future of Oil in U.S. Courts: A Recommendation for Changing the Bremen Doctrine on Enforceability of Forum Selection Clauses, 63 SMU L. Rev. 1343, 1345 (2010).

184 66 Pa. Cons. Stat. § 519 (2000).

185 W. Va. Code § 5D-1-2 (West 2011).

186 Va. Code § 56-580 (West 2012).

187 The Virginia Corporation Commission rejected Appalachian Power's application for a $2.2 billion dollar Integrated Gasification Combined Cycle "clean coal" plant. Appalachian Power Co., 264 P.U.R. 4th 308, 2008 WL 1822541 (Va. S.C.C. Apr. 14, 2008).

188 "Land owners and wind rights holders filed suit, and in 2009 the Kansas Supreme Court upheld the county zoning ordinance, finding that the board's decision to prohibit commercial wind was within its legislative discretion, and that it was reasonably supported by the record. The court noted that a total ban might be 'unwise' but was not illegal." Envtl L. Inst., State Enabling Legislation for Commercial-Scale Wind Power Siting and the Local Government Role 7 (2011), available at http://www.elistore.org/reports_detail.asp?ID=11410.

189 North Carolina law that provides that city and county ordinances may prohibit the installation of solar energy collectors that that are visible from the ground and installed:

(1) On the facade of a structure that faces areas open to common or public access; (2) On a roof surface that slopes downward toward the same areas open to common or public access that the facade of the structure faces; or (3) Within the area set off by a line running across the facade of the structure extending to the property boundaries on either side of the facade, and those areas of common or public access faced by the structure.

Gen. Assemb. N.C. 1387, 2009., Reg. Sess. (N.C. 2009); see also Hannah Wiseman, Expanding Regional Renewable Governance, 35 Harv. Envtl. L. Rev. 477, 508 (2011).

190 See Ashira Pelman Ostrow, Process Preemption in Federal Siting Regimes, 48 Harv. J. on Legis. 289, 292-93 (2011) (noting that by placing constraints on local siting decisions, the Telecommunications Act of 1996 has succeeded in dramatically increasing the number of cell towers).

191 See Patricia E. Salkin & Ashira Pelman Ostrow, Cooperative Federalism and Wind: A New Framework for Achieving Sustainability, 37 Hofstra L. Rev. 1049, 1051-52 (2009) (arguing for federal constraints on state siting processes that restrict wind development).

192 The Federalist No. 45, at 263 (James Madison) (ABA ed., 2009).

193 Ely, supra note 63 at 965-67 (noting that "calls for federal control of the rail industry steadily mounted after the Civil War").

194 See supra notes 73-76 and accompanying text.

195 See James A. Fay, Spills and Fires from LNG and Oil Tankers in Boston Harbor, Green Futures (Aug. 26, 2003), http://www.greenfutures.org/projects/LNG/Fay.html (showing that accident to an LNG tanker in Boston Harbor could cause almost instantaneous fires that would be beyond the capabilities of any existing firefighting technique and would bring catastrophic damage).

196 See supra note 87.

197 The Federalist No. 45, at 259 (James Madison) (ABA ed., 2009) ("[T] he public good . . . is the supreme object to be pursued.").

198 S. Rep. No. 109-78, at 6 (2005).

199 H.R. Rep. No. 109-215, pt. 1, at 171 (2005).

200 Id.; S. Rep. No. 109-78, at 8 (2005).

201 16 U.S.C. § 824a(c) (providing that if FERC determines that there is an emergency in wartime or because of a shortage of facilities for the generation of electric energy, it has the authority "to require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest").

202 See infra notes 282-84 and accompanying text; Richard B. Alley et al., Climate Change 2007: The Physical Science Basis 5, 7 (2007) ("[W]arming of the climate system is unequivocal, as is now evident from observations of increases in global average air

and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level. . . . At continental, regional, and ocean basin scales, numerous long-term changes in climate have been observed. These include changes in Arctic temperatures and ice, widespread changes in precipitation amounts, ocean salinity, wind patterns and aspects of extreme weather including droughts, heavy precipitation, heat waves and the intensity of tropical cyclones." (footnote omitted)); Massachusetts v. EPA, 549 U.S. 497, 507 (2007) (acknowledging climate change disruption). Although oil is not a primary resource for electricity, similar danger exists with respect to oil. See CNA, Powering America's Defense: Energy and the Risks to National Security vii (2009) (identifying the risks to national security created by America's energy policies and practices, including how "U.S. dependence on oil weakens international leverage, undermines foreign policy objectives, and entangles America with unstable or hostile regimes," and how "overreliance on oil burdens the military [and] undermines combat effectiveness"). Further, some of the revenue made through U.S. purchases of petroleum is used to fund terrorism activities aimed to disrupt U.S. interests. Id. at 4.

203 One of the first incidents to raise awareness of the need for federal control over air pollution was a disaster in the small town of Donora, Pennsylvania. In 1948, a zinc mill released a plume of noxious smoke that killed twenty residents. Devra Lee Davis & Carrie Forrester, Past and Present Environmental Health Challenges in Southwestern Pennsylvania: Some Comments on the Right to a Clean Environment, 30 Am. J.L. & Med. 305, 309, 312 (2004). By 1955, Congress passed the Air Pollution Control Act to gather information on "the causes and effects of air pollution." Id. at 316. Twelve years later, Congress passed the Federal Air Quality Act and the Clean Air Act in 1970. Id. at 317. Today, a plaque memorializing the tragedy states: "[m] ajor Federal clean air laws became a legacy of this environmental disaster that focused national attention on air pollution." Id. at 316.

204 The Santa Barbara oil spill occurred in 1969 and is widely credited as the impetus for passage of major federal environmental legislation including the National Environmental Policy Act. Keith C. Clarke & Jeffrey J. Hemphill, The Santa Barbara Oil Spill: A Retrospective, 64 Y.B. of the Ass'n of Pac. Coast Geographers 157, 157-62 (Darrick Dana ed., Univ. of Haw. Press 2002). Described by President Nixon as a disaster that "frankly touched the conscience of the American people," the federal government admitted that it "had largely ignored the need to protect commercial, recreational, aesthetic, and ecological values of the area." California v. Norton, 311 F.3d 1162, 1166-67 (9th Cir. 2002) (quoting Clarke & Hemphill, supra at 160).

205 States retain authority over coal ash waste, a byproduct of the coal production process. In 2008, the Tennessee Valley Authority's Kingston Fossil Plant released 5.4 million cubic yards of toxic coal sludge onto 300 acres of surrounding land, an environmental disaster that many thought was sure to prompt federal regulation of the residue. Matthew Pearl, The Aftermath of the December 2008 Incident in East Tennessee Illuminates the Inadequate Regulation of Coal Ash Impoundments, 16 U. Balt. J. Envtl. L. 195, 195-96 (2009). But four years later, the federal government has yet to finalize its draft rule. Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35128 (proposed June 21, 2010) (to be codified at 40 C.F.R. pt. 257, 261, 264, 265, 268, 271, 302).

206 Included in this list would be theories that "lower levels of government serving smaller numbers of constituents have a comparative advantage in delivery of labor-intensive services, while higher-level governments with greater capital resources have a comparative advantage in delivering capital-intensive services where there are significant economies of scale," Hills, supra note 52, at 869, that the level of authority should match the level of the harm, Henry N. Butler & Jonathan R. Macey, Externalities and the Matching Principle: The Case for Reallocating Environmental Regulatory Authority, 14 Yale L. & Pol'y Rev. 23, 25 (1996) (advocating that the level of environmental regulation should be matched to the level of environmental pollution and that local concerns should be resolved locally), and that state failures drive a **tip** towards federal control, see Percival, supra note 43, at 1144 ("Like civil rights law, environmental law became federalized only after a long history of state failure to protect what had come to be viewed as nationally important interests."). But see Jonathan H. Adler, The Fable of Federal Environmental Regulation: Reconsidering the Federal Role in Environmental Protection, 55 Case W. Res. L. Rev. 93, 101-02 (2004) (rejecting the theory that states failed to protect environmental quality, and instead suggesting four alternative factors that played a role in the centralization of environmental law: (1) increased environmental consciousness after World War II; (2) the nationalization of American politics; (3) the delegitimization of states' rights during the civil rights era; and (4) rent-seeking on the part of regulated entities).

207 See, e.g., Gregory v. Ashcroft, 501 U.S. 452, 458 (1991) (noting that federalism "increases opportunity for citizen involvement in democratic processes; it allows for more innovation and experimentation in government; and it makes government more responsive by putting the States in competition for a mobile citizenry").

208 See Friedman, supra note 25, at 389-405; John O. McGinnis, Laws for Learning in an Age of Acceleration, 53 Wm. & Mary L. Rev. 305, 307-08, 337-38 (2011) (arguing that decentralization will have benefits for "social learning" because states can experiment with different policies, citing as examples federal frameworks which allow states to come up with their own methods of achieving federal goals, including with healthcare through the Patient Protection and Affordable Care Act and education through the Race to the Top Program); see also United States v. Lopez, 514 U.S. 549, 581 (1995) (Kennedy, J., concurring) (noting that "the theory and utility of our federalism are revealed" with guns in school zones, for the states may perform their role as laboratories for experimentation to devise various solutions where the best solution is far from clear); FERC v. Mississippi, 456 U.S. 742, 787-90 (1982) (O'Connor, J., concurring in part and dissenting in part) ("[T]he Court's decision undermines the most valuable aspects of our federalism. Courts and commentators frequently have recognized that the [fifty] States serve as laboratories for the development of new social, economic, and political ideas . . . . [F]ederalism [also] enhances the opportunity of all citizens to participate in representative government . . . . Finally, our federal system provides a salutary check on governmental power.").

209 Glicksman & Levy, supra note 24, at 600.

210 See, e.g., Percival, supra note 43, at 1172 (**pointing** to transboundary pollution, guarantees of minimum standards, economies of scale, and industry preference, for uniform regulations as reasons for the federalization of environmental regulation); Richard B. Stewart, Pyramids of Sacrifice? Problems of Federalism in Mandating State Implementation of National Environmental Policy, 86 Yale L.J. 1196, 1211-19 (1977) (explaining why centralization of environmental legislation is necessary in order to: (1) address the tragedy of the commons and realize national economies of scale; (2) mitigate the disparities in effective political representation; (3) correct market failures arising from pollution externalities; and (4) best take advantage of the public opinion that environmental regulation is the pursuit of "moral ideals" and assure that the sacrifices are shared).

211 See, e.g., Joseph Forderer, State Sponsored Global Warming Litigation: Federalism Properly Utilized or Abused?, 18 Mo. Envtl. L. & Pol'y Rev. 23, 62-63 (2010) (applying the federalism values to the Supreme Court's opinion in Connecticut v. AEP to assess its furtherance of federalism).

212 See, e.g., Sheryll D. Cashin, Federalism, Welfare Reform, and the Minority Poor: Accounting for the Tyranny of State Majorities, 99 Colum. L. Rev. 552, 621 (1999) (arguing against the complete decentralization of welfare reform and advocating for an increased federal role in the form of national standards).

213 See, e.g., Dang, supra note 134, at 328-29 (arguing that the Federal Power Act should be amended to give FERC the power to grant transmission siting approval and to mandate construction and expansion of the transmission grid); Richard J. Pierce, Jr., Environmental Regulation, Energy, and Market Entry, 15 Duke Envtl. L. & Pol'y F. 167, 183 (2005) (arguing for an increased federal role, perhaps by a federal agency or federal courts with authority to override the decisions of state and local governments in certain decisions regarding siting); John Noor, Note, Herding Cats: What To Do When States Get in the Way of National Energy Policy, 11 N.C. J.L. & Tech. 145, 175 (2009) (arguing that FERC should be granted siting authority for transmission projects involving renewable energy). But see James A. Holtkamp & Mark A. Davidson, Transmission Siting in the Western United States: Getting Green Electrons to Market, 46 Idaho L. Rev. 379, 387 (2010) (arguing for a regional transmission siting process instead of a federal preemption of state siting requirements); Jim Rossi, The Trojan Horse of Electric Power Transmission Line Siting Authority, 39 Envtl. L. 1015, 1041-43 (2009) (arguing that expanding federal authority to transmission siting could "crowd out" conservation and efficiency at the state level and provide a means to transmit more power from dirty fuel sources).

214 See, e.g., William L. Cary, Federalism and Corporate Law: Reflections Upon Delaware, 83 Yale L.J. 663, 663-64 (1974) (explaining the risk of a race-to-the-bottom effect under state control of corporate law and proposing a unifying, federal regime).

215 Robert M. Ackerman, Tort Law and Federalism: Whatever Happened to Devolution?, 14 Yale L. & Pol'y Rev. 429, 432 (1996) (providing a "basis for federal intervention in tort law, resting upon sound constitutional theory and public policy").

216 See, e.g., Danielle F. Waterfield, Note, Insurers Jump on Train for Federal Insurance Regulation: Is It Really What They Want or Need?, 9 Conn. Ins. L.J. 283, 286 (2002) (noting the traditional state regulation of the insurance industry, followed by calls for federal intervention).

217 See, e.g., Moncrieff, supra note 17, at 846-50 (arguing for federalization of medical malpractice to correct spillover effects resulting from federal spending on healthcare and that the need for administrative efficiency and correction of interstate externalities trumps arguments for state authority such as the traditional role of states in medical malpractice and the fact that medical malpractice is primarily a matter of local concern).

218 See, e.g., Keith Cunningham-Parmeter, Forced Federalism: States as Laboratories of Immigration Reform, 62 Hastings L.J. 1673, 1673-76 (2011) (asserting that arguments for decentralization of immigration policy based on states acting as laboratories for experimentation are flawed because states do not internalize the costs of these laws or yield replicable results).

219 J. Mitchell Pickerill & Paul Chen, Medical Marijuana Policy and the Virtues of Federalism, 38 Publius 22, 24 (2008) (concluding that the federal government should not assert preemptive jurisdiction over medical marijuana policy based on three "classic virtues" of federalism which support state authority: policy experimentation and innovation, diversity of policy preferences, and protection and enhancement of individual rights and liberties).

220 See Sovacool, supra note 49, at 429-30 ("[T]he case for devolution of environmental policy often rests on a set of four interconnected assumptions: (i) that decentralization induces experimentation and innovation; (ii) devolution provides more flexibility in responding to environmental problems; (iii) decentralization improves accountability and equity; and (iv) states will engage in welfare-enhancing competition to craft better environmental policies.").

221 Other decentralized virtues, like the ability to enhance public participation, are unlikely to be threatened by many forms of increased federal control. Public participation may be minimal in any but the most controversial of PUC hearings. See, e.g., Jeremy C. Ruark, PUC Taking Public Comments over PacificCorp Rate Hike Proposal, Seaside Signal, Aug. 22, 2012, available at http://www.seasidesignal.com/news/article_9307aa70-ebdf-11e1-a185-0019bb2963f4.html ("[D]ue to extremely low attendance the PUC phased out public hearings involving this type of rate case . . . . Instead, the Commission is using public comment boxes on the PUC website linked to the rate cases so customers can weigh in when it is most convenient to them."); see also PUC Aug. 21st Public Forum on Smart Meter Issues-Recap, Ban Tex. Smart meters (Oct. 6, 2012), http://www.bantexassmartmeters.com (discussing the unexpectedly low attendance at a public forum of a contentious issue). Even if local citizens can better participate in the siting process through hearings that take place locally as opposed to in a centralized hearing in Washington, D.C., there are ways to structure increased federal control in a way that still places the day-to-day hearings and ability of citizens to participate locally with the state PUCs.

222 Sovacool, supra note 49, at 431.

223 See, e.g., VoiceStream Minneapolis, Inc. v. St. Croix Cnty., 342 F.3d 818, 824 (7th Cir. 2003) (describing letters objecting to a "proposed tower because of aesthetic considerations [and] a petition from twelve residents living near the . . . site opposing the tower for aesthetic and other reasons"); Sw. Bell Mobile Sys., Inc. v. Todd, 244 F.3d 51, 61 (1st Cir. 2001) ("Few people would argue that telecommunication towers are aesthetically pleasing. Some of the disapproving comments in the cases about generalized aesthetic concerns refer to negative comments that are applicable to any tower, regardless of location.").

224 Mary Ann O'Toole Holley, 'Stealth' Tower Not So Stealthy, Newsmagazine Network, Jan. 13, 2011, http://www.newsmagazinenetwork.com/201101131471/stealth-tower-not-so-stealthy.

225 Overland Park, Kan., Municipal Code § 18.395.070 (2009).

226 If anything, the federal jurisdiction over siting of such infrastructure has ensured even more uniformity in type. The FCC, for example, has standardized radio frequency emissions such that telecommunications towers are not distinguished on this basis and the TCA stipulates that local governments may not base regulation of the wireless industry on health concerns. Laurie Dichiara, Wireless Communication Facilities: Siting for Sore Eyes, 6 Buff. Envtl. L.J. 1, 14 (1998). And the FCC has recently addressed concerns over tower height and migratory bird populations by requiring that proposed towers over 450 feet tall conduct an environmental assessment. 47 C.F.R. § 1.1307 (2012).

227 In 2002, the U.S. Fish and Wildlife Service estimated 33,000 bird deaths annually from collisions with wind turbines. U.S. Fish & Wildlife Service, Migratory Bird Mortality 2 (2002), available at www.fws.gov/birds/mortality-fact-sheet.pdf. Since then, that

estimate has increased to 440,000. See Umair Irfan, Bats and Birds Face Serious Threats from Growth of Wind Energy, N.Y. Times, Aug. 8, 2011, http:// www.nytimes.com/cwire/2011/08/08/08climatewire-bats-and-birds-face-serious-threats-from-gro-10511.html?ref=earth.

228 New York City, for example, opposed natural gas drilling in the Marcellus Shale for years because of the likelihood that the increased industrial activity in the watershed and road construction will contaminate the unfiltered water supply of its eight million residents. N.Y.C. Dep't of Envtl. Prot., Comments on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program 1, 3 (Jan. 11, 2012), available at http://www.nyc.gov/html/dep/pdf/natural_gas_ drilling/nycdep_comments_on_rdsgeis_for_hvhf_20120111.pdf.

229 See Andrew Ratzkin, When the Wind Don't Blow, When the Sun Don't Shine: The Risks of Intermittency, 41 Trends, Sept./Oct. 2009, at 1, 12 (describing the risks associated with intermittent renewable sources, including their inability to be increased or decreased as demand dictates).

230 See, e.g., U.S. N.R.C., Recommendations for Enhancing Reactor Safety in the 21st Century: The Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident 1 (2011) (describing the Fukushima accident and the need for new regulations to better protect public health and safety).

231 See, e.g., U.S. Dep't of Energy, Hawaii: Incentives/Policies for Renewables & Efficiency, DSIRE Database of State Incentives for Renewables & Efficiency, available at http://www.dsireusa.org/incentives/incentive.cfm? Incentive_Code=HI06R&re=1&ee=1 (showing that renewable portfolio standards vary between ten percent (Wisconsin) and forty percent (Hawaii) in the percentage of renewables required, the timeframes for compliance, and what type of power qualifies as "renewable").

232 See supra notes 160-61; Allison & Williams, supra note 162, at 140-46.

233 Sovacool, supra note 49, at 436-37.

234 Power Comm'n v. E. Ohio Gas Co., 338 U.S. 464, 489 (1950) (Jackson, J., dissenting).

235 Davies, supra note 172, at 1341; State Funding Resources and Renewable Portfolio Standards, EPA (last updated Oct. 2, 2012), http://www.epa.gov/lmop/publications-tools/funding-guide/state-resources/index.html.

236 Although this may, in part, explain the rising popularity of cooperative federalism, advocates of cooperative federalism often fall short of providing details about how such shared authority should function. See, e.g., Reza Dibadj, From Incongruity to Cooperative Federalism, 40 U.S.F. L. Rev. 845, 865-73 (2006) (arguing for a cooperative federalism framework to govern corporation-shareholder relationships that envisions the federal government setting "minimal shareholder protections" and then leaves the issue of details to the states based on certain priorities, such as fighting fraud).

237 Friedman, supra note 25, at 319.

238 See infra notes 242-43 (describing West Virginia's extreme reliance on coal despite studies that demonstrate it is a net cost to the state); see also Sabrina Tavernise, As Gas Drilling Spreads, Towns Stand Ground over Control, N.Y. Times, Dec. 14, 2011, at A20 (highlighting the debate between local and state governments over the regulation of fracking shale deposits to access natural gas).

239 See Friedman, supra note 25, at 409; see also, Marion W. Benfield, Jr., Wasted Days and Wasted Nights: Why the Land Acts Failed, 20 Nova L. Rev. 1037, 1040 (1996) (stating that in 1896, every state adopted the Uniform Negotiable Instruments law, developed by the National Conference of Commissioners on Uniform State Laws); Norman Silber, Why the U.C.C. Should Not Subordinate Itself to Federal Authority: Imperfect Uniformity, Improper Delegation and Revised Section 3-102(c), 55 U. Pitt. L. Rev. 441, 456 (1994) (stating that states also achieved a "rough" uniformity under the Uniform Commercial Code (UCC) by each adopting its own version, subject to continuing state legislative modification and judicial interpretation). But see Robert H. Bork & Daniel E. Troy, Locating the Boundaries: The Scope of Congress's Power to Regulate Commerce, 25 Harv. J.L. & Pub. Pol'y 849, 886 (2002) (arguing state tort law allows a single state to set national standards in violation of the commerce clause).

240 David J. Barron, A Localist Critique of the New Federalism, 51 Duke L.J. 377, 381 (2001). Barron argues that "a single-minded desire to protect local autonomy by limiting central power actually may do little to promote the values normally associated with local autonomy." Id. at 379.

241 See Daniel J. Weiss et al., Dirty Deeds Done Dirt Cheap, Ctr for Am. Progress (Feb. 6, 2012), http:// www.americanprogress.org/issues/2012/02/csapr_contributions.html/print.html (stating that sixteen states are suing to halt implementation of the EPA's interstate air pollution rule that seeks to protect downwind states from upwind emitters and that those sixteen states are responsible for more than ninety percent of the nation's total sulfur dioxide and nitrogen oxide air pollution from power plants that these laws are trying to reduce).

242 Where Does Your Electricity Come From?: West Virginia, America'sPower.org, http://www.cleancoalusa.org/abundant/where-does-your-electricity-come (last visited Feb. 24, 2012).

243 Rory McIlmoil et al., Coal and Renewables in Central Appalachia: The Impact of Coal on the West Virginia State Budget x-xiv (2010), available at http://www.downstreamstrategies.com/documents/reports_ publication/DownstreamStrategies-coalWV.pdf); Mountain Ass'n for Cmty. Econ. Dev., The Impact of Coal on the Kentucky State Budget 1, 2 (2009), available at http://www.maced.org/coal/exe-summary.htm.

244 See Solid Waste Agency of N. Cook Cnty. v. U.S. Army Corps of Eng'rs, 531 U.S. 159, 173-74 (2001) (expressing concern that expanding federal jurisdiction over ponds and mudflats under Migratory Bird Rule would impinge significantly on traditional state power over land and water use); William W. Buzbee, Asymmetrical Regulation: Risk, Preemption, and the Floor/Ceiling Distinction, 82 N.Y.U. L. Rev. 1547, 1560 (2007) (stating that state and local governments traditionally regulate land use).

245 Ashira Pelman Ostrow, Land Law Federalism, 61 Emory L.J. 1397, 1400; Uma Outka, supra note 165, at 309 (arguing that federalism norms about local control over land use are too entrenched to offer much hope for structural reform).

246 Buzbee, supra note 244, at 1560.

247 James G. Hodge, Jr., The Role of New Federalism and Public Health Law, 12 J.L. & Health 309, 336 (1998).

248 Ernest A. Young, The Rehnquist Court's Two Federalisms, 83 Tex. L. Rev. 1, 106 (2004).

249 Id.

250 Hodge, supra note 247, at 336.

251 Id. at 338.

252 See Jonathan H. Adler, Judicial Federalism and the Future of Federal Environmental Regulation, 90 Iowa L. Rev. 377, 405 (2005) (noting that, "[t]hus far, federal appellate courts have uniformly rejected Commerce Clause challenges to the scope of federal environmental regulation").

253 Id.

254 Ostrow, supra note 190, at 295-96 (citing the Supreme Court's landmark decision in Village of Euclid v. Ambler Realty Co., 272 U.S. 365, 386-87 (1926), which led to states and local governments to regulate the fields of zoning and land use and upheld local zoning practices in recognition of rapid development of urban populations and the need to regulate land use to accommodate competing interests). When Congress was in the process of passing the Transportation Act of 1920 to **tip** towards federal control over railroads, New York Governor Smith voiced vehement opposition to the bill as a violation of states' rights. Says Railroad Bills Violate State Rights, N.Y. Times, Jan. 27, 1920, at 34. In the electricity generation context, Professor Outka has analyzed some of the early power plant siting statutes, noting the siting decisions were in the hands of local governments. See Outka, supra note 165, at 309. When the EPAct of 2005 was proposed, those opposed to it claimed that the power to site LNG terminals was within the traditional authority of states to determine land use patterns and ensure citizen safety. Scott A. Zimmermann, Comment, Feds and Fossils: Meaningful State Participation in the Development of Liquefied Natural Gas, 33 Ecology L.Q. 789, 791-92 (2006).

255 Anthony J. Bellia, Jr., Federalism 214 (2010) ("Political factors often dictate wholesale federal legislative reliance on state regulation and implementation."). Some suggest that FERC's moves towards federal control over the siting of transmission lines is driven by former FERC Commissioner Kelliher's new position working for NextEra Energy, a company that needs more transmission lines to bring its power to market. See FERC's Transmission Siting Federalism Coup, StopPATH WV Blog (Aug. 27, 2011), http://www.stoppathwv.com/1/post/2011/08/fercs-transmission-siting-federalism-coup.html.

256 Daniel J. Gifford, Federalism, Efficiency, the Commerce Clause, and the Sherman Act: Why We Should Follow a Consistent Free-Market Policy, 44 Emory L.J. 1227, 1260 (1995).

257 Jonathan R. Macey, Federal Deference to Local Regulators and the Economic Theory of Regulation: Toward a Public-Choice Explanation of Federalism, 76 Va. L. Rev. 265, 267 (1990).

258 See, e.g., D. Daniel Sokol, Explaining the Importance of Public Choice for Law, 109 Mich. L. Rev. 1029, 1031 (2011) (reviewing Maxwell L. Stearns & Todd J. Zywicki, Public Choice Concepts and Applications in Law (2009)) (observing that more than sixty years after its initial use by Duncan Black and Kenneth Arrow circa 1950, "legal academics oftentimes do not understand public choice and hold a caricatured view of what it embraces").

259 Jim Rossi, Public Choice Theory and the Fragmented Web of the Contemporary Administrative State, 96 Mich. L. Rev. 1746, 1752 (1998) (citations omitted) (reviewing Jerry L. Mashaw, Greed, Chaos, & Governance: Using Public Choice to Improve Public Law (1997)).

260 Id.

261 Samuel Issacharoff & Richard H. Pildes, Politics as Markets: Partisan Lockups of the Democratic Process, 50 Stan. L. Rev. 643, 650 (1998).

262 William F. Shughart II, Public Choice, The Concise Encyclopedia of Economics, http://www.econlib.org/library/Enc/PublicChoice.html (last visited Feb. 13, 2012).

263 E.g., Richard A. Posner, On Theory and Practice: Reply to "Richard Posner's Praxis", 49 Ohio St. L.J. 1077, 1078 (1989) (defending his views on a wealth maximizing society).

264 Edward L. Rubin, Public Choice in Practice and Theory, 81 Cal. L. Rev. 1657, 1658-59 (1993) (reviewing Daniel A. Farber & Philip P. Frickey, Law and Public Choice (1991) ("Farber and Frickey affirm the behavioral assumptions of the public choice vision, rejecting the romantic notion often proposed by civil republicans that both voters and legislators are, or can be, motivated by public spirit rather than self-interest, and that they can effectuate their desires through rational discourse rather than strategic, self-maximizing behavior.").

265 See, e.g., Richard H. Pildes & Elizabeth S. Anderson, Slinging Arrows at Democracy: Social Choice Theory, Value Pluralism, and Democratic Politics, 90 Colum. L. Rev. 2121, 2142 (1990) ("Rationality must be understood to be a matter of interpretation and evaluation, not merely of aggregation and calculation.").

266 Samuel Issacharoff & Laura Miller, Democracy and Electoral Processes 14 (N.Y.U. School of Law Pub. Law & Legal Theory Research Paper Series, Working Paper No. 09-16, 2010), available at http:// papers.ssrn.com/sol3/papers.cfm?abstract_id=1366503 ("[P]ublic choice models generally abstract the party into a single entity with well-behaved policy preferences.").

267 Mark Kelman, On Democracy-Bashing: A Skeptical Look at the Theoretical and "Empirical" Practice of the Public Choice Movement, 74 Va. L. Rev. 199, 223 (1988) (describing the standard public choice model as one which is grounded in the idea that voter and official behavior is motivated by maximizing their own wealth).

268 See, e.g., id. ("[T]he true claim of most public choice theorists is not just that . . . financial selfishness exists, it is that no other motivation does. This claim is simply groundless.").

269 See, e.g., Russell B. Korobkin & Thomas S. Ulen, Law and Behavioral Science: Removing the Rationality Assumption from Law and Economics, 88 Calif. L. Rev. 1051, 1055-57 (2000) (arguing that rational choice theory, similar to public theory but applied to individuals rather than public officials, does not deal with the nuances of human motivations).

270 Paul S. Weiland, Federal and State Preemption of Environmental Law: A Critical Analysis, 24 Harv. Envtl. L. Rev. 237, 244 (2000) (citation omitted) (internal quotation marks omitted).

271 See id. at 244 (arguing that the National Environmental Policy Act was not the result of special interest lobbying but widespread public support).

272 Id. But see Adler, supra note 33, at 72 (attributing the passage of environmental law to "'strong public demand, coupled with exploitation of that demand by ideological and credit-seeking politicians"' (quoting Daniel A. Farber, Politics and Procedure in Environmental Law, 8 J.L. Econ. & Org. 59, 61 (1992))).

273 Adler, supra note 33, at 98-99.

274 David A. Skeel, Jr., Public Choice and the Future of Public-Choice-Influenced Legal Scholarship, 50 Vand. L. Rev. 647, 669 (1997) (reviewing Maxwell Stearns, Public Choice and Public Law: Readings and Commentary (1997)).

275 Sokol, supra note 258, at 1040 (citation omitted).

276 Proper functioning in this instance refers to a balance of power that furthers the values of our federalism system.

277 See, e.g., Facilitating Access to Federal Property for the Siting of Mobile Services Antennas, 60 Fed. Reg. 42,023 (Aug. 14, 1995) (requiring agency administrators to develop procedures for the siting of mobile service antennas on federal lands); Wireless Service; General Wireless Communications Service, 60 Fed. Reg. 40,712, 40,713 (Aug. 9, 1995) (to be codified at 47 C.F.R. pts. 1, 26) (showing FCC's use of its broad authority under the Communications Act of 1934 to issue wireless regulations that promoted the growth of the then-nascent wireless industry by reallocating spectrum from the federal government to public use.). The FCC created the General Wireless Communications Service for the purpose of "benefit[ing] the public by permitting and encouraging the introduction of new services and the enhancement of existing services" leading to job creation, economic growth and improved access to communications. Id. at 40,712.

278 See, e.g., Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 66 Fed. Reg. 15,858, 15,860 (Mar. 21, 2001) (discussing agency action to increase energy supply and protect consumers from supply disruptions). Recognizing the need for additional transmission lines to be constructed, but understanding its jurisdictional limitations, FERC tried to influence the siting of transmission lines through traditional carrot and stick techniques:
In order to provide incentives for the construction of such projects at the earliest date possible, we propose to give transmission owners of projects that increase transmission capacity at present constraints and can be in service by July 1, 2001, a cost-based rate reflecting a 300 basis **point** premium on equity and a 10-year depreciable life.
Id. at 15,860. FERC also used its broad authority under the Federal Power Act to propose regulations to facilitate the construction of transmission lines by eliminating discriminatory transmission tariffs. See, e.g., Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55,452 (Aug. 29, 2002) (to be codified at 18 C.F.R. pt. 35).

279 See supra notes 277-78.

280 This is not to minimize the federal interest in ensuring that electricity generators are ultimately sited. Surely, the federal government has an interest in ensuring that the nation has a reliable and affordable supply of electricity, but compared to the other siting regimes, the federal interests in electricity siting are even broader to include type.

281 Strategic Plan FY 2009-FY 2013, FERC (Feb. 13, 2012), http:// www.ferc.gov/about/strat-docs/strat-plan.asp.

282 U.S. Energy Info. Admin., Electric Power Annual 2009 2 (2011), available at http://www.eia.gov/electricity/annual/archive/03482009.pdf.

283 U.S. Envtl. Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010 ES-7 (2012), available at http:// www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf ("As the largest source of U.S. greenhouse gas emissions, CO2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2010.").

284 Integration of Renewables, FERC (Nov. 29, 2011), http:// www.ferc.gov/industries/electric/indus-act/integration-renew.asp; see also James H. McGrew, FERC's Green Agenda, Trends, Mar./Apr. 2010, at 1.

285 Other FERC regulations have eliminated other barriers to the integration of renewable resources onto the grid, including FERC Order 2005, Standardization of Small Generator Interconnection Agreements & Procedures, (May 12, 2005), available at http:// www.ferc.gov/EventCalendar/Files/20050512110357-order2006.pdf, and FERC Order 2003, Interconnection for Wind Energy, Order No. 661, Appendix G to Order 2003, (June 2, 2005), available at http://www.ferc.gov/whats-new/comm-meet/052505/E-1.pdf.

286 16 U.S.C. § 824e(a). Section 824e provides that if FERC finds any "rate, charge, or classification" or any "rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order." Id.

287 Federal Energy Regulatory Commission, Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 at 66 (July 21, 2011), available at http:// www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

288 Id. at 9.

289 Id. at 66. Renewable portfolio standards are state mandates that requires utilities to obtain a specified percentage of their electricity from renewable energy sources.

290 Id. at 7.

291 Integration of Variable Energy Resources, 77 Fed. Reg. 41,482, 41,515 (July 13, 2010) (to be codified at 18 C.F.R. pt. 35) (stating that FERC seeks to define a VER as "a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator"). The rule adopts two reforms from a November 2010 Notice of Proposed Rulemaking (NOPR) by requiring transmission providers to offer customers the option of scheduling transmission service at fifteen-minute intervals and by requiring generators using variable energy resources to provide transmission owners with certain data to support power production forecasting.

292 16 U.S.C. § 824e(a) (2006).

293 FERC, Statement of Chairman Wellinghoff on Integration of Variable Energy Resources NOPR (Nov. 18, 2010), available at http:// www.ferc.gov/media/statements-speeches/wellinghoff/2010/11-18-10-wellinghoff-E-1.asp.

294 Peter Behr, FERC Moves Ahead with Campaign To Promote Energy Efficiency and Renewable Energy, N.Y. Times, Nov. 12, 2010, http:// www.nytimes.com/cwire/2010/11/12/12climatewire-ferc-moves-ahead-with-campaign-to-promote-en-22696.html?pagewanted=all.

295 Massachusetts v. EPA, 549 U.S. 497, 528 (2007); see also Coal. for Responsible Regulation v. EPA, 684 F.3d 102 (D.C. Cir. 2012) (per curiam) (rejecting challenges to EPA's greenhouse gas regulations).

296 Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (to be codified at 40 C.F.R. ch. 1).

297 Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56,260 (Oct. 30, 2009) (to be codified at 40 C.F.R. pts. 86, 87, 90, 94, 98, 1033, 1039, 1042, 1045, 1048, 1051, 1054, 1065).

298 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 70, 71).

299 Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule, 75 Fed. Reg. 25,324 (May 7, 2010) (to be codified at 40 C.F.R. pts. 85, 86, 600).

300 Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012) (to be codified at 40 C.F.R. pt. 60).

301 42 U.S.C. § 7411(d)(1) (2006).

302 Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012) (to be codified at 40 C.F.R. pt. 60).

303 EPA acknowledges that coal plants could satisfy the new standards with the installation of carbon capture and sequestration, a largely unproven technology on a commercial scale. Id.

304 See Federal Energy Management Program, Energy Policy Act of 2005, U.S. Dep't of Energy, http:// www1.eere.energy.gov/femp/regulations/epact2005.html#rer (last visited July 1, 2012) (requiring that the federal government source increasing amounts of its electricity use from renewables but granting a "double credit bonus for Federal agencies if renewable electricity is produced on-site at a Federal facility, on Federal lands, or on Native American lands").

305 Exec. Order 13,423, 72 Fed. Reg. 3,919 (Jan. 26, 2007); Federal Energy Management Program, Executive Order 13,423 U.S. Dep't of Energy, http://www1.eere.energy.gov/femp/regulations/eo13423.html (last visited Mar. 11, 2012). "By using renewable energy, Federal agencies increase national security, conserve natural resources, and meet regulatory requirements and goals." Federal Energy Management Program, Renewable Energy, U.S. Dep't of Energy, http://www1.eere.energy.gov/femp/technologies/renewable_energy.html (last visited Aug. 13, 2012).

306 See **AmyStein**, Renewable Energy Through Agency Action, Colo. L. Rev. (forthcoming 2013).

307 U.S. Dep't of the Interior & U.S.D.A., New Energy Frontier: Balancing Energy Development on Federal Lands 14, 17 (2011), available at http://www.doi.gov/whatwedo/energy/upload/NewEnergyFrontier050511.pdf.

308 Id. at 17.

309 Exec. Order No. 12,612, 3 C.F.R. 252 (1987); Exec. Order No. 13,132, 3 C.F.R. 206 (2000); Administrative Conference of the United States, Administrative Conference Recommendation No. 2010-1: Agency Procedures for Considering Preemption of State Law 1 (2010), available at http://www.acus.gov/wp-content/uploads/downloads/2011/06/Recommendation-2010-1-Preemption.pdf [hereinafter Administrative Conference Recommendation].

310 Administrative Conference Recommendation, supra note 309, at 3.

311 Id.

312 Percival, supra note 43, at 1180.

313 Ernest A. Young, Welcome to the Dark Side: Liberals Rediscover Federalism in the Wake of the War on Terror, 69 Brook. L. Rev. 1277, 1307-08 (2004) (citations omitted).

314 See Robert J. Michaels, National Renewable Portfolio Standard: Smart Policy or Misguided Gesture?, 29 Energy L.J. 79, 88 (2008) (arguing that a national RPS would not result in a net increase in employment as some have predicted because "[l]abor is [simply] reallocated to renewables" and workers "are paid with funds that households and businesses would have spent elsewhere").

315 FCC Establishes Shot Clock for Tower Siting Applications, Ga. Mun. Ass'n (Dec. 15, 2009), http://www.gmanet.com/MDR.aspx?CNID=45651.

316 Id. (citing Pub. L. No. 104-104, 110 Stat. 56 (1996) (amending Communications Act of 1934, 47 U.S.C. § 151 (1934)). This declaratory ruling clarified the TCA's general directive to local zoning authorities to act "within a reasonable time" on requests for tower siting by establishing deadlines of 90 and 150 days for review of applications for wireless communication facilities including collocations and tower siting applications. Failure to act after these deadlines opens the door for legal action by the applicant against the local zoning authority. 47 U.S.C. § 332.

317 FCC Notice of Inquiry, Docket No. 11-59, 5384, 5388 (Apr. 7, 2011), http://hraunfoss.fcc.gov/edocs_public/attachmatch/FCC-11-51A1_Rcd.pdf.

318 Id. at 5388; see also Acceleration of Broadband Deployment by Improving Policies Regarding Public Rights of Way and Wireless Facilities Siting, 76 Fed. Reg. 28,397 (May 17, 2011) (to be codified at 47 C.F.R. ch. 1).

319 See Piedmont Envtl. Council, Comments on the FCC Notice of Inquiry Regarding Access to Public and Private Rights-of-Way 1 (2011), available at http://apps.fcc.gov/ecfs//document/view.action?id=7021692588 (questioning the FCC's substitution of "zoning decisions, which are discretionary acts" with "right-of-way permits, which are ministerially granted"); see also Member Alert: Comments Due Sept. 30 on FCC Wireless Facility Siting Policy, Ass'n of Cal. Water Agencies, http://acwa.symsoftsolutions.com/content/federal-relations/member-alert-comments-due-sept-30-fcc-wireless-facility-siting-policy (last visited Oct. 2, 2012) (disagreeing with the wireless communications industry's portrayal of local governments as an obstacle to expansion of broadband services).

320 Reply Comments of the National Telecommunications Cooperative Association at 2, In re Acceleration of Broadband Deployment: Expanding the Reach and Reducing the Cost of Broadband Deployment by Improving Policies Regarding Public Rights of Way and Wireless Facilities Siting, No. 11-59, (F.C.C. 2011), available at http:// ecfsdocs.fcc.gov/filings/2011/09/30/6016843616.html (encouraging the FCC to use its authority "to regulate the public rights-of-way and wireless facilities siting process" and recommending that the FCC "open a Notice of Proposed Rulemaking . . . and explore further enforceable regulatory action").

321 See supra notes 139-40 and accompanying text.

322 See Peter Behr, DOE Shelves Controversial Plan to Hand Off 'National Corridor' Power Line Role to FERC, ClimateWire (Oct. 12, 2011), available at http://www.eenews.net/climatewire/2011/10/12/archive/4? terms=DOE+shelves+controversial+plan (reporting that the Department of Energy Secretary abandoned the Obama administration's proposal to delegate the authority to designate "National Interest Energy Transmission Corridors" to FERC).

323 Id.

324 Constrained by the FPA from making siting decisions on private land, the DOI has taken a much more active role in siting transmission lines on federal lands. Section 368 of the Energy Policy Act of 2005 directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate under their respective authorities corridors on federal land in eleven western states for oil, gas, and hydrogen pipelines, as well as electricity transmission and distribution facilities. West-wide Energy Corridor Programmatic EIS Info. Ctr., http://corridoreis.anl.gov/ (last visited July 1, 2012). In 2011, DOI entered into a Memorandum of Understanding with several other federal agencies for the purpose of "expedit[ing] the siting and construction of qualified electric transmission infrastructure in the United States." Memorandum of Understanding Among the U.S. Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Environmental Protection Agency, The Council on Environmental Quality, the Federal Energy Regulatory Commission, the Advisory Council on Historic Preservation, and Department of the Interior, Regarding Coordination in Federal Agency Review of Electric Transmission Facilities on Federal Land 1 (2009), available at http://www.whitehouse.gov/files/documents/ceq/Transmission%20Siting%C20*o*n%C20Federal%C20Lands%M#OU.pdf. Under the MOU, DOI is the **point** of contact for companies applying for permits to build transmission lines on public lands and national forests. Id. at 9.

325 Nat'l Comm'n on Energy Policy, Siting Critical Energy Infrastructure: An Overview of Needs and Challenges 1 (2006), available at http://bipartisanpolicy.org/sites/default/files/Siting%20Critical%C20Energy% 20Infrastructure_448851db5fa7d.pdf.

326 Edison Electric Institute is the association of U.S. Shareholder-Owned Electric Companies. Its members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent 70% of the U.S. electric power industry. About EEI, Edison Elec. Inst., http:// www.eei.org/whoweare/abouteei/Pages/default.aspx (last visited July 1, 2012).

327 Edison Elec. Inst., Transmission Projects: At a Glance iv (2012), available at http:// www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_ lowres.pdf.

328 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842, 49,872-73 (Aug. 11, 2011) (to be codified at 18 C.F.R. pt. 35).

329 Id. at 49,872. But see id. at 49,858 (stating that many commenters defended FERC's jurisdiction, with one noting that "courts have consistently recognized the Commission's need to adjust its regulation under the FPA to meet the changing needs of the industry").

330 For instance, the language in the Telecommunications Act reveals a delicate balance between Congress's desire to encourage the growth of the industry and efforts to avoid restricting state and local authority over siting of telecommunication towers. Eagle, supra note 111, at 463-64.

331 Even where strong arguments can be made that an Administration desires a federal policy, however, the Supreme Court has noted that "desirability for a federal policy is not a sufficient reason to oust state regulation." Philip J. Weiser, Federal Common Law, Cooperative Federalism, and the Enforcement of the Telecom Act, 76 N.Y.U. L. Rev. 1692, 1735 (2001) (citing Louisiana Pub. Serv. Comm'n v. FCC, 476 U.S. 355, 370 (1986)). Furthermore, an assessment of "federal desirability" is complicated by the multi-faceted nature of the federal government. For instance, even though the Obama Administration desires renewable energy, Congress has recently proposed cuts to renewable subsidies and other incentives, which might argue against "federal desirability." See Philip J. Weiser, Chevron, Cooperative Federalism, and Telecommunications Reform, 52 Vand. L. Rev. 1, 34 (1999) (stating that in the absence of a "clearly superior" policy, Congress should not dictate to the states a particular approach to telecommunications regulation).

45 CTLR 217

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790 F.3d 138
United States Court of Appeals,
District of Columbia Circuit.

MISSISSIPPI COMMISSION ON ENVIRONMENTAL QUALITY, Petitioner
v.
ENVIRONMENTAL PROTECTION AGENCY and Gina McCarthy, Respondents
State of Connecticut, et al., Intervenors.

Nos. 12–1309, 12–1310, 12–1312, 12–1313, 12–1315, 12–1316, 12–1317, 12–1318, 12–1322, 12–1323, 12–1326, 12–1328, 13–1030, 13–1032, 13–1046, 13–1050, 13–1051, 13–1052, 13–1053, 13–1054. | Argued Oct. 21, 2014. | Decided June 2, 2015.

Synopsis
Background: Several states, counties, environmental organizations, and industrial entities petitioned for review of the Environmental Protection Agency's (EPA) determinations that certain geographic areas were, or were not, in attainment of EPA's ground-level ozone national ambient air quality standards (NAAQS).

Holdings: The Court of Appeals held that:

[1] EPA's interpretation of Clean Air Act (CAA) provision permitting it to designate areas "nearby" an area not in attainment of NAAQS to presumptively include counties in the same metropolitan area was reasonable;

[2] EPA's interpretation of CAA to only require it to use ozone pollution data from regulatory monitors was reasonable;

[3] EPA's refusal to use uncertified air-quality data was reasonable;

[4] EPA's use of older data was not arbitrary or capricious;

[5] EPA's application of its five-factor test of determining whether a county contributed to nonattainment of NAAQS was not arbitrary or capricious;

[6] EPA's designation of two counties in Indiana as in nonattainment based on their contribution to Illinois county's violation of NAAQS was not arbitrary or capricious; and

[7] EPA's use of air particle movement modeling to determine impact of pollutant emissions from Texas county was not arbitrary or capricious.

Petitions denied.

West Headnotes (29)

[1] **Environmental Law**
Air pollution
Court of Appeals reviews the Environmental Protection Agency's (EPA) national ambient air quality standards (NAAQS) designations pursuant to the CAA under the same standard it uses in reviewing a challenge brought under the Administrative Procedure Act (APA). 5 U.S.C.A. § 551 et seq.; Clean Air Act, § 108(a)(1), 42 U.S.C.A. § 7408(a)(1).

Cases that cite this headnote

[2] **Environmental Law**
Air pollution
Environmental Law
Determination, Judgment, and Relief
Court of Appeals will set aside the Environmental Protection Agency's (EPA) designation of areas as in attainment of, or not in attainment of, national ambient air quality standards (NAAQS) under the CAA only if it is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law. Clean Air Act, § 108(a)(1), 42 U.S.C.A. § 7408(a)(1); 5 U.S.C.A. § 706(2)(A).

Cases that cite this headnote

[3] **Administrative Law and Procedure**

Environment and health

Environmental Law
Scope of Inquiry on Review of Administrative Decision

Environmental Law
Air pollution

Court of Appeals must give an extreme degree of deference to the Environmental Protection Agency's (EPA) evaluation of scientific data within its technical expertise, especially where it reviews the EPA's administration of the complicated provisions of the Clean Air Act. Clean Air Act, § 101 et seq., 42 U.S.C.A. § 7401 et seq.

Cases that cite this headnote

[4] Environmental Law
Air pollution

Court of Appeals will uphold the Environmental Protection Agency's (EPA) designation of an area as in attainment of, nor not in attainment of, national ambient air quality standards (NAAQS) under the CAA if the record shows that the EPA considered all relevant factors and articulated a rational connection between the facts found and the choice made. Clean Air Act, § 108(a)(1), 42 U.S.C.A. § 7408(a)(1).

Cases that cite this headnote

[5] Environmental Law
Ozone

Environmental Protection Agency's (EPA) interpretation of CAA provision permitting it to designate areas "nearby" an area not in attainment of national ambient air quality standards (NAAQS) for ozone pollution to presumptively include counties in the same metropolitan area as the county violating the NAAQS, rather than designating broad, multi-state areas as nonattainment areas, was consistent with a reasonable interpretation of term "nearby" in CAA, even though areas as far away as Missouri from nonattainment areas in Connecticut and Delaware may have contributed to those states' pollution; EPA's interpretation of "nearby" was in accordance with dictionary definition, it was in accordance with prior designations that Court of Appeals had upheld, Congress chose the metropolitan area as the default boundary for ozone nonattainment areas classified as serious, severe, or extreme, and other statutory provisions existed for addressing long-range, interstate transport of ozone. Clean Air Act, § 107(d), 42 U.S.C.A. § 7407(d).

Cases that cite this headnote

[6] Environmental Law
Ozone

Environmental Protection Agency's (EPA) interpretation of CAA provision requiring it to designate areas as in attainment or not in attainment of national ambient air quality standards (NAAQS) "on the basis of available information" to only require it to use ozone pollution data from regulatory monitors, but not privately collected data, was reasonable, and thus designation of basin area as unclassifiable with respect to ozone NAAQS due to unavailability of data from regulatory monitors was not inconsistent with CAA, even though private data regarding ozone levels in area was available and EPA used it for other purposes; data from regulatory monitors was collected in compliance with agency regulations and required to undergo post-collection quality assurance processes, EPA was unable to perform post-collection quality assurance checks on private data, and data sufficiently reliable for one purpose was not necessarily reliable enough to compel a nonattainment designation. Clean Air Act, § 107(d)(1)(iii), 42 U.S.C.A. § 7407(d)(1)(iii); 40 C.F.R. § 58.1 et seq.

Cases that cite this headnote

[7] Environmental Law
Ozone

Environmental Protection Agency's (EPA) refusal to use uncertified air-quality data during process of designating areas as either in attainment or not in attainment of national ambient air quality standards (NAAQS) for ozone and delay the designation process until after data was certified was reasonable and in accordance with CAA, even though doing so allegedly resulted in several counties being designated as in attainment that otherwise might have been designated in nonattainment; uncertified data submitted to EPA had only undergone preliminary quality control measures, and was still subject to continuing checks and revisions by states until final certification, no authority required EPA to wait until last possible moment to make its designations, EPA had already missed CAA's statutory deadlines for promulgating ozone NAAQS designations, and EPA would have been in never-ending process of trying to finalize designations with new technical data regularly becoming available. Clean Air Act, §§ 107(d), 108(a)(1), 42 U.S.C.A. §§ 7407(d), 7408(a)(1); 40 C.F.R. § 58.16(b, c).

Cases that cite this headnote

[8] Environmental Law
Ozone

Environmental Protection Agency's (EPA) use of older data for evaluating the Memphis metropolitan area, which consisted of counties in three states, for attainment of national ambient air quality standards (NAAQS) for ozone, was not arbitrary or capricious, even though newer data was available that would have shown all counties being in attainment, rather than one county not being in attainment under the older data; only two of the three states had certified the newer data, EPA would only rely on certified data in assessing pollution levels, and it was rational for EPA to use the most recent full set of matched data from the metropolitan area, rather than use a mismatched data set for the area. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[9] Environmental Law
Ozone

Environmental Protection Agency's (EPA) application of its five-factor test for determining whether a county contributed to nonattainment of CAA national ambient air quality standards (NAAQS) for ozone in another county was not arbitrary or capricious, with respect to county in Mississippi that was designated as nonattainment due to its contribution to a county in Tennessee's nonattainment, even though EPA had changed its test from nine factors to five factors; guidance that established nine-factor test was not binding on the agency, consolidation of nine factors into five did not result in EPA deviating from nine-factor test, and EPA provided data showing that Mississippi county's emissions of ozone precursors were the second highest in the metropolitan area and Mississippi county had the second highest number of workers commuting to county that was in nonattainment. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[10] Environmental Law
Ozone

Environmental Protection Agency's (EPA) designation of two counties in Indiana as in nonattainment of CAA national ambient air quality standards (NAAQS) for ozone based on their contribution to an Illinois county's violation of NAAQS was not arbitrary or capricious, despite fact that Illinois allegedly violated its state implementation plan (SIP) for meeting NAAQS by changing vehicle emissions law and metropolitan area in Wisconsin contributed a greater amount to Illinois county's ozone levels than Indiana counties did but was designated as in attainment; Illinois' alleged violation of SIP did not change fact that Indiana counties contributed to Illinois county's nonattainment, county did not have to be but-for cause of nonattainment to be designated a nonattainment area, Wisconsin metropolitan area that contributed to Illinois county's nonattainment was made up of five counties, and Indiana's assessment of Wisconsin area's contribution was based on less stringent analysis than EPA's. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

1 Cases that cite this headnote

[11] **Environmental Law**
Ozone

Environmental Protect Agency's (EPA) use of air particle movement modeling to determine impact of pollutant emissions from one county in Texas on ozone levels in Dallas-Forth Worth metropolitan area, rather than relying on historical wind patterns, was not arbitrary or capricious for use in designating county as a nonattainment area for CAA national ambient air quality standards (NAAQS) for ozone due to its contribution to metropolitan area's nonattainment of ozone NAAQS; EPA took reasonable steps to ensure that model's limitations were considered by evaluating another model and historic wind data that was submitted during comment period, modeling data was useful in county due to light wind speeds and wind from variable directions that also made historical wind patterns less useful, other counties where EPA did not use modeling were significantly different that the Texas county, and the county was part of metropolitan area's combined statistical area. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[12] **Environmental Law**
Ozone

Environmental Protection Agency's (EPA) modification of source-apportionment modeling submitted by Texas for evaluating whether county in Texas should have been designated a nonattainment area for CAA national ambient air quality standards (NAAQS) for ozone was not arbitrary or capricious; interpretation and modification of modeling was within EPA's technical expertise, model did not rely on data from entire ozone season, which EPA did not find sufficient, EPA's interpretation examined both the projected averse impact and the projected maximum impact of emissions from county, EPA identified several methodological flaws in Texas' data, and quality of data submitted by Texas was significantly lower than data used by EPA for other counties without modification. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[13] **States**
Surrender of state sovereignty and coercion of state

Federal government may not compel the states to implement federal regulatory programs.

Cases that cite this headnote

[14] **Environmental Law**
Ozone

States
Surrender of state sovereignty and coercion of state

Environmental Protection Agency's (EPA) overturning of state designation of an area as in attainment of CAA national ambient air quality standards (NAAQS) for ozone and redesignating it as a nonattainment area did not compel the state to implement a federal regulatory program in violation of the Tenth Amendment, even though doing so triggered requirements for the state to enforce myriad federal requirements; the CAA statutory scheme authorized the EPA to promulgate and administer a federal implementation plan of its own if the state failed to submit an adequate state implementation plan, such that the full regulatory burden would have been borne by the federal government if the state chose not to submit an implementation plan. U.S.C.A. Const.Amend. 10; Clean Air Act, §§ 107(d)(1)(B), 110(c), 42 U.S.C.A. §§ 7407(d)(1)(B), 7410(c).

Cases that cite this headnote

[15] **Environmental Law**
Validity
United States
Particular Subjects and Programs

Clean Air Act's (CAA) highway funding sanctions imposed on a state for noncompliance with requirement to submit an adequate plan for achieving national ambient air **quality** standards (NAAQS) or to implement an approved plan was not such a steep price that state officials effectively had no choice but to comply in violation of Congress' authority under the Spending Clause, as argued by Texas in challenging the designation of one county as nonattainment, assuming such standard applied to CAA sanctions; **EPA** could not prohibit approval of projects or grants that Secretary of Transportation determined were intended to resolve a demonstrated safety problem, Secretary of Transportation could approve other projects and grants that would improve air **quality**, and only 17 of Texas' 254 counties were nonattainment areas, so most of Texas' highway funds were not likely to be withheld, which in total only amounted to less than 4% of the state budget. U.S.C.A. Const. Art. 1, § 8, cl. 1; Clean Air Act, § 179(a, b), 42 U.S.C.A. § 7509(a, b).

Cases that cite this headnote

[16] **Courts**
Number of judges concurring in opinion, and opinion by divided court

When a majority of the Supreme Court agrees on a result, but no single rationale explaining the result enjoys the assent of five Justices, the holding of the Court may be viewed as that position taken by those members who concurred in the judgments on the narrowest grounds.

Cases that cite this headnote

[17] **Constitutional Law**
Burden of Proof

The burden of establishing unconstitutionality of a statute is on the challenger.

Cases that cite this headnote

[18] **Commerce**
Activities affecting interstate commerce

Congress's power to regulate interstate commerce is not limited to regulation of an activity that by itself substantially affects interstate commerce, but also extends to activities that do so only when aggregated with similar activities of others. U.S.C.A. Const. Art. 1, § 8, cl. 3.

Cases that cite this headnote

[19] **Commerce**
Activities affecting interstate commerce

The question for a court in evaluating whether Congress exceeded its power to regulate interstate commerce is whether there was a rational basis for the Congress' conclusion that a regulated activity substantially affects interstate commerce. U.S.C.A. Const. Art. 1, § 8, cl. 3.

Cases that cite this headnote

[20] **Commerce**
Environmental protection regulations
Environmental Law
Nitrogen oxides

Environmental Protection Agency's (**EPA**) regulation of nitrogen oxide emissions, a precursor to ozone produced by oil and gas activity, under the CAA's national ambient air **quality** standards (NAAQS) for ozone did not exceed Congress's power to regulate interstate commerce under the Commerce Clause, despite state's argument that the emissions were wholly intrastate; phenomenon of interstate transport of ozone had been thoroughly studied and recognized by Congress, EPA, the Supreme Court, and Court of Appeals. U.S.C.A. Const. Art. 1, § 8, cl. 3; Clean Air Act, §§ 110(a)(2)(D), 184, 42 U.S.C.A. §§ 7410(a)(2)(D), 7511c.

Cases that cite this headnote

[21] **Commerce**
Environmental protection regulations
Environmental Law
Nitrogen oxides

Environmental Protection Agency's (EPA) regulation of nitrogen oxide emissions, a precursor to ozone produced by oil and gas activity, under the CAA's national ambient air quality standards (NAAQS) for ozone did not exceed Congress's power to regulate interstate commerce under the Commerce Clause, even assuming nitrogen oxide emissions were wholly intrastate, where general regulatory scheme of the CAA had a substantial relation to interstate commerce, as did the CAA's applicable ozone provisions, commercial, industrial, and extraction processes that produced the emissions at issue were indisputably done by entities engaged in substantial interstate commerce, including multinational corporations, ozone pollution itself had economic consequences for interstate commerce, and the activities that produced the emissions were the activities that were ultimately regulated. U.S.C.A. Const. Art. 1, § 8, cl. 3; Clean Air Act, § 108(a), 42 U.S.C.A. § 7408(a).

Cases that cite this headnote

[22] **Commerce**
Constitutional Grant of Power to Congress

Where a general regulatory statute bears a substantial relation to commerce, the de minimis character of individual instances arising under that statute is of no consequence to Congress's ability to regulate the individual instances under the Commerce Clause. U.S.C.A. Const. Art. 1, § 8, cl. 3.

Cases that cite this headnote

[23] **Commerce**
Activities affecting interstate commerce

In determining if an activity has substantial effect on interstate commerce, such that Congress has authority to regulate it under the Commerce Clause, courts focus on the activity that the federal government seeks to regulate. U.S.C.A. Const. Art. 1, § 8, cl. 3.

Cases that cite this headnote

[24] **Commerce**
Activities affecting interstate commerce

Although courts are not bound by congressional findings, such findings may assist them in evaluating the legislative judgment that the activity in question substantially affected interstate commerce and thus was permissible under the Commerce Clause. U.S.C.A. Const. Art. 1, § 8, cl. 3.

Cases that cite this headnote

[25] **Administrative Law and Procedure**
Bias, prejudice or other disqualification to exercise powers
Constitutional Law
Air pollution
Environmental Law
Administrative Agencies and Proceedings

State failed to make a clear and convincing showing that regional administrator of Environmental Protection Agency (EPA) acted with an unalterably closed mind and was unwilling to rationally consider arguments in designating a county as a nonattainment area for ozone pollution standards, and thus administrator's failure to disqualify himself from proceedings did not result in denial of due process to state, even though administrator worked for environmental advocacy groups and authored report regarding issue before becoming administrator, and had given speech regarding his aggressive enforcement policy against oil and gas companies; administrator's activities before joining EPA were not type that came close to clear and convincing evidence, administrator's comments on his general approach to enforcement were not specifically about issue at hand, and bias could not be inferred from final designation alone, which was based on an adequate examination of facts and issue. U.S.C.A. Const.Amend. 5; Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[26] **Environmental Law**
Non-attainment areas

The purpose of the Information Quality Act is to ensure and maximize the quality, objectivity, utility, and integrity of information, including statistical information, disseminated by federal agencies and does not constitute a statutory mechanism by which the Environmental Protection Agency's (EPA) conclusions reached while making its nonattainment determinations with regard to CAA national ambient air quality standards (NAAQS) can be challenged. 44 U.S.C.A. § 3516; Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[27] **Environmental Law**
Ozone

Environmental Protection Agency (EPA) did find that county did contribute to violation of CAA national ambient air quality standards (NAAQS) for ozone in metropolitan area, even though in response to a petition for reconsideration challenging the county's designation as a nonattainment area the EPA stated that the county's emissions "can" contribute to ozone exceedances on certain days, where EPA's justification for including the county in the metropolitan area's nonattainment designation was not theoretical, but contained definite findings that county contributed to nonattainment of ozone NAAQS. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

1 Cases that cite this headnote

[28] **Environmental Law**
Ozone

Even assuming fair notice doctrine applied to Environmental Protection Agency's (EPA) designation of a county as a nonattainment area for CAA national ambient air quality standards (NAAQS) for ozone, requiring it to notify state of its requirements for such a designation, EPA did give sufficient notice, where EPA provided guidance document to aid states in making their initial designations, and provided technical support documents to each state before finalizing any of its proposed modifications to a state's initial designation, which gave a precise explanation of all proposed EPA modifications as a roadmap to use during comment period. Clean Air Act, § 107(d)(1)(A)(i), 42 U.S.C.A. § 7407(d)(1)(A)(i).

Cases that cite this headnote

[29] **Administrative Law and Procedure**
Administrative construction

Constitutional Law
Rules and regulations

The "fair notice doctrine," which is couched in terms of due process, provides redress only if an agency's interpretation is so far from a reasonable person's understanding of the regulations that they could not have fairly informed the regulated party of the agency's perspective.

Cases that cite this headnote

***144** On Petitions for Review of Final Action of the United States **Environmental** Protection Agency.

Attorneys and Law Firms

Valerie Satterfield Edge, Deputy Attorney General, Office of the Attorney General for the State of Delaware, argued the cause for the petitioners Delaware Department of Natural Resources and **Environmental** Control and the State of Connecticut. George Jepsen, Attorney General, and Kimberly P. Massicotte and Scott N. Koschwitz, Assistant Attorneys General, were with her on brief.

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Timothy J. Junk, Deputy Attorney General, Office of the Attorney General for the State of Indiana, argued the cause for the petitioner State of Indiana. Gregory F. Zoeller, Attorney General, was with him on brief.

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Tómas Carbonell and Peter Zalzal were on brief for the respondent-intervenor **Environmental** Defense Fund. Vickie L. Patton entered an appearance.

Before: GARLAND, Chief Judge, and HENDERSON and SRINIVASAN, Circuit Judges.

Opinion

PER CURIAM:

The Congress enacted the Clean Air Act (the Act), 42 U.S.C. §§ 7401 *et seq.,* "to protect and enhance the **quality** of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." *Id.* § 7401(b)(1). At issue in this case is Title I of the Act, which requires the **Environmental** ***145** Protection Agency (**EPA**) to promulgate National Ambient Air **Quality** Standards (NAAQS), thus setting the maximum level of permissible pollutant concentration in the atmosphere. *See id.* §§ 7408(a)(1), 7409(a)-(b). After the **EPA** sets the NAAQS, it must determine whether each state is in compliance with these air-**quality** standards and, in the event of a NAAQS violation, how to establish the geographic boundaries around the non-compliant area. *See id.* § 7407(d)(1).

In these consolidated petitions, several states, counties, industrial entities and **environmental** organizations challenge the **EPA's** determination that certain geographic areas are, or are not, in "attainment" with the **EPA's** ground-level ozone NAAQS. *Id.* Some argue that the Act, as applied to them, violates various Constitutional provisions; others argue that the **EPA** misconstrued the terms of the Act. Virtually every petitioner argues that, for one reason or another, the **EPA** acted arbitrarily and capriciously in making its final NAAQS designations. But because the **EPA** complied with the Constitution, reasonably interpreted the Act's critical terms and wholly satisfied—indeed, in most instances, surpassed—its obligation to engage in reasoned decision-making, we deny the consolidated petitions for review in their entirety.

I. BACKGROUND

The EPA began the odyssey resulting in these consolidated petitions nearly seven years ago. Along the way, it construed a variety of the Act's provisions, promulgated regulations and issued informal guidance to assist in the collaborative area-designation effort between it and the states. Before discussing the substance of the issues, a brief overview of the Act and the underlying proceedings in this case is in order.

A. THE CLEAN AIR ACT

Under the Act, the EPA must promulgate NAAQS, which set the maximum ambient, or outdoor, air concentrations for six pollutants that "may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7408(a)(1). Once it establishes a NAAQS, the EPA must designate each "area" in the United States as "attainment" or "nonattainment." *See id.* § 7407(d)(1)(A)(i)-(ii). Alternatively, the EPA may designate an area as "unclassifiable" if the area "permit[s] no determination given existing data." *Catawba Cnty., N.C. v. EPA*, 571 F.3d 20, 26 (D.C.Cir.2009) (citing 42 U.S.C. § 7407(d)(1)(A)(i)-(iii)). The EPA treats an "unclassifiable" area as if it were in attainment. See 42 U.S.C. § 7471.

Generally speaking, the EPA designates an area that meets the relevant NAAQS as in attainment, while areas that exceed the NAAQS receive a nonattainment designation. *See Catawba Cnty.*, 571 F.3d at 26. But even if an area's ambient air concentration complies with the relevant NAAQS, the EPA nonetheless designates it as nonattainment if it "contributes" to a NAAQS violation in a "nearby area." *See* 42 U.S.C. § 7407(d)(1)(A)(i). The Act does not define the terms "contributes," "nearby" or "area."

The EPA works collaboratively with the states to determine the NAAQS-attainment status for all areas within a respective state's borders. No later than one year after the EPA promulgates a new or revised NAAQS, each state must submit recommended "initial designations" to the EPA. *Id.* § 7407(d)(1)(A). A state's initial designations must suggest both the appropriate geographic boundaries for each "area" and whether the EPA should classify the suggested area as attainment, nonattainment or unclassifiable. *See id.* § 7407(d)(1)(A)-(B).

***146** Once it receives a state's initial designations, the EPA may either promulgate them as submitted or modify them as it "deems necessary." *Id.* § 7407(d)(1)(B)(ii). The Act gives the EPA discretion to change a state's recommended designation, to alter a state's proposed geographic area or both. *See id.* Although the EPA "has no obligation to give any quantum of deference to a designation that it 'deems necessary' to change," *Catawba Cnty.*, 571 F.3d at 40, it must nonetheless notify the state of any intended change and provide the state with at least 120 days "to demonstrate why any proposed modification is inappropriate," 42 U.S.C. § 7407(d)(1)(B)(ii). These notifications are known as "120–day letters." *See* Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards, 77 Fed.Reg. 30,088, 30,090 (May 21, 2012) [hereinafter 2008 Designations Rule].

While the EPA has ultimate authority to determine each area's attainment status, each state has "primary responsibility" for ensuring that the geographic areas within its borders either maintain attainment or progress towards it. 42 U.S.C. § 7407(a). Accordingly, once the EPA finalizes its designations, each state must submit to the EPA a State Implementation Plan (SIP) specifying how the NAAQS "will be achieved and maintained." *Id.* For areas in attainment, the SIP must simply "contain emission limitations and such other measures as may be necessary ... to prevent significant deterioration of air quality." *Id.* § 7471.

For a nonattainment area, however, the Act imposes more stringent requirements. A SIP from a state with a nonattainment area must demonstrate that the state intends to implement "all reasonably available control measures" and "reasonably available control technology" to bring the area into attainment. *Id.* § 7502(c)(1). The Act also imposes deadlines, or "attainment dates," on an offending area. *See id.* § 7502(a)(2)(A). For a violation of a primary [1] NAAQS, the offending state must reach attainment "as expeditiously as practicable, but no later than 5 years from the date such area was designated nonattainment." *Id.* The EPA "may extend the attainment date to the extent [it] determines appropriate" but only "for a period no greater than 10 years from the date of designation as nonattainment." *Id.* Taken together, these two requirements often mean that a state with a nonattainment area must implement potentially expensive technology or expensive process changes to reduce pollution levels over a relatively short period of time. If a state fails to reach attainment timely and the failure is due to inadequate implementation efforts, sanctions can be imposed, including loss of federal highway funds and increasingly severe restrictions on emissions sources within the state. *See id.* § 7509(a)-(b).

B. THE 2008 OZONE NAAQS AND THE EPA'S 2008 GUIDANCE

On March 12, 2008, the EPA promulgated new primary and secondary NAAQS for ambient ozone,[2] a component of urban smog. *See* 2008 Designations Rule, ***147** 77 Fed.Reg. at 30,089. Even though ozone is an "essential presence in the atmosphere's stratospheric layer," it becomes harmful at ground level and "can cause lung dysfunction, coughing, wheezing, shortness of breath, nausea, respiratory infection, and in some cases, permanent scarring of the lung tissue." *S. Coast Air Quality Mgmt. Dist. v. EPA,* 472 F.3d 882, 887 (D.C.Cir.2006) (quoting Henry A. Waxman, *An Overview of the Clean Air Act Amendments of 1990,* 21 ENVTL. L. 1721, 1758 (1991)). It also "has a broad array of effects on trees, vegetation, and crops and can indirectly affect other ecosystem components such as soil, water, and wildlife." *Mississippi v. EPA,* 744 F.3d 1334, 1340 (D.C.Cir.2013). Because ozone forms at ground level when "ozone precursors"—specifically, nitrous oxides (NO_x) and volatile organic compounds (VOCs)—react with sunlight, NAAQS compliance largely depends on reducing emissions from ozone-precursor producers like power plants, industrial compounds, motor vehicles and combustion engines. *See* 2008 Designations Rule, 77 Fed.Reg. at 30,089. Complicating this task is that ozone and ozone precursors travel easily through the atmosphere, which can result in NAAQS violations hundreds of miles away from the source of the ozone precursors. *See id.*

Both the EPA's 2008 primary and secondary ozone NAAQS reduced the maximum allowable daily average eight-hour level of ozone from 0.08 parts per million (ppm) to 0.075 ppm. *See* National Ambient Air Quality Standards for Ozone, 73 Fed.Reg. 16,436, 16,436–37 (Mar. 27, 2008). By setting these new NAAQS, the EPA triggered the states' responsibility to submit their initial designations. *See* 42 U.S.C. § 7407(d)(1)(A). To assist this process, the EPA issued a guidance titled "Area Designations for the 2008 Revised Ozone National Ambient Air Quality Standards" [hereinafter 2008 Guidance] on December 4, 2008, which included several matters relevant to the instant petitions.

First, the 2008 Guidance instructed states on the quality of data it expected them to consider. Specifically, it recommended that the states "identify violating areas using the most recent three consecutive years of quality-assured, certified air quality data." 2008 Guidance at 2. The 2008 Guidance also informed the states that "[i]n general, [NAAQS] violations [will be] identified using data from ... monitors that are sited and operated in accordance with [EPA regulations located at] 40 C.F.R. Part 58." *Id.*

Second, the 2008 Guidance provided instruction for establishing geographic boundaries around nonattainment areas, noting first that the "EPA believes it is important to examine ozone-contributing emissions across a relatively broad geographic area." 2008 Guidance at 3. Accordingly, the 2008 Guidance recommended that if an air-quality monitor reports a NAAQS violation, the state should consider using the Core Based Statistical Area (CBSA) or Combined Statistical Area (CSA) in which the monitor is located as the "presumptive" boundary.[3] *Id.* If the violating monitor ***148** is not in a CSA or CBSA, the 2008 Guidance recommended using the county in which the violating monitor is located as the presumptive boundary. *Id.*

The 2008 Guidance made plain, however, that CSAs, CBSAs and county lines were merely *presumptive* boundaries, recognizing that "area-specific analyses ... may support nonattainment area boundaries that are larger or smaller than the presumptive area starting point." *Id.* Stressing that "each potential nonattainment area should be evaluated on a case-by-case basis," the 2008 Guidance instructed the states to consider nine factors when determining a nonattainment area's borders. *See id.* at 2, Attach. 2. These include (1) air-quality data; (2) emissions data (such as location of emissions sources and contribution to ozone concentrations); (3) population density and degree of urbanization (including commercial development); (4) traffic and commuting patterns; (5) population growth rates and patterns; (6) meteorology (such as weather and air-transport patterns); (7) geography and topography (such as mountain ranges or other air-basin boundaries that could affect ozone dispersion); (8) jurisdictional boundaries (such as counties, air districts, existing nonattainment area boundaries and regional planning authority boundaries) and (9) the level of control of emissions sources. *See id*. Attach. 2. The 2008 Guidance stated that the EPA planned to consider these same factors, "along with any other relevant information," in determining whether to modify the states' initial designations. *Id*.

C. THE 2008 OZONE DESIGNATION PROCESS

By 2009, all states had submitted their initial designations to the EPA. Rather than immediately reviewing the initial designations, however, the EPA halted the designation process to consider whether to lower the ozone NAAQS even further. This delay prompted a lawsuit by WildEarth Guardians—an environmental-group petitioner in this case—that sought to compel the EPA to complete the stalled ozone NAAQS designation process.[4] The EPA and WildEarth Guardians eventually entered into a consent decree that required the EPA to finalize its designations no later than May 31, 2012. *See* 2008 Designations Rule, 77 Fed.Reg. at 30,091.

The EPA notified the states in September 2011 that it intended to finalize the ozone NAAQS designations by the May 31, 2012 deadline set forth in the consent decree. In accordance with the 2008 Guidance's instruction to "identify violating areas using the most recent three consecutive years of quality-assured, certified air quality data," 2008 Guidance at 2, virtually every state had already submitted air-quality data from 2008 to 2010 by the time the EPA resumed the designation process. Although the EPA assured the states that it still planned to consider the recommended designations and ozone data they had submitted initially, it recognized that some states may have collected more recent air-quality data for their regions. For this reason, the EPA allowed the states to provide updated recommendations and analyses—so long as any updated air-quality data was certified for quality—but assured them that they were under no obligation to do so. In response to this invitation, several states updated their initial designations and some submitted air-quality data from 2009 to 2011 to replace their older 2008 to 2010 data. The states seeking to use data from 2009 to 2011 agreed to certify their data for ***149** quality by February 29, 2012, so that the EPA had sufficient time to consider the more recent data in advance of its May 31, 2012 deadline to finalize the designations.

The EPA then reviewed each state's initial designations to determine whether to modify them. It first examined the air-quality submissions from the states to determine which monitors reported ozone NAAQS violations. If a state certified its air-quality data from 2011 by the February 29, 2012 deadline, the EPA generally considered its air-quality data from the years 2009 to 2011. For all other states, the EPA considered air-quality data from 2008 to 2010.

After identifying NAAQS-violating monitors, the EPA decided whether to alter the states' respective recommended nonattainment boundaries. To do so, the EPA used a multi-factor, weight-of-the-evidence test that tracked—but was not identical to—the nine-factor test in the 2008 Guidance. Specifically, the EPA collapsed the 2008 Guidance's nine-factor test into a five-factor test, which examined (1) "Air Quality Data," or whether an area's monitor reported a NAAQS violation; (2) "Emissions Data," including emissions levels and controls, population, population density, population growth, degree of urbanization and traffic and commuting patterns; (3) "Meteorology," including wind speed and direction; (4) "Geography/Topography," which examined the effect of physical land features on the distribution of ozone and (5) "Jurisdictional Boundaries," which helped determine whether certain areas could effectively carry out air-quality planning and enforcement functions for nonattainment areas.

Once attainment designations were made, the EPA notified the states of any proposed modifications it deemed necessary and invited them to submit any additional data or comments they wished to have the EPA consider. Although not required by statute, *see* 42 U.S.C. § 7407(d)(2)(B), the EPA also opened a 30–day public comment period on the proposed notifications. Several states, organizations and members of the public—including many of the petitioners in this case—submitted comments. The EPA considered the comments and then promulgated its final designations, which identified 48 nonattainment areas in 26 states, the District of Columbia and Indian country. The nonattainment areas included 192 counties *in toto* and 36 counties in part. The EPA published the majority of its final designations on May 21, 2012, *see* 2008 Designations Rule, 77 Fed.Reg. at 30,088, and in the case of certain Chicago-area designations, on June 11, 2012, *see* Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards for Several Counties in Illinois, Indiana, and Wisconsin; Corrections to Inadvertent Errors in Prior Designations, 77 Fed.Reg. 34,221, 34,221 (June 11, 2012).

After the EPA received and denied 29 petitions for reconsideration, the parties in this consolidated case[5] petitioned this ***150** Court for review. We have jurisdiction under 42 U.S.C. § 7607(b)(1).

II. COMMON LEGAL PRINCIPLES

Before addressing the petitioners' individual challenges, we think it helpful to discuss several principles that bear on most, if not all, of the issues the petitioners have raised.

[1] [2] [3] [4] First, we review the EPA's NAAQS designations under the same standard we use in reviewing a challenge brought under the Administrative Procedure Act (APA). *See Allied Local & Reg'l Mfrs. Caucus v. EPA*, 215 F.3d 61, 68 (D.C.Cir.2000). Accordingly, we will set aside a NAAQS designation by the EPA only if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." *Catawba Cnty.,* 571 F.3d at 41 (quoting 5 U.S.C. § 706(2)(A)). We must, however, give an "extreme degree of deference" to the EPA's evaluation of "scientific data within its technical expertise," *City of Waukesha v. EPA*, 320 F.3d 228, 247 (D.C.Cir.2003), especially where, as here, we review the "EPA's administration of the complicated provisions of the Clean Air Act." *Catawba Cnty.,* 571 F.3d at 41 (citing *Nat'l Ass'n of Clean Air Agencies v. EPA*, 489 F.3d 1221, 1229 (D.C.Cir.2007)). Because the EPA's "basic obligation" is to conduct "reasoned decisionmaking," *id.* at 25, we will uphold its action if the record shows that the EPA "considered all relevant factors and articulated a 'rational connection between the facts found and the choice made,' " *id.* at 41 (quoting *Burlington Truck Lines, Inc. v. United States,* 371 U.S. 156, 168, 83 S.Ct. 239, 9 L.Ed.2d 207 (1962)).

Second, we have long since rejected the argument that the EPA violates the Act if it uses a holistic, multi-factor, weight-of-the-evidence test for determining whether a given area contributes to a NAAQS violation. *See ATK Launch Sys., Inc. v. EPA*, 669 F.3d 330, 336–37 (D.C.Cir.2012) (challenge to 2006 fine particulate matter NAAQS designations); *Catawba Cnty.,* 571 F.3d at 46 (challenge to 1997 fine particulate matter NAAQS designations). Indeed, in *Catawba County,* we made explicit that the EPA does not violate the Act even if it fails to adopt "a bright-line, 'objective' test" for determining contribution and we also held that the "EPA's failure to quantify its analysis" does not render "its interpretation of 'contribute' arbitrary and capricious and therefore unreasonable." 571 F.3d at 39. Rather, because "[a]n agency is free to adopt a totality-of-the-circumstances test to implement a statute that confers broad discretionary authority, even if that test lacks a definite 'threshold' or 'clear line of demarcation to define an open-ended term,' " we have held that, "[t]o be reasonable, such an 'all-things-considered standard' must simply define and explain the criteria the agency is applying." *Id.*

With this background in mind, we now turn to the petitioners' challenges.

III. THE PETITIONERS' CHALLENGES

A. DELAWARE & CONNECTICUT

[5] We begin with a challenge to the EPA's construction of the key statutory provision in this case. Petitioners Delaware and Connecticut challenge the EPA's refusal to designate broad, multi-state nonattainment areas to address the issue of long-range ozone transport. According to the States, the EPA's final designations are inconsistent with its statutory mandate to designate areas as nonattainment if they "contribute[ ] to ambient air quality in a *nearby* area that does not meet [the NAAQS]." 42 U.S.C. § 7407(d) (emphasis added). We conclude, to the contrary, that the designations are consistent with the EPA's reasonable interpretation of the ambiguous statutory term "nearby."

***151** After the EPA reopened the designation process in 2011, Delaware proposed a nonattainment area that would stretch across 16 upwind states and the District of Columbia

—to states as far west as Missouri. Connecticut similarly proposed an 18–state nonattainment area, also stretching west to Missouri. Both States argued for what Delaware described as a "more workable definition of 'nearby' "—one that would ask "whether a source is 'near enough to contribute' to nonattainment or interfere with maintenance." Letter from Del. Dep't of Natural Res. & Envtl. Control to **EPA** 5 (Oct. 28, 2011) [hereinafter Delaware Response].

The **EPA**, however, had taken a different approach in the 2008 Guidance, instead interpreting "nearby" as presumptively including counties in the same metropolitan area as the violating county. 2008 Guidance at 3. In the Guidance, the **EPA** acknowledged that certain regions have ozone transport problems, but it concluded that the Act "does not require that all contributing areas be designated nonattainment, only the nearby areas." *Id.* at 4. The agency explained that "[r]egional strategies, such as those employed in the Ozone Transport Region and **EPA's** NO_x SIP Call are needed to address the long-range transport component of ozone nonattainment." *Id.* In keeping with this understanding of the statute, the **EPA** declined to designate "super-regional" nonattainment areas, *see* Responses to Significant Comments on the State and Tribal Designation Recommendations for the 2008 Ozone NAAQS at 8–9 (Apr. 30, 2012) [hereinafter Response to Comments], and instead made more limited nonattainment designations in both Delaware and Connecticut, *see* Delaware Area Designations for the 2008 Ozone NAAQS 2; Connecticut Area Designations for the 2008 Ozone NAAQS 1.[6]

We evaluate the **EPA's** interpretation of a Clean Air Act provision under the familiar two-step *Chevron* framework. *See Util. Air Regulatory Grp. v. **EPA**,* ––– U.S. ––––, 134 S.Ct. 2427, 2439, 189 L.Ed.2d 372 (2014) (citing *Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.,* 467 U.S. 837, 842–43, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984)). The first question—"whether Congress has directly spoken to the precise question at issue," *Chevron,* 467 U.S. at 842, 104 S.Ct. 2778—has previously been resolved by this Court. In *Pennsylvania Department of **Environmental** Protection v. **EPA*** (*PADEP*), we held that the statutory term "nearby" in section 107(d) is ambiguous; indeed, we reached that conclusion in the course of addressing the precise argument that Delaware makes here. *See* 429 F.3d 1125, 1129–30 (D.C.Cir.2005). In *Catawba County,* we reached the same conclusion. *See* 571 F.3d at 35 (noting that section 107(d) does not define "nearby," and that it is "the kind[ ] of word[ ] that suggest[s] a congressional intent to leave unanswered questions to an agency's discretion and expertise").

Recognizing these precedents, Delaware and Connecticut conceded at oral argument that our analysis must be governed by *Chevron's* second step, Oral Arg. Recording at 3:49–3:54, which requires us to ask only whether the **EPA's** interpretation is reasonable, *see, e.g., PADEP,* 429 F.3d at 1130. But we have addressed that question once as well, also in *PADEP*, where we said that "*Chevron* requires that we defer to the agency's reasonable interpretation of the term, and Delaware has given us no reason to think that **EPA's** interpretation is unreasonable." *Id*. We reach the same conclusion here.

***152** First, the agency's interpretation of "nearby"—as presumptively including counties within the same metropolitan area as the violating county—falls readily within the dictionary definition of "nearby" as "close at hand; not far off; adjacent; neighboring." RANDOM HOUSE COLLEGE DICTIONARY 889 (rev. ed.1980). By contrast, neither the dictionary nor common parlance would regard Missouri as "nearby" to Connecticut or Delaware, as the petitioners' proposals would require.

Second, the **EPA's** construction is consistent with the approach the agency has taken in prior designations proceedings—an approach that this Court has previously upheld as reasonable. *See PADEP,* 429 F.3d at 1127, 1129–30; 2008 Guidance at 3.

Third, the **EPA's** construction is consistent with the statutory scheme. The **EPA** selected the metropolitan area as the presumptive "nearby" area for its contribution analysis in part because the Congress itself chose the metropolitan area as the default boundary for ozone nonattainment areas classified as "serious," "severe," or "extreme." *See* 42 U.S.C. § 7407(d)(4)(A)(iv); 2008 Guidance at 3 n. 5. The Congress' choice is certainly evidence that the legislature envisioned broad but relatively local nonattainment areas.[7]

As in *PADEP*, the petitioners argue that the **EPA's** interpretation is unreasonable because it fails to appreciate the role of ozone transport, and consequently yields designations that fail to include the true contributors to their nonattainment status. *See PADEP,* 429 F.3d at 1129–30. Delaware notes, for example, that 84 to 94 per cent of its ozone results from the contributions of other states, including states as far west as Missouri. *See* Delaware Reply Br. 4. Without emissions reductions from those states, petitioners argue, they cannot meet the 0.075 ppm standard. Thus, by failing to address the principal sources of their ozone pollution, the **EPA's** interpretation eliminates any possibility that they will attain the NAAQS.[8]

Although we are sympathetic to the petitioners' concerns, our role is not to decide whether *their* proposed interpretation is reasonable. Instead, the sole question before us is whether the ***EPA*** interpreted the term reasonably and consistently with the statute. *See PADEP,* 429 F.3d at 1130 (noting that, although a broader "construction of 'nearby' may well be sensible, *Chevron* requires that we defer to the agency's reasonable interpretation of the term"). Here, the **EPA** had already considered the problem the petitioners raised. Part of the rationale for using the metropolitan area as the starting point for the contribution analysis was to account for ozone transported from outside the violating county. *See* 2008 Guidance at 3–4. Although this approach does not fully account for longer-range, interstate transport, the **EPA** has addressed that problem in regulations promulgated under other provisions of the Act. *See, e.g.,* ***153** Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed.Reg. 48,208 (Aug. 8, 2011) (promulgating the Cross State Air Pollution Rule, commonly referred to as the Transport Rule).[9] Although the petitioners recognize the **EPA's** reliance on those other regulatory options, they maintain that they "have been less than successful" up to this point. Delaware Br. 6; *see also id.* at 9. We, however, must defer to the **EPA's** reasonable judgment that regional strategies adopted pursuant to other statutory provisions specific to long-range ozone transport remain the appropriate means for addressing this problem. *See* 2008 Guidance at 4.

The petitioners note that our decision in *PADEP* rested in part upon the fact that there, Delaware had "offered no evidence that 'in practice' **EPA** will not enlarge a nonattainment area in response to [its then] eleven-factor analysis." 429 F.3d at 1130. Indeed, in *PADEP*, Delaware had failed altogether "to produce an eleven-factor analysis." *Id*. But we did not mean by this to suggest that, had Delaware produced the appropriate factor analysis, the **EPA** would have been *required* to adopt an interpretation of "nearby" that included states as far away as those within the petitioners' proposed nonattainment areas. The points discussed above—including the dictionary definition of "nearby" and the consistency of the **EPA's** interpretation with the statute and its prior practice—strongly suggest that the **EPA's** narrower interpretation would still be reasonable.

Nonetheless, if the petitioners had submitted a persuasive five-factor analysis establishing contributions from farther-away states, that would be relevant to our assessment of the reasonableness of the **EPA's** refusal to enlarge the nonattainment area beyond its presumptive scope. In this case, however, although the petitioning States did submit technical analyses, they failed to demonstrate the requisite linkages under the **EPA's** 2008 Guidance. *See, e.g.,* Delaware Response Attach. 2 at 5–7, 11–13 (disputing relevance of factors related to urbanization, traffic, and economic growth); *id*. at 14–15 (with respect to meteorology factor, describing long-range transport without describing weather patterns within the proposed 16–state nonattainment area). Hence, the petitioners did not show that the agency "will not enlarge a nonattainment area in response to" the (current) five-factor analysis, *PADEP,* 429 F.3d at 1130. Rather, the States' analyses were simply insufficient to overcome the agency's definitional presumption.

In sum, we conclude that the **EPA's** final designations of Delaware and Connecticut counties are consistent with a reasonable interpretation of the Clean Air Act.[10]

*154 B. UINTA BASIN

Petitioner WildEarth Guardians (WildEarth) challenges the **EPA's** designation of Uinta Basin, Utah, as "unclassifiable." We find the **EPA's** designation rational and in accordance with the Clean Air Act, and we therefore deny WildEarth's petition.

1. Uinta Basin Background

The **EPA** requires every state to establish a network of regulatory monitoring stations to collect ozone air-**quality** data. *See* 40 C.F.R. pt. 58. The number of regulatory monitors required in an area depends, in part, on the area's population. *See id*. app. D. tbl.D–2. Areas with populations below 50,000 and many areas with fewer than 350,000 inhabitants require no regulatory monitors. *Id*. Many rural areas therefore lack monitors.

Uinta Basin, Utah, had no regulatory monitoring until April 2011. The pre–2011 absence of regulatory-air-**quality** monitors in Uinta Basin meant that, when the **EPA** in 2013 conducted the designation process for the 2008 NAAQS, the agency had regulatory data for Uinta Basin for only two years —2011 and 2012. The 2008 ozone NAAQS, however, reflect three-year averages of ozone levels. *See* 2008 Designations Rule, 77 Fed.Reg. at 30,089. Noting that "there are not yet three consecutive years of certified ozone monitoring data available [from Uinta Basin] that can be used to determine the area's attainment status," *id.,* the **EPA** designated the area as "unclassifiable," which the Clean Air Act defines as an area that "cannot be classified on the basis of available information as meeting or not meeting" the NAAQS, 42 U.S.C. § 7407(d)(1)(A)(iii).

Although no regulatory data exist for Uinta Basin prior to 2011, private companies working under consent decrees have been required to operate ozone air-**quality** monitors in Uinta Basin since 2009. *See* Letter from Robin Cooley, Counsel, WildEarth Guardians to Lisa P. Jackson, Adm'r, **EPA** 3 (July 19, 2012). Under the terms of those consent decrees, the private monitors must comply with many of the same requirements as regulatory monitors. *See* Consent Decree ¶¶ 80–81, *United States v. Kerr–McGee Corp.,* No. 1:07–cv–01034 (D. Colo. May 17, 2007). From 2009 to 2011, the private monitors provided raw data showing ozone levels significantly exceeding the 2008 ozone NAAQS. The **EPA** found the 2009 to 2011 private data insufficient to support a nonattainment designation.

2. The Private Monitoring Data Challenge

[6] WildEarth argues that, in light of the private data, the **EPA** contravened the Act's requirements when it designated Uinta Basin as unclassifiable rather than nonattainment. We disagree.

The Act calls for the **EPA** to make designations "on the basis of available information." 42 U.S.C. § 7407(d)(1)(iii). We have repeatedly found similar language to be ambiguous when assessing whether to defer to an agency's construction. *See Catawba Cnty.,* 571 F.3d at 35, 38 (finding the phrase "based on air **quality** monitoring data" to be ambiguous); *Sierra Club v.* ***EPA***, 356 F.3d 296, 305–06 (D.C.Cir.2004) (finding the phrase "based on photochemical grid modeling" to be ambiguous). The **EPA** therefore may interpret the statutory language as it sees fit, as long as its interpretation is reasonable. *Chevron,* 467 U.S. at 845, 104 S.Ct. 2778. And even assuming the Act obligates the **EPA** to consider certain types of data, there would be no obligation for the agency to base its designations on data it reasonably considers to be unsound, at least if it "adequately explain[s] its reasons for rejecting ... data" on which it declines to ***155** rely. *City of Waukesha,* 320 F.3d at 248. We evaluate the **EPA's** reasons cognizant of the "extreme degree of deference" we owe an agency "when it is evaluating scientific data within its technical expertise." *Catawba Cnty.,* 571 F.3d at 41.

The **EPA** reasonably explained that the private monitoring data afforded an insufficient basis for a nonattainment designation because the agency was unable to perform post-collection **quality** assurance checks on the data. In particular, the **EPA** lacked **quality** assurance data needed to verify and audit the private data. As the agency explained:

> **Quality** assurance data consist, primarily, of biweekly single point **quality** control (QC) checks, used to assess the precision and bias a given instrument is displaying in its day-to-day measurements, and annual independent performance evaluations (audits) of equipment, which rely on independent staff and measuring systems to confirm that the monitors are operating as expected and required.

Letter from Lisa P. Jackson, Adm'r, **EPA** to Robin Cooley, Counsel, WildEarth Guardians 5 (Dec. 14, 2012) (denying reconsideration of Uinta Basin designation). The agency determined that, without audits or **quality** control checks, it could not adequately verify the quality of the private data. That explanation comports with common sense and falls within the substantial deference accorded the EPA in evaluating the soundness of data available to it.

WildEarth presses several counterarguments, none of which we find persuasive. First, WildEarth observes that the consent decrees required the private monitors to operate in "substantial compliance" with 40 C.F.R. Part 58, the quality assurance requirements under which regulatory monitors operate. But "substantial compliance" is not "full compliance," and the EPA could reasonably draw a distinction between the two. Moreover, data from regulatory monitors—which *must* be collected in compliance with 40 C.F.R. Part 58—undergo post-collection auditing and verification processes. *See, e.g.,* 40 C.F.R. pt. 58, app. A, § 3. Those post-collection processes could not be conducted for the private monitor data. Accepting WildEarth's argument would require us to conclude that the EPA must apply *less stringent* post-collection validation requirements to data collected from private monitors in "substantial compliance" with the agency's data-collection regulations than the agency applies to data collected from regulatory monitors in *actual* compliance with those regulations. We see no reason to embrace that counterintuitive result.

Second, WildEarth points out that the EPA has encouraged other federal entities to take notice of the private monitoring data. The EPA acknowledges that it argued, in a judicial proceeding supporting entry of the same consent decrees mandating the private monitoring, that the private monitors would provide data that would be "reliable and of good quality" and "useful in assisting regulators." Resp't's Br. 57. And indeed the data have proven helpful to the EPA in other regulatory contexts. On the basis of the private data, for example, the EPA informed the Forest Service that Uinta Basin ozone concentrations "exceed the NAAQS" and are a "serious problem." Supp. JA 387.

We agree with WildEarth that an agency may be required to articulate why data are sufficiently reliable for one purpose but not for another. *See Cnty. of L.A. v. Shalala,* 192 F.3d 1005, 1022 (D.C.Cir.1999). But the EPA has done so here. That the data may be sufficiently reliable to warrant identifying ozone as a serious issue for a Forest Service analysis under ***156** one statutory provision does not necessarily mean that the data are reliable enough to compel a nonattainment designation under a different statutory regime. To hold otherwise would require the EPA wholly to blind itself to potentially useful private data for *any* purpose if it were to consider that data insufficiently reliable for one purpose. There is no basis for constraining the agency in that way.

That the EPA partially relied on the private data in the course of this very designation process does not undercut that conclusion. While "unclassifiable" represents a single statutory designation, *see* 42 U.S.C. § 7407(d)(1)(A)(i)-(iii), the EPA further divided that classification into two sub-categories: "unclassifiable/attainment" and "unclassifiable." *See* 2008 Designations Rule, 77 Fed.Reg. at 30,089. "Historically for ozone," the EPA designates as " 'unclassifiable/attainment' " those areas for which "air quality information is not available because the areas are not monitored." *Id.* at 30,090. But in Uinta Basin, the EPA instead designated the area "unclassifiable" after determining that the private monitoring "detected levels of ozone that exceed the NAAQS." *Id.* at 30,089.

There is no arbitrariness in the EPA's choice partially—but not fully—to rely on the private data. At the outset, we note that the parties point us to no material differences between an "unclassifiable/attainment" and an "unclassifiable" designation, and we are aware of none. *See* 40 C.F.R. § 51.1100(g) ("Attainment area means, unless otherwise indicated, an area designated as either attainment, unclassifiable, or attainment/unclassifiable."); *cf.* 42 U.S.C. § 7471 (instructing the EPA to give the same treatment to "unclassifiable" and "attainment" areas for SIP purposes). But given the EPA's decision to create two different unclassifiable designations, we will assume *arguendo* that materially different regulatory burdens attend each designation. Even then, however, we agree with the EPA that it was reasonable to conclude that it would be inappropriate to label the Uinta Basin area "unclassifiable/attainment": the private data, even if unverified, at least implied that a NAAQS violation was possible, even if not conclusively proven to the agency's satisfaction. WildEarth, moreover, points to no other area for which private—but not regulatory—monitoring suggested a NAAQS violation. It thus appears that Uinta Basin differed from all other areas meriting an "unclassifiable/attainment" designation. We conclude that the EPA's conclusion partially—but not fully—to credit the private data was reasonable and non-arbitrary, particularly in light of the "extreme deference" we owe the agency. *See* Catawba Cnty., 571 F.3d at 41.

In sum, the **EPA** reasonably declined to rely on data that it considered of insufficient **quality** for designations purposes. With that conclusion, and having reviewed the remainder of WildEarth's challenges and determined that they lack merit, we deny the group's petition for review. *See* Catawba Cnty., 571 F.3d at 52.

C. SIERRA CLUB

[7] Petitioner Sierra Club challenges the **EPA's** refusal to use uncertified 2011 air-**quality** data during the designation process, a decision that resulted in 15 counties avoiding nonattainment designations. Finding the **EPA's** actions rational and in accordance with the Clean Air Act, we deny Sierra Club's petition.

1. Sierra Club Background

In furtherance of the Clean Air Act's " 'core principle' of cooperative federalism," ***EPA*** *v. EME Homer City Generation, L.P.,* ––– U.S. ––––, 134 S.Ct. 1584, 1602 n. 14, 188 L.Ed.2d 775 (2014), states take the lead in the collection of air-**quality** ***157** data. In doing so, states operate regulatory monitors under an array of "[e]xhaustive technical specifications" promulgated by the **EPA**. *Catawba Cnty.,* 571 F.3d at 30; *see* 40 C.F.R. pt. 58. States "edit[ ]" and "validate[ ]" the collected data pursuant to the **EPA**-mandated procedures and report it to the **EPA** according to a prescribed schedule. *See* 40 C.F.R. § 58.16(b)-(c). Data collected in each quarter must be "edited, validated and entered" into the **EPA's** system within ninety days of the end of the quarter. *Id.* "For example, the data for the reporting period January 1—March 31 are due on or before June 30 of that year." *Id.* § 58.16(b). Post-auditing, the data are still considered "uncertified" when submitted to the **EPA**.

While uncertified data from the first quarter (*i.e.,* January 1 to March 31) become available to the **EPA** as of June 30, those data remain subject to continuing audits and edits by states. The data collection process reaches completion only when a state provides final certification that the necessary "ambient concentration and **quality** assurance data are completely submitted ... and ... are accurate." *Id.* § 58.15(a). The **EPA** requires certification by May 1 of the following calendar year for all data collected in the previous year. *Id.* § 58.15(a)(2). States therefore had to certify their 2011 data by May 1, 2012.

As explained, because the 2008 ozone NAAQS represent a three-year average, the **EPA** needs air-**quality** data from three sequential calendar years to classify an area as attainment or nonattainment (as opposed to unclassifiable). *See* 2008 Designations Rule, 77 Fed.Reg. at 30,089. In the designation process for the 2008 NAAQS, the **EPA** gave each state a choice between two options: (i) early-certify 2011 data by February 29, 2012, in which event the **EPA** would consider 2009 to 2011 data for the designation process for that state (Option One); or (ii) decline to early-certify (and stick to the normal May 1 certification deadline), in which event the **EPA** would use 2008 to 2010 data for designations in that state (Option Two). *See id.* at 30,091.

At least eight states selected Option Two. Sierra Club identifies over one dozen counties within those eight states for which the choice between Option One and Option Two (*i.e.,* the choice between designations based on 2008 to 2010 data versus 2009 to 2011 data) allegedly meant that those counties avoided nonattainment designations. *See* Letter from Robert Ukeiley, Counsel, Sierra Club to **EPA**, Re: Designations for the 2008 Ozone NAAQS Docket ID No. **EPA**–HQ–OAR–2008–0476 at 3 tbl.1 (Feb. 3, 2012). Sierra Club contends that the **EPA** was compelled to use 2009 to 2011 data for those areas. We disagree and conclude that the **EPA's** actions were non-arbitrary.

2. Uncertified Data Challenge

Sierra Club first notes that, at the time of the designation process, the **EPA** possessed uncertified 2011 data for all areas. Because the agency's regulations require the submission of uncertified data within ninety days of the end of the quarterly reporting period, *see* 40 C.F.R. § 58.16(b), the **EPA** had all 2011 uncertified data in its possession by the end of March. It should have used that data, Sierra Club argues, notwithstanding the lack of certification. We are unpersuaded.

While the uncertified data must undergo preliminary auditing and quality checks before submission to the EPA, *see id.* § 58.16(c), those preliminary quality control measures are just that—preliminary. As the EPA explains, the data remain subject to continuing checks and revisions by the states until final certification. Resp't's Br. 66. Accordingly, the EPA ***158** reasonably "does not presume that data [validation and auditing] processes are complete and accurate until" the final data certification. *Id.* at 46. Mindful of the significant deference we owe the EPA in matters concerning data quality or sufficiency, *see Catawba Cnty.,* 571 F.3d at 41, we see no basis for second-guessing the EPA's considered judgment on the issue.

Sierra Club next argues that, even if the agency acted reasonably in refusing to rely on uncertified data, it acted arbitrarily in declining to delay the designation process until all states had certified their 2011 data by the standard May 1 deadline. After all, Sierra Club notes, the consent decree under which the EPA conducted the designation process allowed the agency until May 31, 2012, to promulgate the final designations. 2008 Designations Rule, 77 Fed.Reg. at 30,091.

Sierra Club, however, identifies no authority obligating the EPA to wait until the last possible minute to promulgate its designations. And in this case, doing so would have made little sense. The EPA entered into the consent decree precisely to settle allegations that it had *already* missed the Act's statutory deadlines for promulgating the 2008 ozone NAAQS designations. *See id.* Accepting Sierra Club's position would effectively call for the EPA to infringe the Act's deadlines still further. In any event, as the EPA explained in denying Sierra Club's petition for reconsideration of the designations after the May 1, 2012, certification deadline passed and 2009 to 2011 data were fully certified and available to the EPA, "[n]ew technical data become available on a regular basis." Letter from Lisa P. Jackson, Adm'r, EPA to Robert Ukeiley, Counsel, Sierra Club enclosure p. 2 (Dec. 14, 2012). The EPA reasonably concluded that delay "to consider such new information would result in a never-ending process in which designations are never finalized." *Id.* Indeed, Sierra Club itself has already filed a petition for reconsideration based on *2010 to 2012 data*. *See* Sierra Club Reply Br. 8. The EPA could reasonably conclude that the process must end at some point. We conclude that the agency did not act arbitrarily in ending it here. *Cf. Catawba Cnty.,* 571 F.3d at 51 ("New York's underlying complaint is that the iterations should have continued, perhaps *ad infinitum*. But such a process is inconsistent with the CAA: Congress imposed deadlines on EPA and thus clearly envisioned an end to the designations process.").

With that conclusion, and having reviewed the remainder of Sierra Club's challenges and determined that they lack merit, we deny the group's petition for review. *See Catawba Cnty.,* 571 F.3d at 52.

D. MISSISSIPPI

The State of Mississippi challenges the EPA's use of 2008 to 2010 data to classify the counties within the Memphis, Tennessee area, an analysis that resulted in a nonattainment designation for part of DeSoto County, Mississippi. Because we conclude that the EPA's actions were rational and in accordance with the Clean Air Act, we deny Mississippi's petition for review.

1. Mississippi Background

In Mississippi and elsewhere, the EPA conducted the designations for metropolitan areas through a two-step process. First, the EPA examined air-quality data from all regulatory monitors in a metropolitan area. If no monitors in the area showed a NAAQS violation, no county in the area would be designated nonattainment. In that event, there would be no second step. But if a single monitor from the area showed a NAAQS violation, the county housing the violating monitor would ***159** be designated nonattainment. *See* 2008 Guidance at 3–4. In that case, the EPA would proceed to the second step for that metropolitan area.

The second step took account of the fact that the Act mandates nonattainment designations not only for areas themselves exceeding the relevant NAAQS, but also for all areas that "contribute[ ]" to a NAAQS violation in a "nearby area," even if the "contributing" area's air quality—considered alone—meets the NAAQS. *See* 42 U.S.C. § 7407(d)(1)(A)(i); 2008 Guidance at 3–4. In the second step, the EPA assessed each county in a metropolitan area with a violating monitor on a case-by-case basis to determine if the county contributed to the identified violation. If, on the basis of a multi-factor test, the EPA determined that a county "contributed" to the NAAQS exceedance at the violating monitor in another county, the EPA also designated the contributing county as nonattainment. We have repeatedly upheld multi-factor contribution analyses as consistent with the Act's designation process under section 107—a conclusion that Mississippi does not challenge here. *See, e.g., ATK Launch Sys.,* 669 F.3d 330; *Catawba Cnty.,* 571 F.3d 20. *See generally supra* § II.

In 2011 and 2012, the EPA conducted that two-step designation process for the Memphis CBSA. The Memphis CBSA consists of several counties in Tennessee (Shelby, Tipton, and Fayette), Mississippi (DeSoto, Marshall, Tate, and Tunica), and Arkansas (Crittenden). *See* Office of Mgmt. & Budget, OMB Bulletin No. 10–02, Update of Statistical Area Definitions and Guidance on Their Uses 40 (Dec. 1, 2009). At the first step, the EPA evaluated 2008 to 2010 certified air-quality data and detected a NAAQS violation at the monitor in Shelby County, Tennessee. Proceeding to the second step, the EPA conducted the multi-factor analysis and determined that part of DeSoto County, Mississippi, contributed to the Shelby County violation.

On December 9, 2011, the EPA notified Mississippi that it planned to designate part of DeSoto County as nonattainment when it promulgated the final designations in 2012. The EPA invited Mississippi (and all other states) to provide to the agency by February 29, 2012, any additional information for consideration in the final designation process—including any early-certified 2011 data. *See* Memphis, TN–MS–AR Area Designations for the 2008 Ozone NAAQS 3–4 [hereinafter Memphis Area Designations]. Mississippi responded to the EPA's multi-factor analysis with its own multi-factor analysis, disputing the EPA's conclusion that DeSoto County contributed to any violation in Shelby County. Additionally, Mississippi and Tennessee—two of the three states in the Memphis CBSA—early-certified their 2011 data before the February 29, 2012, deadline. Arkansas—the third state in the Memphis CBSA—declined to early-certify any 2011 data.

On May 21, 2012, the EPA published its final designations for the Memphis CBSA. At the first step of the two-step designation process, the agency used 2008 to 2010 data and again identified a violation at the Shelby County monitor. The EPA then moved to the second step and, after considering Mississippi's multi-factor analysis and updating its own analysis accordingly, reiterated its original conclusion that part of DeSoto County contributed to the Shelby County violation. The agency therefore designated part of DeSoto County as nonattainment. *See* Memphis Area Designations at 16. Mississippi claims that designation was arbitrary and capricious. We disagree.

*160 2. Challenge to the First Step of the Designation Process

[8] First, Mississippi argues that the EPA acted arbitrarily in using 2008 to 2010 data for the first step of the two-step designation process (*i.e.,* identifying violating monitors within a CBSA) even though the EPA possessed early-certified 2011 data from Tennessee. The 2009 to 2011 data showed no NAAQS violation at the Shelby County monitor. Accordingly, Mississippi argues, no violation should have been identified at the first step of the two-step designation process. But the EPA declined to evaluate Shelby County using the early-certified 2009 to 2011 data, instead using the 2008 to 2010 data. True, the EPA must adequately explain why it declined to rely on the early-certified 2011 data. *See City of Waukesha,* 320 F.3d at 248. But the agency did so.

At the time of the final designations, the EPA had in its possession early-certified data from Mississippi and Tennessee, but not from Arkansas. In the first step of its two-step designation process, the EPA evaluates all air-quality monitors in a metropolitan area. Without 2011 Arkansas data, the EPA did not have a full set of 2011 data for the Memphis CBSA. The EPA only had data from different time horizons—2008 to 2010 data for the Arkansas portion of the Memphis CBSA, and 2009 to 2011 data for the Tennessee and Mississippi portions of that same CBSA. The agency declined to rely on this mismatched dataset. Instead, the EPA opted to rely on the most recent matched dataset in its possession: the complete set of 2008 to 2010 data. We see no reason—and Mississippi provides none—to declare irrational the EPA's conclusion that comparing data from the same time period would be more appropriate than analyzing data from different time periods in the same evaluation process. Cognizant of the substantial deference we owe the EPA in that highly technical evaluation, *see Catawba Cnty.,* 571 F.3d at 41, we find the EPA was entitled to rely on a matched dataset instead of a mismatched one.

Even assuming the EPA's choice to rely only on matched datasets for the Memphis CBSA was reasonable (as we conclude it to be), Mississippi argues that the EPA's approach nonetheless was arbitrary because the agency required a matched dataset for Memphis-area designations but allegedly relied on a mismatched dataset for Chicago-area designations. "[I]nconsistent treatment," we have found, is a "hallmark of arbitrary agency action." *Id.* at 51. There was no inconsistent treatment here, however. In both Chicago and Memphis, the EPA relied only on matched datasets in the designation process.

With regard to the Chicago metropolitan area, Illinois early-certified its 2011 data. Wisconsin and Indiana—portions of which also lie in the Chicago metropolitan area—did not early-certify. Illinois's early-certified data showed a violating monitor in the Chicago area. At the first step of the Chicago-area designation process, the EPA relied on Illinois's early-certified data, noted the violation, and thus proceeded to the second step's multi-factor contribution analysis for all Chicago-area counties.

Mississippi argues that, because the EPA only possessed early-certified data from Illinois, it used a mismatched dataset for Chicago's designations. Consequently, Mississippi claims that the EPA took different approaches to dataset selection between Memphis and Chicago. Mississippi's argument rests on a flawed understanding of the EPA's designation process.

At the first step of the process, a single violating monitor suffices to conclude the analysis and move to the second step. Though only Illinois had early-certified its ***161** data, that data showed a violating monitor. That was enough to terminate the first step of the process and move to the second step. It thus became irrelevant whether Wisconsin or Indiana data showed any violations: the EPA would proceed to the second step of the analysis regardless, based on the Illinois violation alone. The EPA therefore had a *sufficient* matched dataset of 2009 to 2011 data (albeit data from only one state, Illinois) to proceed to the second step of the designation process using 2009 to 2011 data alone. By contrast, the EPA had no matched dataset of 2009 to 2011 data in the Memphis area sufficient to complete the first step of the two-step process using that data alone. While data showing a *single* violating monitor are enough to end the first step and proceed to the second step, data showing *all* monitors in compliance would be needed to *avoid* proceeding to the second step's multi-factor analysis—*i.e.,* to terminate the two-step process at the first step.

As a result, when Arkansas declined to early-certify its 2011 data, the EPA could not determine if the entire Memphis CBSA showed NAAQS compliance at all monitors for the 2009 to 2011 period; the agency lacked a sufficient 2009 to 2011 matched dataset with which to do so. The EPA then relied on the most recent matched dataset sufficient to complete the first-step analysis (the 2008 to 2010 data), just as the EPA selected the most recent matched dataset sufficient for the first-step analysis of the Chicago area. The EPA therefore acted in a consistent manner in both areas, each time using the most recent matched datasets sufficient to complete the first step of the two-step designation process.

3. Challenge to the Second Step of the Designation Process

[9] Mississippi also challenges the EPA's application of the second step of the designation process. The EPA acted arbitrarily, the state argues, in applying the multi-factor test and concluding that DeSoto County contributed to the Shelby County violation. We find no reason to disturb the EPA's analysis.

First, Mississippi challenges the EPA's differing articulations of the multi-factor test. As pronounced in the 2008 Guidance, the EPA originally conceived of that test as consisting of nine factors. In making the final designations, the EPA applied a five-factor test. *See supra* § I.B–C, The state argues that the EPA's "consolidat[ion]" of the test from nine to five factors was arbitrary and capricious. State & County Br. 15. We disagree.

At the outset, we do not necessarily agree that the EPA was required to adhere to the 2008 Guidance. The 2008 Guidance did not purport to be a legislative rule, and it explicitly provided that it was "not binding on states, tribes, the public or the EPA." 2008 Guidance at 4; *cf. Catawba Cnty.,* 571 F.3d at 33–34 (materially similar guidance for

$PM_{2.5}$ NAAQS designations did not "create or modify legally binding rights").

But even if we assume that the 2008 Guidance *was* binding, the EPA did not deviate from it in the final designations. The "consolidation" of the factors was just that—a consolidation. It effected no deletion. During the final designation process, the agency simply grouped several of the 2008 Guidance factors into a single factor, the consideration of which necessarily entailed consideration of the multiple 2008 Guidance factors now residing within it. We find no examples of a final designation that failed to consider a factor identified in the 2008 Guidance. With "no bright line for any of the factors," and with each factor "weighted considering the unique circumstances of each nonattainment area," Response to Comments at 61, the consolidation worked no substantive ***162** change and thus affords no basis for setting aside the EPA's analysis.

Second, Mississippi challenges the EPA's specific application of the multi-factor test to DeSoto County. We accord the EPA "extreme deference" in applying that test, and will overturn the EPA's designations only if the agency applied the test "so erroneously in a particular case that it could not have reasonably concluded that a county was contributing to nearby violations." *Catawba Cnty.,* 571 F.3d at 40–41. This is not such a case. The agency provided data showing that DeSoto County's NO_x and SO2 (ozone precursors) emissions were the second-highest in the Memphis CBSA. Memphis Area Designations at 8. The county also had the second highest number of workers commuting to counties with violating monitors, the second highest number of vehicle miles traveled in the CBSA, and the highest percentage population growth over the last decade. Those factors led the EPA to conclude that DeSoto County was integrated with Shelby County in a way that indicated ozone contribution. *Id.* at 9–10. Additionally, meteorological analysis at the Shelby County monitor showed weather patterns characterized in part by winds blowing in from DeSoto County. *Id.* at 12. On those bases, the EPA reasonably concluded that DeSoto County contributed to the Shelby County violation.

Mississippi principally argues that significant "commerce activity" occurring outside of DeSoto County (including interstate highway traffic, rail and barge transportation, diesel fuel sales, and air traffic) means that other counties contribute to the Shelby County violation more than DeSoto County does—and that, because some of those counties avoided nonattainment designations, DeSoto County should, too. Miss. Dep't of Envtl. Quality, Air Div., 2008 Ozone Standard Designation Recommendation for DeSoto County, Mississippi 8–12 (Feb. 2012). But the EPA considered that argument and determined in a well-reasoned analysis that the data from Mississippi was only one consideration in the designation process. *See* Response to Comments at 97; *see also* Memphis Area Designations 1–31. The EPA concluded that DeSoto County *did* contribute to Shelby County's violation in light of the many other factors the agency considered. Memphis Area Designations at 16.

Looking at the same data, Mississippi would simply reach a different conclusion. We, however, do not sit to second-guess the EPA's conclusions in an area identified by the Congress as within the agency's technical expertise. We only ask if the EPA "considered all relevant factors and articulated a rational connection between the facts found and the choice made." *ATK Launch Sys.,* 669 F.3d at 336 (internal quotation marks omitted). We conclude that it did.

With that conclusion, and having considered Mississippi's other challenges and determined that they lack merit, we deny the state's petition for review. *See Catawba Cnty.,* 571 F.3d at 52.

E. LAKE & PORTER COUNTIES, INDIANA

[10] Petitioner Indiana challenges the designation of two of its counties as nonattainment. According to Illinois's certified 2009 to 2011 data, the monitoring site at Zion, Illinois exceeded the NAAQS by 1 part per billion (ppb). *See* Chicago–Naperville, Illinois–Indiana–Wisconsin Area Designations for the 2008 Ozone NAAQS at 7–8 [hereinafter Chicago Area Designations]. Zion is about sixty miles from the Indiana border and, like the Indiana counties at issue here, belongs to the Chicago–Naperville–Michigan City CSA. Following the 2008 Guidance, the EPA presumed that all counties in this CSA should be ***163** designated as nonattainment areas due to the Zion violation, and then conducted its five-factor analysis. The agency preliminarily concluded that three Indiana counties—Lake, Porter, and Jasper—should be included in the nonattainment area.

In response to the EPA's 120–day letter, Indiana pointed to multiple asserted flaws in the EPA's analysis. Most relevant here, it said that the agency had failed to account for the impact of a recent statutory change to Illinois's vehicle emissions testing program. It also maintained that the agency's meteorological analysis suffered from multiple weaknesses and inconsistencies.

The EPA ultimately reversed its designation of Jasper County, but finalized the nonattainment designations of Lake and Porter Counties. Chicago Area Designations at 21. Indiana now challenges those nonattainment designations as arbitrary and capricious.

1. Challenge Regarding Illinois's Vehicle Inspection Change

First, Indiana challenges the EPA's position regarding Illinois's statutory change. After a prior nonattainment designation, Illinois had established a vehicle inspection and maintenance program that covered all model years beginning in 1968.[11] In 2006, however, Illinois exempted vehicles with model years between 1968 and 1995 from the testing requirements. *See* 625 Ill. Comp. Stat. 5/13C–15(a)(6)(L) (2012). Indiana maintains that it was the increase in vehicle emissions accompanying this exemption that directly caused the violation at the Zion monitor. Moreover, it contends that this legislative change amounted to an intentional violation of Illinois's SIP.

As the EPA points out, we made clear in *Catawba County* that a "contributing" county need not be the but-for cause of a violation in order to warrant a nonattainment designation. Resp't's Br. 94; *see Catawba Cnty.,* 571 F.3d at 39 ("[E]ven were we to think that 'contribute' unambiguously means 'significantly contribute,' we still disagree that 'significantly contribute' unambiguously means 'strictly cause.' "). And here, regardless of Illinois's statutory change, the EPA's five-factor analysis demonstrated that both Lake and Porter Counties contributed to the Zion monitor. Chicago Area Designations at 6–21.[12]

The alleged illegality of Illinois's statutory change does not affect our conclusion. The Clean Air Act offers other avenues for addressing a State's failure to comply with its SIP. In particular, the EPA Administrator can call for a SIP revision after "find[ing] that the applicable implementation plan for any area is substantially inadequate" ***164** to comply with the NAAQS. 42 U.S.C. § 7410(k)(5). The EPA declined to do so here and, instead, recently approved the Illinois change.[13] Indiana has since petitioned the Seventh Circuit to review the EPA's approval. *See* EPA 28(j) Letter (Oct. 22, 2014). That is the appropriate forum for challenging the Illinois change, which in no way diminished the contribution of the Indiana counties.

2. Challenge to the EPA's Response to Comments

Next, Indiana argues that the EPA failed to adequately respond to its comments about the impact of Milwaukee, Wisconsin's emissions on the violation at the Zion monitor. According to the source apportionment modeling submitted by Indiana, the Milwaukee area contributed over 5 ppb to the Zion violation, while Lake, Porter, and Jasper Counties contributed 4 ppb, 2 ppb, and 0.5 ppb, respectively. *See* Letter from Ind. Dep't of Envtl. Mgmt. to EPA, Enclosure 1 at 13–14 (Apr. 13, 2012). This, Indiana maintains, produced the "inconsistent and unfounded" result of nonattainment designations for the Indiana counties but an attainment designation for the Milwaukee area. *Id.* at 14.

As an initial matter, we note that, because the Milwaukee area is not a single county but rather is a metropolitan area made up of five counties, Indiana's argument is premised on an apples-to-oranges comparison. More important, we have no basis for finding the EPA's designations inconsistent given that Indiana's modeling—which was limited to meteorological linkages and therefore fell short of a full analysis—did not establish that Milwaukee "contributed to" the Zion violation under the agency's five-factor analysis. By contrast, after conducting its full five-factor analysis, the EPA found that Lake and Porter Counties did contribute. Accordingly, the EPA's determination regarding the Milwaukee metropolitan area was neither unreasonable nor inconsistent with its determination regarding the Indiana counties.

We also find that the EPA did adequately respond to Indiana's comments about its modeling results, although without mentioning Milwaukee specifically. Indeed, the modeling was one of the factors that led the EPA to reconsider its designation of Jasper County. *See* Chicago Area Designations at 21 (describing Jasper County's 0.5 ppb contribution as "not significant"). But the EPA simply disagreed with Indiana's premise that 2 ppb and 4 ppb were insufficient contributions when considered as part of the five-factor test, for reasons that were reasonable and well explained. *See id*. at 18 ("In keeping with EPA's ozone contribution levels used to select states that should be covered in regional emission control programs, 2 ppb to 4 ppb ozone concentration contributions are considered to be significant ozone contributions.").

3. The Remaining Challenges

Finally, we briefly consider Indiana's remaining arguments. First, the record does not support Indiana's claim that the EPA improperly relied on late-submitted data from Wisconsin's Chiwaukee Prairie monitor, rather than relying solely on the Zion monitor data, in making the contribution determinations regarding the Indiana counties. *See* Chicago Area Designations at 8 (noting that the EPA considered the Wisconsin data in determining whether Kenosha County, Wisconsin (and not the ***165** Indiana counties) should be included in the Chicago nonattainment area); *id*. at 21–22 (describing bases for Lake, Porter, and Kenosha County designations). Second, the EPA did not fail to adequately explain why it used some 2006 to 2008 weather data in conducting the contribution analysis. The agency explained that historical data provided a "general conceptual model to explain the development and transport of high ozone levels in this area." Addendum to Response to Comments at 7 (May 31, 2012); *see also* EPA Response to Indiana Pet. for Reconsideration 3. That explanation is deserving of the deference that we give to the EPA's "evaluati [on] [of] scientific data within its technical expertise," *Catawba Cnty.,* 571 F.3d at 41 (quoting *City of Waukesha,* 320 F.3d at 247).

In sum, we reject Indiana's contention that the EPA's designations of Lake and Porter Counties are arbitrary or capricious.

F. WISE COUNTY, TEXAS

Petitioners State of Texas; Wise County, Texas; Texas Commission on Environmental Quality; Devon Energy Corporation; Targa Resources Corporation; the Texas Pipeline Association; and the Gas Processors Association (collectively, Texas Petitioners) challenge the EPA's designation of Wise County as nonattainment. They make several claims, including that the EPA subjected Wise County to arbitrarily disparate treatment, violated the U.S. Constitution and acted beyond its authority under the Clean Air Act. For the reasons discussed below, however, we do not disturb Wise County's nonattainment designation.

1. Wise County Background

Wise County is one of 22 counties in and around the Dallas–Fort Worth metropolitan area, which reports some of the most severe NAAQS violations in the country. Although Wise County has no monitor of its own, it borders several counties with a total of seven violating monitors, the closest of which reports ambient ozone levels that exceed the 2008 NAAQS by 0.010 ppm. Moreover, because Wise County falls within the CSA of Dallas–Fort Worth, it is presumptively included within the nonattainment area.

Despite Wise County's presumptive inclusion in the Dallas–Fort Worth nonattainment area, the EPA designated it as attainment when it updated the ozone NAAQS in 1997. For this reason, Texas did not include Wise County among the nine Dallas–Fort Worth counties it recommended for nonattainment status when it submitted its initial designations to the EPA in March 2009.[14] On December 9, 2011, the EPA informed Texas that it planned to include Wise County in the Dallas–Fort Worth nonattainment area due to its "comparatively high emissions" and "close proximity ... to violating monitors." *See* Texas Area Designations for the 2008 Ozone NAAQS at 13 [hereinafter Preliminary Dallas–Fort Worth Area Designations].

The EPA redesignated Wise County based on the five-part "weight of the evidence analysis" articulated in the 2008 Guidance.[15] *See id*. at 1–2. The second and third factors —emissions data and meteorology—factored prominently in the EPA's decision. *See id.* at 13. As for emissions, the EPA concluded that oil-and- ***166** gas collection and production in the Barnett Shale reservoir—a gas-rich geological formation covering a significant portion of Wise County—resulted in Wise County's inclusion among the eight highest emissions-producing counties in the Dallas–Fort Worth area. [16]

As for meteorology, although historic wind patterns in the Dallas–Fort Worth area suggest that air does not normally move from Wise County to counties with monitors registering NAAQS violations, the EPA concluded that Wise County was upwind of the monitors on days when ozone levels at the monitors peaked. *See* Preliminary Dallas–Fort Worth Area Designations at 10. In reaching this conclusion, the EPA used the National Oceanic and Atmospheric Administration's Hybrid Single Particle Lagranian Integrated Trajectory (HYSPLIT) model instead of relying solely on historic wind patterns in the Dallas–Fort Worth area. *See id.* HYSPLIT charts the path, or "back trajectory," that air takes before it collects in a certain area. *See id.* According to the EPA, HYSPLIT modeling "is specifically designed to give an estimate of the probable path a parcel of air travels in reaching a given location at a given time" and is particularly illuminating for an area like Wise County, which has "light and variable" wind patterns. Response to Comments at 59–60.

After the EPA notified Texas that it planned to include Wise County in the Dallas–Fort Worth nonattainment area, numerous individuals and organizations submitted comments urging the EPA to reconsider its Wise County designation. One commenter insisted that other Texas counties were more responsible than Wise County for the NAAQS violations in the Dallas–Fort Worth area. Others argued that the EPA's use of HYSPLIT modeling was arbitrary and capricious because, when designating other areas of the country, the EPA relied solely on historic wind patterns. According to these commenters, if the EPA had done the same with Wise County, it would not have designated Wise County as nonattainment because, according to historical wind patterns in the Dallas–Fort Worth area, Wise County was downwind of violating monitors more than 95 per cent of the time.

For its part, Petitioner Texas Commission on Environmental Quality (Texas Commission) submitted its own data based on photochemical grid source apportionment modeling. Source-apportionment modeling helps determine the potential future impact of an emissions source area (such as Wise County) on downwind monitors by "keep[ing] track of the origin of the [ozone] precursors creating the ozone." Industrial Br. 7. It does so by combining "the meteorology/transport of air parcels during high ozone days with the emissions of [a] specific area[ ]," (here, Wise County), "to evaluate potential impact on ozone levels." Dallas–Fort Worth, Texas Final Area Designations for the 2008 Ozone NAAQS at 16 [hereinafter Final Dallas–Fort Worth Area Designations]. Although the EPA does not typically perform source-apportionment modeling during the NAAQS designation process, it "has used it in the past for large-scale rulemakings, such as the Clean Air Interstate Rule and Cross State Air Pollution Rule" and it considers source-apportionment modeling data if a state submits it. *See* Resp't's Br. 126. According to the Texas Petitioners, source-apportionment modeling suggests that Wise County emissions had only a negligible impact on the monitors registering ***167** NAAQS violations in the Dallas–Fort Worth area.

On April 30, 2012, the EPA issued its omnibus Response to Comments, many of which addressed the objections to the Wise County designation. The EPA defended HYSPLIT modeling as an "excellent tool[ ]" that it generally "prefer [s] over more basic assessments of wind speed and direction." Response to Comments at 59. The EPA found HYSPLIT modeling to be a more precise measure of wind patterns than historic data, which data, according to the agency, is "potentially misleading in cases where wind speeds are light and variable, or vary substantially across the location of the meteorological observation and the monitored high ozone concentrations." *Id.* These conditions existed in the Dallas–Fort Worth area. [17] Although the EPA acknowledged it could not always use HYSPLIT modeling, it nonetheless declined to ignore HYSPLIT data "where the information is available, even if the information is not available in all areas." Response to Comments at 59.

Along with its omnibus responses, the EPA issued its Final Dallas–Fort Worth Area Designations, which again applied the five-factor test. In that document, the EPA addressed the source-apportionment modeling submitted by the Texas **Commission**. The **EPA** took issue with the model's methodology and made several amendments to it.

First, the **EPA** faulted the Texas **Commission** for not using data from an entire ozone season in its model. To account for this omission, the **EPA** examined not only the *average* (*i.e.,* relative) impact of Wise County emissions on Dallas–Fort Worth monitors but also the *absolute* (*i.e.,* maximum) impact of the emissions. *See* Final Dallas–Fort Worth Area Designations at 17. The average/relative approach advocated by the Texas **Commission** averaged the impact that Wise County emissions might have on the monitors on all days when the monitors were expected to exceed the ozone NAAQS. As a practical matter, averaging the impact of Wise County emissions meant that the Texas **Commission's** model accounted for days on which wind patterns were not expected to move air pollutants from Wise County to the violating monitors. According to the **EPA**, the Texas **Commission's** average approach had "the effect of masking the impacts that occur on days when the wind *does* flow from Wise County to violating monitors," an imprecision that was aggravated by the model's limited dataset. *See* Resp't's Br. 136 (emphasis added). To account for this imprecision, **EPA** chose to look at the "direct," or "absolute," predicted effect that Wise County emissions would have on violating monitors rather than the average effect they were expected to have.

Second, the **EPA** noted that the Texas **Commission's** source-apportionment model under-predicted peak ozone levels in the Dallas–Fort Worth area by a range of 0.005 to 0.020 ppm. As a practical matter, the under-prediction meant that the Texas **Commission's** model underestimated the number of days that Wise County contributed to NAAQS violations. To compensate therefor, the **EPA** examined the impact of Wise County emissions not only on days when the monitors exceeded the ozone NAAQS threshold of 0.075 ppm, but also on days when the monitors reported ozone levels in excess of 0.070 ppm.

***168** After making these adjustments, the **EPA** reinterpreted the data from the Texas **Commission's** source-apportionment model and concluded that it in fact *supported* including Wise County in the Dallas–Fort Worth nonattainment area. *See* Final Dallas–Fort Worth Area Designations at 20. Specifically, the **EPA** concluded that Wise County emissions (1) "resulted in 6 occurrences (over 4 days) of an impact of more than 0.75 ppb days" on Dallas–Fort Worth area monitors; (2) "had even larger impacts of up to 5 ppb on the Eagle Mountain Lake monitor," a monitor one-half mile from the Wise County border that reported particularly severe NAAQS violations; and (3) "resulted in 9 occurrences (over 5 days) [causing] impacts of more than 0.75 ppb [to] occur [ ] at" Dallas–Fort Worth monitors. *See id.* For these reasons, the **EPA** maintained its inclusion of Wise County in the Dallas–Fort Worth nonattainment area.

Dozens of individuals and organizations filed petitions for reconsideration of the **EPA's** Wise County nonattainment designation, including the Texas **Commission** and the other Texas Petitioners. On December 14, 2012, the **EPA** denied each petition for reconsideration. Before us, the Texas Petitioners' challenges to the **EPA's** Wise County designation are grouped as follows: (1) The **EPA's** use of HYSPLIT Modeling and its re-evaluation of the Texas **Commission's** source-apportionment modeling were arbitrary and capricious; (2) the **EPA's** designation of Wise County as nonattainment violated the Commerce Clause, U.S. CONST. art. I, § 8, cl. 3, the Tenth Amendment, *id.* amend. X, and the Due Process Clause, *id.* amend. V; and (3) the **EPA** violated at least one of several statutory provisions, including provisions of the Clean Air Act. We address each argument in turn.

2. The Arbitrary & Capricious Challenges

The Texas Petitioners' primary arguments are that the **EPA** erred when it (i) used HYSPLIT modeling rather than prevailing wind patterns [18] and (ii) adjusted the Texas **Commission's** source-apportionment modeling. [19] To prevail on either argument, the Texas Petitioners must demonstrate that the **EPA** acted arbitrarily and capriciously and, to do that, they must show that the **EPA** either failed to consider "all relevant factors" or to articulate a "rational connection between the facts found and the choice made." *ATK Launch Sys.,* 669 F.3d at 336. Mindful of the "extreme degree of deference" we owe to the **EPA** "when it is evaluating scientific data within its technical expertise," *Catawba Cnty.,* 571 F.3d at 41, and for the reasons stated below, we conclude that neither argument has merit.

i. HYSPLIT Modeling

[11] The Texas Petitioners challenge the **EPA's** use of HYSPLIT modeling on three fronts. First, they argue that the **EPA** could not legitimately use HYSPLIT modeling at all because HYSPLIT "cannot measure ozone formation or transport." State & County Br. 45. Second, they contend that the **EPA** arbitrarily treated Wise County differently by using HYSPLIT modeling to designate it as nonattainment while using historic wind patterns to designate other allegedly similar counties as attainment. And third, they argue that, even among other counties that the **EPA** subjected to HYSPLIT modeling, it arbitrarily treated Wise County worse because the respective HYSPLIT models demonstrated that wind moved through those other counties—each of which the **EPA** designated as attainment—more frequently ***169** than it moved through Wise County. We address each argument in turn.

First, we find no merit in the Texas Petitioners' conclusory argument that the **EPA** erred by using HYSPLIT modeling at all because HYSPLIT modeling "cannot measure ozone formation or transport." *See* State & County Br. 45–46. Indeed, we rejected a materially indistinguishable challenge in *ATK Launch Systems,* 669 F.3d at 339, a case involving the **EPA's** 2006 fine particulate matter NAAQS designations. *See id*. at 334. We did so there because the **EPA** had taken "reasonable steps to ensure that the 'HYSPLIT' model's limitations were considered." *Id*. at 339 (quotation mark omitted).

Here too, the **EPA** took reasonable steps to account for HYSPLIT's limitations by evaluating the source-apportionment modeling and historical wind data that the Texas **Commission** submitted during the comment period. *See* Final Dallas–Fort Worth Area Designations at 14–20, 23. Because "[o]zone and ozone precursors can be transported to an area from sources in nearby areas or from sources located hundreds of miles away," *see* 2008 Designations Rule, 77 Fed.Reg. at 30,088, the **EPA** reasonably concluded that HYSPLIT modeling, as a more precise measurement of the path taken by air masses containing ozone precursors, was useful in determining whether wind moving through Wise County could have transported emissions to the areas with the violating monitors.

Second, we find no merit in the Texas Petitioners' argument that the **EPA's** use of HYSPLIT modeling to designate Wise County as nonattainment amounts to arbitrarily disparate treatment. At the outset, it bears repeating that this Court has expressly sanctioned the **EPA's** use of a holistic, multi-factor, totality-of-the-circumstances test for making NAAQS determinations, *see ATK Launch Sys.,* 669 F.3d at 336; *Catawba Cnty.,* 571 F.3d at 39, and we have twice iterated that, when using a multi-factor test, " 'discrete data points' are *not* determinative" because isolating any one discrete consideration " 'ignores the very nature of the ... test, which is designed to analyze a wide variety of data on a case-by-case basis.' " *ATK Launch Sys.,* 669 F.3d at 336 (quoting *Catawba Cnty.,* 571 F.3d at 39) (emphasis added; alteration omitted). Indeed, because the **EPA's** "holistic assessment of numerous factors ... drives the process," we have recognized that "no single factor determines a particular designation." *Id*. For this reason, the **EPA** could have subjected Wise County to arbitrarily disparate treatment only if it treated genuinely "*similar counties* " dissimilarly. *Id*. (emphasis in original). Given "significant" differences among counties, "a direct one-to-one comparison of the data," including the methods used to measure such data, could be "inappropriate" or even "illogical." *Id*. at 337.

As noted, the **EPA** conducted a HYSPLIT analysis in areas where it "believed [HYSPLIT] could provide additional insight into whether [the] area [ ] contribute[s] to nonattainment." Resp't's Br. 110 n. 47. The **EPA** reasonably determined that Wise County was one such area because Dallas–Fort Worth "experiences light wind speeds and winds from variable directions," making HYSPLIT's more sophisticated evaluation of wind patterns "a more useful tool than annualized wind patterns." **EPA** Response to Pet. for Reconsideration from Devon Energy Corp. at 12. According to the **EPA**, this more refined analysis was not necessary for all areas of the country, particularly those in which "there was not significant debate over whether [they] should be included" in a nonattainment area. *See* Resp't's Br. 111. The **EPA's** decision to use HYSPLIT analysis in one area but not in another fits ***170** comfortably within the agency's "technical expertise," *Catawba Cnty.,* 571 F.3d at 41, and the **EPA's** explanation for the differing treatment was rational.

Moreover, although the Texas Petitioners direct this Court to other attainment areas that were not evaluated using HYSPLIT modeling—specifically, Orange County and Cattaraugus County in New York—the "significant" differences between Wise County and those counties "make a direct one-to-one comparison of the data underlying the analyses inappropriate." *ATK Launch Sys.,* 669 F.3d at 337. For instance, the EPA justified its Orange County attainment designation, in part, on its finding that "the density of [Orange County's] emissions and vehicle usages *are not* of the level of the other counties in the CSA that are in New York's proposed New York–Northern New Jersey–Long Island, NY–NJ–CT nonattainment area." New York–Northern New Jersey–Long Island, NY–NJ–CT Nonattainment Area Designations for the 2008 Ozone NAAQS at 16 (emphasis added). In contrast, the EPA justified its nonattainment designation of Wise County, in part, based on the "[t]he close proximity of [Wise County's] *comparatively high* emissions to violating monitors." Final Dallas–Fort Worth Area Designations at 23 (emphasis added).

Similarly, the EPA designated Cattaraugus County as attainment not only because "it is in the prevailing downwind direction from" the nearest violating monitor but also because "other monitors representative of Cattaraugus County, as well as the rest of upstate New York, are *attaining* the ozone standard." *See* Attainment Status for Jamestown, New York and the Remainder of Upstate New York at 6 (emphasis added). But in the Dallas–Fort Worth area, *seven* violating monitors surrounded Wise County and some of the monitors—including one located one-half mile from Wise County's border—reported levels of ambient ozone higher than anywhere else in the United States. Because "the core reason for the disparate designations" did not, as the Texas Petitioners would have it, reflect an "inconsistent approach to meteorology," Industrial Br. 19, the EPA did not arbitrarily and capriciously treat Wise County differently by evaluating its wind patterns using HYSPLIT modeling instead of prevailing wind patterns.

Third, when Wise County is compared to other counties for which the EPA used HYSPLIT modeling, it is clear that the EPA did not arbitrarily subject Wise County to disparate treatment. The Texas Petitioners point to four other counties—York, Dauphin and Lawrence Counties in Pennsylvania and Roane County, Tennessee—each of which the EPA designated as attainment notwithstanding HYSPLIT modeling demonstrated that air moved through them to violating monitors more frequently than through Wise County. But again, a holistic look at why the EPA designated these counties attainment but designated Wise County nonattainment demonstrates that the EPA did not act arbitrarily or capriciously.

For example, York and Dauphin Counties are both near Lancaster County, which houses all violating monitors in the area. Because Lancaster County "is served by a single-county transportation-planning agency," the EPA concluded that there were "strong jurisdictional arguments" for designating Lancaster as "a single county nonattainment area" and, accordingly, designating all other counties in the vicinity—including York and Dauphin—as attainment. *See* Pennsylvania Area Designations for the 2008 Ozone NAAQS at 29–31. In contrast, Wise County is part of the Dallas–Fort Worth CSA (which means it is presumptively included ***171** in the Dallas–Fort Worth nonattainment area) and is also part of the Dallas–Fort Worth metropolitan planning organization (which implements programs and projects to reduce emissions across all included counties). In other words, jurisdictional and regional planning concerns—*not* differing approaches to HYSPLIT modeling data—drove the EPA's conclusion that York and Dauphin Counties should be designated as attainment while Wise County should be designated as nonattainment.

The Texas Petitioners' comparisons of Wise County to Roane County, Tennessee, and Lawrence County, Pennsylvania, fare no better. Roane County is "geographically separated from the nearest county with a violating monitor" by approximately thirty miles and the ozone levels in the county between Roane and the next county with a violating monitor are in attainment. Resp't's Br. 122. The monitor in Lawrence County reports ozone levels that, at 0.066 ppm, are well below the EPA's NAAQS 0.075 ppm threshold. Moreover, the county with a violating monitor nearest to Lawrence County —Allegheny County—is not adjacent to Lawrence County. In contrast to both Roane County and Lawrence County, Wise County is adjacent to multiple counties reporting severe NAAQS violations, the closest of which is located a mere half mile from the Wise County line.

The dispositive principle that the Texas Petitioners try to, but ultimately cannot, avoid is that under the EPA's holistic analysis, "discrete data points" like the data from HYSPLIT modeling "are not determinative, because elevating them ignore[s] the very nature of the [holistic] test, which is designed to analyze a wide variety of data on a case-by-case basis." *ATK Launch Sys.,* 669 F.3d at 336 (quotation mark omitted). Based on the foregoing analysis, we cannot say that, had the EPA declined to evaluate Wise County's wind patterns using HYSPLIT modeling, Wise County "would not have been designated nonattainment." Industrial Br. 19. Because none of the areas discussed by the Texas Petitioners is truly "similarly situated" to Wise County, and because the EPA fully and rationally supported its use of HYSPLIT modeling for Wise County, it did not act arbitrarily or capriciously.

ii. Source–Apportionment Modeling

[12] The Texas Petitioners also challenge the EPA's modification of the Texas Commission's source-apportionment modeling on three fronts. First, they argue that the EPA has not rationally explained why it considered the source-apportionment modeling's projected *absolute* impact—instead of its projected *relative* impact—that wind from Wise County would have on violating Dallas–Fort Worth area monitors. Second, they argue that the EPA's analysis of the Texas Commission's source-apportionment modeling was inconsistent with its analysis of source-apportionment modeling submitted in connection with Illinois's designation of Lake County. And third, they argue that the EPA's decision to examine the model's projected absolute impact rather than its relative impact violated the EPA's earlier modeling guidance.

We note, at the outset, that the EPA's application, interpretation and modification of source-apportionment modeling plainly fall "within its technical expertise" and thus we owe it "an extreme degree of deference." *ATK Launch Sys.,* 669 F.3d at 338 (quotation marks omitted). To withstand judicial review, the EPA needs to articulate only a "rational connection between the facts found and the choice made," *Burlington Truck Lines,* 371 U.S. at 168, 83 S.Ct. 239, show that it treated "*similar counties* " similarly, *ATK Launch Sys.,* 669 F.3d at 336 (emphasis in original), ***172** and demonstrate that it did not run afoul of binding guidance, *see generally Appalachian Power Co. v. EPA,* 208 F.3d 1015, 1020–23 (D.C.Cir.2000). Because the EPA has done all three, we will not disturb its designation of Wise County as nonattainment based on the Texas Petitioners' objections to its interpretation of the Texas Commission's source-apportionment modeling.

First, the Texas Petitioners challenge the EPA's decision to reinterpret the source-apportionment modeling submitted by the Texas Commission. As discussed, *supra* § III.F.1, when the EPA received the Texas Commission's source-apportionment modeling data during the comment period, it observed that the model did not rely on data from an entire ozone season. Rather, the projections in the Texas Commission's model relied on data from June 2006 only. The Texas Commission based its approach on the fact that June 2006 purportedly presented "an exceptionally rich set of air quality and meteorological measurements," "had the most high-ozone days of any month" and experienced "all the meteorological conditions linked to formation of high ozone concentration." *See* Response to Texas Commission on Environmental Quality's Reconsideration Pet. at 3.

Despite these assurances, the EPA did not agree that one month of data, even an "exceptionally rich" month, was sufficient. Specifically, the EPA observed that the ozone season in the Dallas–Fort Worth area was bimodal (*i.e.,* reporting its highest ozone values in July–September but experiencing a lower ozone peak in May–June) and that the Texas Commission's reliance on limited data meant that it failed to account for "all of the meteorology regimes conducive for ozone events" in the Dallas–Fort Worth area. *See* Final Dallas–Fort Worth Area Designations at 16. According to the EPA, "emphasis on the average modeled impact is more appropriate when a full ozone season of model results is available." *See* Resp't's Br. 131. Because the Texas Commission's model was premised on baseline data excluding "events that happen in mid to late-summer that often set" the Dallas–Fort Worth area's ozone levels, the EPA examined both the projected average impact and the projected maximum impact of Wise County emissions. *See* Final Dallas–Fort Worth Area Designations at 16.

At bottom, the EPA had a "basic obligation" to conduct "reasoned decisionmaking." *Catawba Cnty.,* 571 F.3d at 25. When presented with the Texas Commission's source-apportionment modeling, the EPA determined that it "needed to be carefully evaluated and could not simply be accepted at face value," Resp't's Br. 126, identified several methodological flaws in the Texas Commission's data, adjusted the Texas Commission's submissions to account for the flaws and articulated, quite thoroughly, a "rational connection between the facts found and the choice made." *Burlington Truck Lines, Inc.*, 371 U.S. at 168, 83 S.Ct. 239. On this record, we cannot say that the EPA acted arbitrarily or capriciously in re-evaluating the Texas Commission's source-apportionment modeling data. Rather, the EPA's thorough treatment of all available data indicates that it in fact "surpassed" its "obligation of reasoned decisionmaking." *Catawba Cnty.*, 571 F.3d at 25.

Second, the Texas Petitioners argue that the EPA's modification to the Texas Commission's source-apportionment modeling subjected Wise County to arbitrarily disparate treatment. They compare the EPA's interpretation of the Texas Commission's modeling to its interpretation of source-apportionment modeling for the Chicago area. Specifically, they argue that (1) emissions from Jasper County, a Chicago-area ***173** county with attainment status, had a projected average impact on violating monitors similar to Wise County's; (2) the EPA should have evaluated the average impact of Wise County's emissions on violating monitors as it did for Jasper County; and (3) the EPA's evaluation of Wise County's maximum, as opposed to relative, estimated impact was, accordingly, inconsistent and resulted in an arbitrarily different result between Wise County and Jasper County.

Again, we emphasize that applying different methods to different areas, standing alone, does not give rise to arbitrarily disparate treatment and given "significant" relevant differences between two areas, "a direct one-to-one comparison of the data" or the methods used to measure such data can be "inappropriate." *ATK Launch Sys.*, 669 F.3d at 337. Here, the significant difference lies in the quality of data submitted by the Texas Commission compared to that submitted in support of Jasper County. Specifically, the source-apportionment model submitted in support of the Chicago-area designations included data from a full ozone season, which made "emphasis on the average modeled impact ... more appropriate." Resp't's Br. 131. As noted, the EPA modified the Texas Commission's source-apportionment model because it did not include data from a full ozone season.

Moreover, the EPA had to compensate for the fact that the Texas Commission's source-apportionment model underestimated the number of days that monitors in the Dallas–Fort Worth area exceeded the ozone NAAQS because the model under-predicted peak ozone levels around the monitors, sometimes by a significant range. The source-apportionment model for Jasper County, however, had the opposite problem; it did not account for recent emissions reductions at a Jasper County power plant and thus the Chicago-area source-apportionment model *over-reported* Jasper County's emissions impact. *See* Chicago Area Designations at 9–10. Stated differently, because Wise County's model under-reported its emissions impact and Jasper County's model over-reported its emissions impact, the EPA reasonably concluded that the two counties should receive different attainment designations.

Third, the Texas Petitioners argue that the EPA arbitrarily and capriciously deviated from its earlier guidance on source-apportionment modeling, which guidance allegedly expressed a preference for relative, rather than absolute, modeling. Specifically, they argue that the EPA's reliance on Wise County's maximum potential emissions impact directly conflicts with the EPA's 2007 "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze" (2007 Attainment Guidance). In that guidance, the EPA stated that its "recommended test is one in which model estimates are used in a 'relative' rather than 'absolute' sense." *Id*. at 15.

As a threshold matter, the 2007 Attainment Guidance does not speak to the use of source-apportionment modeling in the designation process; rather, it recommends procedures that a state can use after it has been designated as nonattainment to show that its proposed emission control strategy will eventually result in attainment status. But even assuming that the 2007 Attainment Guidance informs the current NAAQS designation process, the EPA did not err by deviating from it. Indeed, the 2007 Guidance expressly contemplates deviations in appropriate cases:

> This document does not substitute for any Clean Air Act provision or EPA regulation, nor is it a regulation itself. Thus, it does not impose binding, enforceable ***174** requirements on any party, nor does it assure that EPA will approve all instances of its application. The guidance may not apply to a particular situation, depending upon the circumstances. The EPA and State decision makers retain

> the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate....
>
> Users are cautioned not to regard statements recommending the use of certain procedures or defaults as either precluding other procedures or information, or providing guarantees that using these procedures or defaults will result in actions that are fully approvable.... EPA cannot assure that actions based upon this guidance will be fully approvable in all instances.

2007 Attainment Guidance at ix.

As noted, the EPA fully explained why it revised and independently evaluated the Texas Commission's source-apportionment modeling to account for "the limited data set [the Texas Commission] relied upon." Resp't's Br. 136. Because the 2007 Attainment Guidance did not compel the EPA to limit its consideration to relative projected impacts, and because the EPA articulated a "rational connection between the facts found and the choice made," *Catawba Cnty.,* 571 F.3d at 41, it did not act arbitrarily or capriciously when it relied on Wise County's absolute, rather than relative, impact on NAAQS-violating monitors.

The fundamental deficiency in the Texas Petitioners' challenges to the EPA's revision of the Dallas–Fort Worth area source-apportionment model is that, to establish that "EPA's administration of the complicated provisions of the Clean Air Act" was erroneous, *Catawba Cnty.,* 571 F.3d at 41, they have to demonstrate more than mere disagreement with the EPA's reasoning. Barring an unreasonable or irrational application of the "scientific data within [the EPA's] technical expertise," *City of Waukesha,* 320 F.3d at 247, we cannot say that the EPA acted arbitrarily or capriciously. The record plainly shows that the EPA "considered all relevant factors and articulated a 'rational connection between the facts found and the choice made' " when it declined to accept the Texas Commission's source-apportionment model without modification. *Catawba Cnty.,* 571 F.3d at 41 (quoting *Burlington Truck Lines,* 371 U.S. at 168, 83 S.Ct. 239). We therefore hold that the EPA did not act arbitrarily or capriciously when it did so.

3. The Constitutional Challenges

In this section, we address three constitutional challenges that Texas, Wise County, and the Texas Commission on Environmental Quality (collectively, Texas State Petitioners) raise to the EPA's designation of Wise County, Texas as a nonattainment area.

i. The Tenth Amendment & The Spending Clause

The Texas State Petitioners, joined by the Mississippi Petitioners, argue that § 7407(d)(1)(B) and related sections of the Clean Air Act—at least to the extent that they authorize the EPA to override the State's designation and declare Wise County a nonattainment area—violate the Tenth Amendment and exceed the Congress' authority under the Spending Clause.

First, the Texas State Petitioners maintain that § 7407(d)(1)(B) unlawfully permits the EPA to "commandeer[ ] State regulators to enforce a federal regulatory program." State & County Br. 32. The section grants the EPA authority to "make such modifications as the Administrator deems necessary to the designations of the areas ... submitted [by the States]." 42 U.S.C. § 7407(d)(1)(B)(ii). According to the petitioners, "[w]hen EPA overrides a State, it compels State regulators to enforce ***175** a myriad of federal requirements involving emissions controls, clean fuel programs, transportation and land use limitations in the designated area." State & County Br. 33 (citing 42 U.S.C. §§ 7511 *et seq.* (outlining requirements specific to ozone nonattainment areas)).

[13] [14] The Texas State Petitioners are correct that "the Federal Government may not compel the States to implement ... federal regulatory programs," *Printz v. United States,* 521 U.S. 898, 925, 117 S.Ct. 2365, 138 L.Ed.2d 914 (1997).[20] But the Clean Air Act does not do that. Instead, the statutory scheme authorizes the EPA to promulgate and administer a federal implementation plan of its own if the State fails to submit an adequate state implementation plan. *See* 42 U.S.C. § 7410(c). And as we recently noted, the Supreme Court has "repeatedly affirm[ed] the constitutionality of federal statutes that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it." *Texas v. EPA,* 726 F.3d 180, 196–97 (D.C.Cir.2013) (citing *New York v. United States,* 505 U.S. 144, 167–68, 173–74, 112 S.Ct.

2408, 120 L.Ed.2d 120 (1992); *Hodel v. Va. Surface Mining & Reclamation Ass'n, Inc.,* 452 U.S. 264, 288, 101 S.Ct. 2352, 69 L.Ed.2d 1 (1981)). Here, too, the "full regulatory burden will be borne by the Federal Government" if a State chooses not to submit an implementation plan. *Va. Surface Mining & Reclamation Ass'n,* 452 U.S. at 288, 101 S.Ct. 2389. Under these circumstances, "there can be no suggestion that the Act commandeers ... the States." *Id.*

[15] Second, the Texas State Petitioners maintain that the Clean Air Act's sanctions for noncompliant states impose such a steep price that State officials effectively have no choice but to comply—in contravention of the Supreme Court's decision in *National Federation of Independent Business v. Sebelius (NFIB),* ––– U.S. ––––, 132 S.Ct. 2566, 2603, 183 L.Ed.2d 450 (2012) (plurality opinion). *See* State & County Br. 33–34. The Act requires the **EPA** to impose sanctions on a State that fails to submit an adequate plan or implement an approved plan if it does not correct the deficiency within 18 months. *See* 42 U.S.C. § 7509(a). The focus of the petitioners' challenge is the sanction regarding federal highway funds. Under the Act, the **EPA** Administrator may prohibit the approval of any transportation projects or grants within the nonattainment area, except those that the Secretary of Transportation determines are intended to resolve a demonstrated safety problem and will likely result in a reduction in accidents. *Id.* § 7509(b)(1)(A). The Secretary of Transportation may also continue to approve a number of other kinds of projects and grants, notwithstanding the **EPA** Administrator's prohibition. *Id.* § 7509(b)(1)(B)(i)-(viii) (authorizing continued approval of projects and grants including capital programs for public transit, projects affecting bus lanes and high occupancy vehicle lanes, programs that improve traffic flow, and programs that "would improve air **quality** and would not encourage single occupancy vehicle capacity").

***176** As Chief Justice Roberts noted in *NFIB*, the Supreme Court has "long recognized that Congress may use" the power given it by the Spending Clause "to grant federal funds to the States, and may condition such a grant upon the States' 'taking certain actions that Congress could not require them to take.' " *NFIB,* 132 S.Ct. at 2601 (quoting *Coll. Sav. Bank v. Fla. Prepaid Postsecondary Educ. Expense Bd.,* 527 U.S. 666, 686, 119 S.Ct. 2219, 144 L.Ed.2d 605 (1999)). "Such measures 'encourage a State to regulate in a particular way, [and] influenc[e] a State's policy choices.' " *Id.* at 2601–02 (quoting *New York,* 505 U.S. at 166, 112 S.Ct. 2408) (alterations in original). "The conditions imposed by Congress ensure that the funds are used by the States to 'provide for the ... general Welfare' in the manner Congress intended." *Id.* at 2602 (quoting U.S. CONST., art. I, § 8, cl. 1).

"At the same time," the Chief Justice continued, the Court's "cases have recognized limits on Congress's power under the Spending Clause to secure state compliance with federal objectives." *Id.* The Court has "repeatedly characterized ... Spending Clause legislation as 'much in the nature of a *contract*.' " *Id.* (quoting *Barnes v. Gorman,* 536 U.S. 181, 186, 122 S.Ct. 2097, 153 L.Ed.2d 230 (2002) (quoting *Pennhurst State Sch. & Hosp. v. Halderman,* 451 U.S. 1, 17, 101 S.Ct. 1531, 67 L.Ed.2d 694 (1981))). "The legitimacy of Congress's exercise of the spending power 'thus rests on whether the State voluntarily and knowingly accepts the terms of the contract.' " *Id.* (quoting *Pennhurst,* 451 U.S. at 17, 101 S.Ct. 1531) (some internal quotation marks omitted). "Congress may use its spending power to create incentives for States to act in accordance with federal policies," the Chief Justice concluded, "[b]ut when 'pressure turns into compulsion,' the legislation runs contrary to our system of federalism." *Id.* (quoting *Steward Mach. Co. v. Davis,* 301 U.S. 548, 590, 57 S.Ct. 883, 81 L.Ed. 1279 (1937)).[21]

[16] In *NFIB*, the Court struck down—as in excess of the Congress' authority under the Spending Clause—a provision of the Affordable Care Act (ACA) that expanded the scope of the Medicaid program and increased the number of individuals the States had to cover. Although the Act increased federal funding to cover much of the States' costs in expanding Medicaid coverage, it also provided that, if a State did not comply with the Act's new coverage requirements, it could lose not only the new federal funding, but all of its existing federal Medicaid funds. *NFIB,* 132 S.Ct. at 2582. The Chief Justice's plurality opinion—for himself and Justices Breyer and Kagan—controls our decision on this issue.[22]

***177** In addressing the question of overbearing financial coercion, the Chief Justice first discussed *Dole,* 483 U.S. 203, 107 S.Ct. 2793, in which the Court rejected such a challenge. In that case, the Congress had threatened to withhold 5 per cent of a State's federal highway funding unless the State raised its drinking age to 21. The Chief Justice noted that, although "the condition was 'directly related to one of the main purposes for which highway funds are expended—safe interstate travel,' " it "was not a restriction on how the highway funds—set aside for specific highway improvement and maintenance efforts—were to be used." *NFIB,* 132 S.Ct. at 2604 (quoting *Dole,* 483 U.S. at 208, 107 S.Ct. 2793). "[A]ccordingly," he said, the *Dole* Court "asked whether 'the financial inducement offered by Congress' was 'so coercive as to pass the point at which pressure turns into compulsion.' " *Id.* (quoting *Dole,* 483 U.S. at 211, 107 S.Ct. 2793) (some internal quotation marks omitted). The Court answered that this monetary sanction was not impermissibly coercive, but rather offered only "relatively mild encouragement to the states" because "all South Dakota would lose if she adheres to her chosen course as to a suitable minimum drinking age is 5%" of her federal highway funds. *Dole,* 483 U.S. at 211, 107 S.Ct. 2793; *see NFIB,* 132 S.Ct. at 2604. "In fact," as the Chief Justice further noted in *NFIB*, "the federal funds at stake constituted less than half of one percent of South Dakota's budget at the time." *NFIB,* 132 S.Ct. at 2604.

In *NFIB*, the Chief Justice found that, as in *Dole,* the conditions the ACA imposed on the States did not "govern the use of" the new funds it granted to the States, but rather took "the form of threats to terminate other significant independent grants" already in existence. *Id.* Accordingly, he said, "the conditions are properly viewed as a means of pressuring the States to accept policy changes" and their level of coerciveness therefore had to be evaluated. *Id.* Upon doing so, the Chief Justice found the ACA's financial sanction to be "a gun to the head," in contrast to the "mild encouragement" in *Dole*. *Id.* A State that opted out of the ACA's Medicaid expansion stood "to lose not merely 'a relatively small percentage' of its existing Medicaid funding, but *all* of it." *Id.* (quoting *Dole,* 483 U.S. at 211, 107 S.Ct. 2793). That, the Chief Justice found, could amount to "over 10 percent of a State's overall budget." *Id.* at 2604–05.

In the case now before us, the Congress has conditioned some federal highway funding on Texas's adoption of an adequate implementation plan. This condition, like the one at issue in *Dole,* is—at least arguably—not a restriction on how the highway funds are to be used, but rather an incentive to encourage States to take action in a related policy area. *But see* discussion *infra*. Although as discussed below we are uncertain whether that alone is sufficient to trigger a coerciveness inquiry, we will proceed to evaluate the coercive effect of section 7509(b). For the following reasons, we find that the potential funding sanctions contained in section 7509(b) of the Clean Air Act are not nearly as coercive as those in the ACA.

First, unlike the situation in *NFIB* and like that in *Dole,* a noncompliant State does not risk losing *all* federal funding for an existing program. To the contrary, the **EPA** Administrator can only prohibit funding for transportation projects or grants applicable to the nonattainment area. 42 U.S.C. § 7509(b)(1)(A); 40 C.F.R. § 52.31(b)(3), (e)(2) (providing that the "highway funding sanction shall apply ... only to ... areas that are designated nonattainment"); *see* ***178** *Virginia v. Browner,* 80 F.3d 869, 881 (4th Cir.1996) ("[A] state does not lose any highway funds that would be spent in areas of the state that are in attainment."). Even within the nonattainment area, the Administrator may not prohibit the approval of projects or grants that the Secretary of Transportation determines are intended to resolve a demonstrated safety problem and will likely result in a reduction in accidents. 42 U.S.C. § 7509(b)(1)(A). Indeed, the Secretary of Transportation may continue to approve a number of other kinds of projects and grants as well, including those that "would improve air **quality**." *Id.* § 7509(b)(1)(B)(viii); *see id.* § 7509(b)(1)(B)(i)-(viii).

Second, the threatened loss of federal highway funding does not even approach the "over 10 percent of a State's overall budget" at issue in *NFIB*. Texas advises us that it received more than $3 billion in federal highway and transit funds in 2013. State & County Br. 33 n. 29. Even if all of that were withheld, it would still have amounted to less than 4 per cent of the State's 2013 budget.[23] But as noted above, Texas does not stand to lose all of its highway funds. The potential sanction applies, at most, to highway funds for projects in nonattainment areas. Wise County is the only county for which the petitioners make a Tenth Amendment argument, and because it is only one of 254 Texas counties, it is unlikely that the loss of even all of that county's federal highway funds would put a serious dent in the State's total budget.[24] Moreover, as also noted above, it is unlikely that even that one county would lose all of its federal highway funding because the potential sanction does not extend to funding for a list of enumerated projects. *See* 42 U.S.C. § 7509(b)(1)(A), (B)(i)-(viii).

[17] In short, it is clear that Texas does not risk losing anywhere near the percentage of its federal funding—either for the program at issue or of its overall budget—that the Court found fatal in *NFIB*. Precisely how much less, we do not know. But the burden of establishing unconstitutionality is on the challenger, and Texas has failed to provide the necessary information. That failure is further ground for rejecting the State's constitutional challenge. *See NFIB,* 132 S.Ct. at 2662 (joint opinion of Scalia, Kennedy, Thomas, and Alito, JJ.) ("[C]ourts should not conclude that legislation is unconstitutional on this ground unless the coercive nature of an offer is unmistakably clear."); *see also United States v. Morrison,* 529 U.S. 598, 607, 120 S.Ct. 1740, 146 L.Ed.2d 658 (2000) (requiring a "plain showing" of unconstitutionality); *United States v. Bland,* 472 F.2d 1329, 1334 (D.C.Cir.1972) (*en banc*) (noting that "the burden of establishing the unconstitutionality of a statute rests on him who assails it").

Finally, although we have concluded that the highway sanction is not unconstitutionally coercive, we note some uncertainty as to whether a coerciveness inquiry was required. ***179** There are two circumstances that may distinguish this case from those in which the Supreme Court has found such an inquiry necessary.

First, as described in *NFIB*, the inquiry in *Dole* was triggered by the fact that the Congress had imposed a condition that did not restrict how the federal highway funds at issue were to be used. Here, by contrast, the condition and sanction do redirect the federal highway funds of non-complying states to programs of the Congress' choosing, including those that "would improve air **quality** and would not encourage single occupancy vehicle capacity." 42 U.S.C. § 7509(b)(1)(B)(viii); *see id.* § 7509(b)(1)(B)(i)-(viii). As the Senate Committee Report on the 1990 Clean Air Act amendments explains, for nonattainment areas in States that fail to submit an adequate SIP, "Federal transportation investments" are "shifted to transportation programs that are designed to provide alternatives to the single occupancy vehicle and that contribute to reducing future [vehicle miles traveled]." S.REP. NO. 101–228, at 26 (1989).

Second, the condition at issue in *Dole*—which required the States to raise their drinking age to 21—was also, at the time of South Dakota's challenge, a *new* condition that had not been part of the original program. In *NFIB*, although the condition was a restriction on how Medicaid funds could be spent, Chief Justice Roberts found that the condition was also a new one. "Indeed," he stressed, "the manner in which the expansion is structured indicates that while Congress may have styled the expansion a mere alteration of existing Medicaid, it recognized it was enlisting the States in a new health care program." *NFIB,* 132 S.Ct. at 2606. This was important, he said, because "Spending Clause legislation [is] much in the nature of a contract," *id.* at 2602 (internal quotation marks omitted), and "[t]hough Congress' power to legislate under the spending power is broad, it does not include surprising participating States with post-acceptance or retroactive conditions," *id.* at 2606 (internal quotation marks omitted). In both *Dole* and *NFIB*, the condition at issue was "new" in two senses of the word: Both conditions had been recently enacted at the time of the litigation, and both conditions imposed additional requirements with which States had to comply to continue receiving preexisting federal funding.

Neither the Clean Air Act's requirement to submit an implementation plan, nor its highway funds sanction, is a condition that has been newly imposed on the States. Although both were new in 1977, *see* Clean Air Act Amendments of 1977, Pub.L. No. 95–95, §§ 103, 176, 91 Stat. 685, 687–88, 749–50 (1977), since then Texas has submitted implementation plans and accepted billions of dollars in highway funding. Accordingly, when the **EPA** issued the Wise County nonattainment designation in 2012, Texas was not suddenly surprised by dramatically new conditions retroactively imposed after a long period in which the State had accepted and relied upon unconditional federal funding—as was the case in *NFIB*.

These differences from the Supreme Court's precedents create some uncertainty as to whether the coerciveness inquiry employed in *Dole* and *NFIB* was even triggered by the Clean Air Act provisions at issue here. Even if it were, the fact that the State has long accepted billions of dollars notwithstanding the challenged conditions may be an additional relevant factor in the contract-like analysis the Court has in mind for assessing the constitutionality of Spending Clause legislation. But we need not resolve that uncertainty today. Because the challenged provisions of the Clean Air Act survive a coerciveness ***180** inquiry in any event, we reject the Texas State Petitioners' challenge to their constitutionality.

ii. The Commerce Clause

The Texas State Petitioners also argue that the Wise County designation exceeds the scope of the Congress' authority under the Commerce Clause. As explained above, *supra* § III.F.1, the designation declared that Wise County contributed enough ozone emissions to nearby violations of the NAAQS to warrant its own nonattainment designation. By virtue of that designation, sources of emissions within the county must comply with a variety of additional requirements. *See, e.g.,* 42 U.S.C. § 7502(c)(1) (requiring the implementation of "all reasonably available control measures"); *id.* § 7502(c)(5) (requiring "permits for the construction and operation of new or modified major stationary sources anywhere in the nonattainment area").

[18] **[19]** The Commerce Clause grants the Congress the power "[t]o regulate Commerce ... among the several States." U.S. CONST., art. I, § 8, cl. 3. The Supreme Court has "recognized ... that '[t]he power of Congress over interstate commerce is not confined to the regulation of commerce among the states,' but extends to activities that 'have a substantial effect on interstate commerce.' " *NFIB,* 132 S.Ct. at 2585–86 (opinion of Roberts, C.J.) (quoting *United States v. Darby,* 312 U.S. 100, 118–19, 61 S.Ct. 451, 85 L.Ed. 609 (1941)); *see United States v. Lopez,* 514 U.S. 549, 558–59, 115 S.Ct. 1624, 131 L.Ed.2d 626 (1995). "Congress's power, moreover, is not limited to regulation of an activity that by itself substantially affects interstate commerce, but also extends to activities that do so only when aggregated with similar activities of others." *NFIB,* 132 S.Ct. at 2586 (opinion of Roberts, C.J.) (citing *Wickard v. Filburn,* 317 U.S. 111, 127–28, 63 S.Ct. 82, 87 L.Ed. 122 (1942)). The question for a court is whether there was a "rational basis" for the Congress' conclusion that a regulated activity substantially affects interstate commerce. *Hodel v. Indiana,* 452 U.S. 314, 323–24, 101 S.Ct. 2376, 69 L.Ed.2d 40 (1981); *see Nat'l Ass'n of Home Builders v. Babbitt (NAHB),* 130 F.3d 1041, 1051 (D.C.Cir.1997) (opinion of Wald, J.).

[20] The Texas State Petitioners' first contention is that the NO_X emissions produced by oil and gas activity in the Barnett Shale in Wise County do not " 'substantially affect' interstate commerce," principally because the emissions are "wholly intrastate." State & County Br. 36. That premise is unsupported by any proffered evidence and is factually incorrect. The phenomenon of *interstate* transport of ozone has been thoroughly studied, and it has been recognized by the Congress, the **EPA**, the Supreme Court, and this Court. [25] The "winds, of course, recognize no [state] boundaries." *United States v. Ford Motor Co.,* 814 F.2d 1099, 1102 (6th Cir.1987).

***181** **[21]** **[22]** But even if the particular emissions from the Barnett Shale stopped at the Texas state line, the regulation of their sources would still be permissible under the Commerce Clause for two reasons. First, "where a general regulatory statute bears a substantial relation to commerce, the *de minimis* character of individual instances arising under that statute is of no consequence." *Lopez,* 514 U.S. at 558, 115 S.Ct. 1624 (internal quotation marks omitted) (emphasis omitted); *see Gonzales v. Raich,* 545 U.S. 1, 17, 125 S.Ct. 2195, 162 L.Ed.2d 1 (2005); *NAHB,* 130 F.3d at 1046 (opinion of Wald, J.). And there is no doubt that the general regulatory scheme of the Clean Air Act has a substantial relation to interstate commerce. Indeed, the same is true even if we focus only upon the Act's generally applicable ozone provisions.

[23] Moreover, we can find a substantial effect not only by examining the emissions that are produced, but also by examining the activities that the challenged statute regulates to reduce the production of those emissions. *See Rancho Viejo, LLC v. Norton,* 323 F.3d 1062, 1067 (D.C.Cir.2003); *NAHB,* 130 F.3d at 1046 & n. 3 (opinion of Wald, J.); *id.* at 1058 (Henderson, J., concurring). As we explained in *Rancho Viejo,* on this rationale we "focus [ ] on the activity that the federal government seeks to regulate." 323 F.3d at 1069; *see Morrison,* 529 U.S. at 609, 120 S.Ct. 1740 (instructing that "the proper inquiry" is whether the challenge is to "a regulation of *activity* that substantially affects interstate commerce") (emphasis added); *Lopez,* 514 U.S. at 558–59, 115 S.Ct. 1624 ("Congress' commerce authority includes the power to regulate ... those *activities* that substantially affect interstate commerce.") (emphasis added). In *Rancho Viejo,* we upheld the constitutionality of the Fish and Wildlife Service's decision to protect an endangered toad species by regulating a housing development, on the ground that the regulated activity, a "202–acre project, located near a major interstate highway, [was] ... presumably being constructed using materials and people from outside the state." 323 F.3d at

1069 (internal quotation marks omitted). Likewise, in *NAHB,* we upheld the Service's decision to protect an endangered fly species by regulating the construction plan for a hospital, on the ground that the commercial land development at issue "ha[d] a plain and substantial effect on interstate commerce." 130 F.3d at 1059 (Henderson, J., concurring); *see id*. at 1056 (opinion of Wald, J.).

Here, the activities that the **EPA** seeks to regulate are the commercial, industrial, and extraction processes that produce the emissions at issue. *See* 42 U.S.C. § 7511a; 2008 Designations Rule, 77 Fed.Reg. at 30,089. The nonattainment designation triggers regulatory controls on the sources of those emissions, many of which are indisputably entities engaged in substantial interstate commerce. In the case of Wise County in particular, those entities include multinational companies engaged in the production and sale of oil and gas from the Barnett Shale, including several of the Industrial Petitioners here.[26] The restrictions triggered by the nonattainment designation thus affect the conditions under which interstate commerce in oil and gas ***182** may proceed. And as such, the designation process "regulates and substantially affects commercial ... activity which is plainly interstate." *NAHB,* 130 F.3d at 1058 (Henderson, J., concurring).

The Texas State Petitioners' second contention is that, "[e]ven if incidental emissions do 'substantially affect' interstate commerce, they are not 'quintessentially economic activity' " and cannot be regulated under the Commerce Clause. State & County Br. 36. This contention is based on the Court's decision in *Lopez,* which held the Gun–Free School Zones Act unconstitutional in part because the statutory provision at issue, which criminalized the possession of a gun in a school zone, had "nothing to do with 'commerce' or any sort of economic enterprise, however broadly one might define those terms." *Lopez,* 514 U.S. at 560–61, 115 S.Ct. 1624; *see also Morrison,* 529 U.S. at 610–11, 613, 120 S.Ct. 1740. There are two answers to this contention.

[24] First, ozone pollution itself has economic consequences for interstate commerce. The Congress so found in the course of amending the Clean Air Act. *See* S. REP. NO. 101–228, at 8 (1989) (noting that exposure to air pollution costs the United States $40 billion annually in additional health care costs, and documenting health effects of ozone and other pollutants); *id*. (noting that "ozone causes annual crop losses of $2 to $3 billion per year"). Although we are not bound by congressional findings, they may assist us in "evaluat[ing] the legislative judgment that the activity in question substantially affected interstate commerce." *Lopez,* 514 U.S. at 562–63, 115 S.Ct. 1624; *see Rancho Viejo,* 323 F.3d at 1069. Indeed, we have previously credited the Congress' findings regarding ozone pollution, concluding that the Act's "legislative history and **EPA's** report to Congress substantiate the heavy impact ozone pollution has on national health care costs and national agricultural production." *Allied Local,* 215 F.3d at 83.

Second, the activities that are ultimately regulated by the designation process are not the ozone precursor "emissions," but rather the activities that produce the emissions. Those include the operation of power plants, gas processors, and vehicles that produce the emissions. *See* 42 U.S.C. § 7511a. As we explained in *Rancho Viejo,* the regulated activity in that case was a company's "planned commercial development, not the arroyo toad that it threaten[ed]." 323 F.3d at 1072. The same point is true here. Just as the Endangered Species Act "does not purport to tell toads what they may or may not do," *id.,* the Clean Air Act does not tell NO_x or VOCs what to do. Rather, it tells the commercial and industrial sources that produce those compounds what they may do.

As we noted in *Allied Local,* the Supreme Court has long made clear that " 'the power conferred by the Commerce Clause [is] broad enough to permit congressional regulation of *activities causing* air or water pollution, or other **environmental** hazards that may have effects in more than one State.' " *Allied Local,* 215 F.3d at 83 (quoting *Va. Surface Mining & Reclamation Ass'n,* 452 U.S. at 282, 101 S.Ct. 2352) (emphasis added); *id*. (noting that the Supreme Court cited *Virginia Surface Mining and Reclamation Association* with approval in both *Lopez* and *Morrison*). "[B]ecause we are required to accord congressional legislation a 'presumption of constitutionality,' " *Rancho Viejo,* 323 F.3d at 1069 (quoting *Morrison,* 529 U.S. at 607, 120 S.Ct. 1740), the petitioners' inability to establish that emissions-producing sources in the State do not substantially affect interstate commerce "is fatal to [their] cause," *id.; see Morrison,* 529 U.S. at 607, 120 S.Ct. 1740 ("Due respect for the decisions of a coordinate ***183** branch of Government demands that we invalidate a congressional enactment only upon a plain showing that Congress has exceeded its constitutional bounds."). The regulation of the sources of Wise County emissions through the Clean Air Act's designation process lies well within the Congress' authority to regulate interstate commerce.

iii. The Due Process Clause

[25] The Texas State Petitioners' third constitutional challenge maintains that the **EPA's** designation of Wise County violated the Due Process Clause because the former Administrator of **EPA** Region 6, Al Armendariz, failed to disqualify himself from the proceedings.

According to the petitioners, Armendariz should have disqualified himself for four reasons. First, Armendariz has a history of working for **environmental** advocacy groups. Second, a report he authored as an advocate before joining the **EPA** concluded that emissions from the Barnett Shale were contributing significantly to local and global pollution. Third, a speech Armendariz gave after joining the **EPA** analogized his aggressive enforcement policy against oil and gas companies that "are not complying with the law" to the way "Romans used to conquer those villages in the Mediterranean" by "crucify[ing]" the first people they saw. Terrence Henry, *Texas **EPA** Official Apologizes for 'Crucify Them' Comments,* Apr. 26, 2012, State Impact NPR, http://stateimpact.npr. org/texas/2012/04/26/**epa**-official-apologizes-for-crucify-comments (quoting Armendariz). "You make examples out of people who ... are not complying with the law," Armendariz said. "There's a deterrent factor.... And they decide at that point that it's time to clean up." *Id.* [27] Finally, in the petitioners' view, "[n]ormally, the prevailing wind direction and **EPA**-standard modeling would have led **EPA** to accept" Texas's designation of Wise County as attainment. State & County Br. 38. All of this, the petitioners argue, "create[s] a presumption that the Agency's mind was closed and it was unwilling or unable to rationally consider arguments against nonattainment." *Id.* at 37.

In *Air Transport Association of America, Inc. v. National Mediation Board,* 663 F.3d 476 (D.C.Cir.2011), we repeated this circuit's approach to the kind of claim that the petitioners raise here. "Decisionmakers violate the Due Process Clause and must be disqualified," we said, "when they act with an 'unalterably closed mind' and are 'unwilling or unable' to rationally consider arguments." *Id.* at 487 (quoting *Ass'n of Nat'l Advertisers, Inc. v. FTC,* 627 F.2d 1151, 1170, 1174 (D.C.Cir.1979)). "[A]n individual should be disqualified from rulemaking only when there has been a clear and convincing showing that the ... member has an unalterably closed mind on matters critical to the disposition of the proceeding." *Id.* (quoting *C & W Fish Co., Inc. v. Fox,* 931 F.2d 1556, 1564 (D.C.Cir.1991) (internal quotation marks omitted)). The four arguments advanced by the Texas State Petitioners are insufficient to make that "clear and convincing" showing. [28]

***184** Our decision in *C & W Fish Company* establishes that neither Armendariz' employment history nor the report he authored before joining the **EPA** required his disqualification. There, we considered the impartiality of an agency administrator who had previously served as the chairman of a group advocating for the precise agency policy at issue in the case, and who after his appointment remarked that there was "no question" that the policy should be implemented. *C & W Fish Co.,* 931 F.2d at 1564. Those circumstances, we said, did "not even approach a 'clear and convincing showing' that [the administrator] had an 'unalterably closed mind.' " *Id.* at 1565.

The petitioners' third argument is also unpersuasive. There is no doubt that Armendariz' "crucifixion" comments were offensive. But that does not suffice to make the requisite showing. The comments described Armendariz' general approach to enforcement, but were neither specifically about the designation process nor specifically targeted at production from the Barnett Shale. Accordingly, they did not reveal Armendariz' views on "matters critical to the disposition of the proceeding." *Ass'n of Nat'l Advertisers,* 627 F.2d at 1170. And even if they had, they would not alone demonstrate an unalterably closed mind on the subject. *See C & W Fish Co.,* 931 F.2d at 1565 (" 'We would eviscerate the proper evolution of policymaking were we to disqualify every administrator who has opinions on the correct course of his agency's future actions.' " (quoting *Ass'n of Nat'l Advertisers,* 627 F.2d at 1174)).

Finally, we cannot infer bias from the fact that, in the opinion of the petitioners, the computer modeling supported an attainment designation for Wise County. As we held in *C & W Fish Company,* "we reject the suggestion that we look to the adequacy of [an agency official's] examination of the facts and issues in order to determine whether he was biased." 931 F.2d at 1564. Rather, "[w]hether [the official] weighed the facts properly is to be examined only in determining if his decision was arbitrary or capricious." *Id.* at 1564–65. And that is an examination that we separately undertake in section III.F.2, *supra*.

For the foregoing reasons, we reject the petitioners' three constitutional challenges to the designation of Wise County as a nonattainment area.

4. The Remaining Challenges

Finally, the Texas State Petitioners argue that we should vacate the **EPA's** Wise County nonattainment designation because the **EPA** (1) failed to comply with the Information **Quality** Act, (2) failed to promulgate regulations defining the terms "necessary" and "contribute," (3) concluded that Wise County emissions "can" contribute to NAAQS violations when it was statutorily required to conclude that Wise County "did" contribute, and (4) failed to give them "fair notice" of the **EPA's** requirements. State & County Br. 46–52. We reject all four contentions.

[26] First, the Texas State Petitioners urge us to conclude that the Information **Quality** Act requires the **EPA** to use "the best available science and supporting studies conducted in accordance with sound and objective scientific practices" in making NAAQS designations, State & County Br. 46 (citing *Prime Time Int'l Co. v. Vilsack,* 599 F.3d 678, 685–86 (D.C.Cir.2010)), and that the **EPA** failed to do so here. But almost every court that has addressed an Information **Quality** Act challenge has held that the statute "creates no legal rights in any third parties," *Salt Inst. v. Leavitt,* 440 F.3d 156, 159 (4th Cir.2006);[29] *see also Harkonen v. U.S.* ***185** *Dep't of Justice,* No. C 12–629 CW, 2012 WL 6019571, at *11 (N.D.Cal. Dec. 3, 2012) (collecting cases). And this Court has held that the Information **Quality** Act is not "an independent measure of **EPA's** NAAQS decision." ***Mississippi***, 744 F.3d at 1347. The purpose of the Information **Quality** Act is to "ensur[e] and maximize [e] the **quality**, objectivity, utility, and integrity of information (including statistical information) *disseminated* by Federal agencies" and does not constitute a statutory mechanism by which the **EPA's** *conclusions* reached while making its nonattainment determinations can be challenged. *See* 44 U.S.C. § 3516 note (emphasis added).

Second, the Texas State Petitioners argue that the **EPA** should define the terms "contribute" and "necessary" through administrative rulemaking in order to rein in the "boundless override discretion" it uses to "commandeer [ ]" states to "enforce its massive regulatory scheme." *See* State & County Br. 48. Our *Catawba County* holding forecloses this argument. There, we held that the **EPA** was "free to adopt a totality-of-the-circumstances test to implement a statute that confers broad discretionary authority." *Catawba Cnty.,* 571 F.3d at 39. Finally, the Texas State Petitioners offer no reason why the word "necessary," which the **EPA** reasonably interpreted as authorizing modification of a state's recommended designation that does "not meet the statutory requirements or [was] otherwise inconsistent with the facts or analysis deemed appropriate by the **EPA**," *see* 2008 Designations Rule, 77 Fed.Reg. at 30,090, must be defined via rulemaking.

[27] Third, the Texas State Petitioners argue that the **EPA** exceeded its authority under the Clean Air Act because it concluded that Wise County emissions "can" contribute to NAAQS violations, whereas the Act authorizes a finding that Wise County "does" so contribute. *See* State & County Br. 50. This argument is premised on the **EPA's** response to a petition for reconsideration challenging the Wise County nonattainment designation, to which the **EPA** responded that "the Wise County emissions are large enough that they *can* contribute to ozone exceedances on certain days." **EPA** Response to Pet. for Reconsideration from Wise Cnty., Office of the Cnty Judge at 2 (emphasis added). But read *in toto,* the **EPA's** justification for including Wise County in the Dallas–Fort Worth nonattainment area was anything but theoretical:

> Wise County [h]as 2008 NEI emissions of 11,911 tons of NO_x and 17,609 tons of VOC; there are 60 people per square mile; has a 2010 population of 59,127 with a growth rate of 5.9 percent between 2000 and 2010; total VMT is 969 million. The close proximity of these comparatively high emissions to violating monitors indicates that this county should be included in the nonattainment area.

> The high growth in these emissions is due in large part to growth in emissions from Barnett Shale gas production development, but also due to growth in population. Examination of back trajectories indicates that at times emissions from Wise County contribute to observed violations in the area and also to observed violations that have helped set the DFW area DV in the past. Source apportionment modeling for a portion of an ozone season indicates that emissions from Wise County can contribute to observed violations in the DFW nonattainment area. These factors support the inclusion of Wise County in the nonattainment area.

***186** Final Dallas–Fort Worth Area Designations at 23. Read in context, we conclude that the **EPA** in fact found that Wise County *does* contribute to NAAQS violations in the Dallas–Fort Worth area.

[28] **[29]** Fourth, the Texas State Petitioners argue the **EPA** failed to provide them with "fair notice" of its requirements. Even assuming the fair notice doctrine applies, *cf. Ark. Dep't of Human Servs. v. Sebelius,* 818 F.Supp.2d 107, 120–21 (D.D.C.2011), the **EPA** did not violate it. The fair notice doctrine, which is couched in terms of due process, provides redress only if an agency's interpretation is "so far from a reasonable person's understanding of the regulations that they could not have fairly informed the regulated party of the agency's perspective." *United States v. Chrysler Corp.,* 158 F.3d 1350, 1354 (D.C.Cir.1998) (alteration omitted). Here, the **EPA** not only provided the 2008 Guidance to aid the states in making their initial designations, it also provided a preliminary technical support document to each state before finalizing any of its proposed modifications to the state's initial designations. *See, e.g.,* Preliminary Dallas–Fort Worth Area Designations. The technical support document, in turn, gave each state a precise explication of all proposed **EPA** modifications as a roadmap to use during the 120–day comment period. Simply put, the **EPA** set forth its analysis, provided an opportunity to rebut its conclusions and ultimately explained why it had not changed its mind. Accordingly, the Texas State Petitioners' fair notice doctrine argument is meritless.

For the foregoing reasons, the consolidated petitions for review are denied.

So ordered.

All Citations

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Footnotes

1 *See infra* n. 2.

2 "Primary" NAAQS exist to protect the "public health," 40 C.F.R. § 50.2(b), and they ensure the safety of "sensitive" populations such as asthmatics, children and the elderly. *See* National Ambient Air **Quality** Standards (NAAQS), **EPA**, http://www.**epa**.gov/air/criteria.html (last updated Oct. 21, 2014). "Secondary" NAAQS exist to protect the "public welfare," 40 C.F.R. § 50.2(b), and they prevent harms like decreased visibility and damage to animals, crops, vegetation and buildings. *See* National Ambient Air **Quality** Standards (NAAQS), **EPA**, http://www.**epa**. gov/air/criteria.html (last updated Oct. 21, 2014).

3 A CBSA is defined by the Office of Management and Budget (OMB) as:

> [A] statistical geographic entity consisting of the county or counties associated with at least one core (urbanized area or urban cluster) of at least 10,000 population, plus adjacent counties having a high degree of social and economic integration with the core as measured through commuting ties with the counties containing the core.

See Standards for Defining Metropolitan and Micropolitan Statistical Areas, 65 Fed.Reg. 82,228, 82,238 (Dec. 27, 2000). A CSA is formed by two or more adjacent CBSAs if there is sufficient "employment interchange" between them. *Id.* In other words, CSAs and CBSAs are both roughly equivalent to a "metropolitan" area. *See generally id.* at 82,235–36. Throughout this opinion, we use the term "metropolitan area" to refer to the CSA or CBSA, as defined in the 2008 Guidance. *See* 2008 Guidance at 3 & n. 2.

4 *See WildEarth Guardians, et al. v. Jackson,* No. 2:11–CV–01661 (D.Ariz. filed Aug. 24, 2011).

5 *See Del. Dep't of Natural Res. & Envtl. Control v.* ***EPA***, No. 12–1310 (D.C.Cir.); *Tex. Pipeline Ass'n v.* ***EPA***, No. 12–1312 (D.C.Cir.); *Wise Cnty., Tex. v.* ***EPA***, No. 12–1313 (D.C.Cir.); *Indiana v.* ***EPA***, No. 12–1315 (D.C.Cir.); *Texas v.* ***EPA***, No. 12–1316 (D.C.Cir.); *Sierra Club v.* ***EPA***, No. 12–1317 (D.C.Cir.); *Gas Processors Ass'n v.* ***EPA***, No. 12–1318 (D.C.Cir.); *Devon Energy Corp. v.* ***EPA***, No. 12–1322 (D.C.Cir.); *Targa Resources Corp. v.* ***EPA***, No. 12–1323 (D.C.Cir.); *WildEarth Guardians v.* ***EPA***, No. 12–1326 (D.C.Cir.); *DeSoto Cnty., Miss. v.* ***EPA***, No. 12–1328 (D.C.Cir.); *Sierra Club v.* ***EPA***, No. 13–1030 (D.C.Cir.); *WildEarth Guardians v.* ***EPA***, No. 13–1032 (D.C.Cir.); *Wise Cnty., Tex. v.* ***EPA***, No. 13–1046 (D.C.Cir.); *Devon Energy Corp. v.* ***EPA***, No. 13–1050 (D.C.Cir.); *Tex. Pipeline Ass'n v.* ***EPA***, No. 13–1051 (D.C.Cir.); *Gas Processors Ass'n v.* ***EPA***, No. 13–1052 (D.C.Cir.); *Texas v.* ***EPA***, No. 13–1053 (D.C.Cir.); *Targa Res. Corp. v.* ***EPA***, No. 10–1054 (D.C.Cir.).

6 Neither State challenges the designations of those areas as nonattainment, other than to contend that the designations should have covered much broader areas.

7 At oral argument, the **EPA** made clear that it does not contend that its reading is the *only* permissible reading of the statute. Oral Arg. Recording at 30:01–30:59; *see also* 2008 Designations Rule, 77 Fed.Reg. at 30,090 (discussing the agency's "discretion" to interpret the term "nearby" in fixing the geographic scope of nonattainment areas).

8 Delaware points to the isolated nonattainment zone of Sussex County as a particularly egregious example of the designations that the **EPA's** interpretation produced. Delaware Br. 12. But even if over 90 per cent of Sussex County's pollution comes from out-of-state sources, as Delaware asserts, the **EPA** found that no surrounding counties had the linkages necessary to justify a nonattainment designation under the agency's five-factor analysis. *See* Delaware Area Designations at 37–49.

9 The **EPA** promulgated the Transport Rule under 42 U.S.C. § 7410(a)(2)(D), which requires SIPs to prohibit air pollution that will "contribute significantly to nonattainment in, or interfere with maintenance [of the NAAQS] by, any other State." Other provisions of the Act also address interstate transport. *See id.* § 7506a (providing for interstate transport **commissions**); *id.* § 7511c (establishing ozone transport region consisting of 11 states and the District of Columbia, which must comply with additional control measures).

10 Delaware also argues that the **EPA** acted inconsistently with the statute by only designating as nonattainment nearby areas that are "contributing to a violation," rather than those that "contribute[ ] to ambient air **quality**" in a violating area, 42 U.S.C. § 7407(d)(1)(A)(i). Delaware Br. 12–13. As the **EPA** explained, however, its use of the phrase was simply shorthand for its contribution analysis; it did not represent a heightened standard. *Cf. ATK Launch Sys.,* 669 F.3d at 338–39 (rejecting the argument that the **EPA** applied a dissimilar standard when it variously used the terms "significant contribution" and "contribution").

11 *See* Approval and Promulgation of Air **Quality** Implementation Plans; Illinois; Motor Vehicle Inspection and Maintenance, 64 Fed.Reg. 8,517, 8,519 (Feb. 22, 1999); Approval and Promulgation of Air **Quality** Plans; Illinois; Post–1996 Rate of Progress Plan for the Chicago Ozone Nonattainment Area, 65 Fed.Reg. 78,961, 78,967–68 (Dec. 18, 2000).

12 Indiana protests that there likely would have been no violation at all at the Zion monitor if it were not for the emissions resulting from the statutory change. That argument is merely a rephrasing of the but-for causation rule that we rejected in *Catawba County.* In any event, the argument is not supported by the Indiana modeling analyses upon which it is based. *See* Letter from Ind. Dep't of Envtl. Mgmt. to **EPA**, Enclosure 1 at 27–30 (Apr. 13, 2012). The first analysis concluded only that the change in Illinois's program contributed 0.2 ppb to the Zion violation—not enough to account for the 2009 to 2011 exceedance of 1 ppb. The second analysis rested on a factual premise that the State never adequately explained: that the statutory change caused the emission reduction benefits of Illinois's vehicle emissions testing program to decrease by 35 per cent.

13 *See* Approval and Promulgation of Air **Quality** Implementation Plans; Illinois; Amendments to Vehicle Inspection and Maintenance Program for Illinois, 79 Fed.Reg. 47,377 (Aug. 13, 2014).

14 Initially, Texas based its recommended designations on air-**quality** data from 2005 to 2007. On October 31, 2011, Texas updated its initial designations with certified air-**quality** data from 2008 to 2010.

15 As noted above, *see supra* § I.B–C, the 2008 Guidance initially established a nine-part test but the **EPA** subsequently collapsed those nine factors into five.

16 Specifically, Wise County had the fourth highest level of VOC emissions among nineteen counties in the Dallas–Fort Worth area and the sixth highest level of NO_x emissions. Preliminary Dallas–Fort Worth Area Designations at 6 tbl.3.

17 *See* Final Dallas–Fort Worth Area Designations at 14 (emphasizing that HYSPLIT modeling is especially appropriate for Wise County because Dallas–Fort Worth area "is generally characterized as having ozone exceedances with lower wind speeds and winds from many directions").

18 *See* State & County Br. 45–46; Industrial Br. 14–26.

19 *See* State & County Br. 39–44; Industrial Br. 26–30.

20 *See* *Nat'l Fed'n of Indep. Bus. v. Sebelius,* ––– U.S. ––––, 132 S.Ct. 2566, 2602, 183 L.Ed.2d 450 (2012) (plurality opinion) (noting that the Court has struck "down federal legislation that commandeers a State's legislative or administrative apparatus for federal purposes"); *Printz,* 521 U.S. at 933, 117 S.Ct. 2365 (invalidating federal legislation compelling State law enforcement officers to perform federally mandated background checks on handgun purchasers); *New York v. United States,* 505 U.S. 144, 174–77, 112 S.Ct. 2408, 120 L.Ed.2d 120 (1992) (invalidating a provision of a federal statute compelling a State either to take title to nuclear waste or to enact particular state waste regulations).

21 As we discuss below, the Texas State Petitioners argue that the threat of highway sanctions makes the promulgation of SIP provisions for a nonattainment area effectively compulsory. They do not argue that the sanctions provision fails to comply with any other constitutional requirements governing conditions on federal grants to the States. *See* *South Dakota v. Dole,* 483 U.S. 203, 207–08, 107 S.Ct. 2793, 97 L.Ed.2d 171 (1987) (requiring that conditions promote the general welfare, be unambiguous, be related to the federal interest, and be consistent with other constitutional provisions).

22 When a majority of the Supreme Court agrees on a result, but "no single rationale explaining the result enjoys the assent of five Justices, 'the holding of the Court may be viewed as that position taken by those Members who concurred in the judgments on the narrowest grounds....' " *Marks v. United States,* 430 U.S. 188, 193, 97 S.Ct. 990, 51 L.Ed.2d 260 (1977) (quoting *Gregg v. Georgia,* 428 U.S. 153, 169 n. 15, 96 S.Ct. 2909, 49 L.Ed.2d 859 (1976) (plurality opinion)). The *NFIB* plurality found a Spending Clause violation on narrower grounds than did the joint opinion of Justices Scalia, Kennedy, Thomas, and Alito, *NFIB,* 132 S.Ct. at 2656–69. *See* *Mayhew v. Burwell,* 772 F.3d 80, 88–89 (1st Cir.2014). It therefore controls here. *Id.*

23 *See* Nat'l Ass'n of State Budget Officers, The State Expenditure Report 2012–2014 8 (2014) (listing 2013 expenditures as approximately $93 billion); Texas General Appropriations Act for the 2012–13 Biennium xi (2011), *available at* http://www.lbb.state.tx.us/Documents/GAA/General_ Appropriations_Act_2012–13.pdf (appropriating approximately $79 billion for 2013).

24 Seventeen other Texas counties are also in nonattainment areas. *See* Final Dallas–Fort Worth Area Designations at 1; Houston–Galveston–Brazoria, Texas Final Area Designations for the 2008 Ozone NAAQS at 1. But that is still only a small percentage of the State's total of 254 counties. *See also* Envtl. Prot. Agency, Map of Texas 8–hour Ozone Nonattainment Areas (2008 Standard), *available at* http://www.**epa**.gov/oaqps 001/greenbk/tx8_2008.html.

25 *See* 42 U.S.C. §§ 7410(a)(2)(D), 7511c (Clean Air Act provisions addressing interstate transport of ozone); S. REP. NO. 101–228, at 34 (1989) (discussing Clean Air Act amendments designed to "[c]ontrol ... interstate ozone pollution"); *id.* at 13 (noting that "ozone is not a local phenomenon but is formed and transported over hundreds of miles and several days"); 2008 Designations Rule, 77 Fed.Reg. at 30,089 (finding that ozone and ozone precursors travel easily through the atmosphere, which can result in NAAQS violations hundreds of miles from the precursors' source); *EME Homer City Generation, L.P.,* 134 S.Ct. at 1594 (detailing the "journey" taken by ozone precursors, which "often develop into ozone ... by the time they reach the atmospheres of downwind States"); *Virginia v. **EPA**,* 108 F.3d 1397, 1400 (D.C.Cir.1997) (describing the "ozone transport phenomenon" in the lower atmosphere).

26 Industrial Petitioner Devon Energy Corporation, for example, "is a leading independent oil and natural gas exploration and production company," with operations "focused onshore in the United States and Canada." Industrial Br. iv. "Devon is also one of North America's larger processors of natural gas liquids, with ... natural gas processing facilities in many of its producing areas, including Wise County, Texas." *Id.; see id.* at 13 ("Industrial Petitioners and members with operations in Wise County were immediately subjected to increased regulatory burdens due to the nonattainment designation.").

27 After a video of the speech was discovered, Armendariz resigned. *Id.* Soon thereafter, the **EPA** promulgated the Wise County nonattainment designation.

28 The Supreme Court has held that States are not "persons" within the meaning of the Due Process Clause. *See* *South Carolina v. Katzenbach,* 383 U.S. 301, 323–24, 86 S.Ct. 803, 15 L.Ed.2d 769 (1966); *see also* *Republic of Argentina v. Weltover, Inc.,* 504 U.S. 607, 619, 112 S.Ct. 2160, 119 L.Ed.2d 394 (1992) (citing *Katzenbach,* 383 U.S. at 323–24, 86 S.Ct. 803); *Price v. Socialist People's Libyan Arab Jamahiriya,* 294 F.3d 82, 96 (D.C.Cir.2002). Although one circuit has

held that counties are protected in some circumstances, *see County of Santa Cruz v. Sebelius,* 399 Fed.Appx. 174, 176 (9th Cir.2010), we need not consider the issue because we find no violation here.

29 *But see Prime Time,* 599 F.3d at 685–86 (affirming dismissal of Information **Quality** Act challenge on different grounds without addressing argument that the statute creates no legal rights in third parties).

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June 2014

Supreme Court Throws Out the Bathwater, Keeps the Baby, on EPA's GHG Regulations

BY KEVIN POLONCARZ

In a long-anticipated end-of-term decision, on June 23, 2014, a majority of the U.S. Supreme Court issued a ruling throwing out EPA's greenhouse gas (GHG) "Tailoring Rule," which revised the statutory thresholds for requiring federal air permits under the Clean Air Act (CAA), finding that the EPA's interpretation that such permits could be required due solely to a source's GHG emissions was not mandated by the CAA and that the EPA's decision to "tailor" the thresholds specifically for GHGs was contrary to the language of the statute. A separate majority also found that EPA could permissibly find that sources already required to obtain a permit for pollutants of conventional pollutants—so called "anyway sources"—must install the "best available control technology" (BACT) for GHGs.

Although the decision makes clear that a majority of the Supreme Court is unwilling to step back from its decision in *Massachusetts v. EPA*, upholding the EPA's authority to regulate GHG emissions under the CAA, the ruling comes as a strong rebuke to the EPA and its efforts to fit GHGs into a statutory construct developed for undeniably different purposes than avoiding global warming. The ruling also comes on the heels of EPA's announcement of its proposed Clean Power Plan (described here), which proposes a far-reaching set of emissions guidelines for states to reduce GHG emissions from fossil fueled electric generating units.

While the Court's decision speaks generally of the limits on the deference that will be afforded to EPA as it seeks to deliver on President Obama's plan to achieve demonstrable reductions in power sector emissions in the absence of Congressional action (described here), seldom does an agency's interpretive feat rise to the level of the current case, where EPA essentially took a number clearly written in the statute and multiplied that number by a thousand to avoid consequences it believed were unintended by Congress. Additionally, in a footnote elsewhere in the decision, the Court reaffirms the holding of its other major decision concerning GHG regulation—*American Electric Power Company v. EPA*—which was premised upon EPA's authority to regulate GHG emissions from the Power sector. Thus, there are reasons to believe the Court's decision means little with respect to the lawfulness of EPA's proposed power plant standards.

More immediately, the decision alters the permitting landscape for many proposed sources that would not otherwise require PSD permits, such as gas-fired power plants that are increasingly being relied upon to provide fast-ramping power when intermittent renewable sources (i.e., wind and solar) are not generating. Although such highly efficient sources would be expected to meet the BACT standard for GHGs, elimination of the requirement to obtain PSD permits avoids a favored avenue for project opponents to delay construction of such projects. *See, e.g., In re: La Paloma Energy Center, LLC*, PSD Appeal No. 13-10, (Mar. 14, 2014) (described here).

Background

In response to the Supreme Court's landmark 2007 decision in *Massachusetts v. EPA*, in which it held that GHGs may be regulated as an air pollutant under the CAA, EPA issued an Endangerment Finding for GHGs. 74 Fed. Reg. 66,496 (Dec. 15, 2009). Pursuant to the CAA's requirement that EPA establish motor-vehicle emission standards for "any air pollutant . . . which may reasonably be anticipated to endanger public health or welfare," 42 U.S.C. § 7521(a)(1), the EPA then promulgated the "Tailpipe Rule" for GHGs, which set GHG emission standards for cars and light trucks as part of a joint rulemaking for fuel economy standards issued by the National Highway Traffic Safety Administration. 75 Fed. Reg. 25,324 (May 7, 2010).

EPA found that the Tailpipe Rule automatically and necessarily triggered regulation of *stationary* sources of GHG (e.g., power plants and petroleum refineries) under the Prevention of Significant Deterioration (PSD) program, which requires construction permits for stationary sources that have the potential to emit over 100 or 250 tons per year (tpy) of "any air pollutant," 42 U.S.C. §§ 7475, 7479(1), and Title V, which requires operating permits for stationary sources that have the potential to emit at least 100 tpy of "any air pollutant," *Id*. § 7602(j).

EPA then issued two rules phasing in permitting of stationary sources of GHG:

- In the Timing Rule, EPA delayed when major stationary sources of GHGs would otherwise be subject to PSD and Title V permitting, concluding that these requirements would commence on January 2, 2011—the date on which the Tailpipe Rule became effective. 75 Fed. Reg. 17,004 (Apr. 2, 2010).
- In the Tailoring Rule, EPA departed from the CAA's 100/250 tpy emissions threshold and provided that only the largest sources—those exceeding 100,000 tpy carbon dioxide equivalent (CO2e)—would initially be subject to GHG permitting. 75 Fed. Reg. 31,514 (June 3, 2010).

In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld all four rules—the Endangerment Finding, Tailpipe Rule, Timing Rule and Tailoring Rule—in *Coalition for Responsible Regulation v. EPA*, 684 F. 3d 102 (2012) (*per curiam*). Last year, the Supreme Court granted six petitions for certiorari, but limited its review to only one question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases." 571 U. S. ____ (2013).

Court Rejects EPA'S Requirement for PSD and Title V Permits Based Solely on GHGS

The crux of the problem EPA sought to address through the Tailoring Rule was that, unlike conventional air pollutants typically regulated under the CAA, GHGs—and carbon dioxide, in particular—are emitted in vastly greater quantities, such that the 100-or 250-tpy thresholds would be exceeded by many common sources, including schools, hospitals and office buildings. To avoid the insurmountable permitting burden that would result if all of these sources were now subject to PSD or Title V permitting, EPA therefore said it needed to "tailor," i.e., increase, the threshold for GHGs from 100-tpy to 100,000 tpy CO_2e. EPA attempted to justify its departure from the statutory text based upon the legal doctrines of "absurd results," "administrative necessity" and "one step at a time." The D.C. Circuit elided altogether the question of whether the EPA's departure was lawful, finding instead that the industry petitioners were not harmed by, and therefore lacked standing to challenge, the Tailoring Rule because, by increasing the threshold, EPA only afforded industry relief from requirements that would otherwise apply.

On June 23, 2014, in a majority opinion issued by Justice Scalia in the case of *Utility Air Regulatory Group v. EPA*, No. 12-1146 (hereinafter, "*UARG*"), the Supreme Court, held that the EPA "had taken a wrong interpretive turn" when it decided that, upon the effective date of the Tailpipe Rule's standards, "any air pollutant" necessarily included GHGs (for purposes of determining applicability of the PSD and Title V permitting programs) and then replaced the unambiguous statutory thresholds—100 or 250 tpy of any air pollutant—with a threshold of 100,000 tpy CO_2e for GHGs. *See* slip op. at 21-24.

In the majority's view, the EPA should have given a more limited construction to the words "any air pollutant" and found instead that PSD and Title V permitting were not automatically triggered for GHGs by the Tailpipe Rule's. The Court reconciled its decision with *Massachusetts v. EPA*, which found that GHGs unambiguously fit within the CAA's "capacious" definition of "air pollutant," observing that "*Massachusetts* does not strip EPA of authority" to apply a narrower understanding of the term "any air pollutant," where inclusion of GHGs "would be inconsistent with the statutory scheme." Slip op. at 14.

Separate Majority Upholds Requiring GHG BACT for Anyway Sources

While the majority opinion threw out the Tailoring Rule's thresholds and the application of PSD permitting based solely on source emissions of GHG, a separate majority of the Court also upheld EPA's requirement that "anyway sources"—i.e., those that already trigger PSD and Title V permitting by virtue of emissions of conventional pollutants—must meet BACT. Once a source is subject to PSD permitting, the CAA requires that the source be "subject to the best available control technology" for "each pollutant subject to regulation under [the CAA]." 42 U.S.C. §7475(a)(4).

A majority of the Court found that, given the lack of any ambiguity in the scope of the BACT requirement—it applies to "each pollutant subject to regulation under [the CAA]"—Congress's expectation was clearer and, therefore, it was reasonable for the EPA to require "anyway sources" to meet BACT for GHGs. *See* slip op. at 27. Although it upheld the EPA's authority to require GHG BACT for anyway sources, the Court does not uphold the Tailoring Rule's threshold for what constitutes a "significant" emissions rate triggering the BACT requirement. According to the majority, EPA may require GHG BACT "only if the source emits more than a *de minimis* amount of greenhouse gases" *Id*., at 28-29. However, upon promulgating the Tailoring Rule, the EPA expressly said that a truly *de minimis* amount might be much less than the rule's 75,000-tpy threshold. *Id*., at 8 note 3. Thus, at the very least, EPA must now justify this or another, presumably lower threshold as *de minimis* if it should wish to continue requiring BACT for anyway sources.

Importantly, a majority of the Court clearly rejected Justice Alito's view (in his concurring and dissenting opinion joined by Justice Thomas) that *Massachusetts* was wrongly decided and GHGs should never have been subject to regulation under the CAA in the first place. According to Justice Scalia's majority opinion, "[w]e are not talking about extending EPA jurisdiction over millions of previously unregulated entities, but about moderately increasing the demands EPA (or a state permitting authority) can make of entities already subject to its regulation." *See id*., at 28. Countering views that requiring BACT for GHGs would be an unwieldy exercise that would lead into examination of the light bulbs used in a facility's cafeteria, Justice Scalia cites to the experience of one amicus, which has obtained several PSD permits (Calpine Corporation) and observed that, for anyway sources, the GHG analysis was only a small part of the overall permitting process. *Id*. at 26. For these reasons, the Court was able to distinguish between the term "any air pollutant" for purposes of determining the scope of the permitting obligation in the first instance, and the term "each pollutant subject to regulation" for purposes of determining the scope of the BACT requirement; only in the latter case would it allow EPA to read GHGs as being included.

The Court's decision in this respect evinces its desire to forge a middle ground. The Solicitor General revealed at oral argument that "anyway sources" accounted for 83% of stationary source GHG emissions, whereas the additional coverage afforded through the Tailoring Rule amounted to only 3% more. *See* slip op. at 12-13. Thus, by preserving the EPA's authority to require BACT for GHGs from anyway sources, the EPA would presumably still be able to target nearly all the emissions that might otherwise be subject to the BACT requirement, without triggering a cascade of potential permitting obligations for other sources.

Implications

The most immediate impact of the Court's decision is that many smaller sources, such as gas-fired power plants, which would not require a PSD permits but for their emissions of GHGs, may no longer require such a permit. Additionally, many modifications to existing sources that would result in greater than a 75,000-tpy increase in GHG, but no significant increase of any criteria air pollutant, may no longer be required to obtain PSD permits. Thus, notwithstanding the emphasis placed by the Solicitor General and the Court's decision on the fact that anyway sources account for 83% of stationary source emissions and all the rest captured by the Tailoring Rule only accounted for 3% more, there may actually be many projects currently in the planning stages, including retrofits to existing coal-fired power plants needed to achieve the EPA's Mercury and Air Toxics Standards, that will now escape the PSD permitting obligation and the BACT requirement for GHGs.

Those new sources or modifications to existing plants might nevertheless be subject to regulation under EPA's proposed New Source Performance Standards (NSPS) for fossil fuel-fired electric utility generating units (see related alert here) or its more recently proposed Clean Power Plan (also known as the existing source performance standards (ESPS)) (see related alert here); so the absence of a requirement to meet BACT for GHGs may not mean such sources will actually be emitting GHG in amounts that would not otherwise occur if the Court had upheld the Tailoring Rule, which leads to the question of whether the Court's ruling in *UARG* has any bearing on the proposed NSPS or ESPS and EPA's authority to pursue regulation of such sources under Section 111 of the CAA. Apart from the fact that *UARG* dealt with the EPA's authority to interpret the CAA in a case involving its regulation of stationary source GHG emissions, it is not clear that the Court's decision will impact on the outcome of any litigation challenging the final version of either the NSPS and ESPS.

At first take, one might make much of the Court's statement that, "[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate a significant portion of the American economy, . . . we typically greet its announcement with a measure of skepticism." Slip op. at 19 (internal citations omitted). While such an admonition to the EPA might suggest that a majority of the Court would view the far-reaching and ambitious interpretation of section 111(d) reflected by the proposed ESPS with a similar dose of skepticism, the EPA ostensibly has greater authority to interpret what constitutes the "best system of emission reduction" from existing sources, than to multiply a statutory threshold by 1,000.

Thus, *UARG* may tell us little about how a majority of the Court would rule on the interpretive questions posed by the EPA's proposed Clean Power Plan. Further, on the question of whether the EPA has authority to regulate GHG emissions under section 111 in the first instance or must similarly adopt a narrow reading of "any air pollutant" in section 111(d)(1)(A), a footnote elsewhere in the opinion affirms that the Court's decision in *American Electric Power Company v. Connecticut*, 564 U. S. (2011) was premised upon the EPA having authority to regulate GHG emissions under section 111 of the CAA. *See* slip op. at 14 note 5. Critics of the EPA's proposed approach would therefore be wrong to presume that the Court's decision in UARG means EPA's proposed ESPS will suffer a similar fate. Indeed, there are strong reasons to think that the proposed ESPS are more legally durable, given that the "building blocks" are established independently of one another and are deemed to be severable by the EPA.

More immediate questions arise with respect to the direct implications of the Court's ruling on the rules states adopted as part of their State Implementation Plans (SIPs) pursuant to the Tailoring Rule. Many such rules did not simply incorporate by reference the definitions and requirements of EPA's regulations, but separately established GHG permitting obligations as part of the state's New Source Review (NSR) permitting program. It is not necessarily the case that those rules are no longer enforceable and we might expect that the EPA will provide guidance on the status of those SIP-approved rules and pending permit applications in the near term.

Conclusion

While critics of the EPA's regulatory campaign to address GHG emissions and climate change in the absence of Congressional action may have scored a significant victory, the Supreme Court's decision in *UARG* does not represent the undoing of those efforts. The EPA will undoubtedly continue with its proposed rules to achieve significant reductions in power sector emissions and nothing in *UARG* blocks it from doing so.

The author obtained the first PSD permit to regulate GHGs issued under the CAA (for a 619-MW combined cycle gas fired power plant now in operation in California) and subsequently obtained the first PSD permits to regulate GHG emissions from renewable (geothermal) power plants under the Tailoring Rule.

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May 2015

Focusing On a Blind Spot In EPA's Clean Power Plan: Why Emissions From New Gas-Fired Power Plants Must Be Accounted For In State Plans

By Kevin Poloncarz & Ben Carrier

A major component of President Obama's Climate Action Plan consists of two sets of rules proposed by the United States Environmental Protection Agency (the "EPA") that would, for the first time, establish limits on the emissions of carbon dioxide ("CO_2") from new fossil fuel-fired electric generating units ("EGUs") and require states to develop plans for how they will reduce CO_2 emissions from existing EGUs.

- The "new source performance standards," which are being developed pursuant to section 111(b) of the Clean Air Act (the "Act"), were sent to the White House's Office of Management and Budget for interagency review earlier this month.[1]

- The guidelines for existing power plants—"Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" Proposed Rule, known as the "Clean Power Plan"—are being developed pursuant to section 111(d) of the Act and are expected to be finalized this summer. Projected to achieve a 30% reduction in CO_2 emissions from the U.S. electric generating sector by 2030, relative to 2005 levels, they would establish emissions performance goals for each state at the level that EPA found can be achieved through implementation of four so-called "building blocks": (1) efficiency improvements that can be achieved at coal-fired power plants; (2) re-dispatch from coal-fired to existing natural gas combined cycle ("NGCC") power plants; (3) increased generation by renewable resources; and (4) energy efficiency and other demand-side reduction measures.[2]

The proposed Clean Power Plan affords states an unprecedented degree of flexibility in how they can achieve their respective goals. It does not mandate that states actually implement *any* of the four building blocks, so long as emissions from their existing EGUs are reduced to the extent needed to meet the goals. As a consequence, EPA expects that implementation of the Clean Power Plan will also result in the construction of a significant number of new NGCC facilities. Yet, under the proposed Clean Power Plan, those new NGCCs would only be subject to the new source standards promulgated under section 111(b): EPA has not proposed to consider the reductions that can be achieved through the construction and operation of new NGCC facilities in calculating states' goals under section 111(d), nor has it proposed to require states to include any requirements for new NGCCs in their section 111(d) compliance plans.

Disparate treatment of new and existing NGCC facilities will create market distortions that could result in the construction of significantly more new NGCC capacity than is actually needed to meet demand and achieve the state's emission performance goals. This risk is particularly acute in states employing a market-based program or carbon fee that only applies to existing sources. Further, if electricity load from existing affected EGUs were simply shifted to new NGCC facilities without accounting for the emissions from those new facilities, then it is possible that a state could demonstrate illusory compliance with its emission performance goals, without actually achieving the reductions in power sector emissions required by the Clean Power Plan. While section 111 of the Act requires that new and existing sources be treated differently, it does not mandate that EPA simply ignore the risk that states may circumvent the Clean Power Plan's and the Act's overall emission reduction goals in this manner.

The memorandum from Paul Hastings LLP (linked here and below) examines the legal authority for EPA to require that, where new NGCC facilities will in fact be built and operated to reduce emissions from affected EGUs, the state must account for the emissions from such new NGCC facilities in its state plan. Importantly, by requiring states to account for new NGCC emissions in their section 111(d) plans, new NGCC facilities would *not* become "affected EGUs" under the Clean Power Plan or "existing sources" subject to section 111(d) of the Act. New NGCCs would continue to be subject to separate standards under section 111(b). States, however, would be prevented from demonstrating illusory compliance with their respective emission performance goals by simply shifting dispatch from affected EGUs to new NGCC facilities, without accounting for the impact that the emissions from such new NGCCs would have on system-wide CO_2 emissions.

Paul Hastings' memorandum regarding the treatment of new NGCCs under the Proposed Clean Power Plan is linked here.

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1 *See* "U.S. EPA Proposes Separate CO2 Emissions Standards for New Natural Gas-Fired and New Coal-Fired Power Plants" for more background on the new unit standards.

2 *See* "EPA Proposes Its Landmark Guidelines For Reducing Carbon Emissions from Existing Fossil Fuel-Fired Power Plants" for more background on the proposed Clean Power Plan.

PAUL
HASTINGS

MEMORANDUM

date:	May 21, 2015
to:	W. Thaddeus Miller, Executive Vice President, Chief Legal Officer and Secretary, Calpine Corporation
cc:	J. D. Furstenwerth, Sr. Director, Environmental Services, Calpine Corporation Diana Woodman Hammett, Esq., VP and Managing Counsel, Calpine Corporation Yvonne McIntyre, VP Federal Affairs, Calpine Corporation
from:	Kevin Poloncarz Ben Carrier
subject:	Treatment of New NGCC under Proposed Clean Power Plan

This memorandum discusses how new natural gas combined-cycle (NGCC) power plants should be addressed under the United States Environmental Protection Agency's (EPA) "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" Proposed Rule (hereinafter, Proposed Rule or Proposed Clean Power Plan). *See* 79 Fed. Reg. 34830 (June 18, 2014) (Docket ID No. EPA–HQ–OAR–2013–0602).[1] In particular, this memorandum discusses the legal authority for EPA to mandate that states relying upon new NGCC to achieve their respective CO_2 emission performance goals must account for the emissions from new NGCC in their state plans. While this memorandum discusses the requirements for state plans, the concepts would apply equally to any federal implementation plan EPA should issue for a state.

I. INTRODUCTION AND SUMMARY

A significant question that EPA raised in the Preamble to the Proposed Clean Power Plan is how, given the structure of section 111 of the Clean Air Act (Act or CAA), CO_2 emissions reductions resulting from the substitution of generation from existing affected EGUs with generation from new NGCC should be accounted for in determining each state's compliance with its emission performance goals.[2] Even though new NGCC units were not proposed to be part of the BSER or considered in computing the proposed state goals, EPA projects that the Clean Power Plan will result in the construction of 11 to 22 gigawatts (GW) of new NGCC capacity by 2020.[3] Thus, EPA has expressly acknowledged that implementation of the Clean Power Plan will result in construction of significant new NGCC capacity and, as a consequence, significant emissions from such units. If load from existing affected EGUs were simply shifted to new NGCC facilities without accounting for the emissions from those new units, then it is possible that a state could achieve compliance with its respective emission performance goals, without

[1] This memorandum assumes familiarity with the Proposed Rule, its alternative formulations of the best system of emission reduction (BSER), the category of affected electric generating units (EGUs) subject to the Proposed Rule, the portfolio approach for assigning responsibility for achieving the required CO_2 emission performance goals to entities other than the affected EGUs, and the relationship of the Proposed Rule's rate-based goals to illustrative mass-based equivalents.

[2] *See* 79 Fed. Reg. 34830, 34924 (posing whether: "considering the legal structure of CAA section 111(d), should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a portfolio approach) also be considered?").

[3] *Id.* at 34933 (stating that "[b]oth the two-block and the four-block approaches result in construction of additional NGCC capacity by 2020, with 11–18 GW of new NGCC for the two-block approach and 20–22 GW of new NGCC capacity for the four-block approach.").

achieving reductions in, or possibly even increasing, the overall carbon intensity or net emissions from its power sector. Section 111 does not command that EPA countenance such circumvention of the Clean Power Plan's and the Act's overall emission reduction goals. Rather, because sections 111(b) and 111(d) both require that the standards established pursuant to them each reflect the "best *system* of emission *reduction*" (and given the interconnected nature of the electricity system and the global nature of CO_2 pollution), EPA has clear authority to reject a state plan where, by merely shifting load from affected EGUs to new NGCC facilities, the plan would amount to no more than illusory compliance with a state's emission performance goals and would not achieve the full scope of required reductions in carbon intensity and/or total CO_2 emissions from the state's electricity system.

EPA has already proposed an interpretation of the interrelationship between sections 111(b) and 111(d) in the Proposed Rule, whereby affected EGUs cannot simply modify or reconstruct their way out of obligations under a state plan because allowing them to do so would undermine the emission reduction goals of section 111(d). Requiring states to account for emissions from new NGCC in their state plans would similarly avoid circumvention of section 111(d)'s emission reduction goals and would represent a logical outgrowth of both this existing proposal and EPA's solicitation of comment on how emissions changes resulting from shifting dispatch from affected EGUs to new NGCC should be calculated for purposes of determining compliance with states' goals.

Within the existing framework of the Proposed Rule, EPA could clarify that, where new NGCC facilities will, in fact, be built and operated to reduce emissions from the affected EGUs, the state must account for their emissions in the state plan. Importantly, by requiring states to address the emissions from new NGCC in this manner, new NGCC facilities would *not* become "affected EGUs" under the Clean Power Plan or "existing sources" under section 111. New NGCC would continue to be subject to separate standards under section 111(b). States, however, would be prevented from demonstrating illusory compliance with their respective emission performance goals by simply shifting dispatch from affected EGUs to new NGCC facilities, without accounting for the impact that the emissions from such new NGCCs would have on system-wide CO_2 emissions.

II. BACKGROUND

In the preamble to the Proposed Rule, EPA states that its analysis "regarding the feasibility of policies to increase utilization rates of existing NGCC units on average to 70 percent applies equally to new NGCC units"[4] and that it views "the opportunity to reduce CO_2 emissions at affected EGUs by means of addition and operation of new NGCC capacity as clearly feasible."[5] Additionally, EPA's Regulatory Impact Analysis for the Proposed Rule states that "[w]hile not included in the goal setting for building block 3, the addition of new NGCC capacity would have a similar impact [as adding new nuclear or renewable energy capacity to the electric system] *and is one option states may choose to achieve the goal*."[6]

EPA further notes that its "compliance modeling for this proposal suggests that the construction and operation of new NGCC capacity will be undertaken as [a] method of responding to the proposal's requirements"[7], even though dispatch of new NGCC capacity is not included as part of BSER. Specifically, EPA states that "[b]oth the two-block and the four-block approaches result in construction of additional NGCC capacity by 2020, with 11-18 GW of new NGCC for the two-block approach and 20-22 GW of new NGCC capacity for the four-block approach."[8] In a Technical Support Document (TSD), EPA

[4] *Id.* at 34876.

[5] *Id.*

[6] EPA, Regulatory Impact Analysis for Proposed Clean Power Plan, at 2-13, Docket No. EPA-HQ-OAR-2013-0602-0391 (June 2014) (emphasis added).

[7] 79 Fed. Reg. 34830, 34876.

[8] *Id.* at 34933.

projects that the Proposed Rule will result in even greater new NGCC capacity than what is stated in the preamble: 22.7 GW of new NGCC capacity is anticipated to be built as a result of the Proposed Rule (i.e., over and above the capacity that is expected to be built in the base case).[9]

A. *The Clean Air Act Contemplates That New And Existing Sources Be Treated Differently*

As a threshold matter, Congress created two separate regulatory structures for new and existing sources. The Proposed Rule was developed pursuant to section 111(d) of the CAA, which states, in relevant part, that EPA "shall prescribe regulations which shall establish a procedure similar to that provided by section 7410[10] of this title under which each State shall submit to [EPA] a plan which [] establishes standards of performance for any existing source for any air pollutant

> (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408 (a) of this title [i.e., criteria pollutants] or emitted from a source category which is regulated under section 7412 of this title [i.e., hazardous air pollutants (HAPs)] but
>
> (ii) to which a standard of performance under this section would apply if such existing source were a new source…"[11]

In turn, the term "new source" means "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."[12] The term "existing source" means "any stationary source *other than a new source*."[13]

Section 111(b) sets forth the procedure for EPA to establish standards of performance for new sources (i.e., New Source Performance Standards (NSPS)). After including a category of stationary sources in the section 111 list, EPA "shall publish proposed regulations, establishing Federal standards of performance for *new sources* within such category."[14] Conversely, under section 111(d), EPA prescribes regulations for *states* to submit plans establishing standards of performance "for *any existing source*" "to which a standard of performance under this section would apply *if such existing source were a new source*…"[15] Therefore, section 111(b) requires EPA to issue standards directly applicable to new

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[9] EPA, Technical Support Document: Resource Adequacy and Reliability Analysis, Table A5. "New Capacity Policy Case Incremental to Base Case in 2020", Docket No. EPA-HQ-OAR-2013-0602-0163.

[10] Section 7410 pertains to the States' formulation of State Implementation Plans (SIPs) to attain or maintain the National Ambient Air Quality Standards (NAAQS).

[11] 42 U.S.C. § 7411(d)(1); *see also* Pub. L. No. 101-549, § 108(g), 104 Stat. 2399, 2467 (1990). This amended version of section 111(d) was passed by the U.S. House of Representatives, while a different amendment (which replaced some text with a cross-reference to section 112) was passed by the U.S. Senate. Both versions of section 111(d) were enacted into law in the Statutes at Large. A legal challenge pending in the Court of Appeals for the District of Columbia Circuit claims that EPA has no authority to promulgate the Proposed Rule because (1) the House amendment to section 111(d) is the only valid version of the section and (2) this version does not permit the regulation of CO_2 from existing power plants because EPA has already regulated existing power plants under section 112, albeit for a different pollutant (i.e., under the Mercury and Air Toxics Standards (MATS)). *See Murray Energy, et al. v. EPA, et al.*, No. 14-1112 (D.C. Cir.) (argued April 16, 2015). Calpine submitted an *amicus curiae* brief in support of EPA in this case and has argued that the petitions are wholly without merit.

[12] 42 U.S.C. § 7411(a)(2).

[13] *Id.* § 7411(a)(6) (emphasis added).

[14] *Id.* § 7411(b)(1)(B) (emphasis added).

[15] *Id.* § 7411(d)(1) (emphasis added).

sources; section 111(d), on the other hand, requires state plans establishing standards of performance for existing sources, which, by definition, are not new sources.

B. *How Failing To Account For Emissions From New NGCC Threatens The Integrity of Emission Reductions To Be Achieved Under The Clean Power Plan*

EPA raised the question of how to account for new NGCC in the preamble to the Proposed Rule.[16] In response, commenters have suggested several different approaches, such as inclusion of new NGCC as part of both the BSER determination and state goal calculation process; adding the megawatt-hours (MWh) generated by new NGCC to the denominator for purposes of demonstrating a states' affected EGUs' compliance with a rate-based goal, but not correspondingly adding the emissions from new NGCC to the numerator;[17] and only allowing states to credit emissions from new NGCC to the extent the new facilities actually displace generation from existing EGUs. Calpine suggested that, over time, new NGCC subject to the NSPS could become affected EGUs under the Clean Power Plan as the NSPS is automatically updated on a periodic basis to reflect improvements in CO_2 emissions performance.[18]

Commenters also described the problems associated with disparate treatment of new and existing NGCC units under the Proposed Rule.[19] Calpine focused on the perverse incentives and resulting distortions within competitive electricity markets that would arise if new NGCC facilities are not subject to equivalent requirements.[20] The problem ultimately comes down to figuring out how to account for the emissions from new NGCC, while respecting the structure of section 111. If, as suggested by some, the MWh generated by new NGCC were credited towards compliance with a rate-based standard, but the concomitant emissions were not also accounted for in determining the state's compliance with its rate-based goal, then a state could circumvent the emission reduction goals of the Clean Power Plan merely by substituting a large share of its existing generation from existing fossil fuel-fired units with new NGCC. Even if the MWh generated by new NGCC were not credited towards a state's compliance, the same

[16] *See* 79 Fed. Reg. 34830, 34924 ("request[ing] comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. Specifically, considering the legal structure of CAA section 111(d), should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a bass-based state plan (e.g., in a plan using a portfolio approach) also be considered?").

[17] *See* Duke Energy Comments on Proposed Clean Power Plan, at 10, Docket No. EPA-HQ-OAR-2013-0602-27188 (Dec. 4, 2014) (stating that "[a]lthough new NGCC units are outside the scope of the section 111(d) program, it would be permissible for a state that employs the rate-based approach under section 111(d) to allow the megawatt hours generated by these newly constructed NGCC units to be included in a state's compliance demonstration.").

[18] *See* Calpine Comments on Proposed Clean Power Plan, at 19-21, Docket No. EPA-HQ-OAR-2013-0602-22799 (Nov. 26, 2014) (recommending an approach whereby the NSPS for stationary combustion turbines would be updated periodically based on standardized data sources and the expectation of continual CO_2 emission rate improvement, so that, upon being updated, stationary combustion turbines subject to the prior version of the NSPS would become affected EGUs under the Clean Power Plan).

[19] *See*, *e.g.*, Clean Air Task Force Comments on Proposed Clean Power Plan, at 102, Docket No. EPA-HQ-OAR-2013-0602-22612 (Dec. 1, 2014) (stating that, "[t]o maintain the environmental efficacy of the rule, EPA must direct states to account for the CO_2 emissions of new NGCC units as part of state compliance demonstrations… Without this adjustment to building block 3, the CPP may create perverse incentives to build unnecessary new NGCC units.").

[20] *See* Calpine Comments on Proposed Clean Power Plan, at 17, Docket No. EPA-HQ-OAR-2013-0602-22799 (Nov. 26, 2014).

possibility for circumvention exists, particularly for states with rate-based goals lower than the average emissions rate of new NGCC facilities. Further, states electing to translate their rate-based goals to mass-based emission performance levels would also be able to achieve compliance merely by shifting dispatch to new NGCC. In either case, the failure to account for the emissions from new NGCC means that compliance with a state's emission performance goals could be demonstrated on paper, while the carbon intensity and/or total mass of emissions from the state's power sector might remain roughly the same or even increase.

In light of the interconnected nature of the electricity grid and the global nature of CO_2 pollution and its associated harms to the environment, achieving illusory emission reductions from affected EGUs by merely shifting dispatch to new NGCC would be inconsistent with section 111's mandate that the standards of performance issued under sections 111(b) and 111(d) each comprise "the best system of emission *reduction*",[21] as well as the Act's overarching goal of *reducing* emissions.[22] Further, given the extent to which EPA projects states will rely upon new NGCC and the possibility that failing to account for emissions from new NGCC could undermine the goals of the Clean Power Plan, EPA's failure to consider and resolve this problem may be subject to challenge as arbitrary and capricious rulemaking.[23]

III. EPA'S AUTHORITY TO REQUIRE STATES TO ADDRESS NEW NGCC IN STATE PLANS

Under the regulatory framework already proposed for the Clean Power Plan, EPA has clear authority to require that, where a state will construct and operate new NGCC as a means to reduce emissions from its existing EGUs, states must account for such emissions in demonstrating compliance with the plan's identified emission performance level. Where a state plan indicates that the state will achieve its goals by retiring or reducing operation of affected EGUs, but fails to account for the emissions from new NGCC facilities built to serve load that would otherwise have been served by the affected EGUs, EPA has clear authority to reject the plan: Given the interconnected nature of the power grid and the global nature of CO_2 pollution, the failure to account for the emissions from such new NGCC facilities could defeat the overall emission reduction goals of section 111 and the Act. Importantly, by forcing states to account for the emissions from new NGCC in this manner, new NGCC facilities would *not* "become" affected EGUs under the Proposed Rule.

Thus, without amending the Proposed Rule in any significant respect, EPA could clarify states' obligations with respect to new NGCC in the preamble to the final rule or in subsequent guidance, just as EPA has issued extensive guidance regarding requirements for approval of SIPs under section 110.[24] EPA might also, as a logical outgrowth of the Proposed Rule, add a "backstop" provision to the final rule, which confirms its authority to reject a state plan which, by merely shifting generation from the affected EGUs to new NGCC facilities, would amount to no more than illusory compliance with the Clean Power Plan's goals and would not achieve the intended emission reductions from the power sector as a whole. This requirement would be justified by the need to avoid circumvention of the common emission reduction

[21] 42 U.S.C. § 7411(a)(1) (emphasis added).

[22] *See* 79 Fed. Reg. 34830, 34886 (stating that "[i]n enacting the CAA, Congress established 'pollution prevention' as a 'primary goal' of the Act and described it as 'the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source.' Building blocks 2, 3, and 4 are pollution prevention measures, and, in light of the importance of pollution prevention in the CAA, it is reasonable to interpret 'system of emission reduction' in section 111 to incorporate those measures."); *see also* 42 U.S.C. §§ 7401(a)(3), (c).

[23] *See Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42-43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem.").

[24] *See* 42 U.S.C.§ 7411(d)(1) (requiring EPA to prescribe regulations establishing "a procedure similar to that provided by section 7410 [i.e., for submission of SIPs for attainment of the NAAQS]…").

purposes of both the NSPS and the Clean Power Plan, i.e., sections 111(b) and 111(d) both require that the standards established pursuant to each of them comprise the "best *system* of emission r*eduction*"; and, in the context of the interconnected electricity system and a pollutant with global impacts, Congress surely did not mandate that EPA adopt an approach whereby the two sets of standards working alongside one another would achieve no actual emission reductions from the state's power sector.

While the following discussion focuses on requirements for state plans, the principles illustrated herein apply equally to any federal implementation plan that might be imposed on a state.

A. *Requiring States To Account For New NGCC Is Consistent With Section 111*

EPA must operate "within the bounds of reasonable interpretation" (*City of Arlington, Tex. v. F.C.C.*, 133 S. Ct. 1863, 1868 (2013) (internal citation omitted)) in requiring states to address emissions from new NGCC in their state plans.[25] EPA would have strong responses to claims that such a requirement is unreasonable and contrary to the structure of section 111.

First, by not including new NGCC within the category of "affected EGUs" subject to the Proposed Rule, EPA has already afforded distinct treatment to new and existing sources in accordance with section 111. In other words, EPA is not treating new NGCC facilities as existing sources. On the other hand, nothing in section 111 mandates that, in the context of the interconnected electricity grid, EPA must simply ignore the impact that operation of new units subject to section 111(b) will have on states' ability to achieve the emissions reductions required under section 111(d). Notably, requiring states to account for emissions from new NGCC facilities does not require that new NGCC be included either as part of the BSER under section 111(d) or in the calculation of states' emission performance goals.

Second, requiring states to account for emissions from new NGCC is necessary to avoid circumvention of the overall emission reduction goals of section 111 and the Act.[26] Surely Congress did not intend that, working alongside one another, sections 111(b) and 111(d) could potentially result in an *increase* in total emissions or the overall emissions intensity from new and existing sources, in light of the pollution prevention purposes of the Act.[27] Given the relationship of sections 111(b) and 111(d) and the fact that they were both intended to *reduce* emissions, EPA could reasonably decide that state plans submitted under section 111(d) must account for the emissions from new NGCC that will be operated to reduce emissions from the affected EGUs to ensure that the required emission reductions do, in fact, occur.[28] Such an interpretation would be entitled to deference as consistent with "the design and structure of the statute as a whole."[29]

Finally, EPA could emphasize that the choice to construct and operate new NGCC to achieve reductions

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[25] *See Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837, 842–844 (1984) (holding that, if Congress has not directly spoken to the precise question at issue, then a court will defer to EPA's interpretation of the Act if it is reasonable in light of the text, the structure, and the purpose of the Act).

[26] *See Carpenter, Chartered v. Sec. of Veterans Affairs*, 343 F.3d 1347, 1352 (D.C. Cir. 2003) (stating that, "a regulation is reasonably related to the purposes of the legislation to which it relates if the regulation serves to prevent circumvention of the statute and is not inconsistent with the statutory provisions.").

[27] *See* 42 U.S.C. §§ 7401(a)(3), (c).

[28] *See Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2203 *reh'g denied sub nom. Scialabba v. de Osorio*, 135 S. Ct. 22, 189 L. Ed. 2d 874 (2014) (Kagan, J., plurality op.) (stating where "internal tension" in a statute "makes possible alternative reasonable constructions," "*Chevron* dictates that a court defer to the agency's . . . expert judgment about which interpretation fits best with, and makes the most sense of, the statutory scheme.").

[29] *See Util. Air Regulatory Grp. v. E.P.A.*, 134 S. Ct. 2427, 2442 (2014) (internal citation omitted).

in emissions from affected EGUs is ultimately one to be made by the state and its stakeholders (e.g., utilities, public utility commissions, permitting authorities, integrated energy planning agencies, etc.). Once that choice has been made, however, EPA cannot allow the state to circumvent the overall emission reduction requirements of the Clean Power Plan and the Act by failing to account for the emissions from such new NGCC facilities. As the Proposed Rule relies on the interconnected nature of the power grid to drive emission reductions at affected EGUs, the final rule must also recognize and account for the risk that the interconnected nature of the grid may allow states to rely on new NGCC to achieve illusory compliance with their goals, which could undermine the emission reduction purpose of both the Clean Power Plan and the Act.

B. *EPA Should Reject State Plans That Fail To Account For Emissions From New NGCC Power Plants*

The preamble to the Proposed Rule makes clear that, "[t]he credibility of state plans under CAA section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans."[30] To that end, EPA states that, "*any material component* of a state requirement or program included in a state plan that *could affect emission performance by affected EGUs* should be accurately represented in emission projections included in the state plan."[31] The emission performance of the affected EGUs in a state will undoubtedly be affected by construction and operation of new NGCC facilities. Thus, if a state fails to account for new NGCC in its plan, but the accompanying projections for how it will achieve its goals indicate operation of new NGCC to displace load from the affected EGUs, EPA should find the plan deficient and require the state to resubmit a plan that properly accounts for the impact of new NGCC facilities and their associated emissions. This authority to reject state plans that are deficient in this respect is already implied by the Proposed Rule[32] and could be clarified by EPA, either in the preamble to the final rule or in subsequent guidance, along with statements clarifying the obligation of each state to account for emissions from such new NGCC in its emission performance projections.

Additionally, EPA could also add a "backstop" provision to the final rule, which confirms its authority to reject a state plan where, by merely shifting generation from the affected EGUs to new NGCC facilities, without accounting for the emissions from such new NGCC facilities, the plan would amount to no more than illusory compliance with a state's goals and would not achieve the full scope of required reductions in carbon intensity and/or total CO_2 emissions from the state's power sector. The justification for such a requirement would be the need to protect against circumvention of the common emission reduction purposes of both the NSPS and the Clean Power Plan.[33] EPA has experience crafting such regulatory backstop provisions to avoid circumvention of underlying statutory emission reduction goals.[34]

Indeed, elsewhere as part of the Clean Power Plan, EPA has proposed an interpretation of the relationship of sections 111(b) and 111(d), whereby existing sources that are modified or reconstructed—hence, triggering applicability of a section 111(b) standard—must remain subject to obligations under a section 111(d) plan "to avoid creating incentives for sources to seek to *avoid their obligations under a*

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[30] 79 Fed. Reg. 34830, 34922.

[31] *Id.* (emphasis added).

[32] *See*, *e.g*., Proposed Rule §§ 60.5715, 60.5790(b).

[33] *See Carpenter, Chartered v. Sec. of Veterans Affairs*, 343 F.3d at 1352, *supra* note 26 (stating that, "a regulation is reasonably related to the purposes of the legislation to which it relates if the regulation serves to prevent circumvention of the statute and is not inconsistent with the statutory provisions.").

[34] *See*, *e.g*., Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals; Final Rule (i.e., Cross-State Air Pollution Rule), 76 Fed. Reg. 48028, 48464, 48477 (promulgating 40 C.F.R. § 97.706(c)(2) and 40 C.F.R. § 97.725, which establish "assurance levels" in response to the court's decision in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008), modified on rehearing, *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir. 2008)).

CAA section 111(d) plan by undertaking modifications…, which would *undermine the emission reduction goals of CAA section 111(d).*"[35] EPA should propose a similar justification for including a provision that clarifies its authority to reject a state plan where a state's failure to account for emissions from new NGCC would undermine the integrity of the emission reductions to be achieved from the overall power sector under section 111(d). Given the system-wide approach to the BSER reflected by the Proposed Rule, EPA should adopt an interpretation of the relationship of sections 111(b) and (d) that gives full and independent effect to each, but assures that they work in tandem to achieve the Act's overall emission reduction goals and that construction of new NGCC facilities is not utilized by states to avoid their obligations under section 111(d).[36] Addition of such a provision in the final rule could be accomplished as a logical outgrowth of the Proposed Rule's treatment of modified and reconstructed sources and EPA's solicitation of comment on how to account for the emissions from new NGCC.[37]

EPA will have adequate information available during its review of state plans to determine whether a plan's projection for how the state will achieve its goals is, in reality, premised upon construction and operation of new NGCC facilities. In the Technical Support Document entitled "Projecting EGU CO_2 Emission Performance in State Plans", EPA describes the type of analytical tools states may use to project compliance with their emission performance goals.[38] These include national- or utility-scale capacity expansion and dispatch planning models, dispatch simulation models and growth tools, which can be used to "approximate future emissions from existing *and new fossil fuel-fired EGUs* under different assumed growth, retrofit, and load-reduction scenarios."[39] The projections submitted by states using such tools will necessarily indicate the extent to which compliance is premised upon the construction and operation of new NGCC, even if the state should fail to identify new NGCC as an element of its compliance plan. Thus, any non-deficient plan submittal will contain the information EPA needs to determine whether a state has failed to account for the role new NGCC will play in achieving its emission performance goals. Just as EPA has the authority to reject modeling demonstrations submitted under section 110 that fail to account for all emissions impacting a nonattainment area,[40] EPA should make

[35] 79 Fed. Reg. 34830, 34904 (emphasis added).

[36] *See Robinson v. Shell Oil Co.,* 519 U.S. 337, 341 (1997) (stating that reasonable statutory interpretation must account for both "the specific context in which ... language is used" and "the broader context of the statute as a whole").

[37] *See supra* notes 2, 16; *cf., Environmental Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) ("The logical outgrowth doctrine does not extend to a final rule that finds no roots in the agency's proposal because something is not a logical outgrowth of nothing…") (internal citations omitted).

[38] *See* Technical Support Document, Projecting EGU CO_2 Emission Performance in State Plans, at 6-12, Docket No. EPA-HQ-OAR-2013-0602-0462 (Jun. 2014) (hereinafter, Projecting Emission Performance TSD).

[39] *Id*. at 11 (emphasis added).

[40] Section 172(c)(3) of the CAA requires that nonattainment plans "include a comprehensive, accurate, current inventory of actual emissions from all sources of the relevant pollutant or pollutants *in such area*." 42 U.S.C. § 7502(c)(3) (emphasis added). While the statute limits the inventory requirement to sources located within the identified nonattainment area, for purposes of the modeled attainment demonstration, EPA also requires states to include "large upwind sources just outside the nonattainment area" when performing the required photochemical modeling. *See* 64 Fed. Reg. 70548, 70551 (Dec. 16, 1999) (describing the modeling requirements for an attainment demonstration in proposing to conditionally approve or, in the alternative, to disapprove Texas' SIP submittal for Houston/Galveston ozone nonattainment area due to deficiencies in the inventory); *see also* Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional

clear its authority to reject state plans that fail to account for the emissions from new NGCC facilities that will be constructed and operated to reduce emissions from affected EGUs. Forcing states to account for the emissions from new NGCC facilities in this fashion does not cause such new NGCC facilities to become "affected EGUs" or "existing sources" under section 111(d), any more than requiring states to model the emissions from large sources located outside a nonattainment area causes them to become nonattainment area sources.[41]

C. *The Proposed Rule Provides The Framework For Mandating That States Account For Emissions From New NGCC Operated To Reduce Emissions From Affected EGUs*

EPA has already laid the groundwork in the Proposed Clean Power Plan to *allow* states to account for emissions from new NGCC in their plans. EPA should, however, make clear in the final Clean Power Plan that, if a state will, in fact, construct and operate new NGCC facilities to reduce utilization rates and emissions from the affected EGUs and thereby achieve its emission performance goals, then the state *must* account for the emissions from new NGCC in its state plan to assure the integrity of the reductions achieved through plan implementation.

In the Projecting Emission Performance TSD, EPA instructs that, where a state relies upon a multi-sector emissions budget trading program to achieve its goals, "state plan emission projections would need to evaluate projected CO_2 emissions across all source categories covered by the state or multi-state program… [in order to] project the CO_2 emissions performance of affected EGUs…"[42] Likewise, where a state is, in fact, going to build and operate new NGCC to reduce emissions from the affected EGUs while still meeting demand for electricity, the state must, of necessity, include new NGCC in its emissions performance projections, so as to assure its emission reduction goal is actually met and that significant emissions from new NGCC do not threaten the integrity of the reductions to be achieved by the plan.

An important and material distinction can be drawn between, on the one hand, entities responsible for energy efficiency (EE), renewable energy (RE) and other forms of zero-carbon generation, whose role in achieving the state's goals *may* be accounted for by the state plan (e.g., by crediting the MWh generated towards compliance), and, on the other hand, new NGCC that will be constructed and operated to achieve a state's goals and whose emissions *must* therefore be accounted for in the plan. In the former case, the EE and other zero-carbon resources produce no emissions. While they may add MWh to the denominator for purposes of determining compliance with a rate-based goal, they add nothing to the numerator; nor would they add anything to the total mass emissions that needs to be accounted for to determine compliance with a mass-based target. New NGCC facilities constructed and operated to reduce emissions from affected EGUs, on the other hand, will generate significant emissions that, if not accounted for in the state plan, could completely or partially eliminate any emissions reductions occurring from the affected EGUs. In light of the global nature of harms attributable to CO_2 pollution and the interconnected nature of the electricity grid, the failure to account for such emissions could undermine the Act's and section 111(d)'s emission reduction goals, rendering the rule arbitrary and capricious.

In addition, unlike EE, RE and other forms of zero-carbon energy that will be relied upon to achieve a state's goals, new NGCC units are already regulated under section 111. Given the clear interrelationship and interdependency between sections 111(b) and 111(d)—indeed, no standards of performance need be developed under the latter until an NSPS has been completed under the former—EPA could squarely

Haze, at § 2.7.5 (Dec. 2014), *available at*: http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf ("Modeling inventories must cover all areas of the modeling domain, which will include areas *outside of a nonattainment area*….") (emphasis added).

[41] *See id.*

[42] Projecting Emission Performance TSD, *supra* note 38, at 37.

defend an approach that requires states to account for the emissions from new NGCC in determining compliance with their respective goals under section 111(d). Thus, EPA has a clear justification for, on the one hand, *allowing* states to credit emission reductions achieved through zero-carbon generation if they so choose and, on the other hand, *mandating* that states account for new NGCC emissions in state plans.

At a minimum, therefore, a state plan must demonstrate that new NGCC emissions are accounted for in achieving the state emission performance level.[43] While the specific details for how the state must account for emissions from new NGCC should be left to the state's discretion, it must be sufficient to assure that the plan achieves the overall goals of the Act and does not result in illusory compliance, i.e., apparent reductions in emissions from the affected EGUs, but with significant unaccounted emissions from new NGCC facilities. To assure that its plan is not deficient in this respect, states could include the same accounting mechanisms and substantive requirements for new NGCC facilities as for existing sources with equal emissions. For example, in the case where a state is relying upon an emissions allowance or fee-based system to achieve compliance with a rate- or mass-based goal, this could be demonstrated by subjecting both the affected EGUs and new NGCC facilities to the same monitoring requirements and the same obligation to hold allowances or pay the fee.

Notably, EPA has already published illustrative mass-based equivalents that include projected emissions from new NGCC, "in the event that an implementing authority may want to include new sources of generation in its compliance approach."[44] While this statement suggests that inclusion of new sources of generation and their emissions is at the election of the state, EPA should clarify that, if a state's compliance strategy explicitly or necessarily depends upon the construction and operation of new NGCC to displace load from the affected EGUs and still meet demand, emissions from those new NGCC facilities must be accounted for in demonstrating compliance with any mass-based target. This would avoid the type of market distortions and illusory emission reductions that might arise if, by only accounting for emissions from the affected EGUs and ignoring emissions from new NGCC facilities in a state plan, a state would end up shifting significantly greater demand from its affected EGUs to new NGCC facilities than would otherwise occur if new and existing NGCC units were subject to equivalent requirements. Where EPA issues a federal implementation plan for a state, EPA should make clear that it will avoid such market distortions and circumvention of the Clean Power Plan's goals by simply imposing equivalent requirements on both new and existing units.

IV. CONCLUSION

Although section 111 sets forth mutually exclusive definitions for "new" and "existing" sources, EPA has clear authority under the regulatory framework of the Proposed Rule to mandate that states relying upon new NGCC facilities to reduce operation of the affected EGUs and thereby achieve their goals must account for the emissions from new NGCC facilities in their state plans. If a state plan fails to address new NGCC in this manner, then the state could achieve illusory compliance with its goals, even though the carbon intensity or total CO_2 emissions from the state's power sector would experience no significant decline and might actually increase. Importantly, requiring states to account for their emissions does not

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[43] Depending upon the state's existing fleet of affected EGUs and the extent to which it will rely upon new NGCC, the specified CO_2 emission performance *level* appearing in the plan may need to reflect adjustments from EPA's published CO_2 emission performance *goal*, so as to reflect the impact of the new NGCC facilities on the state's rate-based target. The Proposed Rule already implies that such adjustments may need to be made when specifying a plan's emission performance level. *See* Proposed Rule § 60.5820 (indicating the distinction between EPA's calculated "CO_2 emission performance goal" for a state and the corresponding "emission performance level" specified by the state in its plan). EPA could clarify the need to perform such an adjustment and the mechanics for doing so upon promulgating the final Clean Power Plan or in subsequent guidance.

[44] 79 Fed. Reg. 67406, 67408.

cause such facilities to become “affected EGUs” or “existing sources”. Nor does it mandate that new NGCC be included either as part of the BSER or in the computation of state goals. Thus, an approach that requires states to address new NGCC in their plans in this fashion would not run afoul of the distinction drawn between new and existing sources by sections 111(b) and (d), but is necessary to avoid circumvention of the overall emission reduction goals of section 111 and the Act.

August 2015 Follow **@Paul_Hastings**

EPA Finalizes Ambitious Clean Power Plan

By Kevin Poloncarz & Ben Carrier

On August 3, 2015, the Environmental Protection Agency (hereinafter, "EPA") released its final "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (the "Clean Power Plan" or "Final Rule"), a much-anticipated regulation to reduce carbon dioxide ("CO_2") emissions from existing power plants. Compared to the June 18, 2014 proposed Clean Power Plan ("Proposed Rule", *see* 79 Fed. Reg. 34830 (June 18, 2014)), the Final Rule establishes more ambitious CO_2 emission reduction goals while providing additional flexibility to affected electric generating units ("EGUs") and states in meeting the Clean Power Plan's goals. Along with the Final Rule, the EPA concurrently proposed a federal plan to implement the requirements of the Clean Power Plan in states that do not submit an approvable plan. The proposed Federal Plan also provides proposed model rules that states can adopt to facilitate interstate trading to achieve either their respective rate- or mass-based goals.

The Clean Power Plan is one of the boldest and most ambitious environmental regulations of our time and, for those reasons alone, is likely to be one of the most contested as well. Several states and coal producers already challenged the Proposed Rule in court, even before it was final, and are poised to challenge the Final Rule again, once it appears in the Federal Register. Sixteen states have already sought an administrative stay of the Final Rule pending resolution of litigation.

The final Clean Power Plan represents a strong, legally defensible approach to achieving meaningful reductions in carbon emissions in light of Congressional inaction and is on more solid legal footing than the Proposed Rule in several key respects.

- By establishing nationally uniform emission rates for each of coal-fired power plants and natural gas-fired combined cycle ("NGCC") power plants, the Final Rule more closely adheres to the EPA's historic approach for developing standards under Section 111 of the Clean Air Act ("CAA").

- By calculating these emission rates using a regional, rather than state-specific approach, the resulting rates better reflect the interconnected nature of the electricity grid and create a leveler playing field among states.

- By calculating these rates based upon what can be achieved by shifting generation to existing NGCC and new renewable power plants, the Final Rule's emission rates and resulting state goals are based solely on how efficiently electricity is generated and not how much of it is consumed.

- By imposing the emissions standards directly on the affected EGUs and authorizing trading to achieve the required reductions, the Final Rule follows an approach that has long been applied to reduce emissions from the power sector under the CAA.

The Final Rule responds to the 4.3 million comments received by the EPA by providing an unprecedented degree of flexibility for states to design their plans and achieve their goals. It also provides several years for states to comply, with the interim and final goals not going into effect until 2022 and 2030, respectively. States also have until 2018 to submit their compliance plans. Given these long lead times, states and other petitioners are unlikely to demonstrate the irreparable injury that would justify staying the Final Rule while anticipated litigation proceeds.

Notably, the Final Rule vastly increases the opportunities for states to design plans that allow for interstate trading, without requiring states to combine their respective targets or submit multi-state plans. While the form of the Proposed Rule and state-specific goals posed obstacles to regional coordination, the Final Rule creates the very realistic possibility that a nationwide carbon trading program will emerge, administered by the EPA and trading one or two products.

In fact, electric utilities familiar with existing emissions trading programs (such as the Acid Rain Program and Cross-State Air Pollution Rule under the CAA or the greenhouse gas cap-and-trade programs implemented by California and the Regional Greenhouse Gas Initiative ("RGGI")) will see many familiar features in the Final Rule and proposed Federal Plan, such as multi-year compliance periods, banking (but no borrowing) of allowances, and incentives to achieve early reductions. In these respects, the Final Rule can hardly be said to shy away from criticism that President Obama and the EPA are seeking to impose by regulation a carbon trading program of the sort that Congress has failed to enact. Rather, it reflects the President's efforts to establish his legacy on climate change and a framework that will achieve meaningful reductions in U.S. emissions, in advance of the next UNFCCC Conference of the Parties ("COP") 21 in Paris this December.

Contours of the Final Clean Power Plan

The final Clean Power Plan builds upon the ambition of the Proposed Rule's overall CO_2 emission reduction goals, while providing additional flexibility to states to achieve those goals. The Final Rule will decrease CO_2 emissions from the power sector by 32% below 2005 levels by 2030, compared to the Proposed Rule's goal of reducing power sector emissions by 30% by 2030.

The Best System of Emission Reduction

The Final Rule identifies the "best system of emission reduction" ("BSER") for existing power plants as the emissions reductions achievable from three building blocks, which roughly track the first three building blocks of the BSER in the Proposed Rule:

1. Use of heat rate improvement rates ranging from 2.1 to 4.3% as the average heat rate improvement achievable by steam generating units (rather than the uniform 6% in the Proposed Rule);
2. Re-dispatch from higher-emitting affected steam generating units to lower-emitting NGCC units with an NGCC utilization rate of 75% of summer capacity (rather than the 70% of nameplate capacity in the Proposed Rule); and,
3. Replacing electricity generated by fossil fuel-fired EGUs through new renewable energy ("RE") capacity alone (i.e., existing RE generation is not part of BSER), using National Renewable Energy Laboratory data on RE costs and potential.[1]

Unlike the Proposed Rule, the Final Rule does not include demand-side energy efficiency ("EE") measures in calculating the BSER. As the preamble to the Final Rule states "our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire, provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not."[2] Although each of the building blocks function independently and are severable (in the event of a court's finding them unlawful), this significantly strengthens the Final Rule.

EPA reiterates in the preamble to the Final Rule (as it did in the Proposed Rule) that the BSER determination does not necessitate that any state actually use the three building blocks, and other measures may be employed to reduce CO_2 emissions from affected EGUs. For instance, the Final Rule authorizes the creation of emission rate credits ("ERCs"), which may be used to achieve affected EGUs' rate-based goals, through EE measures that avoid generation from the affected EGUs. In short, states can utilize any measures to achieve the required emission reductions.

Final Emission Performance Rates and State Emission Performance Goals

The Clean Power Plan establishes nationally uniform CO_2 emission performance rates for each of two subcategories of fossil fuel-fired EGUs—fossil fuel-fired electric steam generating units and stationary combustion turbines—that express BSER for CO_2 from the power sector.

- For fossil fuel-fired steam generating units, the final emission performance rate is 1,305 pounds of CO_2 per megawatt-hour (net) ("lb CO_2/MWh").
- For stationary combustion turbines, the emission performance rate is 771 lb CO_2/MWh.

These emissions rates are based on "a consistent regionalized approach to quantification of emission reductions achievable through all the building blocks."[3] EPA chose the least stringent rate resulting from its regionalized application of the building blocks to derive a single, national goal for each subcategory. In turn, the Clean Power Plan establishes state-specific rate-based and mass-based goals that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUs. As EPA states, "[e]ach state goal therefore reflects uniform stringency of emission reduction requirements with respect to affected units in each source subcategory, but also reflects the EGU fleet composition and historical generation specific to that particular state."[4]

The state rate-based goals reflect a weighted average of the uniform emission rates, as applied to each state's mix of affected EGUs. Thus, a state's rate-based goals can be no less stringent than the emission performance rate for a steam generating unit and no more stringent than the emission performance rates for a combustion turbine. For instance, North Dakota's rate-based goals are equivalent to the emission performance rates for a steam generating unit (reflecting the fact that North Dakota only has affected steam generating units) and Rhode Island's rate-based goals are equivalent to the emission performance rates for a combustion turbine (reflecting the fact that Rhode Island only has stationary combustion turbine affected EGUs).

In response to comments from many stakeholders who suggested that the EPA should promulgate mass-based targets for each state, the Final Rule includes mass-based goals, which reflect application of the BSER to the state's existing fleet and incorporate a growth adjustment. The Final Rule also includes a set of mass-based goals for states that want to include both existing affected EGUs and new sources within their plan, adding a "new source complement" to each state's budget to account for emissions growth. A state's use of the final mass-based goal with the new source complement is a presumptively approvable means to address the risk of "leakage" from existing NGCCs to new fossil units.[5] According to the EPA, the incentive for increased operation of new NGCC, which are not affected EGUs under Section 111(d), vis-à-vis existing NGCC, which are subject to emissions standards under a state plan, could "negate the implementation of the BSER and would result in increased emissions undermining the emission reduction goals of the BSER and emission performance rates."[6] Accordingly, in the Final Rule, state plans to achieve mass-based goals must address such leakage.[7]

Adjustments to Interim Goals and Rates

Although it is designed to achieve greater emissions reductions than the Proposed Rule, the Final Rule extends from 2020 to 2022 the first year that states must begin complying with state emission performance rates or goals. Additionally, rather than the Proposed Rule's proposal for one interim emission performance goal for the entire ten-year period of 2020 to 2029, the Final Rule's eight-year interim period from 2022 through 2029 is separated into three steps: 2022-2024, 2025-2027, and 2028-2029. States must achieve the interim CO_2 emissions performance rates over the period of 2022 to 2029 and the final CO_2 emission performance goals by 2030, as judged in 2032 for the period 2030-31. Additionally, these interim rates were significantly adjusted so that they provide a less abrupt initial reduction expectation for states. This was accomplished primarily by phasing in the reductions achievable under building block 2 from redispatch to NGCC over a longer time period.

Discretion for States in Choosing Form of Emission Standards

The emission standards in a state plan may incorporate the subcategory-specific CO_2 emission performance rates established by the Final Rule or, in the alternative, may be set at levels that ensure that the state's affected EGUs, "individually, in aggregate, or in combination with other measures undertaken by the state achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029 and by 2030, respectively."[8] The EPA states that the translated state goals are an "alternative yet equivalent expression of the BSER that the state may choose to use to establish emission standards for its affected EGUs."[9] As the EPA emphasizes, the Final Rule's rate- and mass-based goals for each state are merely accounting devices to assist the states in designing plans that will assure their affected EGUs achieve their respective performance rates. Accordingly, "each state…will need to choose whether its plan will be designed to achieve the CO_2 emission performance rates, statewide rate-based goals, or statewide mass-based goals by the affected EGUs."[10]

The Final Rule establishes two main formats for state plans:

- The "emission standards approach" consists of a state establishing emission standards for its affected EGUs sufficient to meet the requisite performance rates or state goal, thus placing all of the requirements directly on its affected EGUs.

- The "state measures approach" would result in the affected EGUs meeting the statewide mass-based goal by relying upon *state*-enforceable measures that apply to entities other than affected EGUs (e.g., renewable portfolio standards that apply to load-serving entities), in conjunction with any federally enforceable emission standards applicable to the affected EGUs. If a state elects such a state measures approach, it must adopt a mass-based limit and include a "backstop" of federally enforceable measures for the affected EGUs, which would only be triggered in the event that the state fails to achieve its mass-based goal and would also require the state to make up for any shortfall.

The state measures approach provides a pathway for state plans to rely upon existing market-based trading programs, such as RGGI or California's Cap-and-Trade Program implemented pursuant to Assembly Bill ("AB") 32, which have broader coverage than affected EGUs and/or incorporate additional flexibility and cost-containment mechanisms.

The Final Rule and accompanying proposed Federal Plan are remarkable for the degree to which they encourage the development of nationwide carbon markets by allowing states to develop "ready-for-interstate-trading" plans[11] and otherwise link trading plans together. The proposed Federal Plan sets forth two distinct trading programs, either a mass-based trading program or a rate-based program. While the EPA currently intends to finalize only one approach as the federal plan for states that do not adopt their own approvable plan, the proposal also provides model rules, which states can utilize to develop presumptively approvable state plans that can be linked with other similar state plans and any federal plan for trading purposes, without needing to develop either a merged goal or a multi-state plan. States still have the option of participating in multi-state plans; however, this clearer path towards interstate trading—along with the uniform emission performance rates and clear mass-based goals—dramatically increases the likelihood that a broad emissions market will develop as part of Clean Power Plan implementation.

2020-21 Compliance Replaced By Incentive Program

Although the initial interim compliance period does not commence until 2022, to encourage early investments in RE and demand-side EE, the EPA is establishing the Clean Energy Incentive Program ("CEIP"). Through the CEIP, states will have the opportunity to award allowances and ERCs to qualified providers that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. The states that take advantage of this option will be eligible to receive from the EPA matching allowances or ERCs, up to a total for all states that represents the equivalent of 300 million short tons of CO_2 emissions.

Final Rule Addresses Reliability Concerns

A significant stakeholder concern with the Proposed Rule was its potential effect on electric reliability. The Final Rule addresses this concern by extending the initial interim compliance period from 2020 to 2022 and adjusting the interim emissions goals. Also, each state must demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. Furthermore, the Final Rule clarifies that states have the ability to propose amendments to approved state plans in the event that unanticipated and significant electric system reliability challenges arise and compel affected EGUs to generate at levels that conflict with their compliance obligations under those plans. Finally, the Clean Power Plan provides for a reliability safety valve for individual sources where there is a conflict between the requirements the state plan imposes on a specific affected EGU and the maintenance of electric system reliability "in the face of an extraordinary and unanticipated event that presents substantial reliability concerns."[12]

More Time For States To Submit State Plans

The Final Rule requires each state to submit a final plan by September 6, 2016, but allows an optional two-phased submittal process. If a state needs additional time to submit a final plan, then the state may request an extension by submitting an initial submittal by September 6, 2016. If the initial submittal explains why additional time is needed and fulfills other requirements, then a state may have until September 6, 2018 to submit a state plan.

Anticipated Litigation

Before the Clean Power Plan was even finalized, industry and state petitioners had challenged the Proposed Rule, claiming that it violated the plain meaning of the Clean Air Act and seeking an extraordinary writ from the Court. Petitioners' central claim was that EPA should be barred from regulating carbon pollution from existing power plants because EPA only has one statutory mechanism for promulgating the Proposed Rule (i.e., section 111(d) of the CAA) and this statutory mechanism is unavailable due to the interplay of sections 111(d) and 112 of the Act. On June 9, 2015, A three-judge panel consisting of Judge Thomas Griffith, Judge Brett Kavanaugh, and Judge Karen Henderson rejected as premature the challenges seeking to block the Proposed Rule, finding in a *per curiam* judgment that the court lacked jurisdiction to review the proposal.[13]

State and industry petitioners have since petitioned for panel rehearing and rehearing *en banc*. Significantly, such petitions request that, if the Court does *not* grant rehearing, it should instead stay issuance of the mandate until the Final Rule is published in the Federal Register; at that time, the Court could then vacate its ruling as purely academic; the states would file their Petition to Review the Final Rule and would seek to consolidate that petition with the existing *Murray Energy* cases. Petitioners' strategy for seeking this is to retain a panel of judges which they believe was receptive to their underlying claims in oral argument.

Many legal experts expect the next phase of Clean Power Plan litigation to focus on whether the D.C. Circuit should stay implementation of the Final Rule as it reviews petitioners' arguments on the merits.[14] On August 5, 2015, a coalition of sixteen states, led by West Virginia, asked the EPA Administrator to stay the Final Rule pending completion of "the impending litigation regarding the [Final] Rule's legality."[15] The states only gave the EPA until 4:00 pm on August 7, 2015 to respond, "so that Petitioners can know whether they must seek emergency relief in court", and said they will consider the EPA's failure to act by that time as "a constructive denial of the request."[16] The Federal Rules of Appellate Procedure require that petitioners seeking a stay of agency action first request such a stay from the agency.[17] Thus, it appears that several states that had previously filed premature challenges to the Proposed Rule are now preparing to file motions to stay implementation of the Final Rule, notwithstanding that such a filing would still be premature, until the Final Rule is published in the Federal Register.

A petition for a stay must demonstrate, among other things, whether the movant will be irreparably harmed if a stay is not granted. In this case, this factor would militate strongly against petitioners' claim for a stay because the final Clean Power Plan provides states (1) up to *three* years for the submission of state plans and (2) *seven* years before the first CO_2 emissions reductions must be achieved. Additionally, states have the option of not developing their own plans and allowing EPA to issue a federal plan on their behalf; EPA also clarified in the Final Rule that no sanctions would be imposed upon states that decide not to submit their own plan.[18] Further, unlike the Proposed Rule, the Final Rule imposes the emission reduction obligations directly upon the affected EGUs. Given the long lead-time between promulgation of the Final Rule and the Clean Power Plan's implementation, states and industry will face significant hurdles demonstrating that they would be irreparably harmed by having to wait for litigation on the merits of the Final Rule.

Besides the one particular argument at issue in the *Murray Energy* cases, petitioners are likely to challenge the EPA's authority to set numeric emissions performance goals for affected EGUs in the first place and to consider emissions reductions achievable by other plants operating within the interconnected electricity grid in setting those goals. In these respects, the Final Rule is strongly positioned to rebuff such claims by establishing nationally uniform emission performance rates for each of two subcategories of fossil fuel-fired EGUs, by only considering reductions in the carbon intensity achievable by shifting dispatch to lower-emitting sources in setting those rates, and by imposing federally enforceable emissions standards directly on the affected EGUs. Additionally, by premising the BSER on reductions achievable through emissions trading, the Final Rule grounds itself in the approach that has long been used to reduce emissions from power plants operating within the interconnected electricity grid under the CAA.

Conclusion

The final Clean Power Plan represents a cornerstone of President Obama's environmental legacy. In his remarks announcing the Clean Power Plan on August 3rd, the President called it "the single most important step America has ever taken in the fight against global climate change."[19] He also provided a forceful response to likely critics, who will pronounce the Final Rule a "war on coal" or raise the same "stale arguments" previously raised against earlier efforts to reduce emissions under the CAA, describing the price of continued inaction and the "moral obligation" to address climate change (referencing Pope Francis' recent encyclical, *Laudato si'*, for moral authority beyond the CAA). Certainly the Clean Power Plan will face challenges both in court and Congress, but the President's steely resolve and ecclesiastical tone indicate that he and the EPA are ready for the fight.

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If you have any questions concerning these developing issues, please do not hesitate to contact any of the following Paul Hastings lawyers:

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1 As the EPA states in the preamble to the Final Rule, "[i]n case of an investment in either building block 2 or building block 3 by a unit subject to a rate-based form of CO_2 performance standard, it would be reasonable for state plans to authorize affected EGUs to use an approved and validated instrument such as an 'emission rate credit' (ERC) representing the emissions-reducing benefit of the investment." Final Rule, Pre-Publication Version, at 355. The Final Rule establishes minimum criteria for the creation of valid ERCs vis-à-vis block 2 and block 3 measures, and for the use of such ERCs by affected EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans.

2 *Id.* at 63.

3 *Id.* at 392.

4 *Id.* at 415.

5 *Id.* at 1175.

6 *Id.* at 837. As the preamble to the Final Rule states, "if the form of the standard does not address leakage or incents the kinds of generation shifts that we identify as leakage, the states must otherwise address leakage in order to ensure that the standards of performance applied to the affected EGUs are, in the aggregate, at least equivalent with the emission performance rates, and therefore appropriately reflect the BSER as required by the statute." *Id.* at 835.

[7] For a discussion of the problem associated with leakage to new NGCC and the legal basis for the EPA to require states to address leakage, see *Focusing On a Blind Spot In EPA's Clean Power Plan: Why Emissions From New Gas-Fired Power Plants Must Be Accounted For In State Plans* (May 2015).

[8] Id. at 11.

[9] *Id.* at 821.

[10] *Id.* at 32.

[11] *See id.* at 882; proposed Federal Plan at 58.

[12] *Id*. at 50.

[13] *Murray Energy, et al. v. EPA, et al*., No. 14-1112 (June 9, 2015).

[14] Any challenges to the Clean Power Plan filed before the publication of the Final Rule in the Federal Register are likely to be rejected as premature under 42 U.S.C. § 7607(b)(1).

[15] Application for Administrative Stay by the State of West Virginia and 15 Other States, at 1.

[16] *Id*. On August 6, 2015, the petitioners in the *Murray Energy* cases, filed a letter with the D.C. Circuit, arguing that the EPA's issuance of the Final Rule warranted the Court's granting their petitions for panel rehearing and rehearing *en banc*, so that the Court could now hear the merits of its argument. *See* letter filed pursuant to Fed. R. App. P. 28(j), *In re Murray Energy*, Case Nos. 14-1112, 14-1151, Doc. 1566647, at 1.

[17] *See* Fed. R. App. P. 18(a)(1).

[18] Final Rule at 1453, 40 C.F.R. § 60.5736 ("The EPA will not withhold any existing federal funds from a State on account of a State's failure to submit, implement, or enforce an approvable plan or plan revision, or to meet any other requirements under this subpart or subpart B of this part.").

[19] Remarks by the President in Announcing the Clean Power Plan, The White House, Office of the Press Secretary (Aug. 3, 2015), *available at*: https://www.whitehouse.gov/the-press-office/2015/08/03/remarks-president-announcing-clean-power-plan.

A "Switching Costs" Approach: EPA's Clean Power Plan As A Model For Allocating The Burden Of Carbon Reductions Among Nations

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A pressing international environmental issue today is how to allocate the burden of achieving carbon reductions among nations. One superficially appealing approach—adopted in part by the Kyoto Protocol and the EU's European Trading System—is to require that each nation reduce its aggregate annual emissions by an equal percentage. Other approaches, including the one adopted in later phases of the European Trading System, require reductions in emissions according to the relative wealth of each nation. Still other approaches that have been discussed include requiring each nation to reduce per capita (as opposed to aggregate) emissions by an equal percentage.

None of these approaches, however, has provided a workable system of emissions reductions that appears capable of garnering worldwide acceptance. In this Article we explore another option, one roughly modeled on the United States Environmental Protection Agency's Clean Power Rule. In the proposed Clean Power Rule, EPA was required to allocate the burden of reducing carbon emissions from electricity production among the States. EPA chose a novel approach that is quite different from that adopted in Kyoto or the EU—what we call a "Switching Costs" approach. Under this approach, each State is allocated reduction percentages in emissions rates or mass emissions that depend heavily on the State's switching opportunities – its opportunities to switch from coal to natural gas and from fossil-fuel energy sources to renewable energy. In states in which switching opportunities are relatively abundant, and hence transition costs relatively low, higher percentage reductions in emission rates per megawatt or mass emissions are required. One result is that increases in electricity rates in the State should be more similar, closer to equal, than they would be under an approach that required emissions reductions without regard to variations in the switching opportunities available to each State. Thus, as Bob Sussman reported, EPA's analysis of its proposed Rule's effects on rates in twenty different regions within the United States suggested rates will "vary somewhat," but "these variations are fairly small, generally within 2 percent below or above the national average in 2030."[1]

The final EPA rule seems to limit the range in state targets and perhaps reduces the extent of variation in State targets based on the differences in switching opportunities available to each State. For example, Arizona, which has readily available solar alternatives, faced a much higher target under the proposed plan than the final rule, whereas Kentucky, which is coal-dependent and has little in the way of an infrastructure to allow a ready shift to natural gas or renewables, faced a much lower target under the proposed plan than under the final one. Moreover, EPA does not appear to have released an analysis of how much the final rule, as opposed to the proposed one, will affect electricity rates in different regions of the United States; EPA seems to suggest that the final rule has so much flexibility built into it that costs cannot be predicted on a state-by-state basis. It is possible that there will be more substantial variation in ratepayer costs across the country as a result of the EPA final rule than there would have been under the proposed rule.

Nonetheless, we can use the EPA Rule as suggestive of an approach to allocation of carbon reductions among the member states or nations to a multilateral agreement that is based on the relative availability and hence relative costs to each participant of switching from a high-emission fossil fuel to a lower-emission one and/or switching power production to renewable sources. Nations for whom switching would be relatively less expensive would be required to reduce emissions more (either in terms of the emissions rate per megawatt or in terms of mass emissions) than nations for whom switching would be relatively more expensive. Focusing on the availability of switching opportunities and hence the

[1] Bob Sussman, Debating the EPA's Clean Power Plan Proposal – EPA's State Goals for Reducing Carbon Pollution from Power Plants: A Thoughtful and Fair Solution, July 29, 2014, http://www.brookings.edu/blogs/planetpolicy/posts/2014/08/18-debating-epa-clean-power-proposal

costs of emission reductions to ratepayers as the measure for what constitutes an "equal" or "fair" burden among states or nations has several normative and political feasibility advantages over other approaches. Just as when a group of diners agree to split a bill for a large dinner in which each diner ordered different items with somewhat different prices and each diner has a different economic situation, allocation emissions reductions based on an equal ratepayer costs or something close to it avoids normatively intractable arguments about how much each state or nations' population is ethically responsible for its historic emissions (as opposed to current ones) and how much differences in wealth should translate into differences in ethical obligations with regard to efforts to address common problem. Everyone puts in roughly the same amount to the pot. And because as a political reality those states or nations that have relatively few switching opportunities and hence relatively high switching costs are likely to be much more politically resistant to ambitious emissions targets than those that have ample switching opportunities and relatively low switching costs, this approach may be more politically acceptable than those that have been tried to date.

However, one potential downside is that the switching opportunities approach may create a disincentive for a State (or nation) to create more opportunities for transitioning to low- or zero-emission power sources, because such efforts could result in the State (or nation) being allocated a higher emission reductions target in the next round of targets, which, if nothing else, reduces its flexibility as to future energy-related and economic decisions. Switching costs are in part the product of factors outside of direct political control – how much sun or wind that is available to a given jurisdiction is in part a product of geography – but they are also a product of political decisions regarding public investments and incentives for private investments in energy production infrastructure. There are, however, ways to deal with such disincentives that make the switching opportunities approach a promising model for international accords. Indeed, EPA took a step in this direction in the Final Rule by offering credit awards to States that quickly create renewable generation capacity.

Allocations of emissions reductions (either in terms of rate per megawatt or by mass) in terms of switching opportunities and switching costs might be a less appealing, less compelling idea in a regime in which there is highly effective tradable-permit or carbon tax regime. In an ideal tradable permit regime and an ideal carbon tax regime, we would expect to see the largest reductions in emissions in places in which the costs of reducing carbon emissions by whatever means are available are lowest, and that would imply that, at least among otherwise similar jurisdictions (notably, jurisdictions with comparable efficiency levels at emitting facilities and comparable demand-side conservation or efficiency), we would expect to see greater reductions in those where switching costs were relatively low. However, the transaction costs and political economy problems surrounding CO2 cap-and-trade regimes have been much discussed, as have the institutional design and political feasibility problems of carbon taxes. In the United States, for example, any hint of an explicit carbon tax has been disavowed by political leaders, and Australia recently repealed its carbon tax. It may well be that an agreement based on a switching-costs-sensitive initial allocation of emissions reduction obligations could have the political traction to actually be adopted, and, once adopted, trading and taxing carbon could be added as an overlay to further reduce costs of emissions reductions. But even so, beginning with a switching-cost-sensitive allocation may be necessary to move to a workable trading or tax regime. In this account, a switching-costs-sensitive-allocation is a second-best regime that may allow for the realization of a first-best regime.

In Part I, we review the allocation plans that have been tried so far on an international scale, and why they have not succeeded. In Part II, we explain EPA's Clean Power Rule and what we are calling the switching opportunities approach that is at least roughly suggested by the Rule. In Part III, we discuss the two different "cost-sensitive" approaches adopted by the EPA under the Clean Air Act so far, and in Part IV, we discuss the basis for using the Clean Power Plan as a model, and the advantages and disadvantages of "scaling up" the switching opportunities approach to the international arena.

I. Past and Current Allocation Regimes

A. Kyoto Annex I

In 1982, the United Nations Framework Convention on Climate Change (UNFCC) first established an international system for addressing climate change by nation-states, and also established the principle that nations ought to stabilize greenhouse gas emissions (GHGs) "at a level that would prevent dangerous anthropogenic interference with the climate system."[2] However, there were no binding emissions reductions commitments in the UNFCC itself. It wasn't until 1997 that the Kyoto Protocol to the UNFCC set binding emissions reductions commitments for developed countries (listed in Annex 1 to the UNFCC), to be met during the period of 2008 to 2012.[3] These reductions were spelled-out for each Annex 1 country in Annexes A and B of the Kyoto Protocol, and together were designed "to reduc[e] their overall emissions of [greenhouse] gases by at least 5 per cent below 1990 levels in the commitment period 2008 to 2012."[4] For most developed countries, this required the same emissions reduction, namely to 92% of 1990 levels by the end of the commitment period (or a roughly 8% reduction in GHG emissions), while some of the less developed or newly independent former Soviet states were given higher targets.[5] Developing countries, most notably China, were not on the list of nations required to reduce emissions.[6]

On its face, then, this first approach requires roughly equal emissions reductions by the most developed countries. However, the Kyoto Protocol also

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[2] See United Nations Framework Convention on Climate Change, May 9, 1982, S. Treaty Doc. No. 102-38 (1992), 1771 U.N.T.S. 107, 165, U.N. Doc. A/AC/237/18, at Art. 2, available at http://unfccc.int/resource/docs/convkp/conveng.pdf.
[3] See Kyoto Protocol to the United Nations Framework Convention on Climate Change art. 12, Dec. 10 1997, U.N. Doc FCCC/CP1997/L.7/Add.1, available at http://unfccc.int/resource/docs/convkp/kpeng.pdf, 37 I.L.M. 22 [hereinafter Kyoto Protocol].
[4] See Kyoto Protocol, at Art. 3.1.
[5] Id. at Annex B.
[6] Id.

provides for so-called flexibility mechanisms that might lead to fewer (or more) emissions reductions in each nation itself. For example, Article 6 of the Protocol provides for "joint implementation," which "allows a country with an emission reduction or limitation commitment under the Kyoto Protocol (Annex B Party) to earn emission reduction units (ERUs) from an emission-reduction or emission removal project in another Annex B Party, each equivalent to one tonne of CO2, which can be counted towards meeting its Kyoto target."[7] Similarly, Article 17 of the Protocol allows for Emissions Trading, which "allows countries that have emission units to spare - emissions permitted them but not "used" - to sell this excess capacity to countries that are over their targets."[8] And Article 12 establishes the so-called Clean Development Mechanism, which "allows a country with an emission-reduction or emission-limitation commitment under the Kyoto Protocol (Annex B Party) to implement an emission-reduction project in developing countries. Such projects can earn saleable certified emission reduction (CER) credits, each equivalent to one tonne of CO2, which can be counted towards meeting Kyoto targets."[9]

Nonetheless, despite these flexibility mechanisms, the basic principle under the Kyoto Protocol remains the same. The most developed countries must reduce emissions by roughly equal amounts. The only flexibility is in whether those emissions reductions take place within the country or outside it.

B. The European Union's ETS

Following the Kyoto Protocol, the European Union (EU) instituted an emissions trading system (ETS) in order to fulfill its member states' obligations

[7] See UNFCC website, at http://unfccc.int/kyoto_protocol/mechanisms/joint_implementation/items/1674.php ; see also Kyoto Protocol, at Art. 6
[8] See UNFCC website at http://unfccc.int/kyoto_protocol/mechanisms/emissions_trading/items/2731.php
[9] See UNFCC website at http://unfccc.int/kyoto_protocol/mechanisms/clean_development_mechanism/items/2718.php

under the treaty. Under the ETS, the EU employed two different methods of allocating responsibility for controlling GHGs. First, the EU adopted a system that allocated responsibility according to the individual country's wealth. Then, as the Kyoto commitment period ended, the EU adopted a system that allocated responsibility collectively. Finally, the EU also adopted mandatory annual emissions targets for sectors not covered by ETS.

1. ETS Phases I and II—Individual Wealth Allocation

As an Annex I party to the Kyoto Protocol, the European Community and its 15 Member States at the time of ratifying the Protocol agreed to reduce GHG emissions by at least 8% below 1990 levels during the "commitment period" of 2008 to 2012.[10] By signing on as a collective entity, the EU took the first step in setting up a "cap and trade" system among its Member States. The basic structure of such a system entails establishing an overall limit, or cap, on GHG emissions, granting facilities that emit GHGs allowances for each ton of carbon dioxide (or equivalent) that they emit, and giving the business that control these facilities one of three main options. They can emit as much carbon dioxide as they have allowances, emit less and trade their excess allowances, or emit more and purchase excess allowances. With a declining number of total allowances each year and penalizing businesses for non-compliance, total emissions decline, while businesses are incentivized to invest in emission-reducing capital projects.[11]

The EU administered this program through its ETS. In preparation for the Kyoto commitment period, the EU created a preliminary first phase which functioned as a pilot program for testing out this new cap and trade system, while

[10] United Nations Framework Convention on Climate Change, Kyoto Protocol Reference Manual On Accounting of Emissions and Assigned Amount (2008).
[11] European Commission, *Allowances and caps*, http://ec.europa.eu/clima/policies/ets/cap/index_en.htm (last updated May 8, 2015).

the second phase coincided with the commitment period from 2008 to 2012.[12] The EU further allocated responsibility for the 8% reduction among its Member States based on relative wealth.[13] For example, the nation with the highest GDP per capita, Luxembourg, had to reduce its emissions by 28% vs. 1990 levels, whereas Portugal as the poorest of the 15 was allowed to increase its emissions by 27%.[14] With caps in place for each individual country, each Member State submitted National Allocation Plans (NAPs) that provided detailed emissions information for each GHG-emitting facility, or "installation" covered by the Kyoto Protocol—mainly power generators and energy-intensive industrial sectors—within its borders.[15] The EU subsequently reviewed the NAPs and granted the appropriate number of allowances to individual installations so that Member States met their individual reduction targets.[16] Thus, by signing onto Kyoto as a collective entity, the EU created a system that redistributed individual nations' responsibilities for climate change based on wealth relative to fellow Member States.

2. ETS Phase III—Collective Allocation

As the Kyoto commitment period ended and follow-on international climate change negotiations stalled, the EU continued the ETS program, with some

[12] European Commission, *EU ETS 2005-2012*, http://ec.europa.eu/clima/policies/ets/pre2013/index_en.htm (last updated May 8, 2015).
[13] European Commission, *Kyoto emissions targets: Joint fulfillment, 'burden sharing' and base years*, http://ec.europa.eu/clima/policies/g-gas/kyoto/index_en.htm (last updated May 8, 2015).
[14] European Commission, *Kyoto emissions targets: Joint fulfillment, 'burden sharing' and base years*, http://ec.europa.eu/clima/policies/g-gas/kyoto/index_en.htm (last updated May 8, 2015).
[15] European Commission, *National allocation plans*, http://ec.europa.eu/clima/policies/ets/pre2013/nap/index_en.htm (last updated May 8, 2015).
[16] European Commission, *National allocation plans*, http://ec.europa.eu/clima/policies/ets/pre2013/nap/index_en.htm (last updated May 8, 2015).

modifications to increase its effectiveness.[17] Phase III, which started in 2013, maintained the basic structure of the system, but eliminated caps for individual countries.[18] Instead, the EU established a single cap to cover the entire Union, which decreases over the course of Phase III so that 2020 emissions will be 21% lower than 2005 levels.[19] The responsibility to reduce emissions then falls directly upon individual GHG-emitting installations to reduce emissions each year, or purchase a sufficient number of allowances via the cap-and-trade system to cover actual emissions.[20] Thus Member States are effectively bypassed in allocating responsibility, as an installation that emits 1,000 tons of carbon dioxide in Luxembourg will be treated exactly the same as an installation that emits 1,000 tons of carbon dioxide in Portugal. This system therefore treats Member States as equals, restricting emissions activity only to the extent that a Member State has GHG-emitting facilities within its borders.

As an alternative view, this approach also allocates responsibility among Member States based on their relative income levels. Assuming richer states to have more GHG-emitting facilities within its borders as a reflection of more extensive industrialization, while poorer, less industrialized nations will have fewer GHG-emitting facilities, Phase III effectively requires richer states to bear more of the burden of reducing emissions than poorer states. While this approach is quite

[17] *See generally* United Nations Framework Convention on Climate Change, *Status of the Doha Amendment*, http://unfccc.int/kyoto_protocol/doha_amendment/items/7362.php (last updated May 28, 2015).

[18] European Commission, *Allowances and caps*, http://ec.europa.eu/clima/policies/ets/cap/index_en.htm (last updated May 8, 2015).

[19] The cap set in 2013 was 2,084,301,856 allowances, decreasing by 1.74% linearly each year through 2020. European Commission, *Allowances and caps*, http://ec.europa.eu/clima/policies/ets/cap/index_en.htm (last updated May 8, 2015). The EU changed the reference year for climate change objectives from 1990 to 2005 because the wealth of data collected in 2005 provides the most transparent method to measure progress. European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/faq_en.htm (last updated June 8, 2015).

[20] European Commission, *Allowances and caps*, http://ec.europa.eu/clima/policies/ets/cap/index_en.htm (last updated May 8, 2015).

different from that of Phases I and II—namely because individual facilities are treated exactly the same in Phase III regardless of location within the EU—it still promulgates sharing responsibility based on some variation of relative income levels.

3. Non-ETS / Effort Sharing Decision

Since that ETS only covers approximately half of all GHG emissions, EU Member States adopted mandatory annual emissions targets for sectors not covered by ETS under the Effort Sharing Decision.[21] Similar to the approach in ETS Phases I and II, the Effort Sharing Decision establishes caps for each Member State based on their relative GDP, with rich countries required to decrease emissions while granting poorer countries the flexibility to increase emissions.[22] In particular, the Decision establishes limits for annual GHG emissions in 2020 compared to 2005 levels based on a Member State's GDP per capita relative to the EU average.[23] Countries with GDP per capita higher than the average must reduce their emissions by up to 20%, while nations lower than the average may increase their emissions up to 20%.[24] In the aggregate, these restrictions should reduce EU-wide emissions in

[21] ETS Phase III covered less than half of all emissions, including carbon dioxide from power and heat generation, energy-intensive sectors, and commercial aviation; nitrous oxide from production of nitric, adipic, glyoxal and glyoxlic acids; and perfluorocarbons from aluminum production. Sectors not covered by ETS include transport (excluding aviation), buildings, agriculture, and waste sectors, which collectively account for 55% to 60% of all EU emissions. European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/index_en.htm (last updated June 8, 2015).

[22] European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/index_en.htm (last updated June 8, 2015).

[23] Decision No. 406/2009/*EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020*, 2009 O.J. (L 140/136).

[24] Decision No. 406/2009/*EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to*

non-ETS sectors by 10% compared to 2005 levels.[25] Combining that with the 21% reduction in ETS sectors is expected to accomplish the overall emissions reduction goal of 20% in 2020 vs. 1990 levels.[26]

Therefore, as with ETS Phases I and II, emission reduction efforts for non-ETS sectors allocate responsibility based on each Member States' relative income. Wealthy countries must cut emissions, while poorer countries may increase emissions. However, this approach is built upon the assumption that less wealthy countries will experience a higher rate of economic growth, leading to higher emissions, so such countries will still effectively need to reduce their emissions over the period.[27] Nevertheless, in striking the Effort Sharing Decision, Member States divided up emission reductions based on relative wealth.

C. Current Schemes Unsuccessful

While the current allocation schemes described *supra* have certainly done *something* to reduce GHG emissions, they have been demonstrably inadequate. By almost every account, the Kyoto Protocol has not resulted in substantial emissions reductions. It has not obtained the formal agreement of the United States, and formal signatories appear to be largely unmoved by it with respect to actual energy policy decisions. Emissions continue to rise, and when and where they stall, economic slowdowns appear to account for that phenomenon as much or more than Kyoto-inspired policy. By all accounts, the first phase of the EU TS did not produce emissions reductions that otherwise would not have occurred. It is possible that the

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meet the Community's greenhouse gas emission reduction commitments up to 2020, 2009 O.J. (L 140/136).

[25] European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/faq_en.htm (last updated June 8, 2015).

[26] European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/index_en.htm (last updated June 8, 2015).

[27] European Commission, *Effort Sharing Decision*, http://ec.europa.eu/clima/policies/effort/index_en.htm (last updated June 8, 2015).

current phase will fare much better. But the current phase requires centralized planning and regulation in the form of per-facility targets that is hard to imagine outside of federal or quasi-federal union, and thus is hard to imagine working as part of an international agreement on the scale of Kyoto or even a multilateral agreement among non-common-union nation states.

The Kyoto and to a large Extent EU approach to allocation is cost-insensitive. Emission reductions targets are allocated without regard to the question of how much it would cost to have each target achieved. Thus, on its face, putting aside the possibility that trading or other mechanisms will help equalize costs to a degree, this approach calls on some actors to take on targets that entail very high compliance costs relative top others. From both an efficiency and equity perspective, this is problematic, as commentators have explained.[28]

The post-Kyoto round of talks have focused on inclusion of a larger number of nations, including poorer or less industrialized nations, and have involved extensive discussions of differentiated responsibilities based on a range of factors – wealth or GDP of the nation, economic dependence on fossil fuel production, threat from climate change and need to adapt, as, for example, in the case of low-lying countries. But the compliance costs for each nation of emission reductions – and in particular costs of switching from coal to oil to natural gas and from fossil fuels to renewables – has not been an explicit focus of the largely unfocused discussions of differentiated responsibilities.

II. Proposed and Possible Future Allocation Regimes

A. Equal Emissions Per Capita, Emissions Based On Historical Contribution To Climate Change, and Emissions Based On GNP Or GNP Per Capita

[28] [Fill in]

Given the failure of the current regime, it is natural to ask whether a different emissions reduction scheme would do better. There has been no shortage of other schemes proposed. For example, some developing nations such as China have proposed allocating emissions reductions per capita.[29] The aim of such a scheme would be to allow roughly equal emissions for each person in the world, regardless of where they lived. "The intuition here is that every person on the planet should begin with the same emissions right; it should not matter whether people find themselves in a nation whose existing emissions rates are low or high."[30] While such a scheme certainly has intuitive appeal, there are several reasons why it will likely never become the basis for a new agreement. First, for pragmatic reasons, developed countries like the United States will likely never agree to it. "Nations are unlikely to sign an international agreement if they will be significant net losers, and wealthy nations might lose a great deal from any approach that does not use existing emissions as the baseline for reductions."[31] Second, it is not even clear that the per capita approach would benefit most developing nations. As Posner and Sunstein demonstrate, "there are rich small states [],and poor big states [], and everything in between. [T]here is no statistically significant correlation between population and per capita GDP."[32] While China and India would certainly benefit from such a scheme, many other developing nations would not.

In sum, it is highly unlikely that a per capita emissions scheme will form the basis of a new agreement going forward, and it is equally unlikely that such a scheme would be fulfill the distributive justice rationales that underpin it in any event.

29 See, e.g., National Development and Reform Commission, People's Republic of China, China's National Climate Change Programme 58 (2007), available at www.ccchina.gov.cn/WebSite/CCChina/UpFile/File188.pdf

30 Eric Posner and Cass Sunstein, Should Greenhouse Gas Permits Be Allocated on a Per Capita Basis?, 97 Calif. L. Rev. 51, 53 (2009).

31 Id. at 55.

32 Id. at 74. They also note that because permits are allocated to governments, not citizens, wealthy elites in developing nations would likely still hold the dominant number of permits. Id.

Similar objections surround proposals to gear emissions reductions to nation's historical contributions to net carbon emissions. In this polluter-pay approach, nations that have long been industrialized would pay much more than newly or non-industrialized nations. But, normatively, holding current populations of industrialized countries responsible for past emissions by past generations is problematic, at least from some philosophical perspectives as Posner and Sunstein also argue. Moreover, politically, the idea that past polluting nations owe much more in terms of emissions reduction efforts because of their past "wrongs" would seem to be a political non-starter that would run counter to the "we are all in this together" spirit collective action against climate change would seem to require.

Allocations tied to a nation's GDP are also normatively problematic, because there is no widespread acceptance by as to what constitutes a "rich" country as opposed to a "middle class" or poor one and, even more so, there is no widespread agreement as to how much of a social obligation or an obligation of helping rich nations owe or should be deemed to owe poor ones. Indeed, it is not obvious that there is a general buy-in to the idea that rich countries should substantially aid poor ones: much foreign aid by wealthy countries, and by the US in particular, appears driven by military and geopolitical considerations more than a normative commitment to help nations in need.

B. Allocation Based On Net Welfare Benefits Of Emissions Reductions and Climate Change Mitigation

As economists have pointed out, the equal-percentage-reduction approach of Kyoto and (to a lesser degree) the EU has no rationale in welfare economics, which would endeavor to factor in costs and benefits to each nation of reducing emissions. But an allocation regime based on equal-welfare-effects would be far too complex and contestable to be workable. How much each nation benefits from reducing carbon in the atmosphere is not an easy question: some nations are more vulnerable to climate change but there is a great deal of uncertainty regarding vulnerabilities in the event of different climate change scenarios, as well as the basic uncertainty as to what effect any climate change mitigation effort will affect climate change. Reducing emissions may have substantial non-climate, health benefits, such as less asthma or other lung disease, but these too may be contestable and it is not obvious that a nation that has not been motivated to achieve these health benefits for their own sake would accept their being used as a rationale for being subject to a higher emissions reductions target than they would have received without consideration of those benefits.

In welfare economics, benefits are only half the picture; costs are the other half. To assess the full economic costs to each nation of emissions reductions would entail an assessment not just of the direct cost of compliance with possible emissions reduction targets but also with the overall economic effects of the compliance efforts, including downstream effects on investment, savings and employment. As suggested by the debates in the United States over whether any given environmental regulation will ruin an industry or actually help it long-term, as to whether environmental regulation is an economic drag or a long-term win-win , it is highly contestable what the overall economic costs of a nation shifting to a low-carbon or no-carbon future will be. For that reason presumably, and defensibly, EPA in the Regulatory Impact Analysis for the Clean Air Act refuses to attempt to quantify social costs of its rule and uses compliance costs as the sole costs to be considered as part of a cost benefit analysis. As discussed below, however, the direct, upfront, compliance costs – the costs of switching from coal to natural gas and/or coal and gas and oil to renewables -- may be more subject to reliable, commonly-accepted estimates.

C. Other possible schemes

There are many other possible bases for allocating emissions.[33] Yet so far, none of them has gained any traction in the international talks designed to lead to a new agreement. Thus, a reasonable question is: are there better ways to allocate

[33] See Daniel Bodansky, Pew Center on Global Climate Change, International Climate Efforts Beyond 2012: A Survey of Approaches (2004).

responsibility for carbon emissions (and net reduction thereof) among nations? Is there an allocative approach that has not yet been tried, but that may work better?

III. A Cost-Sensitive Approach

Nearly every criticism of emissions reduction measures includes a concern over costs. Nations are concerned that the overall costs of GHG reductions will be too high, and/or that such costs will not be shared equitably among nations. One response to such criticism, then, would be to make costs an explicit part of any emissions reduction scheme.

In this section, we examine two different models for a cost-sensitive emissions reduction approach. Both models derive from prior EPA rulemakings under the Clean Air Act. The first and more traditional model seeks to equalize costs among states with respect to each ton of emissions reduction. In other words, under this model, states subject to the rule must each reduce emissions in the amount that can be achieved at a certain price-per-ton of abatement. This was EPA's approach under its various ozone abatement rules, most recently the Cross State Air Pollution Rule, or CSAPR, as discussed more fully below.

The second cost-sensitive approach is the one EPA employed in its Clean Power Plan. Under this approach, EPA did not explicitly seek to equalize the cost-per-ton of emissions abatement. Instead, EPA seems to have made certain assumptions about how much it would cost states to switch to clean power sources, based on factors such as the state's natural endowments (sunshine, wind, etc.), the amount of clean power capacity already built or planned, a state's political capacity to make further emissions reductions, and grid accessibility for that state. These various "cost" measures then became factors in the amount of GHG reductions each state would be required to bear. The costs were not equalized on a "per ton" measure, but rather in a more amorphous, overall way.

A. The Traditional Cost-Conscious Model

EPA initially designed an emissions reduction system that tries to roughly equalize costs among polluters when it promulgated rules regarding ozone precursors. In EPA's 1998 nitrogen oxide (NOx) SIP call, EPA decided that the 23 "significant contributor" upwind states "need only reduce their ozone by the amount achievable with 'highly cost-effective controls,'" which EPA defined to be "ones that could be achieved (in EPA's estimate) for less than $2000 a ton."[34] The result of this cost-based cutback meant, of course, that emissions reductions "would vary from state to state depending on variations in cutback costs."[35] However, the costs per ton of abatement would remain roughly the same. In other words, each state would be required to reduce NOx emissions by the amount that could be achieved at a uniform cost, but because the costs-per-ton of reduction for some states would be higher (generally those were the states that had already taken the easy measures to reduce emissions) and costs-per-ton of reduction for some states would be lower (generally those were the states that hadn't done much yet, and thus had several easy measures still available to them), the end result was that states faced different percentages of required reduction depending on where they were along the marginal abatement cost curve. [ADD CITATION]

A similar design was carried forward into EPA's Cross State Air Pollution Rule, or CSAPR. Here, EPA designed a system with respect to the ozone precursors nitrogen oxide (NOx) and sulfur dioxide (SO2). If an "upwind" state emits these chemicals in threshold amounts detected at "downwind" states, then the CSAPR mandates that the upwind states reduce emissions by reference to certain cost thresholds, which would be uniformly applied within groups of upwind states. These uniform or equal cost thresholds are then applied to create different emissions "budgets" in each upwind state. As the Supreme Court described it: "EPA translated the cost thresholds it had selected into amounts of emissions upwind States would be required to eliminate. For each regulated upwind State, EPA created an annual emissions 'budget.' These budgets represented the quantity of pollution

[34] See Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000).
[35] Id.

an upwind State would produce in a given year if its in-state sources implemented all pollution controls available at the chosen cost thresholds."[36]

As with the NOx SIP call, each upwind state under the CSAPR is subject to a uniform cost threshold,[37] but these uniform costs translate into different emissions "budgets" for each upwind state.[38] EPA calculated how much pollution each upwind State could eliminate "if all of its sources applied pollution control technologies available at particular cost thresholds,"[39] and then required the states to reduce pollution by that amount. Again, this approach attempts to roughly equalize the costs per ton of reduction that the upwind states will face. Indeed, EPA explicitly *rejected* a uniform percentage-of-emissions reduction rule (akin to the Kyoto rule discussed *supra*) because such a rule would have had perverse effects. As the EPA noted in one of its Technical Support Documents for the Transport Rule: "since all contributing states would be required to do the same percent reduction of existing emissions, states that had previously implemented stringent control programs might not be able to achieve the required reductions using existing control technologies, while others that had previously done little (and presumably have

[36] EPA v. EME Homer City Generation, L.P., 134 S.Ct. 1584, 1621-1622 (2014).
[37] Technically, the cost thresholds were uniform within different groups of upwind states. As the D.C. Circuit has recently noted: "In the end, EPA adopted four cost thresholds for the 27 upwind States subject to the Transport Rule. For all States subject to the Rule for annual NOx, EPA set a $500/ton cost threshold. *See* Transport Rule, 76 Fed. Reg. at 48,250. For States subject to the Rule for ozone-season NOx, EPA also set a $500/ton cost threshold. *See id.* For States subject to the Rule for SO2, EPA divided the States into two groups. For Group 1 States, EPA set a $2,300/ton cost threshold. *See id.* at 48,259. For Group 2 States, EPA set a $500/ton cost threshold. *See id.*" EME Homer City Generation, L.P., v. EPA, 795 F.3d 118, 2015 U.S.App. LEXIS 13039, at 13-14 (D.C. Cir. 2015).
[38] See, e.g., the widely varying state budgets included in EPA's June 2012 "Final June Revisions Rule State Budgets and New Unit Set-Asides TSD", found here: http://www3.epa.gov/crossstaterule/pdfs/FinalJuneRevisionsRuleStateBudgetsandNewUnitSetAsidesTSD.pdf
[39] EME Homer City Generation, L.P v. EPA, 795 F.3d 118 (D.C. Cir. 2015).

larger absolute contributions) would achieve their required reductions using significantly less than optimal control technologies."[40]

Of course, some of EPA's hesitation to use equal percentage reduction of emission measures in the CSAPR (and in its NOx SIP call) was driven by the complexity of NOX and SO2 interactions, and the impossibility of tying individual upwind states' contributions to particular downwind states' receptors.[41] Nonetheless, the equal costs idea played a prominent role in the design of the CSAPR.

This roughly equal costs measure then resulted in varying emissions budgets for each state. EPA assumed a traditional increasing marginal cost curve. As it stated in one of its technical documents to the Transport Rule (the precursor to the CSAPR), "EPA designed a series of IPM [Integrated Planning Model] runs that imposed increasing marginal costs for reduction of SO2, annual NOx, or ozone season NOx emissions and tabulated those projected emissions at each cost level."[42] In other words, EPA assumed the marginal cost of emissions abatement would increase as that abatement increased. With that assumption in mind, EPA then selected various points along this increasing marginal abatement cost curve and projected emissions at those levels. It used air quality measures to determine where the marginal benefits of increased abatement would decrease. Based on these data, EPA decided what each upwind state's emissions budget would be.

B. EPA's Clean Power Plan Considers Costs Differently

[40] "Alternative Significant Contribution Approaches Evaluated," EPA Technical Support Document for the Transport Rule, July 2010, found at: http://perma.cc/4LJC-SY9N

[41] See EPA v. EME Homer City Generation, L.P., 134 S.Ct. 1584, 1604-1605 (2014). Note that these concerns should not play as large a role with respect to GHG emissions, because those emissions do not depend on interactions with other GHG emissions for their potency, nor do they cause local effects that depend on exactly where the wind blows them.

[42] See "Analysis to Quantify Significant Contribution," Technical Support Document for the Transport Rule (July 2010), at 6, found at http://www3.epa.gov/crossstaterule/pdfs/TSD_analysis_to_quantify_significant_contribution_7-8-10.pdf

EPA's Clean Power Plan, on the other hand, is sensitive to costs in a much different way, perhaps because it addresses power plants' carbon dioxide emissions,[43] and is aimed, in addition to enhancing efficiency, at switching power generation away from carbon emitting sources altogether.[44] Under the Plan, EPA assigned emissions reduction targets to each state.[45] These targets vary in terms of the requisite emissions reductions, and are not equal in terms of either a required percentage reduction in net emissions or emissions per capita or per household.[46]

More precisely, under the EPA's plan, each state must meet a target of emissions reduction, called the Best System of Emission Reduction, or BSER. This derives from Section 111(d) of the Clean Air Act's requirement that EPA prescribe regulations that require each state to submit a plan that "establishes standards of performance" for existing sources of air pollution. A "standard of performance" is in turn a term of art, defined under Clean Air Act Section 111(a)(1) to mean "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."

Based on its evaluation of various GHG abatement measures, "EPA identified three categories of demonstrated measures, or 'building blocks,' that are technically viable and broadly applicable, and can provide cost-effective reductions in CO_2

[43] See Clean Power Plan Overview, at http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-overview
[44] See EPA Fact Sheet: Clean Power Plan Benefits of a Cleaner, More Efficient Power Sector, at http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-benefits-cleaner-more-efficient-power-sector
[45] See Clean Power Plan Framework, at http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-framework
[46] See id.

emissions from individual existing EGUs."[47] These building blocks include the three that were reflected in the final rule: **(1)** Increasing the operational efficiency of existing coal-fired power plants; **(2)** Shifting electricity generation from higher emitting fossil fuel-fired steam power plants (generally coal-fired) to lower emitting natural gas-fired power plants; and (3) Increasing electricity generation from renewable sources of energy like wind and solar.[48]

The EPA applies these "building blocks" in order to calculate the BSER for each state.[49] EPA's exact formula is complex, and involves a consideration of a number of judgment calls. In its Goal Computation Technical Support Document, EPA used historical 2012 emissions data for each state as the basis for each state's emission rate goal under the Proposed Rule.[50] EPA then applied the BSER "building blocks" to compute interim and final goals in various ways. In doing so, certain cost-based factors became clear. When it comes to energy efficiency in consumption or demand-side efficiency, which EPA left out of the final "building blocks" (though it still gives states the opportunity to use this kind of energy efficiency in some ways to meet their goals), EPA assumed a traditional rising marginal cost of emissions abatement curve: "It is generally assumed in most energy efficiency projections that the cost of installing energy efficiency measures will become more expensive into the future as state programs move beyond 'low-hanging fruit' and increasingly focus on achieving deeper and broader energy savings through whole-building, multi-fuel programs addressing new buildings and building retrofits."[51]

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[47] See GHG Abatement Measures (EPA Technical Support Document) at 1-1, found at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[48] See Clean Power Plan, Technical Summary for States, at 1, found at: http://www3.epa.gov/airquality/cpptoolbox/technical-summary-for-states.pdf

[49] Id. at 1-2.

[50] See "Goal Computation Technical Support Document," Technical Support Document for the CAA Section 111(d) Emission Guidelines for Existing Power Plants, US EPA (June 2014), at 8, found at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf

[51] See "Projecting EGU CO2 Emission Performance in State Plans," Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources:

On the other hand, when applying the renewable energy building block, EPA appears to have assumed a very different cost curve. In the proposed rule at least, EPA looked at the "current goals of leading states in the same region" which reflected "renewable potential in particular regions of the country."[52] EPA used "the state-level effective RE levels derived from RPS requirements to quantify regional RE targets consistent with states' reasonable level of increased RE development."[53] EPA derived regional RE generation targets and growth rates and imposed "the same regional RE target in percentage (share of total generation) terms to all states in a given region."[54] The regional targets would be set for the year 2029. "The EPA then determined the constant rate at which each region would need to increase its generation each year to reach the regional RPS target, if these rates are applied in the period 2017-2029. The constant rate of annual RE generation increase calculated from this approach is called the growth factor."[55] Regional growth factors varied from a low of 6% in the West region, to a high of 17% in the East Central region.[56]

Implicit in the *constant* growth factor is that EPA either assumed a flat marginal cost curve or was simply indifferent to costs. What EPA did *not* do was assume a rising marginal cost curve and assume that early growth would be more rapid or that states that hadn't done much already could do more at lower cost. Indeed, EPA seemed to make the opposite assumption in some cases, due to the design of the regional targets, as discussed *infra*.

Electric Utility Generating Units, US EPA Office of Air and Radiation (June 2014) at 27, found at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-projecting-egu-co2emission-performance.pdf

[52] "GHG Abatement Measures," TSD June 2014 at 4-1, 4-2, found at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[53] Id. at 4-12.

[54] Id. at 4-19.

[55] Id. at 4-19.

[56] Id. at 4-18. The West region is comprised of Colorado, New Mexico, Wyoming, Montana, and all states to the west (except Alaska and Hawaii). The East Central region is comprised of Ohio, West Virginia, Virginia, Maryland, Delaware, Pennsylvania, and New Jersey. *See* id. at 4-14.

Importantly, "the regional RE target is *not applied directly* as an immediate requirement of each state but is instead used to calculate a regional growth factor that is then applied to each state's pre-existing RE generation, such that *historic RE performance acts as a limiting factor* on the extent to which a state is assumed to reach the regional target."[57] What this meant was that "the absolute megawatt-hour target will be smaller for states starting with a lower absolute amount of RE generation and larger for a state starting with a higher absolute amount of RE generation."[58] Moreover, "several states do not reach the RE percentage target in the proposed approach, such as Kentucky in the Southeast and Nevada in the West."[59] Kentucky, which got 0% of its energy from renewables in 2012, would only get to 1.9% by 2029, whereas Nevada, which was at 8% in 2012, would get up to 19%.[60] By contrast, Ohio, which got only 1% of its energy from renewables in 2012, would get to 10.6% by 2029, and Oregon, which got 12% of its energy from renewables in 2012, would get all the way up to 20.6% by 2029.[61]

These vast discrepancies are due to several regional and state-specific factors, but EPA was clear that its overall approach was "designed to respect each state's *ability* to improve toward the RE targets."[62] Again, EPA did *not* simply assume that all states faced a roughly similar (and rising) marginal cost curve. Instead, EPA was sensitive to the various factors—such as regional differences and natural endowments—that might limit states' ability to "switch" power generation to renewables. While the CPP's final rule is more complex still—it both changes the final state targets *and* the methods by which states can meet those targets[63]—there

[57] Id. at 4-19 (emphases added).
[58] Id. at 4-19.
[59] Id. at 4-19.
[60] Id. at 4-24.
[61] Id. at 4-24.
[62] Id. at 4-20 (emphasis added).
[63] See http://www.districtenergy.org/blog/2015/08/12/are-you-better-off-under-the-clean-power-plan-than-you-were-14-months-ago/

is still no assumption that states that haven't deployed much RE can rely on "low-hanging fruit" to do more than states that have.[64]

Indeed, the CPP has come under criticism from some states and commentators for precisely this reason. They have complained that the CPP demands something of all states and does not systematically "reward" states that have already done more to switch to renewables, nor "punish" states that have not.[65] Rather than being a flaw, this appears to be part of the overall design.

C. A "Switching Costs" Approach

The above analysis of the Clean Power Plan and the CSAPR is consistent with the notion that where a regulatory regime is focused not simply on increasing efficiency but on "switching" generation from one form to another, we should assume a very different marginal cost of abatement function and not simply demand more from states that have not yet done much "switching" yet. In other words, the goal of the Clean Power Plan was not simply to make current coal plants more efficient (i.e., building block #1), but rather to replace some of those plants with low or no-GHG-emitting renewables. In setting the regional targets to support its RE building block, EPA was sensitive to natural endowments such as sunshine or wind

[64] On the other hand, some states with already robust RE are given relaxed targets because each state is subject to the same RE growth assumption until it reaches the RE generation target, whereupon it is kept at that target level for the remainder of the relevant time period. *See* GHG Abatement Measures, at 4-19.

[65] *See* New Jersey Department of Environmental Protection Press Release, Sept. 2, 2015 (quoting DEP Commissioner Bob Martin, "One of the greatest ironies of the so-called Clean Power Plan is that while New Jersey has made great strides in reducing carbon emissions and other pollutants as well that cause smog and other air quality problems, states that are upwind of New Jersey actually are assigned emission reduction goals that fall far short of what New Jersey has already achieved."), found at: http://www.nj.gov/dep/newsrel/2015/15_0073.htm . *See also* "Clean Power Plan: Issues to Watch," Center for Progressive Reform, August 2015, at 62-63 ("This 'every state must do its part' approach arguably results in failing to reward states that made significant investments in de-carbonizing measures in the past while rewarding those states that put off such investments," while warning that generalizations are "tricky" and that compliance cost estimates across states vary widely).

in order to set the assumed renewables growth rates for states within that region. These natural endowments certainly affect the switching costs for Building Block 3 faced by the states. There are also, of course, significant capital costs involved in building out renewable capacity, whether it be for wind or solar or other forms of renewable energy. Such capital costs are particularly high for utility-scale thermal solar projects and offshore wind projects.[66] Indeed, capital costs may be a reason to assume, in a "switching" scenario, a marginal cost of abatement function that is not the traditional steadily rising one, but rather one that has a significant "hump" around the time when new facilities must be constructed.[67] This is especially true when switching to renewables as opposed to natural gas.[68]

IV. Applying A Cost-Sensitive Model to The International Context

The state-specific targets in EPA's proposed Clean Power Plan received much criticism from individual states on technical grounds, and the final rule no doubt also will be subject to technical criticisms. But for our purposes the key question is not whether EPA got its formula right or applied it correctly in each instance. The question is whether the idea implicit in EPA's approach—that the different costs each state faces in terms of switching to lower-carbon or no-carbon generation—should factor into an allocation of emissions reductions. EPA's plan raises the question of whether compliance costs – as opposed to the more amorphous and

[66] *See* EIA Report, at 6 (Table 1), found at: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

[67] There is also some reason to believe that the marginal cost of emissions abatement would decrease after the capital expenditure "hump" as states (and nations) gain experience in the new technologies. For example, Germany has lower installed costs of solar than the United States, in part because its solar sector is more robust. *See* Fred Heutte, Senior Policy Associate, NW Energy Coalition, "Experience Curves and Solar PV," (Sept. 3, 2012), found at: http://www.nwcouncil.org/media/6867808/2012-09-03-nwec-experience-curves-and-solar-pv.pdf

[68] EPA separately analyzed the costs of switching from coal to natural gas (Building Block 2). There it found that the cost of fuel, and not capital costs, were the major cost drivers. *See* GHG Abatement Measures, at 6-5.

difficult-to-assess economic costs – should count in a substantial way when responsibilities for a common pollution problem (here, climate change) are allocated as among states.

The first thing to note is that we assume the cost function for GHG reductions in the international context will follow the more complex “switching costs” function described *supra* instead of the traditional steadily increasing function of the CSAPR. By “costs” we focus, as EPA does under the Clean Power Plan, largely on switching costs—i.e., the costs of switching from coal to gas, and gas to solar and/or wind. No doubt there will be some high-emitting nations for which relatively low-cost efficiency measures can do a great deal to reduce GHG emissions. But ultimately we assume that such measures will be of limited value and that, ultimately, those nations will face a “hump” in their cost curves as they are forced to switch their forms of power generation.[69]

Therefore, using the Clean Power Plan’s cost assumptions as a starting point, we ask the question: could a “switching costs” approach form a plausible basis for an international agreement? In other words, could an approach that is sensitive to different nations’ costs (whether capital costs or natural endowments) and different regional factors, resulting in potentially quite varied emissions reduction goals, succeed where other approaches have failed?

A. The Advantages Of A Cost-Sensitive Approach

1. Facilitating Agreement

[69] For simplicity’s sake, we focus here on power generation, because it is the single largest sector responsible for GHG emissions globally. See IPCC 5th Report, Ch. 7, at 516 (noting that “[t]he energy supply sector is the largest contributor to global greenhouse gas emissions” and that “[i]n 2010, the energy supply sector was responsible for approximately 35% of total anthropogenic GHG emissions”). Nonetheless, we recognize that GHG emission sources come from many different sectors, and power generation is only one piece of the puzzle. We also recognize that a “switching costs” approach may be of limited value for countries that currently have very little in the way of GHG emissions, but might have such emissions in the future.

An approach of imposing relatively lower percentage reductions on states or nations with relatively high switching costs could be helpful in obtaining agreement among states or nations even if some sort of trading regime is also part of the proposed regime. For the nation or state facing high switching costs, the availability and costs of any emissions credits that could be bought under a trading regime will, ex ante, be quite unpredictable. Thus, in deciding whether to agree or how strongly to oppose a proposed emission reductions target, the powers-that-be in the nation or state with high switching costs will have to assume that they may be called upon to make all the emissions reductions through actual reduction within their own borders as opposed to relying on the possibility that lower cost emissions credits will be available to be purchased from states or nations that face relatively lower switching costs.

To make this point more concrete, imagine a regime with just two states or nations – A and B. A has relatively high switching costs, because it has four large coal-powered plants, no natural gas infrastructure yet, and only modest but expandable wind power infrastructure that provides a small fraction of its power. B has one old coal-powered plant, two natural gas plants with expansion capacity and substantial wind, solar and hydropower infrastructure, with possibilities for expanded use. In a Kyoto-like regime, both A and B might be told that they must reduce emissions by 50%. To do so, A could close two of its four coal-powered plants, while developing natural gas generation capacity and ramping up renewable capacity. The costs of doing so would be high. State B would have to do quite a bit less to meet its target, as it already has natural gas power generation and renewable generation that could be ramped up to substitute for the power currently generated by its single coal power plant (which, let us assume, now accounts for a large share of its emissions). State B could exceed its 50% target by relying more on renewable expansion than natural gas expansion, and it could then sell excess emissions credits to State A. But State B might decide not to overcomply, that is, exceed the 50% target, because of questions about the reliability of renewables. Moreover, if State B did overcomply and exceed the 50% target, it might not want to sell credits corresponding to any extra emissions reductions to State A at all. Rather, State A might instead prefer to bank those credits as protection in case it needs to emit more from its natural gas plants because of unanticipated surges in power demands or because of problems of reliability in the power produced by its renewables infrastructure. Indeed, under the S02 trading regime established by the 1990 Clean Air Act amendments, utilities engaged in just such banking, with the result that there was less selling by "over-complying" utilities than might have otherwise been the case. Finally, ex ante, State A would have no way of knowing the price of any credits that would be sold by State B. The overall point is simply this: even where a trading regime might help defray cost faced by states or nations that must transition to cleaner energy ex post (after the targets are accepted by the states or nations), ex ante, making targets sensitive to switching costs might facilitate the agreement to targets by states or nations that face relatively high switching costs.

2. Resonating With A Message of Unity

Second, being sensitive to switching costs treats climate change as a wholly collective problem created by all, and for which all must make roughly "equal" contributions in terms of increased electricity rates, at least. By contrast, in approaches where allocation are based on percentage reductions in a state's emissions or emissions per capita, the costs any person incurs may depend largely on where he or she happens to live, on her State of current residence. To make current residency a key factor in the burdens individuals bear might be tenable if we assume that the current residents of a state or nation are responsible in some meaningful sense for the aggregate or per capita emissions levels in that state or nation. But where there is substantial mobility across state or national lines, and/or where emissions levels in each state or nation are in any case a result of historical choices made over several generations, this assumption seems untenable. Thus, the switching cost approach has a cosmopolitan, beyond-boundaries, all-in-it-together appeal that regimes based on equal emissions reduction percentages do not.

The switching costs approach also avoids imposing different burdens on relatively wealthier states as compared to less wealthy ones – at least state GDP or per capita GDP is not an explicit criterion. By avoiding State GDP as a factor, the switching costs approach avoids the normatively intractable debates about whether there should be distributive justice-based redistribution from wealthy states to poor ones and how much richer countries owe poorer ones and what counts as a rich or poor state.[70] In the US context, where there is a governance structure that allows for redistribution from wealthy to poor regardless of State residence, as for example, in the form of all subsidies for low-income households, EPA can avoid distributive justice-based calls for greater costs to be borne by wealthy states without simply ignoring distributive justice altogether.

B. Do The Advantages Apply Outside The US?

These advantages of the switching costs approach may or may not translate onto the international scale, where we are speaking of a group of nations rather than a group of states that are part of a federal regime with federal constitutional supremacy. The we-are-all-in-it-together appeal of the EPA approach, as well as its implicit reliance on direct aid to individuals as a means of addressing distributive justice, might work less well in the EU context than in the US context, given the greater sense of distinct national identity and legal sovereignty EU member states have vis-à-vis the EU, as compared to US states vis-à-vis the US government. The normative appeal of the EPA approach might be even less robust in the context of a multilateral agreement involving countries throughout the planet.

However, the switching costs approach may help facilitate agreement on the international level, just as it is intended to foster political consensus domestically within the United States. The "break" given nations that face large switching costs

[70] See, e.g., Lisa Friedman and Gayathri Vaidyanathan, "All eyes on India in wake of U.S.-China agreement," E&E News, Sept. 25, 2015, found at: http://www.eenews.net/eenewspm/2015/09/25/stories/1060025351 (noting that India's Prime Minister Modi's speech at the United Nations focused on what he termed "climate justice").

may make them less hesitant to enter into an agreement. Moreover, under this approach, more is asked of nations that tend to have local or domestic politics that make them willing to do more. Such nations have already acted in such a way as to create renewables infrastructure and a speedy ramp up in reliance on renewables, often because these are nations where concern about climate change is greatest and there is the greatest domestic support for concerted action to mitigate climate change.

Another advantage of the EPA approach, and perhaps its greatest, is that it encourages the largest emissions reductions where they are cheapest to achieve, and in that sense promotes cost-effectiveness and helps contain the overall costs of climate change mitigation. To some extent a cap and trade regime, and even more so, a carbon tax regime, would achieve the same end of encouraging the biggest bang for the buck (or euro or . . .) in terms of emissions reduction. And the EPA plan envisions some emissions trading, although that is a legally controversial part of the plan. To the extent, in the international context, neither cap and trade nor a carbon tax are politically feasible, or can only be implemented in part, EPA's equal cost approach could be the best available alternative to encourage the most cost-effective climate change mitigation.

D. Disadvantages Of A Switching Costs Approach

One disadvantage of a switching costs approach is that it is based on predicted costs of emissions reductions, and such predictions require a large amount of data and may not be accurate. Indeed, a number of States – like New Jersey - and industry groups have argued that EPA's cost projections are faulty. [FILL IN]. On the other hand, emissions reduction percentage regimes of all sorts require an understanding of emissions baselines, and as the EU learned, estimates of such baselines require a great deal of information and can be inaccurate. [FILL IN]. In any regime, collecting and analyzing the needed data will not be straightforward and will require refinements.

The more persuasive criticism of the EPA approach is the one leveled by New Jersey, as discussed *supra*: that it creates perverse incentives by potentially assigning states that create clean power infrastructure higher emissions reduction targets than states that declined to make such investments. Under the EPA approach, a State might choose not to make "voluntary" clean power investments because it would not want EPA to respond by imposing upon the State additional emissions reduction obligations that may be more than or on a faster and less flexible timetable than the State otherwise would adopt on its own. Of course, as stated, states that are leaders in clean power investments might be exactly those states that, as a political matter, are open to strong EPA climate policies and that will continue to invest in cleaner power even if it is understood that stricter EPA emissions reduction targets will result. California might be one such state. Political economy and politics in each State vary, and it thus it is difficult to judge the robustness of the perverse incentives argument. On the international front, it may be even more difficult to say whether a switching costs approach will lead nations to adopt a strategy of not undertaking clean power investments they otherwise would have undertaken.

However, even if the perverse incentives argument is unpersuasive in terms of predicting strategic behavior by states or nations, it has rhetorical force, and that rhetorical force can translate into less support for a switching costs approach than is needed, politically, for adoption and effective implementation. [More]. For that reason alone, it is worth asking how a switching costs approach could be configured to mitigate the perverse incentives objection to it. Indeed, we see the shift between the proposed EPA rule and the final one as, in part, an effort to do just that.

E. Mitigating Perverse Incentives

One way that any perverse incentives created by the EPA approach can be mitigated is by structuring targets so that they reward a state or nation by achieving an extent of switching ahead of time of what is required by the first round targets. So, for example, assume that in a first round the target a nation that has heavily invested in developing solar capacity is given a relatively high target because its further ramp up costs for solar are relatively low. The nation then ramps up solar even more than required to meet its target and creates low-cost opportunities for further reliance on renewables. In setting the round two target, the nation should not be penalized for in effect over-enthusiasm, so its round two target should not be ramped up to reflect that it now has even lower relative switching costs. The nation might nonetheless continue to ramp up renewable production, but the fact that it was not required to do so as part of the round two targets could be key to avoiding political charges that the regime punished the best actors. By the same token, switching costs may be reduced as a factor in second and beyond targets so as to help ensure that the states with relatively high switching costs do not intentionally continue to occupy that position as a long-term matter.

Another way to mitigate the perverse incentives implicit in EPA's approach is to use it as only part of what goes into the setting of targets. If targets are set so that switching costs is only say a forty or fifty percent factor, the extent of any perverse incentives is proportionally reduced.

It would seem that EPA, in its final rule, took both these tacks in mitigating possible perverse incentives, although EPA did not explicitly cite perverse incentives as its motivation. In the final rule, states that develop "early" renewable capacity ahead of what their target would require receive a credit they can use against future emission reductions requirements. And in the final rule, the imposition of nationwide performance standards for coal and natural gas plants in effect reduces the economic advantages to states of not seriously considering building up renewable capacity. At the international level, it is hard to imagine the imposition of a standard floor for performance at coal and gas plants, but there might be shared commitments to certain efficiency/performance targets along with aid commitments from wealthier countries to poorer ones to help to them achieve those kinds of targets. In fact, that structure – standard or uniform commitments to performance coupled with a commitment to aid from more technologically-advanced countries to less advanced ones – is found in a number of international environmental agreements, such as [ ].

F. The Broad View – Many Ways Differentiate

In any workable international agreement regarding climate change, the commitments, obligations and entitlements of nations may need to be differentiated in order to achieve agreement and make the agreement workable in practice. The circumstances of all the nations of the world, after all, are extremely varied – far more varied than the circumstances of the states in the United States. As one academic commentator recently concluded:

> The point is that there will not be one type of differentiation that 'fits all' and covers all the very different circumstances and situations of parties. It will be the right combination or 'mix' of substantive commitments, incentive structures, entitlements, procedural requirements, etc., which will be crucial for the success of a new agreement. A well designed and fine-tuned 'catalogue' of options (with differing commitments or entitlements) which parties can choose from upon signature or ratification might be a feasible way forward, reflecting the diversities of a globalized and interconnected world in the sophisticated design of a comprehensive agreement.[71]

What the EPA approach to switching costs highlights is one useful way to differentiate among participants to a climate change agreement, namely, differentiation based on the relative magnitude of switching costs each nation faces. In that way, the EPA approach offers guidance for the construction of an international accord that was not previously a focus of either commentary or an actual international accord.

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THE TRANSNATIONAL REGIME COMPLEX FOR CLIMATE CHANGE

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ABSTRACT

In climate change as in other areas, recent years have produced a "Cambrian explosion" of transnational institutions, standards, financing arrangements and programs. As a result, climate governance has become complex, fragmented and decentralized, operating without central coordination. Most studies of climate governance focus on inter-state institutions. This paper, in contrast, maps a different realm of climate change governance: the diverse array of transnational schemes. The paper analyzes this emerging system in terms of two theoretical frameworks developed to describe, explain and evaluate complex governance arrangements -- regime complex theory and polycentric governance theory -- revealing fruitful avenues for positive and normative research. The paper concludes by arguing that the benefits of institutional complexity could be increased, and the costs reduced, through non-hierarchical "orchestration" of climate change governance, in which international organizations or other appropriate authorities support and steer transnational schemes that further global public interests.

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THE TRANSNATIONAL REGIME COMPLEX FOR CLIMATE CHANGE

An explosion of transnational institutions is reshaping governance in numerous issue areas, including environmental protection, climate change and other sustainability issues. In all these areas, a central feature of the governance explosion – what Keohane & Victor (2011), speaking of climate change governance, calls a "Cambrian explosion" – is a proliferation of organizations, rules, implementation mechanisms, financing arrangements and operational activities. Proliferation is evident in the database analyzed in Bulkeley et al (2011), which includes some 60 organizations, and in the even wider range of organizations considered here.

The result is a highly complex institutional environment. Transnational climate change governance is *fragmented* or *polycentric*: responsibilities for tasks such as adopting rules and funding public goods are shared among multiple organizations that have diverse memberships and operate at different scales. It is also *decentralized*: most organizations have been created from the bottom up by particular groups of actors and pursue their individual goals with little if any central coordination.

In this paper I map the emerging system of transnational climate change governance. The principal units of analysis are organizations engaged in governance.[1] I map these organizations according to the identity of their constituent actors – from business firms to city governments to varied combinations of public and private stakeholders. The involvement of non-state actors is the most innovative feature of transnational governance (Falkner, 2011), and a major part of what makes it "transnational." In

[1] A mapping that traced the cross-organizational links created by individuals would be a valuable complement, but would require more information than is readily available.

addition, the nature of the actors that create and govern organizations is a major determinant of their goals and capabilities.

Under the analytical framework set out in Bulkeley et al (2011):

- The organizations I consider are "transnational" because they operate in more than one country and include private actors and/or sub-national units of government as well as, or rather than, states and inter-state organizations (IOs).
- They engage in "governance" because they possess the authority and actually undertake to steer the conduct of target actors toward collective goals. However, while many transnational organizations possess some form of authority, few are authorized to adopt legally binding rules. Instead, most transnational rule-making schemes engage in what Duncan Snidal and I (2009 a; 2009 b; 2010) call "regulatory standard-setting" (RSS) – such rule-making is "regulatory" because it establishes norms of conduct in situations with Prisoners Dilemma/externality incentives (the normal realm of mandatory regulation); but like technical product or interconnectivity standards its norms are voluntary, are created largely by non-state actors, and address non-state actors rather than states.
- They should be considered institutions of "governance," moreover, even though many of them engage primarily in information sharing, financing, developing pilot projects or other operational activities rather than standard-setting. Providing collective goods is an important element of governance (Andonova, Betsill and Bulkeley, 2009). In addition, operational activities are imbued with norms, and often influence the conduct of target actors.

I then discuss the emerging system of transnational climate change governance in terms of two complementary analytical frameworks: regime complex theory and polycentric governance theory. Both were developed to address decentralized governance arrangements, and thus appear compelling as perspectives on transnational governance. Yet both have been primarily concerned with contexts other than the transnational: the first inter-state, the second domestic.

While a complete analysis under these frameworks is beyond the scope of this paper, considering their application to transnational climate change governance – even preliminarily – provides significant benefits. First, both frameworks help to characterize a diffuse and unstructured system. Second, they include a number of complementary propositions about the creation, operation and effects of organizations in decentralized systems. Considering which of these propositions apply to transnational governance reveals potentially fruitful (and less fruitful) lines of positive analysis. Third, both frameworks suggest benefits and costs of decentralized governance, helping to ground normative analysis of the climate governance system. Finally, precisely because they appear so compelling, it is important to consider the extent to which these frameworks actually apply to transnational climate change governance.

The first framework is drawn from the international relations literature on "regime complexes," arrays of inter-related institutions. Traditional regime complex theory contributes useful insights for transnational governance, but its core arguments have limited applicability. Those arguments are bounded in two significant ways. First, they focus predominantly on inter-state regimes (Aggarwal, 1998; Alter and Meunier, 2009; Helfer, 2004; Oberthür and Stokke, 2011; Raustiala and Victor, 2004), albeit with a few significant exceptions (Green, 2011; Kelley, 2008). Second, they are primarily concerned with regimes that promulgate legally binding rules; in the "soft law" world of RSS, a number of implications do not hold. However, a more flexible conception of regime complexes (Keohane and Victor, 2011), which focuses on the causes and effects of institutional fragmentation, is potentially more valuable.

The second framework is drawn from the literature on "polycentric governance," especially the work of Elinor Ostrom and colleagues on the management of common pool resources and environmental change (Ostrom 2010 a; 2010 b). Like regime complex theory, polycentric governance theory focuses on decentralized or fragmented institutions. But its particular focus, especially in environmental contexts, is decision-making and organization at different scales. The literature demonstrates that groups acting at relatively small scales can successfully organize collective action to deal with common pool resources and other social dilemmas (Poteete et al, 2010). In addition, decentralized centers of authority can interact in ways that allow them to operate coherently as a system. Normatively, Ostrom argues that polycentric, multi-scalar systems have significant advantages over unified institutions operating at a single large scale. This argument has important implications for climate change governance.

The paper concludes by suggesting that the benefits of decentralization identified by both frameworks could be maximized, and the costs minimized, through modest forms of coordination, which could appropriately be performed by IOs such as the United Nations Environment Program (UNEP). I refer to such coordination, following earlier work, as "orchestration."

MAPPING THE CLIMATE CHANGE REGIME COMPLEX

The International *Regime Complex*

In an important paper, two leading scholars of international governance, Robert O. Keohane and David Victor (2011), argue that the diverse range of institutions involved in climate change governance constitutes a regime complex (RC), with characteristic benefits and costs compared to a unitary international regime. The authors provide a graphical map of the climate change RC, reproduced here as Figure 1.[2]

INSERT FIGURE 1 HERE

[2] The regimes and institutions within the oval are those in which substantial rule-making or other activities have already taken place. Those completely or partially outside the oval are those in which additional rule-making is needed.

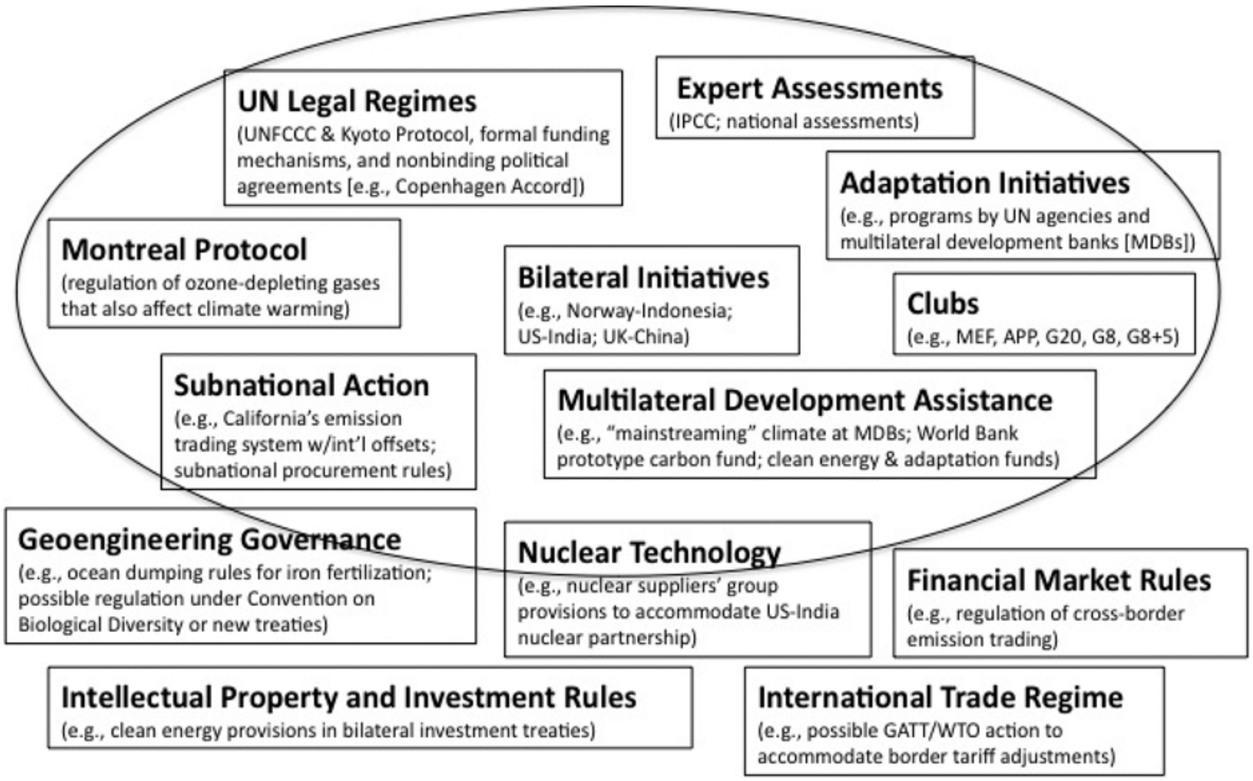

Figure 1

The Regime Complex for Managing Climate Change

Keohane & Victor (2011), at 10

This mapping makes a valuable contribution by highlighting the multiple forms of governance (e.g., multilateral, club, bilateral, expert), issues (e.g., adaptation, nuclear, trade, financial), and governance functions (e.g., scientific assessment, rule-making, financial assistance) that figure in the response to climate change. It is immediately apparent, however, that virtually every institution in Figure 1 is inter-state in nature.[3] The only exceptions are the institutions in the "Subnational Action" category and national assessments. That limitation is consistent with the RC literature as a whole. In addition, most institutions in the Keohane & Victor RC are devoted to making and applying rules, almost all of them (apart from the Subnational Action category) applicable to states; the main exceptions are the IPCC and other assessment bodies, IO adaptation programs and various funding mechanisms. This too is consistent with the larger RC literature.

The Transnational *Regime Complex*

Keohane & Victor's mapping of the *international* regime complex for climate change provides only a partial view of climate change governance, as it excludes almost all of the *transnational* organizations active in the area. Based on my work with Snidal on RSS, I present in Figure 2 a different way of mapping the transnational climate change RC, using what we call the Governance Triangle.

INSERT FIGURE 2 HERE

[3] Some institutions in the Bulkeley et al. (2011) database also appear in Figure 1. These include the Asia-Pacific Partnership on Clean Development and Climate (APP), Major Economies Forum on Energy and Climate (MEF), and World Bank climate funds; the Regional Greenhouse Gas Initiative (RGGI) and Western Climate Initiative (WCI) are not mentioned explicitly, but fall within the Subnational Action category.

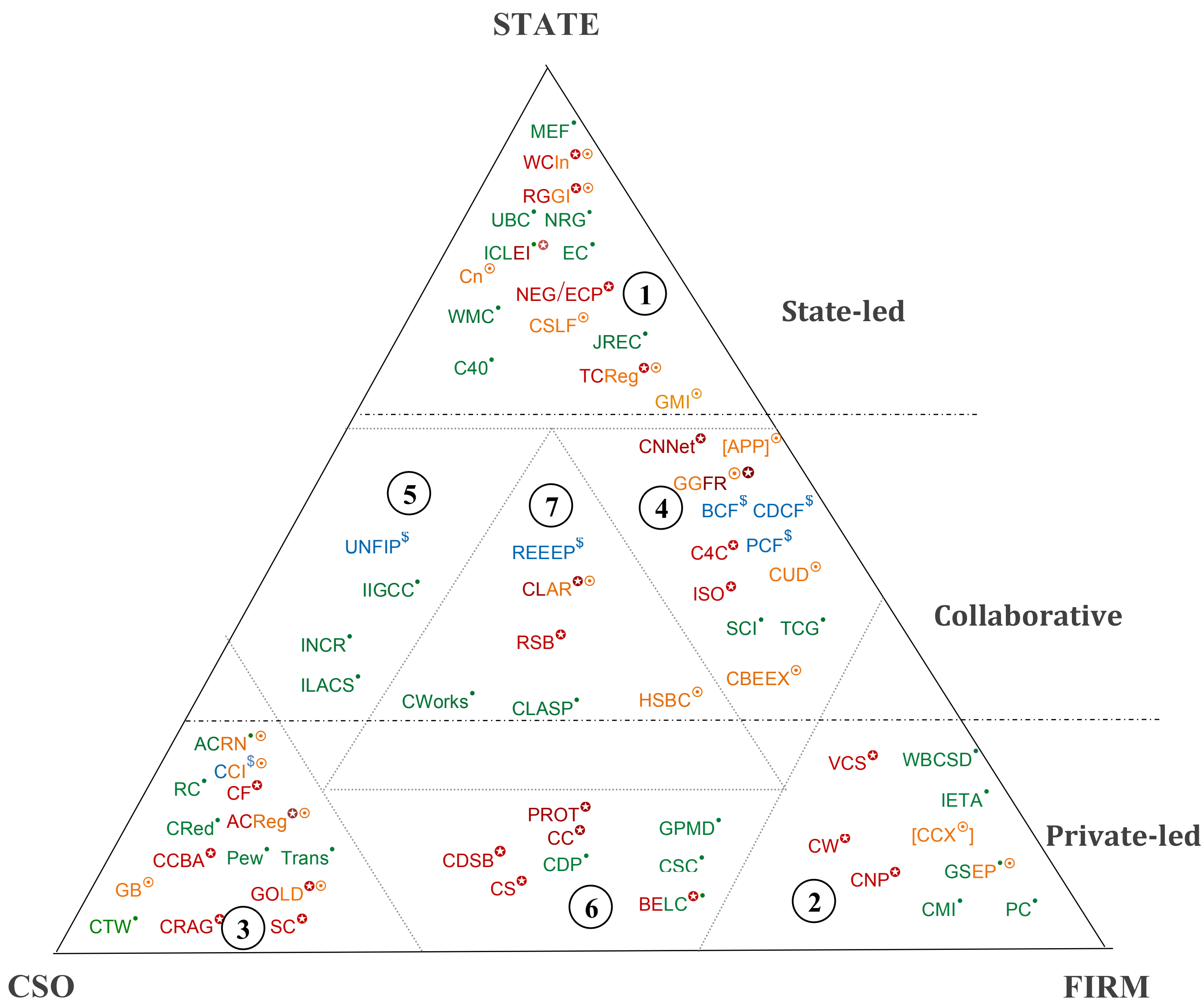

Figure 2

The Transnational Climate Change Governance Triangle

Standards & Commitments

Operational

Information & Networking

Financing$

The organizations shown in Figure 2 are largely the same as those considered in Bulkeley et al (2011). However, I omit a few schemes in their database,[4] and add some additional schemes,[5] for a total of 68. (Table 1 below identifies each scheme.) The added schemes appear significant based on public and policy discussions and the scholarly literature. Yet like other scholars (Hoffmann, 2011:24) I do not purport to include every relevant organization; for example, the UN database of "partnerships for sustainable development" alone lists 38 partnerships identifying climate change as their primary focus.[6] The decentralization of transnational climate change governance mean that such schemes are constantly being created and modified, and no central authority keeps track of those currently in operation.

Organizations are situated on the Triangle in accordance with the identity of their constituent actors: more specifically, the roles played by actors from three major categories – State, Firm and Civil Society Organization (CSO) (the vertices of the Triangle) – in each organization's governance.[7] The placement of an organization is determined by judging each actor group's approximate "share" in its creation, governance and operations: the greater the role played by actors of a particular type, the closer the

[4] E.g., Carbon Trade Watch, Challenge Europe, Climate Change Champions, Slim City Initiative. These schemes appear to have limited impact, have ceased operation, and/or attempt to "influence" governance rather than engage in it.

[5] World Mayors Council on Climate Change and carbon*n* Cities Climate Registry (Zone 1); CarbonNeutral Protocol and Point Carbon (Zone 2); Transition Network (Zone 3); the Prototype and Community Development Carbon Funds, Global Gas Flaring Reduction Partnership and ISO accounting standards (Zone 4); Institutional Investors Group on Climate Change (Zone 5); Climate Counts, Greenhouse Gas Protocol and Climate Disclosure Standards Board (Zone 6); and Climate Action Reserve (Zone 7).

[6] http://webapps01.un.org/dsd/partnerships/public/welcome.do. This is only slightly over 10% of the total of 348 registered partnerships. Four of these partnerships – NRG, REEEP, CLASP and GMI – are shown on the Triangle. Other registered partnerships – e.g., GGFR – list climate change as a secondary focus. Pattberg 2010 analyzes 19 partnerships identifying themselves as focusing on climate change, finding a predominance of schemes led by states and focusing on informational activities.

[7] For a fuller discussion, see Abbott & Snidal 2009a and b. This paper and Bulkeley et al. (2011) implicitly "code" a few schemes differently: this paper focuses on the actors involved in the governance of a scheme, whereas Bulkeley et al. considers all the actors that participate in a scheme's programs.

scheme is located to that actor group's vertex.[8] In other words, the distance between each vertex and the opposite side of the Triangle is a continuum, reflecting the level of involvement by the respective actor type.[9]

An actor group's share reflects the nature and extent of its direct participation in the governance of an organization. This depends in significant part on formal rules and relationships. For example, World Resources Institute and World Business Council for Sustainable Development (WBCSD) created the Greenhouse Gas Protocol (PROT) in Zone 6 (Green, 2010); the Board of the Roundtable on Sustainable Biofuels (RSB) in Zone 7 includes representatives of seven public and private stakeholder groups. Participation also depends on less formal relationships, including external collaborations and financial contributions. For example, the Carbon Disclosure Project (CDP) collaborates with "strategic partners" in fields such as accounting, consultancy and data management, and receives funding from government agencies, foundations, firms and CSOs.

Each actor group is defined broadly, so that among them they encompass virtually all participants in transnational governance. In principle, moreover, each group includes both individual and collective actors. For example, the Firm category includes individual business firms as well as industry associations.

For clarity, the Triangle is divided into seven Zones, representing the major combinations of actor types. Organizations in the vertex Zones (1-3) are governed by actors of a single type; those in the quadrilateral Zones (4-6) involve two actor types; and

[8] One should not overstate the precision of scheme placement. The Triangle is intended primarily as a heuristic device. Virtually all the organizations in Figure 2 involve complex governance arrangements, of which placement on the Triangle can only be a summary representation.

[9] This is in contrast to Figure 1, in which the arrangement of organizations conveys little information except whether an organization has adopted rules relevant to climate change.

those in the central Zone 7 involve actors of all three types. In addition, two dashed horizontal lines divide the Triangle into "tiers" defined by the nature of governmental involvement. In the top "State-led" tier (equivalent to Zone 1), public institutions such as sub-national governments are dominant; in the bottom "Private-led" tier (Zones 2, 3 and 6), firms and CSOs are dominant; and in the middle "Collaborative" tier (Zones 4, 5 and 7), governmental bodies share governance with firms and/or CSOs.[10]

For example, the Regional Greenhouse Gas Initiative (RGGI) is located in Zone 1 because it is an arrangement among public institutions, in this case federal states. The Global Methane Initiative (GMI)[11] is situated lower in Zone 1 because of its emphasis on partnerships with non-state actors. C40 Cities Climate Leadership Group (C40) is situated in the lower left of the Zone because of its close relationship with the Clinton Climate Initiative (CCI), sponsored by the William J. Clinton Foundation.[12] Business schemes such as the Global Sustainable Electricity Partnership (GSEP), an association of electricity companies (formerly e8), and WBCSD occupy Zone 2; CSO schemes such as the Gold Standard (GOLD), CarbonFix (CF) and Social Carbon (SC) occupy Zone 3.

Zone 4 includes government-business collaborations, such as the Global Compact's Caring for Climate Initiative (C4C); Zone 5 includes a smaller number of government-CSO collaborations, such as the Investor Network on Climate Risk (INCR), which joins public and private investors.[13] Zone 6 schemes are notable because they are

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[10] The three tiers correspond to the public, private and hybrid forms of authority in Bulkeley et al. (2011).

[11] Formerly Methane to Markets

[12] The CCI cities program has been the delivery partner of C40 since 2006; the two programs are now fully integrated. http://live.c40cities.org/about-us/

[13] INCR is treated as involving CSOs for two reasons. First, the CSO CERES coordinates the scheme. Second, I treat pension funds, foundations and other investors like those in INCR as CSOs insofar as they seek to change the behavior of target actors in the Firm category, e.g., through direct dialogue and

collaborations among CSOs and Firms, whose relationships are more often adversarial; examples include PROT and the Climate Disclosure Standards Board, a consortium of business and environmental organizations. Finally, Zone 7 includes tripartite schemes such as RSB and the Renewable Energy and Energy Efficiency Partnership (REEEP), a "Type II partnership" announced at the 2002 World Summit on Sustainable Development (WSSD).

If one were to combine the Keohane & Victor mapping of inter-state institutions with the Governance Triangle, all the institutions in Figure 1 would appear in Zone 1 of the Triangle,[14] along with the standard-setting, operational and information-sharing schemes currently shown in that Zone. The schemes in the other six Zones of the Triangle would remain as they are. This combined mapping would show the *true* climate change regime complex: the diverse inter-state arrangements Keohane & Victor identify, *plus* the expanding array of transnational schemes shown on the Governance Triangle.

The Triangle clearly conveys the sheer number of transnational climate change schemes. It also highlights the diversity of their organization (that is, their dispersion around the Triangle) in terms of the roles of the three actor groups.[15] Finally, it provides a snapshot of the relative roles played by government, business and civil society – individually and in varied forms of "entanglement" (Porter, 2009) – in transnational climate change governance.[16]

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shareholder resolutions. Participation by such investors also supports the placement of other schemes including CDP and IIGCC.

[14] As noted above, a few schemes already appear in both Figure 1 and Zone 1 of Figure 2.

[15] The vertices of the Triangle simply denote the three actor groups; they do not imply that those groups have equal power or are otherwise equivalent.

[16] In short, such presentations allow for both micro and macro readings (Tufte 1990, 37-51).

This mapping lays the empirical groundwork for further analysis. Even a cursory glance at Figure 2 reveals the remarkable level of activity by sub-national governmental bodies (Betsill and Bulkeley, 2006), the equally striking activity of CSOs, the imbalance in public-private partnerships between those involving business and those involving CSOs, the emergence of CSO-business RSS schemes, and similar features. These features raise many questions for explanatory analysis – e.g., why have CSOs and sub-state bodies been so active, why have some (but not all) IOs engaged actively with business and civil society, and why have different groups focused on particular activities – and for the assessment of individual schemes and categories of schemes in terms of effectiveness, normative impact and distributional consequences.

Snidal and I hypothesize that organizations will vary in their impacts based on the characteristic strengths and weaknesses that different actor types contribute to organizations they create and govern (Abbott & Snidal, 2009 a; 2009 b). Firms, for example, can contribute material resources, business expertise and managerial capabilities; however, their self-interested character tends to produce relatively lax (self-) regulation[17] and limited credibility for organizations they dominate. CSOs, in contrast, typically contribute independence from business (particularly important when business is the target), value-based motivations that enhance public credibility,[18] and normative and social expertise; they may also provide significant operational capacities (different from those of business), but generally contribute fewer material resources.[19] The Triangle provides the empirical basis for testing such hypotheses. Normatively, this capabilities

[17] For example, Green (2011) at 11 describes features of the Firm-sponsored Verified Carbon Standard that are more lenient than the CDM and other voluntary offset programs.

[18] Some CSOs, such as trade unions, may be equally self-interested.

[19] However, while most environmental NGOs lack material resources, the same may not be true of other actors included in the CSO category, such as private foundations and "socially responsible investors."

analysis suggests that schemes falling within particular Zones (including, importantly, all single-actor schemes) systematically lack important governance capacities.

Organizational Activities

Figure 2 also denotes the principal activity of each organization.[20] The schemes denoted by the superscript symbol ✪ are primarily engaged in rule-making and implementation. In a few public schemes, such as RGGI, an initiative of several US state governments, the rules are mandatory. In most others they are voluntary RSS standards. Reflecting the centrality of carbon markets to climate change governance (Bernstein, 2001; Bernstein, Betsill, Hoffmann and Paterson, 2010), the majority of RSS schemes govern the quality of projects designed to generate carbon offset credits for voluntary markets, and in some cases for mandatory "compliance" markets as well (Boyd and Salzman, 2011). Others set accounting standards governing the measurement and disclosure of greenhouse gas emissions. Still others seek individualized commitments from firms, local governments and other targets rather than promulgating general standards. For example, ISO, PROT, RSB, GOLD and CF are RSS schemes; C4C, ICLEI and the Climate Neutral Network (CNNet) are voluntary commitment schemes.

Schemes denoted by the symbol ⊙ primarily engage in operational activities (which may require incidental standard-setting). For example, the Asian Cities Climate Change Resilience Network (ACRN), a project of the Rockefeller Foundation, "aims to catalyze attention, funding, and action [by] experimenting with and testing local approaches to building climate change resilience for institutions and systems serving poor and

[20] Again, there are some differences in the coding of activities between this paper and Bulkeley et al. (2011). These occur largely because Figure 2 depicts the primary activity (or in some cases two primary activities) of a scheme, whereas Bulkeley et al. considers all the activities in which a scheme engages.

vulnerable communities."[21] The China Beijing Environmental Exchange (CBEEX), created by business with city government approval, operates a pilot carbon market (Kossoy & Ambrosi, 2010: 32). The Chicago Climate Exchange (CCX) operated a carbon exchange until December 2010, when its operation was suspended.[22] The Climate Registry (TCReg), formed by North American states and provinces, operates a registry through which firms and other organizations can report carbon emissions. TCReg (like several other schemes) is denoted by both ✪ and ⊙, as it also sets emissions accounting standards. Schemes denoted by $ are primarily engaged in financing climate change projects, a type of operational activity. For example, CCI funds demonstration projects, as well as convening public and private stakeholders to develop new approaches.

Finally, schemes denoted by • are primarily forums for sharing information and networking; a few also engage in lobbying. For example, ICLEI - Local Governments for Sustainability (ICLEI) "provides technical consulting, training, and information services to build capacity, share knowledge, and support local government…."[23] The International Emissions Trading Association (IETA) seeks to be "the most up-to-date and credible source of information on emissions trading and greenhouse gas market activity," as well as "the premier voice for the business community on emissions trading." CDP, acting on behalf of institutional investors, gathers and disseminates information on emissions from businesses and other organizations.

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[21] http://www.acccrn.org/about-acccrn/background

[22] I show CCX in brackets to reflect the end of its carbon exchange. In 2011 CCX expanded its registry activities. https://www.theice.com/ccx.jhtml

[23] http://www.iclei.org/index.php?id=about

Here again, as a snapshot of transnational climate change governance, Figure 2 reveals interesting patterns. For example, there are relatively few rule-making schemes on the Triangle compared with the international regime complex shown in Figure 1. However, standard-setting is widely distributed: every Zone but one includes at least one RSS or voluntary commitment scheme. Thus, transnational standard-setting is at least as fragmented as the international rule-making depicted in Figure 1. CSOs, business-CSO partnerships and sub-national governmental bodies are particularly active in standard-setting. Most sub-national schemes, however, focus on information-sharing and networking, as do several Firm schemes. Financing organizations frequently operate as public-private collaborations.

Further research is needed, however, to assess the effectiveness, normative impact and distributional consequences of these diverse schemes and activities. The Triangle does not currently depict either the strength of each organization's rules or operations (Downs, Rocke and Barsoom, 1996) or their practical impact. Both features are difficult to measure.[24] However, considerable information suggesting depth and impact – and the relationships between them – is available and should be included in future research.[25]

In terms of effectiveness, all voluntary schemes face the problem of providing incentives to induce firms and other targets to participate and comply (Büthe, 2010a, b; Green 2010). The "shadow" of potential state intervention (Börzel and Risse, 2010) can be a significant incentive; however, failure of US cap-and-trade legislation and limited progress in negotiating further commitments under the Kyoto Protocol (KP) have reduced

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[24] The ISEAL Alliance, an association of social and environmental standards schemes, most of them in Zone 6, has adopted the ISEAL Impacts Code to help member schemes assess and communicate their impacts and effectiveness. http://www.isealalliance.org/content/impacts-code

[25] A second difficulty relates to depicting the depth of cooperation in rule-making, information-sharing and operational schemes in a commensurable way.

the incentive for firms to participate in schemes relating to carbon credits and trading, as evidenced by the suspension of the CCX carbon exchange. Consumer demand and public expectations also provide incentives, but are often diffuse, non-specific and unreliable.

Transnational Climate Change Governance as a Regime Complex

The Original Regime Complex Concept

Regime complex theory has obvious potential as a tool for characterizing and analyzing transnational climate change governance: the theory focuses on complex sets of institutions, especially on interactions among them. However, while RC theory does contribute useful insights, it provides limited analytical leverage in the transnational context.

Raustiala & Victor (2004) introduced the concept of an RC. They noted that most previous studies of interaction among international institutions or regimes had focused on *nesting*: a relationship in which one institution has hierarchical authority over others and can resolve any rule conflicts between them (Aggarwal, 1998). For example, in theory the WTO is hierarchically superior to regional trade agreements. In the area of plant genetic resources, however, Raustiala & Victor found that distinct, non-nested regimes had begun to *overlap*: regimes operating in issue areas previously seen as distinct, such as biodiversity and trade, had both come to affect plant genetic resources. In this situation rule inconsistencies can easily arise – indeed, actors intentionally create inconsistencies through "regime -shifting" (Helfer, 2004) – and are difficult to resolve. Inconsistencies also create opportunities for forum-shopping by targets, which may undercut regulation.

And states must contend with inconsistencies in the course of implementing and interpreting international rules and negotiating new ones.

The relationships of nesting and overlap continue to dominate RC theory. Alter & Meunier (2009), introducing a symposium on regime complexity, emphasize both relationships: *nested* regimes are hierarchical; *overlapping* regimes possess authority over the same set of issues but are neither mutually exclusive nor hierarchical. They treat all other institutions as *parallel*, not part of an RC.

Transnational climate change organizations as a traditional regime complex

Can the schemes on the Governance Triangle be characterized as a regime complex under the traditional definition? One approach to that question involves treating transnational climate change governance *as a single regime*. The transnational regime might then be seen as *weakly nested* under the inter-state FCCC/KP regime. Transnational schemes almost uniformly pursue the same broad goals, if not the same specific targets, as the FCCC/KP; to that extent, those institutions form the "center" of the overall climate change regime.[26] Like the FCCC/KP, transnational schemes predominantly focus on mitigation and emphasize carbon markets; some schemes focused on carbon trading – notably CCX – have weakened along with the international regime. Many transnational schemes aim to supplement the FCCC/KP, as by demonstrating and funding concrete ways to meet agreed emissions caps. Transnational RSS schemes base their norms on international rules: virtually all carbon offset schemes recognize the standards of the Clean Development Mechanism (CDM) (Green, 2011).

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[26] Thanks to an anonymous reviewer for this terminology.

Yet nesting remains weak. Some transnational schemes have very weak links with the FCCC/KP (Pattberg 2010). Most offset schemes go beyond CDM standards, promoting projects that provide social or ecological co-benefits along with emissions reductions, perhaps even at the expense of some reductions (Estrada, Corbera and Brown, 2009). Transnational norms, implementation mechanisms and programs function differently from inter-state regimes, as they address private or sub-state actors. Most importantly, I can identify no case in which an inter-state institution is hierarchically superior to transnational schemes, with authority to resolve any rule inconsistencies. Without true nesting, there is no strong mechanism for ordering the fragmented array of transnational schemes.[27]

In terms of *overlap*, a number of transnational climate change schemes address issues central to other regimes. For example, several schemes address *energy:* e.g., REEEP, RSB, GGFR and GOLD (which focuses on renewable energy and energy efficiency credits). Others address *biodiversity:* e.g., CF (which focuses on forestry credits) and the Climate, Community and Biodiversity Alliance (CCBA). Still others address *sustainable development*, including its social "pillar": e.g., Social Carbon (SC) and the Network of Regional Governments for Sustainable Development (NRG). Conversely, schemes based in other regimes affect climate change. For example, the Forest Stewardship Council promotes sustainable forestry, producing significant climate change benefits (Potts 2010).

[27] I return to this point below. One potentially significant mechanism stems from the possibility of using privately certified offset credits within mandatory national or supra-national carbon markets or emissions control regimes. In such a case, the standards of the compliance market would determine the eligibility of private credits, so private schemes would take care to make their own standards compliant. This is not true nesting, however, as the compliance standards only have influence when a private scheme chooses to make its credits eligible.

However, these areas of overlap seem benign: the standards and activities of the schemes involved are largely complementary. The problems of rule inconsistency identified in RC theory – and the more serious rule conflicts emphasized in many studies of overlap, especially between the WTO and environmental regimes (Oberthür and Gehring, 2011: 31-32) – are less significant here. Instead, overlap is more likely to lead to positive outcomes and synergy: increasing actor choice, creating complementary standards and addressing problems in multiple ways.

A different approach involves treating *each individual scheme* as a separate regime, and analyzing nesting and overlap among them. Here again, few if any transnational schemes are *nested*. A number of organizations are linked institutionally or programmatically, but not through strong hierarchical relationships.

At least two groups of transnational schemes appear to *overlap*. The first includes schemes that set standards for carbon offset projects; this group includes CCBA, CF, GOLD, SC and the Verified Carbon Standard (VCS).[28] As noted above, most of these schemes recognize CDM standards; many also recognize other private standards (Green 2011). Beyond that, however, the schemes diverge significantly, addressing different types of offset projects, regulating them in different ways and promoting varied co-benefits. They operate more as alternatives than as overlapping rule systems.

The second overlapping group includes schemes that promulgate standards for emissions reductions and other aspects of climate performance, or that seek individualized pledges of climate performance from firms and other actors. This group includes CNNet, recently launched by UNEP; C4C, an initiative of the UN Global

[28] Formerly "Voluntary Carbon Standard."

Compact and WBCSD; and the Business Environmental Leadership Council (BELC), sponsored by the Pew Center (Pew). These organizations also overlap with broader corporate social responsibility schemes, such as the Global Compact itself and the WBCSD Principles for Sustainable Development.

Again, none of these organizations promulgates mandatory rules, so rule inconsistencies or conflicts are not serious issues. Forum shopping, however, is a real possibility: project developers can select which offset standard to adopt,[29] and firms can select which climate performance norms to accept. Such forum shopping can create harmful competitive incentives: schemes may compete for adherents by weakening their standards, fueling a "race to the bottom."

Alternatively, schemes might compete to be seen as leaders, perhaps pressured by public inter-scheme comparisons conducted by CSOs (Overdevest, 2010), or hoping to set benchmarks and influence the regulatory discourse. Such competition could fuel a "race to the top."[30] Yet even it may have pathological effects. For example, schemes may feel it necessary to take extreme positions, driving forum-shoppers to more lenient standards; they may also focus on issues that will bring them publicity and support, overlooking those that cannot be "branded." And organizations may sponsor new schemes simply to demonstrate that they are active on climate change, contributing to excessive regulatory proliferation. More research is needed to determine the extent of these effects in transnational climate change governance.

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[29] Since offset standards vary in their substantive focus, however, the choice may not be based on a desire to "exit" from a stronger rule set, as in the most serious kinds of forum-shopping.

[30] Market effects may also produce a race to the top: offset schemes such as GOLD assert that their credits "sell for up to 25 percent more than normal" credits in the CDM compliance market, driven presumably by reputation-conscious buyers. Boyd & Salzman, 2011; http://www.cdmgoldstandard.org/Who-we-are.68.0.html

While transnational climate change schemes are at best weakly nested or overlapping, they are not *parallel* as that term is used in RC theory: unrelated institutions operating in distinct issue areas. The organizations on the Triangle explicitly operate within the same issue area, climate change. Most take careful account of the activities of others. Many are designed to complement other transnational schemes – filling perceived gaps (e.g., in offset standards) or providing complementary services (e.g., financing and pilot projects) – as well as the UNFCCC/KP system. In sum, transnational climate change organizations have many more connections than the parallel institutions of regime complex theory (Green, 2011; Hoffman, 2011: 14, 19). I call these relationships "*conscious parallelism*," borrowing a term from competition law. Traditional RC theory has little to say about this phenomenon.

Transnational climate change organizations as a "loosely coupled" regime complex

Keohane & Victor (2011) adopts a broader approach to regime complexes. They posit a continuum of governance structures, from a single integrated institution with comprehensive rules, at one extreme, to a highly fragmented governance arrangement with no identifiable core and non-existent or very weak linkages among individual institutions, at the other. Near the middle of this continuum is the regime complex, in which institutions are "loosely coupled" but lack any overall architecture. In this conception, then, the components of an RC are not nested,[31] and need not be overlapping, so long as they are loosely connected.

Both the inter-state and the transnational climate change organizations in Figures 1 and 2 appear to satisfy this definition: both sets of governance arrangements lack clear

[31] Keohane & Victor see nested regimes as also occupying an area near the center of the continuum.

institutional architectures, yet in both cases organizations and standards are "loosely coupled" through a common focus on climate change, the focality of the FCCC/KP, and the relationships of "conscious parallelism."

The broader form of regime complex theory directs attention away from the specific relationships of nesting and overlap, and more broadly to the degree of fragmentation among organizations and standards, the causes and effects of fragmentation, and potentially to ways of managing fragmentation within a loosely coupled system (cf. van Asselt, Pattberg, Biermann and Zelli, 2009).

Several features appear to account for the high level of fragmentation in transnational climate change governance. Keohane & Victor argue that a major factor leading to the multiplicity of inter-state institutions is the need to address distinct problems within the general area of climate change. The same is true of transnational schemes, which focus on emissions reduction, emissions measurement, certifying credits from offset projects, trading offset credits, developing clean technologies and other problems. While most inter-state institutions in Figure 1 concentrate on rule-making, moreover, transnational schemes also engage in financing, project development, operating markets and registries, information-sharing and other activities. Each issue and activity has a different problem structure, involves different interest groups, and requires different competencies and resources.

Equally significant, transnational climate change schemes are formed by, and address, diverse actors. For example, sub-national schemes such as RGGI, NRG and Union of Baltic Cities (UBC) operate at different levels (province, region and city) and in different regions. Schemes in other Zones are created and governed by diverse CSOs, firms and CSO-firm collaborations. All those actors possess distinct interests, values and capabilities, which influence the goals and capabilities of the organizations they constitute. The resulting diversity is a significant contrast to the inter-state world of regime complex theory.

Assessing the transnational regime complex for climate change

Regime complex theory identifies several benefits from institutional multiplicity, many of which are also relevant to transnational governance. For example, the existence of multiple schemes – along with low barriers to entry for the creation of new ones – make it possible to fine-tune standards and programs to particular situations and targets. Over time, this may lead to the emergence of "clubs," which unite like-minded participants in voluntary schemes such as C4C (Prakash and Potoski, 2006). Such clubs may be more willing than other actors of their type to adopt rigorous standards and procedures; they can set social benchmarks by which other schemes are judged. Loosely coupled organizations are also more flexible than unitary systems in responding to changing conditions, especially change that affects issues and actors unevenly.

Some less desirable effects predicted by RC theory may also arise among transnational schemes. For example, the creation of multiple offset and commitment schemes reflects regime-shifting, in which norm entrepreneurs move issues to new forums in pursuit of desired standards. The resulting proliferation increases fragmentation and transactions costs. However, while regime complex theory views regime-shifting as a strategic effort to escape burdensome rules or create rule inconsistencies, RSS schemes do not enable actors to "exit" from mandatory rules. In fact, transnational offset standards are generally stronger than the CDM, while emphasizing environmental or social co-benefits.[32] Yet they have not produced serious rule conflicts or gridlock. Similarly, most voluntary commitment schemes address areas where no standards existed before, or where existing standards (e.g., the Global Compact) were not climate-specific.

Other effects arise out of the competitive incentives created by the existence of multiple schemes, notably as a result of forum-shopping: the possibility of a race to the bottom, pathological effects of competition, unnecessary fragmentation. Competition may also lead to inefficiencies such as repetitive programs and turf battles. Even apart from competition, fragmentation increases transactions costs for firms, project developers and others that must decipher multiple standards, methodologies and programs; it may also create confusion among consumers. These effects suggest the importance of managing or "orchestrating" transnational climate change governance (Abbott and Snidal 2009b; 2010; Abbott et al, 2011) to maximize its benefits and minimize its harmful effects, a point to which I return in the final section.

Transnational Climate Change Governance as a Polycentric System

Polycentric Governance and Climate Change

Polycentric governance involves multiple, formally independent centers of decision-making authority that operate at multiple scales (Cole 2011). Early polycentric governance research by Elinor Ostrom and others focused on metropolitan areas in which multiple domestic government agencies, each with limited jurisdiction, provided public services such as water and policing (Ostrom, 2010 a). While the general belief was that

[32] While these rules may be stronger "on paper," however, their impact also depends on voluntary applications of the rules.

multiplicity was inefficient, researchers found that smaller agencies often provided superior services, and that multiple agencies often developed forms of interaction – including contracting and dispute resolution procedures – that avoided gaps and overlaps and enhanced efficiency.

Researchers in this tradition next examined small-scale common pool resources such as fisheries and irrigation systems. They identified numerous cases around the world in which small and medium-sized social groups successfully organized collective action to manage local common resources on a sustained basis, without the mandatory government intervention traditional collective action theory would prescribe (Poteete et al, 2010). Polycentric governance scholars developed an analytical framework (the Institutional Analysis and Development framework, or IAD) that incorporates a range of variables influencing social interactions in diverse settings. The IAD highlights the attributes of a specific community – including its history of interactions, knowledge and social capital – as well as its members' common understandings of actor responsibilities and appropriate behavior. Researchers have used IAD to identify broad "design principles" common to most cases of successful cooperation. However, local context appears to be crucial to a community's success in organizing collective action and to the specific techniques used. Considerable theoretical development is still needed, then, to understand when groups and organizations in particular contexts will be able to organize sustainable collective action (Ostrom, 2010 a).

For problems like climate change, the scale at which collective action takes place becomes particularly important. Although a "global" problem, climate change is in fact the cumulative result of individual and group decisions at multiple scales, from the individual and family through the state. Governance responses must address those varied contexts. In addition, decisions at each scale produce local benefits and costs in addition to their global impact. For all these reasons, theorists in this tradition hold that climate change is best addressed through governance that is not only polycentric, but also multi-scalar, with communities at each scale adopting decisions and taking actions appropriate for that scale and for their unique social and ecological contexts. Even if states could agree on a new, unified climate change treaty, in this view, that treaty might well be ineffective unless it were supported by actions at smaller scales (Cole, 2011; Ostrom, 2010 b).

Two general features of smaller organizations contribute to the success of multi-scalar governance. The first is a greater capacity to overcome collective action problems – the same problems that plague international governance. Small and medium-sized organizations can at least approximate the face-to-face communication characteristic of local communities. As a result, they are more likely to build trust among participants and to maintain it through reputational sanctions and reciprocity. The second feature is particularized knowledge and a greater opportunity for learning. Small and medium-scale organizations can take advantage of local knowledge developed for local contexts. In addition, experimentation and innovation are more likely to occur in a polycentric, multi-scalar system than in a unitary regime. Organizations can observe others in similar situations and at similar scales, learning from their experiences. Over time, then, polycentric units are likely to adopt superior strategies.

Of course, neither polycentric governance nor small-scale action is guaranteed to resolve complex problems such as climate change. If nothing else, actions at larger scales are necessary to control "leakage," free-riding and other pathologies. Theory and evidence both suggest, however, that polycentric, multi-scalar governance can make significant contributions. Polycentric governance theory thus emphasizes the positive results of institutional multiplicity: not only the fine-tuning, high-standards clubs, complementarity, choice and reinforcement identified by regime complex theory, but also enhanced possibilities for collective action, knowledge and learning in smaller-scale organizations.

Transnational climate change governance as polycentric and multi-scalar

As the Governance Triangle clearly shows, transnational climate change governance is highly polycentric. The array of organizations, standards and programs on the Triangle appears at least as "chaotic" (Ostrom, 2010 a) as a metropolitan area served by multiple water utilities or police forces. Yet polycentric governance theory suggests that such an array can produce effective collective action, support learning, and to some extent function as a coherent system. Information and networking schemes, denoted on the Triangle by the symbol •, are particularly important in this regard. It is easy to view such schemes as less significant than those that set standards, provide financing or organize concrete projects, and their impact is difficult to assess. Yet if cities, firms, CSOs and other actors are to observe their peers on a global scale, benchmark their strengths and weaknesses, and learn from their successes and failures, schemes that facilitate interaction, disseminate information and encourage learning are essential.

Somewhat less obviously, transnational climate change governance – more so than inter-state governance – is also multi-scalar:

- Many transnational organizations set standards, seek performance commitments, coordinate policy and engage in operational activities on a *global* scale, or at least across many countries. C4C, for example, accepts pledges from firms around the world. Others concentrate their efforts within a particular geographical *region*.[33]
- The constituent actors of Zone 1 schemes include *provinces* and states, sub-state *regions* and *cities*. The schemes themselves operate internationally (C40, ICLEI) or regionally (UBC), but the participants whose actions they coordinate and support operate at multiple, smaller scales.
- Finally, many transnational schemes promote *small-scale*, even *local* actions. RSS schemes set standards for local offset projects, and some promote context-specific social and ecological co-benefits; voluntary commitment schemes promote action by individual firms; funding schemes support local initiatives; and operational schemes organize local projects.

Assessing polycentric transnational climate change governance

Polycentric governance theory, like the looser version of regime complex theory, focuses attention on the causes, benefits and costs of fragmentation, although with a greater emphasis on organizational size and scale. It likewise offers some similar insights. The relationships that polycentric units develop as they move from chaos to coherence resemble the loose couplings and conscious parallelism of an RC. The need to address distinct problems and actors helps explain fragmentation under both approaches, although polycentric governance theory emphasizes the unique attributes and contexts of small-scale social groups. Both theories identify similar benefits from decentralization:

[33] Some similar organizations, of course, operate within a single nation.

the ability to fine-tune governance to specific contexts; the opportunity for clubs of cooperative actors to emerge; and the flexibility to modify standards and programs in response to changing conditions. However, the emphasis of polycentric governance theory on scale, and on the importance of small-scale cooperation, sets it apart.

The greatest contrast between the two approaches lies in their treatment of the potential costs of fragmentation. Traditional RC theory, while identifying some benefits of fragmentation, has focused on interactions that create friction, such as rule inconsistencies, forum-shopping, regime-shifting and gridlock. Keohane & Victor place less emphasis on such problems, making their approach more appropriate for a world of voluntary standards. But polycentric governance theory shows little concern for any ill effects of fragmentation.

The most likely explanation for this difference is that polycentric governance theory has focused on local modes of collective action that benefit local communities, e.g., through management of local resources. In such a world, local institutions may learn from and set benchmarks for one another, but they do not actively compete for adherents or resources. Transnational climate change organizations, however, compete intensively. While their competition seems largely benign, it undoubtedly increases transactions costs and may generate other pathological effects.

CONCLUSION: TOWARD ORCHESTRATION OF CLIMATE CHANGE GOVERNANCE

The "Cambrian explosion" in transnational climate change governance has produced a large number of organizations, varying widely in terms of constituent and target actors, activities and scale of operation. Individually, for all their virtues, these schemes often lack important governance competencies. As a system, they are numerous and decentralized, operating with little coordination.

Regime complex theory identifies important benefits from decentralization, but also significant costs; normatively, it suggests the need to manage fragmentation. Polycentric governance theory views decentralization more positively, especially when it involves organizations operating at local scales, yet some degree of coordination remains essential. Even if small-scale groups realize some local benefits from their responses to climate change, such responses are primarily public goods; collective action must be encouraged, and beggar-thy-neighbor responses avoided. In addition, even if small-scale institutions could autonomously generate satisfactory responses, they are unlikely do so as rapidly as necessary. Finally, while some degree of decentralization may provide opportunities for experimentation and learning, a high level of fragmentation can impede learning.

Orchestration provides a way to harness the benefits of decentralization while minimizing the costs (Abbott and Snidal, 2009 b; Abbott et al, 2011). Orchestration is a non-hierarchical strategy, a "light coordination mechanism" (Pattberg 2010). As such, it is particularly well suited for IOs, which generally lack strong hierarchical authority; UNEP, a likely potential orchestrator of climate change governance, is a prime example. Even weak IOs such as UNEP can orchestrate by *supporting* transnational organizations that pursue desired goals and *steering* the governance and activities of those schemes through incentives, persuasion and similar means.

Different forms of support may be relevant at different stages of governance. Initially, an IO can use its legitimacy and focal position to convene relevant actors and catalyze formation of transnational schemes. In effect, this orchestrates the system as a whole by helping to fill governance gaps and rectify imbalances, e.g., a disproportionate number of business-dominated schemes. UNEP has a broad mandate to "catalyze and coordinate" environmental action; it has used that authority to stimulate business self-regulation and reporting, establish multi-stakeholder schemes including the Global Reporting Initiative (GRI), and participate in collaborative schemes including REEEP and RSB. The World Bank has also used its authority to catalyze public-private partnerships such as GGFR.

The FCCC/KP system provides norms that transnational schemes have adapted to their own purposes; public norms have provided focal points for cooperation and enhanced legitimacy, while steering schemes to follow democratically approved policies. In climate change, however, transnational application of international norms was wholly unintended: IOs could increase their impact by explicitly designing norms that facilitate transnational RSS.

IO endorsement can strengthen schemes; it can also steer them by singling out those that address significant problems, adopt representative governance structures, incorporate a range of actor capabilities, address appropriate scales and otherwise promise effective governance. UNEP, the UN and the WSSD all endorsed GRI; the WSSD also endorsed Type II partnerships. IOs can provide modest material support, enhancing the steering effect by supporting specific activities. IO participation in public-private schemes such as RSB allows for multiple forms of support and steering.

Polycentric governance theory suggests additional approaches. Perhaps most promising, IOs could facilitate learning by establishing a clearinghouse for transnational schemes (Pattberg 2010), assessing their structures and operations, and diffusing the resulting knowledge. Going one step further, IOs could promote experimentation:[34] supporting different types of transnational schemes, standards and programs, assessing their results, promoting peer review, diffusing knowledge about them, and helping to replicate or scale up transferable innovations. The EU and some states engage in experimentalist governance, but transnational experimentation is rarely pursued in a structured way (Overdevest and Zeitlin, 2011; Sabel and Zeitlin, 2010; 2011).

In all these forms, orchestration provides a feasible approach to global governance that can bridge existing gaps between the international and transnational regime complexes, enhancing the benefits of fragmentation, decentralization and scale.

[34] Hoffmann (2011:17) refers to RSS schemes as "experiments," but defines experimentation simply as trial-and-error, without any systematic support or control.

TABLE 1

TRANSNATIONAL SCHEMES SHOWN IN FIGURE 2

ZONE 1	**C40 •**	C40 CITIES CLIMATE LEADERSHIP GROUP
	CN ⊙	CARBON*N* CITIES CLIMATE REGISTRY
	CSLF ⊙	CARBON SEQUESTRATION LEADERSHIP FORUM
	EC •	ENERGY CITIES
	GMI ⊙	GLOBAL METHANE INITIATIVE
	ICLEI •✪	ICLEI - LOCAL GOVERNMENTS FOR SUSTAINABILITY
	JREC •	JOHANNESBURG RENEWABLE ENERGY COALITION
	MEF •	MAJOR ECONOMIES FORUM ON ENERGY AND CLIMATE
	NEG/ECP✪	CONF. OF NEW ENGLAND GOVERNORS AND E. CANADIAN PREMIERS
	NRG •	NETWORK OF REGIONAL GOVERNMENTS FOR SUSTAINABLE DEVELOPMENT
	RGGI ✪⊙	REGIONAL GREENHOUSE GAS INITIATIVE
	TCREG ✪⊙	THE CLIMATE REGISTRY
	UBC •	UNION OF THE BALTIC CITIES
	WCIN ✪⊙	WESTERN CLIMATE INITIATIVE
	WMC •	WORLD MAYORS COUNCIL ON CLIMATE CHANGE
ZONE 2	**CMI •**	CARBON MARKET INSTITUTE (INCORPORATING AETF)
	[CCX] ⊙	CHICAGO CLIMATE EXCHANGE [SUSPENDED VOLUNTARY MARKET DEC. 2010]
	CNP ✪	CARBONNEUTRAL PROTOCOL
	CW ✪	CLIMATEWISE
	GSEP •⊙	GLOBAL SUSTAINABLE ELECTRICITY PARTNERSHIP (formerly e8)
	IETA •	INTERNATIONAL EMISSIONS TRADING ASSOCIATION
	PC •	POINT CARBON
	VCS ✪	VERIFIED CARBON STANDARD
	WBCSD •	WORLD BUSINESS COUNCIL FOR SUSTAINABLE DEVELOPMENT
ZONE 3	**ACRN •⊙**	ASIAN CITIES CLIMATE CHANGE RESILIENCE NETWORK
	ACREG ✪⊙	AMERICAN CARBON REGISTRY

	CCBA ✪	CLIMATE, COMMUNITY AND BIODIVERSITY ALLIANCE
	CCI $⦿	WILLIAM J. CLINTON FOUNDATION CLIMATE INITIATIVE
	CF ✪	CARBONFIX STANDARD
	CRAG ✪	CARBON RATIONING ACTION GROUPS
	CRED •	COMMUNITY CARBON REDUCTION PROGRAMME
	CTW •	CARBON TRADE WATCH
	GB ⦿	GREEN BELT MOVEMENT
	GOLD ✪⦿	THE GOLD STANDARD
	PEW •	PEW CENTER ON GLOBAL CLIMATE CHANGE
	RC •	RED CROSS/RED CRESCENT CLIMATE CENTRE
	SC ✪	SOCIALCARBON
	TRANS •	TRANSITION NETWORK (TRANSITION TOWNS)

ZONE 4	**APP ⦿**	ASIA-PACIFIC PARTNERSHIP ON CLEAN DEVELOPMENT AND CLIMATE (UNTIL 201
	BCF $	BIOCARBON FUND
	C4C ✪	UN GLOBAL COMPACT CARING FOR CLIMATE
	CBEEX ⦿	CHINA BEIJING ENVIRONMENTAL EXCHANGE (ALSO SHANGHAI, TIANJIN)
	CDCF $	COMMUNITY DEVELOPMENT CARBON FUND
	CNNET ✪	CLIMATE NEUTRAL NETWORK
	CUD ⦿	CONNECTED URBAN DEVELOPMENT
	GGFR⦿✪	GLOBAL GAS FLARING REDUCTION PARTNERSHIP
	ISO ✪	ISO GHG ACCOUNTING STANDARDS 14064-14065
	PCF $	PROTOTYPE CARBON FUND
	SCI •	SLIMCITY INITIATIVE
	TCG •	THE CLIMATE GROUP
ZONE 5	**IIGCC •**	INSTITUTIONAL INVESTORS GROUP ON CLIMATE CHANGE
	ILACS •	INTERNATIONAL LEADERSHIP ALLIANCE FOR CLIMATE STABILIZATION
	INCR •	INVESTOR NETWORK ON CLIMATE RISK
	UNFIP $	UN FUND FOR INTERNATIONAL PARTNERSHIPS
ZONE 6	**BELC✪•**	BUSINESS ENVIRONMENTAL LEADERSHIP COUNCIL
	CC ✪	CLIMATE COUNTS

	CDP •	CARBON DISCLOSURE PROJECT
	CDSB ✪	CLIMATE DISCLOSURE STANDARDS BOARD
	CS ✪	WWF CLIMATE SAVERS
	CSC •	CLIMATE SAVERS COMPUTING INITIATIVE
	GPMD•	GREEN POWER MARKET DEVELOPMENT GROUP
	PROT ✪	GREENHOUSE GAS PROTOCOL
ZONE 7	**CLAR✪⦿**	CLIMATE ACTION RESERVE
	CLASP •	COLLABORATIVE LABELING AND APPLIANCE STANDARDS PROGRAM
	CWORKS•	CLIMATE WORKS FOUNDATION BEST PRACTICES NETWORKS
	HSBC ⦿	HSBC CLIMATE PARTNERSHIP
	REEEP $	RENEWABLE ENERGY AND ENERGY EFFICIENCY PARTNERSHIP
	RSB ✪	THE ROUNDTABLE ON SUSTAINABLE BIOFUELS

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Figure 1

The Regime Complex for Managing Climate Change

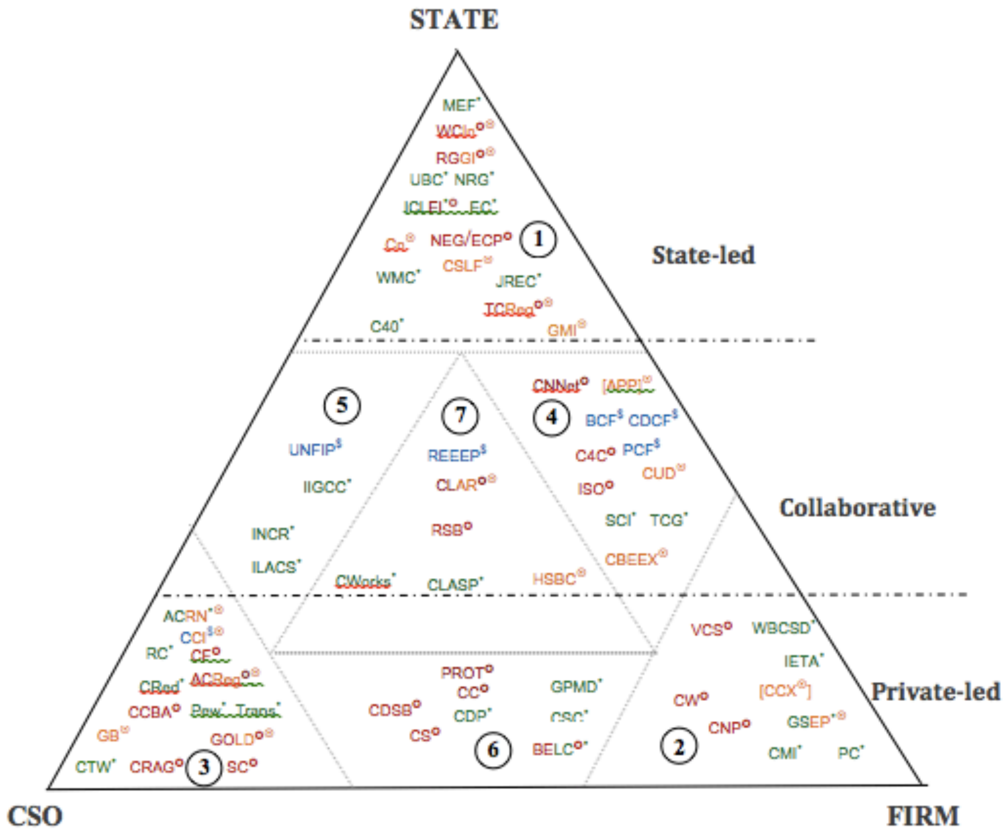

Figure 2

The Transnational Climate Change Governance Triangle

Standards & Commitments Operational

Information & Networking Financing$

The Limits of Administrative Law as Regulatory Oversight in Linked Carbon Markets

*Danny Cullenward**

ABSTRACT

Many commentators have celebrated the link between carbon markets in California and Québec as an example of effective coordination of sub-national climate policy instruments. Here, I argue that this enthusiasm is misplaced. California recently amended its carbon market regulations to enable significant leakage of emissions to neighboring states. These reforms reduce the environmental effectiveness of the market, contradict clear statutory guidelines, and dilute the integrity of the state's compliance instruments. Moreover, the reforms took place in an administrative process that never recognized the leakage implications, raising questions as to whether California alerted its Canadian counterparts of the consequences of its internal reforms. I review this transition from three perspectives: the relevant administrative proceedings in California, the mutual obligations both governments accepted under a bilateral agreement, and the standards California law imposes on prospective linked markets. Each perspective reveals major shortcomings. Rather than demonstrating a successful model for harmonizing carbon market systems across different legal jurisdictions, the link be-

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tween California and Québec exemplifies a major institutional weakness: in a linked carbon market, participating governments must continuously monitor the administrative processes of each jurisdiction in order to maintain market integrity. But as the California experience demonstrates, administrative law may not be up to the task of ensuring that practical market operation follows the rule of law.

I.
INTRODUCTION[1]

Many believe that sub-national climate mitigation policies offer a meaningful path forward by simultaneously encouraging global negotiations and persisting in the absence of international agreements. Although state and provincial governments certainly deserve credit for early action on climate, everyone understands that no local government can solve a global problem on its own. Thus, a critical task for sub-national climate policymakers is encouraging others to join or harmonize efforts with their systems. With this goal in mind, the link between California's and Québec's carbon markets appears to offer the first major victory in linking climate policy systems since the contentious integration of the Kyoto Protocol's Clean Development Mechanism into the European Emissions Trading Scheme.[2] Will the partnership between California and Québec set an example for others?

Here, I argue that excitement over the link between the carbon markets in California and Québec is both unwarranted and premature. Fundamentally, proponents of this link have overlooked the practical challenges of maintaining the integrity of linked carbon markets through parallel administrative legal pro-

1. This article is based on work prepared for a conference presentation. *See* DANNY CULLENWARD, LINKAGE, LEAKAGE AND ADMINISTRATIVE LAW (2014), *available at* http://www.environment.ucla.edu/perch/resources/panel-3-cullenward.pdf (presented at the California-Quebec Adventure: Linking Cap and Trade as a Path to Global Action? at the University of California, Los Angeles on April 1, 2014).

2. For an overview of the European system and its link with the Clean Development Mechanism, *see generally* ALLOCATION IN THE EUROPEAN EMISSIONS TRADING SCHEME (A. Denny Ellerman et al. eds., 2007). For a critical overview of the problematic experience with carbon offset credits, *see generally* Michael W. Wara, *Measuring the Clean Development Mechanism's Performance and Potential*, 55 UCLA L. Rev. 1759 (2008). The controversy over the use of questionable offset credits remains a significant concern among climate policy experts. *Compare* Richard G. Newell et al., *Carbon Market Lessons and Global Policy Outlook*, 343 SCIENCE 1316, 1316-17 (2014) (supporting the increased use of carbon markets without mentioning the European Union's experience with offset credits), *with* Danny Cullenward & Michael Wara, *Carbon Markets: Effective Policy?*, 344 SCIENCE 1460, 1460-61 (2014) (raising concerns about the potential for leakage and low-quality offsets to undermine carbon market performance).

cesses. Rather than demonstrating a successful example, the link between California and Québec provides a useful illustration of how governments are likely to fail to anticipate significant risks in recognizing one another's market-based compliance mechanisms. The California-Québec experience also highlights a critical tension in the drive to link carbon markets: with each new jurisdiction's entrance into a linked market, the burden of regulatory and civil society oversight increases for all involved.[3] These problems suggest that linking carbon markets is more difficult than previously imagined, raising questions about the viability of expanding sub-national carbon markets as a path towards regional and international policy harmonization.

Reflecting on these challenges, I argue that administrative law is an inadequate tool for maintaining the integrity of technically complex policy instruments like carbon markets. Even in the relatively simple case involving two linked jurisdictions whose market designs share common origins—California and Québec both developed their respective policies through the Western Climate Initiative ("WCI"), an effort to develop a re-

3. The other major example of this phenomenon occurs in the northeastern states' Regional Greenhouse Gas Initiative ("RGGI"). For an insightful treatment of the political economy in this carbon market, *see generally* Bruce R. Huber, *How Did RGGI Do It? Political Economy and Emissions Auctions*, 40 ECOLOGY L.Q. 59 (2013). The number of states participating in the system has vacillated over time, reaching ten at one point. There are currently nine RGGI participants, due to the recent departure of New Jersey. *See State Statutes & Regulations*, REG'L GREENHOUSE GAS INITIATIVE, http://www.rggi.org/design/regulations (last visited July 3, 2014). Each state has its own implementing legislation and regulations, based on a model program rule. *See id.* Participating states are clustered in New England and in the Mid-Atlantic, regions of the United States that already cooperate in a number of economic spheres due to their close proximity. This suggests that oversight issues may be fewer in RGGI than in the case of linked markets involving market designs not based on a single model rule, or those that involve jurisdictions with fewer preexisting economic relationships. RGGI's price levels have also been extremely modest, generally ranging between $2 and $4 per metric ton of carbon dioxide. *See* POTOMAC ECONOMICS, ANNUAL REPORT ON THE MARKET FOR RGGI CO_2 ALLOWANCES: 2013, at 18 (2014), *available at* http://www.rggi.org/docs/Market/MM_2013_Annual_Report.pdf. As a result, the modest market prices provide very little room for regulatory changes in one state to significantly affect region-wide prices—unlike in California.

gional cap-and-trade program for greenhouse gases[4]—substantial flaws in the California-Québec linkage have become apparent.

While the two governments were engaged in the detailed and laudable work required to harmonize the joint operation of their market systems, California was modifying its own regulations through formal and informal processes. These reforms resulted in significant adjustments to the liability regime underlying California's market structure.[5] The new rules allow regulated entities in California to transfer the liability for their high-emitting electricity imports to unregulated parties in neighboring states. This allows parties to replace their dirty imports with cleaner resources via transactions that create the false appearance of emissions reductions in California's market, without reducing net emissions to the atmosphere. Because California has historically imported a large amount of high-emissions coal power from neighboring states, there is a significant potential for regulated entities to exploit the new rules. As a result, the reforms have major implications for the demand for compliance instruments—not to mention the environmental integrity of California's flagship climate policy. Presumably, changes of this magnitude would have been relevant to the Québécois government, which,

4. *See History*, W. CLIMATE INITIATIVE, *available at* http://www.westernclimateinitiative.org/history (last visited July 3, 2014). However, WCI was more than shared history. The process culminated in a draft policy design concept that members were encouraged to implement. *See generally* W. CLIMATE INITIATIVE, DESIGN FOR THE WCI REGIONAL PROGRAM (2010), *available at* http://www.westernclimateinitiative.org/component/remository/general/program-design/Design-for-the-WCI-Regional-Program/. WCI participants fell into one of two categories: partners and observers. *See id.* at 3. At its peak, WCI participants included seven states (Arizona, California, New Mexico, Montana, Oregon, Utah, and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario, and Québec). *Id.* Many others participated as observers, including six American states (Alaska, Colorado, Idaho, Nebraska, Nevada, and Wyoming), three Canadian provinces (Nova Scotia, Saskatchewan, and Yukon), and six Mexican states (Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas). *Id.* As a result, jurisdictions that participated in the WCI process share a history and common program design. Thus, the link between California and Québec should present fewer challenges than would be present in a link between two systems that do not share these qualities.

5. *See infra* Parts II.B, III.

by this time, had already amended its market regulations to accept California-issued compliance instruments and was negotiating a bilateral agreement with California concerning the joint operation of their linked markets. Yet nowhere in the state's own administrative record does the California Air Resources Board ("ARB") recognize the impact of its internal reforms on the market's integrity. Only in response to public comments—issued after the two governments formally linked their markets—did ARB consider the argument that its reforms undermined the integrity of its cap. Ultimately, ARB dismissed these concerns, despite its own economic advisers' observations to the contrary.[6]

This article focuses on the extent to which formal administrative processes are capable of preserving the integrity of linked carbon markets. Section II begins with a review of two simultaneous administrative processes in California: one enabling the link with Québec and another amending the core carbon market regulations. Next, I describe the effect of California's internal reforms on the carbon market's integrity in Section III. Section IV reviews the bilateral agreement between the two governments, asking whether California satisfied its obligation to keep Québec informed about the expected impacts of its new regulations. Finally, I consider the safeguards California law imposes on ARB when considering new market partners in Section V. Consider the hypothetical situation in which another state relaxed its resource shuffling rules, as California did in reality, but that California did not. Would that jurisdiction meet California's stringent standards for evaluating prospective partners? I conclude that the answer would be no, but only if state policymakers were to look beyond a formalist analysis of the legal standards in prospective linking partners. In practice, actual market conditions will be determined as much by informal guidance documents and discretionary enforcement strategies as by codified legal standards. This suggests that the regulatory oversight cost of pursuing a bottom-up, state-by-state strategy for linking carbon markets raises significant and underappreciated challenges. It also highlights the inadequacy of administrative law as a mechanism

6. *See infra* Part III.

to anticipate problems from linking carbon markets.

II.
A TALE OF TWO ADMINISTRATIVE PROCESSES

Like complex financial contracts, which are generally reviewed by specialized attorneys and signed by each client organization's executives, linked carbon markets are the product of sequential negotiation and review. The key difference is that, while discussions about linking carbon markets begin through private discussions between policymakers, they are formalized through parallel administrative law processes. In turn, administrative law places the burden of due diligence on agencies. Agencies evaluate prospective partners and promulgate linking regulations, all while remaining subject to the standard requirements of public notice and comment periods. Once linked, the markets are designed to operate as a single, dynamic financial system, with regulatory oversight divided among participating governments.

As a result, environmental regulators—which legislatures typically task with operating carbon markets—must now accept the duties of international (or at least interstate) financial regulators. Their new currency is tradable compliance instruments. The fundamental legal mechanism in carbon markets is the requirement that regulated industries (known in California as "covered entities") surrender one compliance instrument for each metric ton of greenhouse gases they emit.[7] When one market links with another, it does so by allowing its regulated entities to use the compliance instruments of its linked partner.[8] When two

7. *See, e.g.,* CAL. CODE REGS. tit. 17, § 95856 (2014) (requiring covered entities in California's carbon market to submit compliance instruments); CAL. CODE REGS. tit. 17, § 95802(a)(83) (defining covered entities); CAL. CODE REGS. tit. 17, § 95802(a)(68) (defining compliance instruments as including allowances, offsets, and other instruments issued by jurisdictions with which California has officially linked its market system); CAL. CODE REGS. tit. 17, § 95802(a)(9) (defining allowances as tradable compliance instruments); CAL. CODE REGS. tit. 17, § 95802(a)(14) (defining offsets as tradable compliance instruments).

8. *See, e.g.,* CAL. CODE REGS. tit. 17, § 95802(a)(68) (defining compliance instruments in California as including those instruments issued by jurisdictions with which California's market has been formally linked); CAL. CODE REGS. tit. 17, § 95943 (approving compliance instruments issued by the Government of

markets mutually recognize each other's instruments they form a bilateral link.[9] Thus, a regulator that previously might have been worried about putting catalytic converters on car tailpipes now faces a new and challenging task: harmonizing the details of its domestic market regulations with those of prospective partner jurisdictions.

In practical terms, bilateral linking allows the regulated parties in one jurisdiction to employ compliance instruments from either system to meet the requirements of their home jurisdiction. Due to the mutual recognition of these instruments, the entire linked market is affected if either regulator makes a mistake or a harmful change in domestic policy. Therefore, it is essential that jurisdictions choose their linking partners carefully.

As I describe below, California's process for vetting and approving a link with another cap-and-trade market unfolded at the same time ARB decided to modify its core market regulations. Because these reforms occurred in parallel, they offer an interesting opportunity to examine how the administrative law process conducts due diligence when assessing prospective market links, as will be discussed in Sections IV and V in greater detail. Here, I provide an overview of the process by which California linked its market to Québec's (Section II-A), a review of California's internal carbon market reforms (Section II-B), and a comprehensive timeline of the key events in both processes (Section II-C).

A. California's Linking Regulations

California never intended to be the only jurisdiction pricing carbon. In fact, its climate policy was developed with the goal of participating in a regional carbon market. After all, the state's program has its origins in the Western Climate Initiative ("WCI"), a regional effort among state and provincial leaders to harmonize sub-national climate policies across the western

Québec for use in California's market as of January 1, 2014).

9. Dallas Burtraw et al., *Linking by Degrees: Incremental Alignment of Cap-and-Trade Markets*, RESOURCES FOR FUTURE, Apr. 2013, at 1, 7-9, *available at* http://www.rff.org/Documents/RFF-DP-13-04.pdf.

United States and much of Canada.[10] Despite WCI's impressive initial membership, only a handful of jurisdictions adopted carbon markets (or any other stringent climate policies). By the time the California market came into being, Québec was one of the few WCI jurisdictions that had followed a similar path. With their shared history and common market design principles,[11] a prospective link seemed natural.

This is not to say that the prospective link did not present challenges. Questions about the integrity of a linked system, its enforceability mechanisms, and legal jurisdictional issues remained. In 2012, the California Legislature passed S.B. 1018, which requires the governor of California to make four affirmative findings before linking with any other carbon market. The governor must conclude that: (1) the other program is "equivalent to or stricter than" California's market, (2) linking maintains the State of California's jurisdiction over participants in linked markets to the maximum extent permitted by the state and federal constitutions, (3) the linking jurisdiction has enforcement powers that are "equivalent to or stricter than" those of California, and (4) participation in a linked system by California will not impose "significant liability" on the state government for any failure associated with the linkage.[12]

In response to this statute, ARB, the Office of the Attorney General, and the Office of the Governor each compared the California and Québécois programs.[13] After review, the governor made the necessary affirmative findings to enable the formal regulatory amendments. The internal review only lasted from February to April of 2013, though the development of linking regulations and informal discussions between California political leaders, California agency staff, and their Québécois counterparts began much earlier. Critically, the formal administrative review of Québec's system analyzed a snapshot of the prospective

10. DESIGN FOR THE WCI REGIONAL PROGRAM, *supra* note 4, at 3.

11. *See generally id.* (describing a common policy design for carbon markets among WCI members).

12. CAL. GOV'T CODE § 12894(f) (West 2013).

13. *See* discussion *infra* Part II.C (providing citations to the relevant milestones in the linking process).

linked market rather than employing a continuous approach to regulatory oversight. Instead, the ongoing and joint operation of the two markets is subject to a bilateral agreement signed by the two governments.[14]

B. *California's Domestic Reforms*

At the same time California was preparing to link with Québec, ARB was in the middle of significantly changing its core market rules. These reforms occurred first through informal regulatory guidance documents and later through formal administrative procedures. Notably, the informal changes to California's market design began just before Québec finalized its link to California, and the formal changes concluded after California finalized its link to Québec.[15] In other words, California made a significant domestic regulatory transition in the middle of the process whereby the two governments linked their carbon markets. As a result of both their subject matter and timing, California's domestic reforms speak directly to the sufficiency of using formal administrative law processes to conduct due diligence on prospective linking partners.

California's internal reforms concern treatment of emissions from imported electric power, an important emissions category included in the state carbon market.[16] Understanding the effect of the reforms requires some additional context, beginning with the observation that California is a significant net importer of

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14. *See* Agreement Between the California Air Resources Board and the Government du Québec Concerning the Harmonization and Integration of Cap-and-Trade Programs for Reducing Greenhouse Gas Emissions, Cal.-Que., Sept. 27, 2013 [hereinafter "Bilateral Agreement"], *available at* http://www.arb.ca.gov/cc/capandtrade/linkage/ca_quebec_linking_agreement_english.pdf. For convenience, I refer only to the English language version of the Bilateral Agreement; however, an equally authoritative version was executed in French at the same time, *available at* http://www.arb.ca.gov/cc/capandtrade/linkage/ca_quebec_linking_agreement_french.pdf.

15. *See* discussion *infra* Part II.C (providing citations to the relevant milestones in the linking process).

16. *See* CAL. CODE REGS. tit. 17, § 95852(b) (2014) (making "first delivers" of electricity responsible for the emissions associated with their electric power supplies); CAL. CODE REGS. tit. 17, § 95802(a)(146) (defining electricity importers as "first delivers").

electricity. In 2012, for example, California imported 34% of its net power consumption from neighboring states.[17] In terms of greenhouse gas emissions, the impacts of California's domestic and imported power consumption are roughly equal; in 2012, electricity production from in-state facilities accounted for 11.2% of total state emissions, whereas imports accounted for 9.6%.[18] Thus, while California imports about one-third of its electric power, those imports contribute about half of the emissions from its overall electricity consumption.

The key insight here is that California's imported power has been significantly more carbon-intensive than its domestic power. Indeed, the largest share of imported power emissions comes from a handful of high-carbon coal-fired power plants, which are mostly located in the Southwest.[19] In contrast, California does not have any significant in-state coal power plants.[20] Instead, its domestic electricity production primarily comes from a mixture of relatively low-carbon natural-gas-fired power plants, along with zero-carbon nuclear and renewable energy systems, including hydropower.[21] Therefore, the treatment of emissions from

17. Cal. Energy Comm'n, *California Electrical Energy Generation*, ENERGY ALMANAC, *available at* http://energyalmanac.ca.gov/electricity/electricity_generation.html (last visited July 10, 2014) [hereinafter *California Electrical Energy Generation*] (reporting Net Energy Imports of 102,786 GWh and California Generation plus Net Imports of 302,113 GWh for the year 2012).

18. CAL. AIR RES. BD., CALIFORNIA GREENHOUSE GAS EMISSION INVENTORY: 2000-2012, at 12 (2014), *available at* http://www.arb.ca.gov/cc/inventory/pubs/reports/ghg_inventory_00-12_report.pdf.

19. *See* CAL. AIR RES. BD., CALIFORNIA'S 2000-2012 GREENHOUSE GAS EMISSIONS INVENTORY TECHNICAL SUPPORT DOCUMENT 15-18 (2014), *available at* http://www.arb.ca.gov/cc/inventory/doc/methods_00-12/ghg_inventory_00-12_technical_support_document.pdf (describing "specified" imports from certain identified coal power plants).

20. *See California Electrical Energy Generation*, *supra* note 17 (reporting Commercial In-State Generation from coal power of 1,580 GWh in 2012, which is approximately 0.5 percent of the total California Generation plus Net Imports of 302,113 GWh).

21. *See id.* (reporting high production from in-state power plants using natural gas, nuclear, hydroelectric, and other renewable energy resources). Note that despite conventional wisdom to the contrary, hydropower is actually not a zero-greenhouse gas resource. Inundated biomass and changed biogeochemistry in reservoirs can lead to significant emissions of carbon dioxide, methane, and nitrous oxide. *See generally* GREENHOUSE GAS EMISSIONS – FLUXES AND

imported power will play a significant role in the performance of California's carbon market.

This context is necessary to understand California's internal market reforms, which focus on an issue called resource shuffling. As discussed in more detail in Section III, *infra*, resource shuffling occurs when electricity importers swap out their high-emitting resources and replace them with cleaner imports.[22] For example, if a utility sells its legacy coal power import contract to a neighboring state, replacing the lost coal deliveries with natural-gas-fired power, this has the effect of reducing emissions within California's market. Critically, however, it does not result in the coal plant shutting down. Quite the opposite: the coal plant will continue to produce dirty electricity for its new, unregulated owners. The swap merely re-arranges which party on the western electricity grid is legally responsible for consuming the carbon-intensive resources, without reducing net emissions to the atmosphere. Instead, the liability for those emissions simply "leaks" to an unregulated party.[23] Thus, the fact that California has historically imported significant deliveries of coal

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PROCESSES: HYDROELECTRIC RESERVOIRS AND NATURAL ENVIRONMENTS (Alain Tremblay et.al.eds.,2005) [hereinafter "Hydroelectric Reservoirs"] (a standard reference in the field with a focus on Québécois reservoirs). In the tropics, these emissions can rise to levels comparable to the pollution from equally sized power plants. *See generally* Philip M. Fearnside & Salvador Pueyo, *Commentary: Greenhouse-gas emissions from tropical dams*, 2 NATURE CLIMATE CHANGE 382, 382-84 (2012). However, there are no documented reservoirs in temperate areas that produce this scale of impact. Reservoirs in Québec have been well studied, while California reservoirs have not. *See generally* HYDROELECTRIC RESERVOIRS. Luckily, there is little reason to think that California's reservoirs are causing significant emissions. For an overview of the scientific issues, *see generally* Ivan B. T. Lima et al., *Methane Emissions from Large Dams as Renewable Energy Resources: A Developing Nation Perspective*, 13 MITIGATION & ADAPTATION STRATEGIES FOR GLOBAL CHANGE 193, 193-206 (2008) (estimating global methane emissions from hydroelectric reservoirs of 104 million tons per year and assessing strategies for capturing and/or destroying these emissions).

22. The newest market regulations define resource shuffling as "any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation." CAL. CODE REGS. tit. 17, § 95802(a)(338) (2014). The definition then refers to a number of exemptions, discussed later in this paper. *See id.* (citing CAL. CODE REGS. tit. 17, § 95852(b)(2)(A)); *see infra* Part III.

23. For additional discussion on leakage, *see infra* Part III.

power creates an attractive opportunity for prospective resource shufflers: if allowed, the cheapest compliance option for many utilities would be to sell their coal power to neighbors who do not face legally binding climate policies.[24]

ARB has consistently prohibited resource shuffling as a formal matter,[25] but new regulations effectively repeal this ban. In response to pressure from stakeholders, ARB adopted what it calls a "safe harbor" approach to resource shuffling. Specifically, ARB identified 13 activities that are exempted from the definition of, and therefore the prohibition on, resource shuffling.[26] These safe harbor reforms were introduced first through an informal regulatory guidance document in November 2012,[27] and subsequently

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24. *See* Severin Borenstein et al., *Report of the Market Simulation Group on Competitive Supply/Demand Balance in the California Allowance Market and the Potential for Market Manipulation* (2014), *available at* http://www.arb.ca.gov/cc/capandtrade/simulationgroup/msg_final_v25.pdf (finding that "there is likely to be significant 'reshuffling' of electricity purchases among buyers and sellers across state lines"); *see also id.* at 17, fig. 1 (showing "Costless Reshuffling" and "Costly Reshuffling" as the lowest-cost abatement options for regulated entities in California). Note that the other zero-cost listing ("Complementary Measures") is technically not a compliance option. Rather, this term refers to the emission reductions required by other state policies, whose effects will contribute to emission reductions in the sectors subject to California's carbon market. *See id.* at 14 (defining complementary policies as programs that abate GHGs "outside the cap and trade program."). Because these emissions reductions are mandatory, they are distinct from the range of voluntary options regulated entities in the carbon market might choose to reduce their emissions. *See generally* Michael Wara, *California's Energy and Climate Policy: A Full Plate, But Perhaps Not a Model Policy*, 70 BULL. OF ATOMIC SCIENTISTS 26 (2014) (discussing the relationship between California's complementary policies and its carbon market).

25. CAL. CODE REGS. tit. 17, § 95852(b)(2) (prohibiting first delivers from resource shuffling). Note that the core prohibition on resource shuffling was unmodified in the regulatory amendments, though the underlying definition was changed in ways that are unimportant for the purposes of this article. *See* CAL. CODE REGS. tit. 17, § 95802(a)(338). Note further that if an activity fits within one of the safe harbors, it is exempted by definition from the prohibition. *Id.* This is true even if the activity would otherwise fit into one of the affirmatively defined categories of resource shuffling defined in § 95852(b)(2)(B).

26. CAL. CODE REGS. tit. 17, § 95802(a)(338) (defining resource shuffling as excluding the safe harbor exemptions codified in § 95852(b)(2)(A)).

27. *See* CAL. AIR RES. BD., CAP-AND-TRADE REGULATION INSTRUCTIONAL GUIDANCE, APPENDIX A: WHAT IS RESOURCE SHUFFLING? (2012) [hereinafter INSTRUCTIONAL GUIDANCE APPENDIX A], *available at* http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

codified in a formal regulatory process that was approved in April 2014.[28] As explained in Section III, *infra*, the safe harbors are so broad as to effectively overwhelm the prohibition against resource shuffling that technically remains on the books. They also include explicit exemptions that allow utilities and other regulated parties to divest their legacy coal assets without running afoul of the prohibition on resource shuffling.

From the standpoint of linking markets, California's internal reforms lower the environmental quality of the state's compliance instruments. To the extent that regulated parties in California rely on resource shuffling to leak emissions, a party acquiring compliance instruments from the California system can no longer rely on those instruments to represent net emission reductions. For the same reason, a linked market that accepts these compliance instruments will also see the environmental integrity of its system degrade. Thus, California's internal reforms should have raised significant concerns for Québécois policymakers. The fact that they occurred after Québec amended its regulations to accept California compliance instruments should only increase the stakes.

C. *Regulatory Timeline*

The major milestones in California's internal reforms and linking process are identified below. Notably, California began its internal reforms through an informal guidance document that was released one month before Québec finalized its link to California. The formal regulatory process began six months later and concluded after the two governments signed an agreement concerning the joint operation of their market systems. For convenience, I omit the many years of discussion about linking the two systems, taking for granted the two governments' mutual interest in creating a robust and effective linked market by the beginning of 2012. In addition, I use the labels "(L)" and "(R)" to denote events related to linking the markets and California's internal reforms, respectively.

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28. *See* Cal. Air Res. Bd. Res. 14-4 (Apr. 25, 2014) [hereinafter Resolution 14-4], *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/res14-4.pdf.

(L) May 2012: ARB releases proposed regulations that would operationalize its link with Québec.[29]

(R) October 2012: ARB directs its staff to develop a "safe harbor" approach to reforming the prohibition on resource shuffling.[30]

(R) November 2012: ARB issues an informal guidance document adopting its "safe harbor" approach to resource shuffling.[31]

(L) December 2012: Québec finalizes regulations that operationalize its link with California.[32]

(L) February 2013: ARB notifies the governor's office of its intention to link with Québec.[33]

(L) February 2013: California Attorney General issues advice to the Governor's office on the legality of the proposed link.[34]

(L) April 2013: Governor Brown issues the necessary findings

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29. *See* CAL. AIR RES. BD., PROPOSED AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS TO ALLOW FOR THE USE OF COMPLIANCE INSTRUMENTS ISSUED BY LINKED JURISDICTIONS, STAFF REPORT: INITIAL STATEMENT OF REASONS (2012), *available at* http://www.arb.ca.gov/regact/2012/capandtrade12/isormainfinal.pdf.

30. *See* Cal. Air Res. Bd. Res. 12-51 (Oct. 18, 2012), *available at* http://www.arb.ca.gov/cc/capandtrade/final-resolution-october-2012.pdf; *see also* CAL. AIR RES. BD., CALIFORNIA CAP-AND-TRADE PROGRAM ATTACHMENT A: CLARIFYING RESOURCE SHUFFLING DEFINITION (2012), *available at* http://www.arb.ca.gov/cc/capandtrade/attachmenta.pdf (identifying thirteen specific safe harbor provisions).

31. *See* INSTRUCTIONAL GUIDANCE APPENDIX A, *supra* note 27.

32. *See* Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances, R.R.Q., c. Q-2, r. 46.1 [hereinafter Quebec Regulations], *available at* http://www2.publicationsduquebec.gouv.qc.ca/dynamicSearch/telecharge.php?type=3&file=/Q_2/Q2R46_1_A.HTM.

33. *See* Letter from James N. Goldstene, Executive Officer, Cal. Air Res. Bd., to Edmund G. Brown, Governor of Cal. (Feb. 22, 2013), *available at* http://gov.ca.gov/docs/SB_1018_Transmittal_to_Governor.pdf; *see also* CAL. AIR RES. BD., DISCUSSION OF FINDINGS REQUIRED BY GOVERNMENT CODE SECTION 12894, at 1 (2013) [hereinafter DISCUSSION OF SECTION 12894 REQUIRED FINDINGS], *available at* http://www.arb.ca.gov/regact/2012/capandtrade12/2nd15dayatta6.pdf. (stating that the document's purpose is to provide "background and support for the Air Resources Board's plan to request that the Governor make certain findings as a predicate to linking the Cap-and-Trade programs developed in parallel by California and Québec.").

34. *See* Letter from Christopher S Crook, Cal. Deputy Attorney Gen., to Cliff Rechtschaffen, Senior Advisor to the Governor of Cal. (Mar. 5, 2013), *available at* http://gov.ca.gov/docs/AG_Letter_SB_1018.pdf.

to allow California to link with Québec.[35]

(L) April 2013: ARB approves final regulations that operationalize the link with Québec, to become effective January 2014.[36]

(R) July 2013: ARB releases a discussion draft of prospective carbon market regulatory reforms that would codify the "safe harbor" approach to resource shuffling.[37]

(R) September 2013: ARB formally proposes new regulations that codify the "safe harbor" approach to resource shuffling.[38]

(L) September 2013: California and Québec sign a bilateral agreement concerning the joint operation of their linked markets.[39]

(L) November 2013: ARB issues its linkage readiness report.[40]

(L) January 2014: Both markets are officially and bilaterally linked.[41]

(R) April 2014: ARB approves new market regulations, codifying the "safe harbor" approach to resource shuffling.[42]

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35. *See* Letter from Edmund G. Brown, Governor of Cal., to Mary Nichols, Chair, Cal. Air Res. Bd. (Apr. 8, 2013), *available at* http://gov.ca.gov/docs/Request_for_SB_1018_Findings.pdf.

36. *See* Cal. Air Res. Bd. Res. 13-7 (Apr. 19, 2013) [hereinafter Resolution 13-7], *available at* http://www.arb.ca.gov/cc/capandtrade/linkage/resolution13-7.pdf.

37. *See* CAL. AIR RES. BD., CAP-AND-TRADE REGULATIONS DISCUSSION DRAFT JULY 2013, at 96-99 (2013), *available at* http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf.

38. *See* CAL. AIR RES. BD., STAFF REPORT: INITIAL STATEMENT OF REASONS, APPENDIX E: PROPOSED REGULATION ORDER 83-87 (2013), *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappe.pdf (proposing to amend CAL. CODE REGS. tit. 17, § 95852(b)(2) (2012)).

39. *See* Bilateral Agreement, *supra* note 14.

40. *See* CAL. AIR RES. BD., LINKAGE READINESS REPORT (2013) [hereinafter LINKAGE READINESS REPORT], *available at* http://www.arb.ca.gov/cc/capandtrade/linkage/arb_linkage_readiness_report.pdf; *see also* Letter from Edmund G. Brown to Mary Nichols, *supra* note 35, at 4 (requiring ARB to submit a progress report to the Governor by November 2013); *see also* Resolution 13-7, *supra* note 36, at 9 (resolving to submit a progress report to the Governor by November 2013).

41. *See* CAL. CODE REGS. tit. 17, § 95943(a) (2014) (allowing covered entities in California to employ compliance instruments issued by the Government of Québec as of January 1, 2014); *see also* Quebec Regulations, *supra* note 32, at Appendix B.1 (deeming compliance instruments issued by ARB "equivalent" to the those created by the Québécois regulations).

42. *See* Resolution 14-4, *supra* note 28.

As this timeline indicates, ARB began the process of reforming its market regulations shortly before Québec formally recognized California compliance instruments for use in its own market. California's internal reforms then progressed over the next year, significantly changing the state's liability regime. After successfully proceeding through the statutory requirements for linking its carbon market to others, ARB issued its reciprocal link with Québec a few months before its internal reforms were completed.

From an administrative law perspective, it is critical to note that California changed its market regulations after Québec agreed to accept Californian compliance instruments as equivalent to Québécois compliance instruments. Thus, the impact of California's internal reforms on its own market also affected Québec. As the next section describes, California's regulatory changes had profound consequences for the environmental integrity of California's market, yet no public government document acknowledged these consequences during the administrative proceedings.

III.
LEAKAGE FROM RESOURCE SHUFFLING

California's internal reforms raise important concerns about the environmental, financial, and legal integrity of its carbon market. The core problem is known as leakage, which California state law defines as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."[43] To the extent resource shuffling is allowed, it results in leakage. In turn, leakage undermines the environmental performance of the carbon market as a climate policy instrument. Should the emissions reductions reported in California result from a transfer of emissions liability outside of the state policy system, no net climate benefits would actually accrue. Thus, when ARB amended its regulations to allow regulated parties to resource shuffle, the regulator encouraged leakage and reduced the extent to which the carbon market reduces emissions of greenhouse gases to the atmosphere.

43. CAL. HEALTH & SAFETY CODE § 38505(j) (2010).

In addition to diminishing the environmental performance of the market, California's reforms also affect its financial and legal integrity. Specifically, the new regulations reverse a once-clear state policy to avoid leakage. When the California legislature passed A.B. 32, the Global Warming Solutions Act of 2006, it delegated broad authority to ARB to develop appropriate policies and measures to reduce state emissions to 1990 levels by the year 2020.[44] Although the legislature did not specify which types of policies or instruments should be adopted, it created some important requirements for ARB to follow. One of the most important requirements is a directive that, "to the extent feasible," ARB shall "minimize leakage" in the design of its market regulations.[45] Unfortunately, as discussed below, ARB's resource shuffling reforms uphold neither the spirit nor the letter of this statutory requirement.

A. *Expert Opinion in the Administrative Process*

As a threshold matter, one might question whether ARB understood the likely consequences of its domestic reforms; however, there is no doubt that the regulator had advance warning from trusted sources regarding the obvious leakage implications of relaxing its resource shuffling rules. For example, before ARB first adopted its safe harbor policy through a regulatory guidance document issued in November 2012, several prominent economists concluded that resource shuffling posed serious threats to the effectiveness of sub-national climate policies like those of California.[46] A subsequent study, first published in January

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44. *Id.* at § 38550 (defining the 2020 target); *id.* at § 38562(a) (authorizing ARB to adopt regulations to achieve the 2020 target).

45. *Id.* at § 38562(b)(8).

46. *See generally* Meredith L. Fowlie, *Incomplete Environmental Regulation, Imperfect Competition, and Emissions Leakage*, 1 AM. ECON. J.: ECON. POL'Y 72 (2009) (estimating the leakage risks from various market design approaches in California); James Bushnell et al., *Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction*, 2 REV. ENVTL. ECON. & POL'Y 175 (2008) (finding that "reshuffling" in state-level, market-based policies like carbon markets could lead to significant leakage); Karen Palmer et al., *Allowance Allocation in a CO_2 Emissions Cap-and-Trade Program for the Electricity Sector in California*, RESOURCES FOR FUTURE, Oct. 2009, at 1, 24-27, *available at*

2013, identified the leakage risks from resource shuffling in California's carbon market, finding that "current policy will lead to substantial 'reshuffling' and limit the impact of California's emissions cap."[47]

Lest these concerns seem merely academic, it is worth noting that three of the economists in question were members of the Emissions Market Assessment Committee ("EMAC"), a trio of prominent academics that advised ARB on the carbon market through December 2013.[48] Indeed, a draft EMAC report from June 2013 found that if resource shuffling were permitted in California's market, between 120 and 360 million tons of carbon dioxide could leak to neighboring states.[49] Examining only the leakage risks from allowing California utilities to divest from their legacy coal power imports (a subset of all possible resource shuffling transactions), an independent study found that ARB's safe harbor amendments could cause between 108 and 187 million tons of carbon dioxide to leak to neighboring states if all legacy coal contracts were divested.[50] (For comparison, a 2013 study

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http://www.rff.org/RFF/Documents/RFF-DP-09-41.pdf (discussing leakage concerns in detail); Justin Caron et al., *Leakage from Sub-national Climate Initiatives: The Case of California*, MASS. INST. TECH. JOINT PROGRAM ON SCI. & POL'Y OF CLIMATE CHANGE (May 2012), *available at* http://globalchange.mit.edu /files/document/MITJPSPGC_Rpt220.pdf (estimating the leakage risks for California's carbon market); James Bushnell and Yihsu Chen, *Allocation and Leakage in Regional Cap-and-Trade Markets*, 34 RESOURCE & ENERGY ECON. 647 (2012) (estimating the leakage risks for California's carbon market).

47. James Bushnell et al., *Downstream Regulation of CO_2 Emissions in California's Electricity Sector*, 64 ENERGY POL'Y 313, 313 (2014), *available at* http://www.sciencedirect.com/science/article/pii/S0301421513008690. These results were first published as a University of California working paper. James Bushnell et al., Downstream Regulation of CO_2 Emissions in California's Electricity Sector (January 2013) (Energy Institute @ Haas Working Paper #236), *available at* http://ei.haas.berkeley.edu/papers.html.

48. *See Emissions Market Assessment Committee*, CAL. AIR RES. BD., *available at* http://www.arb.ca.gov/cc/capandtrade/emissionsmarketassessment /emissionsmarketassessment.htm (last visited July 3, 2014). The EMAC members are Severin Borenstein (University of California, Berkeley), James Bushnell (University of California, Davis), and Frank Wolak (Stanford University). *Id.* The contract supporting EMAC activities expired in December 2013. *Id.*

49. Borenstein et al., *supra* note 24, at 14.

50. Danny Cullenward & David Weiskopf, Resource Shuffling and the California Carbon Market 2 (July 18, 2013) (unpublished working paper), *available at* https://www.law.stanford.edu/publications/resource-shuffling-and-the-

from the Electric Power Research Institute estimated that the cumulative mitigation required under California's carbon market through 2020 is between approximately 100 and 400 million tons.[51])

Thus, by the time ARB began a formal administrative process to codify the safe harbors first promulgated as informal guidance provisions, its own economic advisers and many independent researchers had concluded that exemptions to the prohibition on resource shuffling would lead to significant leakage. More bluntly, the evidence suggested that, if permitted, resource shuffling could lead to a quantity of leakage comparable to the size of the carbon market as a whole, meaning that regulated companies could rely on resource shuffling to achieve a significant portion of their expected emission reductions. These findings were also included in the administrative record.[52]

Although many technical experts identified leakage from re-

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51. ELECTRIC POWER RESEARCH INST., EXPLORING THE INTERACTION BETWEEN CALIFORNIA'S GREENHOUSE GAS EMISSIONS CAP-AND-TRADE PROGRAM AND COMPLEMENTARY EMISSIONS REDUCTION POLICIES 6-4 (2013), *available at* http://www.epri.com /abstracts/Pages /ProductAbstract.aspx ?ProductId=000000003002000298 (click on the "Download" hyperlink) (indicating a wide range of potential abatement of between 97 and 397 million tons). The estimates quoted here assume the full use of carbon offsets. *Id.* at 6-5. The range reflects whether covered entities use the Allowance Price Containment Reserve, a buffer pool of compliance instruments set aside in case of high prices, and the performance of California's many "complementary policies." *See id.* at 6-4. These policies are separate regulations like the renewable portfolio standard, low carbon fuel standard, and other policies that exist independent of the carbon market but nevertheless contribute to the emission reductions in economic sectors covered by the carbon market. *See id.* at 4-1. For additional comparisons between the estimated leakage risks and the size of the carbon market, *see* Cullenward & Weiskopf, *supra* note 50, at 27-30.

52. *See* Letter from Danny Cullenward, Philomathia Research Fellow, Berkeley Energy & Climate Inst., to Steven Cliff, Chief, Climate Change Program Evaluation Branch (Oct. 23, 2013), *available at* http://www.arb.ca.gov /lists/com-attach/4-acc2013-VDcAc1wxAzwBYgZo.pdf (attaching Danny Cullenward, Op-Ed., *Don't Let Accounting Tricks Dominate the Carbon Market*, SAN JOSE MERCURY NEWS, Oct. 21, 2013, and Cullenward & Weiskopf, *supra* note 50); Letter from Danny Cullenward, Philomathia Research Fellow, Berkeley Energy & Climate Inst., to Cal. Air Res. Bd. (April 4, 2014), *available at* http://www.arb.ca.gov/lists/com-attach/253-capandtrade13-VjVcNVY6UW9WNQln.pdf (attaching Bushnell et al., *supra* note 47, and Borenstein et al., *supra* note 24).

source shuffling as a critical market design issue, it is surprising how few commented directly on the specific reforms proposed by ARB. Cullenward and Weiskopf were the first to do so, finding that the initial safe harbors explicitly exempt resource shuffling of legacy coal power imports. In addition, the safe harbors effectively repeal the overall prohibition through a series of loosely constructed exemptions that regulated parties could exploit to justify nearly any transaction.[53] It is extremely unlikely that ARB could ever enforce its prohibition against resource shuffling in practice because one of the adopted safe harbors places the evidentiary burden on ARB to show that a purported resource shuffling transaction was motivated exclusively by a purpose of avoiding compliance obligations in the carbon market.[54] As a result, ARB's safe harbor policy undermines the formal prohibition on resource shuffling.

Given these broad exemptions, it is unsurprising that one can observe transactions that are causing leakage and would constitute resource shuffling under the carbon market regulations, but for the safe harbor policies adopted by ARB. Indeed, during the period between ARB's promulgation of the informal guidance document and its approval of formal regulatory amendments that codify the safe harbors into law, at least three major resource-shuffling-related transactions occurred. These transactions leaked 30 to 60 million tons of carbon dioxide into neighboring states.[55] Moreover, each transaction squarely fits in one of

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53. *See* Cullenward & Weiskopf, *supra* note 50, at 21-26 (reviewing each safe harbor and the logical gaps in the exemption-based safe harbor policy). This analysis was based on the safe harbors contained in the informal guidance document, which differed only slightly compared to the formal regulatory text subsequently approved by ARB in April 2014. These changes were minor and do not affect the conclusion that the codified safe harbors explicitly permit divestment of legacy coal power imports. *See* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 3-5 (reviewing individual safe harbor provisions now codified in the California market regulations).

54. *See* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 4 (citing CAL. CODE REGS. tit. 17, § 95852(b)(2)(A)(7) (2014)) (noting that a defendant in an enforcement action need only name generic reasons like diversifying contractual counterparties, reducing local air pollution impacts, or other tangential facts to claim protection under the broadest safe harbor provision).

55. Danny Cullenward, *Leakage in California's Carbon Market*, 27 ELECTRICITY J. (forthcoming 2014). *See also* Letter from Danny Cullenward to

the safe harbor provisions Cullenward and Weiskopf criticized as permitting the divestment of California's legacy coal imports.[56]

Thus, by the time ARB voted to adopt its market reforms, it had significant evidence in its administrative record that: (1) absent a clear rule prohibiting resource shuffling, significant leakage would result; (2) that the safe harbors gutted the prohibition on resource shuffling; and (3) resource shuffling of legacy coal contracts pursuant to the safe harbor exemptions had already caused significant leakage.[57] Nevertheless, ARB concluded that its safe harbors would not lead to significant leakage[58] and that no analysis of these risks was required under the California Environmental Quality Act.[59]

B. *Some Legal and Practical Consequences*

In the face of substantial evidence that its reforms would lead to significant leakage, ARB's resource shuffling amendments

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Cal. Air Res. Bd., *supra* note 52, at 5-7 (documenting the three transactions and calculating their associated leakage impacts); Debra Kahn, *Calif. Cuts Part of Its Greenhouse Gas Emissions by Exporting Them*, E&E CLIMATEWIRE, Apr. 25, 2014, *available at* http://www.eenews.net/climatewire/stories/1059998444; Evan Halper & Ralph Vartabedian, *Despite California climate law, carbon emissions may be a shell game*, LOS ANGELES TIMES, Oct. 25, 2014, http://www.latimes.com/science/la-me-climate-shell-game-20141026-story.html; David Roberts, *California's carbon market is leaking*, GRIST, Oct. 30, 2014, *available at* http://grist.org/climate-energy/californias-carbon-market-is-leaking/

56. *Compare* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 3-4 (evaluating the safe harbor exemptions for coal power imports in a comment letter to ARB prior to ARB's adoption of the regulatory amendments), *with* Cullenward & Weiskopf, *supra* note 50, at 23-24 (evaluating the same safe harbor exemptions in July 2013, prior to the formal regulatory amendments).

57. *See generally* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52.

58. *See generally* CAL. AIR RES. BD., AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS: FINAL STATEMENT OF REASONS 227-328 (2014) [hereinafter FINAL STATEMENT OF REASONS] (responding to public comments on the resource shuffling amendments during the 45-day notice-and-comment period); *id.* at 784-860 (responding to public comments on the resource shuffling amendments during the 15-day notice-and-comment period).

59. *See id.* at 1049-52 (responding to public comments on the environmental assessment conducted under the California Environmental Quality Act and concluding that no further analysis is required).

are, in my view, a violation of the statutory requirement to "minimize leakage" "to the extent feasible."[60] ARB should not have adopted such a permissive approach to resource shuffling. In fact, ARB need not have modified the original prohibition on resource shuffling at all.

While the original prohibition was admittedly inflexible and could have been improved, ARB should have adopted one of at least two alternatives that would have avoided leakage. First, ARB could have relaxed its rules while requiring companies whose transactions cause leakage to continue to be responsible for the emissions that would have otherwise left the system, pricing these emissions at the market rate.[61] This solution would have increased the market's administrative complexity, but it would have imposed the costs of controlling leakage directly on the parties responsible for leakage. Second, ARB could have relaxed its resource shuffling rules and observed the leakage that results, subsequently tightening the overall carbon market cap to account for that leakage. While a much simpler solution to implement, this path would have required a separate and politically fraught administrative process. It would have also socialized the costs of leakage across all market participants, rather than putting the costs directly on parties causing leakage.[62]

As these options demonstrate, ARB had feasible alternatives to accomplish its policy objectives without causing significant leakage—including the option not to amend the regulations in the first place. Thus, the safe harbor reforms adopted in April

60. CAL. HEALTH & SAFETY CODE §§ 38562(b)(8) (West 2007).

61. For a fully developed regulatory text implementing this approach, *see* Cullenward & Weiskopf, *supra* note 50, at 35-37, 39-43 (describing this approach as a "reverse offset").

62. EMAC economist James Bushnell first suggested this option to me. Note that under this policy approach, electric utilities would still be allowed to shift emissions liability to other states. Although the regulator would simultaneously tighten the cap to reflect this transfer, the distributional consequences of these decisions would be significant. Utilities (and their customers) would avoid the direct cost of compliance, which would fall diffusely on the market as a whole through a tighter cap that is binding on all regulated parties. In contrast, if utilities (and their customers) were to retain the liability for emissions that were allowed to leak out of the market, the costs would fall on those parties who cause the leakage, not diffusely across all market participants.

2014 are inconsistent with the statutory requirement that ARB minimize leakage to the extent feasible.

In addition to contradicting its enabling statute, ARB declined to evaluate the environmental impacts of its safe harbor approach, raising concerns about the inadequacy of its analysis for the purposes of the California Environmental Quality Act ("CEQA").[63] ARB claimed that it was not making any significant changes to its regulations and therefore could rely on a 2010 environmental assessment document.[64] Ironically, however, the 2010 environmental review was conducted in the rulemaking process that led to the simple and effective prohibition on resource shuffling that ARB's most recent reform has effectively gutted. ARB's reliance on this older document is therefore seriously inadequate.[65]

Beyond the environmental and legal consequences of California's domestic reforms, it is useful to consider the market impacts. By allowing regulated parties to divest their high-carbon imports, resource shuffling relieves regulated parties of the obligation to surrender emissions permits. Thus, resource shuffling decreases overall demand in the carbon market. Because the maximum potential for resource shuffling is comparable to the size of the entire carbon market, the impacts on prices should be significant. Whether private actors in the energy markets fully exploit this strategy remains to be seen; however, at this point no legal barrier exists to prevent them from doing so. Even in the short term, downward pressure on carbon market prices from re-

63. *See* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 8-10 (noting that California's environmental review of the 2013-14 amendments merely referenced an assessment conducted in 2010 during the rulemaking that led to the simple prohibition against resource shuffling, without accounting for the fact that ARB was creating major exemptions to this once-strong prohibition).

64. *See* FINAL STATEMENT OF REASONS, *supra* note 58, at 1050-52 ("Because the impacts of the proposed amendments fall within the scope and scale of those already analyzed in the 2010 [environmental review document], and the amendments do not result in any additional or more severe impacts than previously analyzed in the prior certified environmental documents, the EA concluded that no additional alternatives analysis for the amendments was required.").

65. *See* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 8-10 (criticizing ARB's environmental analysis for the purposes of CEQA).

source shuffling—due to at least three significant coal-fired power plant contract divestments—is likely to have contributed to the current market conditions.[66] California carbon prices have generally stayed between approximately $13 and $20 per metric ton of CO_2 over the short history of the market.[67] Beginning in July 2013, and coincident with ARB's proposed regulations implementing its safe harbor policy, the market price fell steadily towards the minimum price floor. Over the following six months, three major coal-fired power plant contract divestments caused tens of millions of tons of CO_2 to leak out of the market, with the market price stabilizing at just above the minimum market price floor.[68] These observations are consistent with the theory that the safe harbors have enabled and will continue to enable significant leakage out of California's market.

The impact on the long-term financial stability of the carbon market is even more worrisome. State law clearly directed ARB to minimize leakage. Regardless of whether ARB's resource shuffling amendments run afoul of this standard as a matter of state administrative law (or evaded the necessary environmental review under CEQA), there is little question that the safe harbor policy is a significant reversal of a core market design parameter. As explained above, the extent to which regulated entities in the electricity sector can rely on resource shuffling to divest their legal high-carbon imports has major implications on the demand for compliance instruments and thus the prevailing market price. In turn, ARB's reforms call into question the fundamental effectiveness of California's carbon market as a policy instrument. If the market regulator cannot—or will not—commit to

66. *See generally* Cullenward, *Leakage in California's Carbon Market*, *supra* note 55 (reviewing the leakage impacts from coal contract divestments enabled by ARB's reforms).

67. *See id.* at fig. 4 (presenting secondary trading data for California Carbon Allowances, the tradable emissions permits in the California market); *see also* CAL. CARBON DASHBOARD, *available at* http://calcarbondash.org/ (last visited July 7, 2014) (providing data and visualizations describing trading activity in California's carbon market).

68. *See* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 55, at fig. 4. Note that the price floor establishes a minimum price, below which ARB will not sell emissions permits at its quarterly auctions. *See* CAL. CODE REGS. tit. 17, §§ 95911(b)-(c) (2014).

market rules that produce moderately high carbon prices, will private actors treat the market price as a credible signal of California's long-term climate policy goals?[69] Once a regulator manipulates its rules to artificially reduce the carbon price—by sacrificing the environmental integrity of the market—it seems highly unlikely that investors will risk capital on the basis of a market price that is subject to political intervention. In particular, private investors are unlikely to use the carbon market price to justify investment in new energy infrastructure projects like renewable power plants and transmission lines, for which the economics must be sound over a period of decades, not months. Thus, ARB's market reforms undermine the credibility of its plan to use carbon markets to affect long-term energy investment decisions in California.

IV.
CALIFORNIA'S RESPONSIBILITIES UNDER THE BILATERAL AGREEMENT

In addition to looking at the impacts of this regulatory change from a domestic legal perspective, one can also evaluate it as an example of the challenges associated with operating a linked carbon market according to the principles articulated in intergovernmental agreements. Recognizing the need to harmonize their regulations and codify a set of best practices for the joint operation of the linked market, California and Québec signed the Bilateral Agreement in September 2013.[70] This document states that the two governments have a shared objective to "work jointly and collaboratively toward the harmonization and integration of . . . [their respective] cap-and-trade programs."[71]

To help the parties achieve this goal, the Bilateral Agreement sets out several substantive and procedural standards each government commits to follow. The most relevant passage is found in Article 4, which discusses each government's responsibilities

69. California has an aspirational target of reducing its greenhouse gas emissions 80% below 1990 levels by the year 2050. *See* Arnold Schwarzenegger, *Executive Order #S-03-05*, CAL. OFFICE OF GOVERNOR (June 1, 2005), *available at* http://www.climatechange.ca.gov/state/executive_orders.html.

70. Bilateral Agreement, *supra* note 14.

71. *Id.* at Art. 1.

when reforming its internal market regulations:

> Either Party, or the Parties together, may consider making changes to their respective program . . . To support the objective of harmonization and integration of the programs, any proposed changes or additions to those programs shall be discussed between the Parties. The Parties acknowledge that sufficient time is required to enable effective public review and comment prior to adoption. The Parties shall consult regarding changes that may affect the harmonization and integration process or have other impacts on either Party. Each Party's public process for making program changes must be respected.[72]

Under this provision, each signatory retains the authority to amend its own regulations according to the applicable domestic administrative law requirements (*e.g.*, public notice and comment) that apply.[73] The critical requirement in Article 4, however, is not a repetition of each party's domestic legal standards; rather, it is the inclusion of a new obligation for both governments: mandatory discussion between the parties of any proposed domestic regulatory changes. Therefore, Article 4 raises two interesting questions about the simultaneous administrative processes that were underway in California during the development of the Bilateral Agreement. First, did ARB understand the leakage impacts of its safe harbor reforms on the prohibition on resource shuffling? (Recall that in the state administrative record, ARB disputes the claims that its reforms degrade the prohibition on resource shuffling and would cause significant leakage.[74] Nevertheless, as I argued in Section III-A, ARB had credible evidence to the contrary.) Second, did ARB and the Québécois government discuss the significant leakage implications of California's internal reforms?

While the answer to these questions is not publicly known at this time, there are four possible outcomes (see Table 1).[75]

72. *Id.* at Art. 4.

73. *Id.* at Art. 3 ("The procedural requirements of each Party shall be respected, including appropriate and effective openness and transparency of each Party's public consultations.").

74. *See* sources cited *supra* notes 58-59.

75. This analysis is premised on the argument that the safe harbor reforms

TABLE 1: POSSIBLE OUTCOMES

		Bilateral discussion of leakage?	
		Yes	No
Did ARB expect leakage?	Yes	Coordinated[76] violation of California administrative law	Unilateral violation of Bilateral Agreement, Art. 4
	No	Mutual failure to anticipate major market impact	Unilateral failure to anticipate major market impact

First, if ARB understood the leakage impacts of its reforms and shared this information with its Québécois partners, then the state administrative record does not reflect the agency's understanding of its own actions, which were taken in coordination with a foreign government. This would raise additional concerns about the legality of its reforms under state law.[77] Second, if ARB understood the leakage impacts but did not share this information with the Québécois, this would likely violate Article 4 of the Bilateral Agreement. Enabling leakage risks at approximately the scale of the entire market almost certainly rises to the level of "changes that may affect the harmonization and integration process or have other impacts on either Party," which

enable and have caused resource shuffling, and therefore leakage, as discussed in Section III. *See also* Cullenward, supra 55 (documenting leakage from resource shuffling transactions).

76. In calling the violation coordinated, I am not implying that the Government of Québec had any obligation to evaluate the restrictions California law places on ARB, nor to object to any potential violation. Rather, the point is that the two governments were coordinated in their understanding of the market transformation ARB initiated.

77. The Bilateral Agreement also requires parties to uphold the integrity of their domestic public regulatory processes, but presumably this requirement is of a lesser importance compared to any related violations of state law. *See* Bilateral Agreement, *supra* note 14, at Art. 4. I am not aware of any statutory or case law that addresses whether a state government can conduct foreign affairs in a way that contradicts its own description of those affairs in a formal administrative process, but the kinds of deferential standards applied to the foreign affairs of the federal government, under Article II of the United States Constitution, would not apply here.

require discussion between the two governments.[78] Third, if ARB did not expect leakage and discussed its erroneous findings with the Québécois, who ultimately took the same view as ARB, then both governments failed to anticipate a major market impact. Finally, if ARB did not expect leakage and therefore did not discuss the matter with Québécois policymakers, then the California government unilaterally failed to anticipate the impact of a domestic regulatory change that arguably required mutual discussion.[79] Fundamentally, none of these outcomes demonstrates a successful link between complex carbon markets.

V.
LINK UNTO OTHERS: A THOUGHT EXPERIMENT

The previous two sections evaluate California's resource shuffling reforms from the perspectives of California law and the mutual requirements codified in its Bilateral Agreement with Québec. This section asks whether the protections California law imposes on ARB to evaluate prospective linking partners would have identified the appropriate risks if California were preparing to link with a jurisdiction that was amending its regulations to enable significant leakage. Using this framework, I consider whether California state law—which places both substantive and procedural restrictions on ARB's ability to link with other markets—would prohibit ARB from linking with that jurisdiction. I reach three related conclusions: first, that California's review process is unlikely to identify the relevant leakage risks, and therefore is prone to dangerous links; second, that the analytical needs in this process are highly technical, and therefore not suited to review by lawyers alone; and third, that a single review is insufficient to ensure the integrity of a dynamic and ongoing financial market.[80]

78. *Id.*; *see also* California Air Resources Board, supra note 40 at 14 (claiming that ARB staff discussed California's 2013 market reforms "in detail" with their Québécois counterparts, referring to the internal regulatory changes that included the safe harbor approach to resource shuffling).

79. Hence, there is no fourth option: ARB could not have entered into bilateral discussions with Québec about the leakage impacts of its reforms if ARB earnestly did not expect any leakage to result.

80. To be clear, I am not suggesting here that there was anything improper

I begin with the relevant statutory framework. As reviewed previously in Section II.A, California law requires the governor to make four independent and affirmative findings prior to linking the state carbon market with other jurisdictions.[81] The California Legislature requires the governor to act in "his or her independent capacity," after receiving similarly independent legal advice from the Office of the Attorney General (OAG), in order to establish "new oversight and transparency" over any prospective market links.[82] Two of the required findings are not relevant to this example,[83] while two speak directly to the question of maintaining the integrity of linked market systems:

> (1) The jurisdiction with which the state agency proposes to link has adopted program requirements for greenhouse gas reductions, including, but not limited to, requirements for offsets, that are equivalent to or stricter than those required by [California's climate laws].
>
> . . .
>
> (3) The proposed linkage provides for enforcement of applicable laws by the state agency or by the linking jurisdiction of program requirements that are equivalent to or stricter than those required by [California's climate laws].[84]

I refer to these requirements as the "stringency" and "enforceability" findings, respectively.[85]

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with regard to the link with Québec. Rather, my goal is to illustrate how the type of analysis conducted with respect to the link with Québec would likely fail to anticipate the kinds of risks Québec actually faced when linking with California. This is a generic risk that faces any carbon market regulator that seeks to impose high standards on its own market but wishes also to link with others.

81. CAL. GOV'T CODE § 12894(f) (West 2013).

82. *Id.* (requiring independent action from the Governor); *id.* at § 12894(a)(1) (requiring the attorney general to review any proposed link for consistency with all applicable laws); *id.* at § 12894(a)(2) (declaring that the purpose of these requirements is to establish oversight and assure transparency).

83. *Id.* at § 12894(f)(2) (requiring that the State of California be able to enforce its carbon market laws against regulated entities in both jurisdictions, to the maximum extent permissible under the state and federal constitutions); *id.* at § 12894(f)(4) (requiring that the link not expose the State of California to any significant liabilities if the link were to fail).

84. *Id.* at §§ 12894(f)(1), (3).

85. That the stringency standard sets a generic goal ("equivalent to or stricter than") and specifically references only one technical area (carbon offsets)

For the purposes of illustration, let us assume that ARB wishes to link its carbon market with that of State X, a hypothetical jurisdiction that shares both the common WCI carbon market design framework and California's overall environmental target of returning to 1990 emissions levels by the year 2020. State X has a similar history of legacy coal power imports and has recently amended its treatment of imported power exactly as California has done in reality. Assume further that California has retained a strict and unmodified prohibition on resource shuffling, which ARB views as essential to keeping the environmental integrity of the program intact.[86] Regardless of whether ARB failed to appreciate the impact of the leakage reforms in State X, was misled by State X policymakers, or wished to pursue the link despite the leakage risks it either identified independently or in consultation with State X, the agency has concluded that the prospective link meets California's legal standards. As a result, ARB notifies the governor's office that it intends to link with State X's carbon market. If the process unfolds as it did with respect to the link with Québec, will additional review identify the leakage risks that the agency missed in its initial assessment?

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raises some interesting questions about the backward-looking nature of carbon market institutions. The problematic experience with carbon offsets under the Clean Development Mechanism ("CDM") led to significant controversy among experts, policymakers, and civil society. Indeed, a significant quantity of these problematic instruments has been used to satisfy compliance with the European Union's Emissions Trading System, though regulators there have restricted this option for the post-2020 trading period. *See* Cullenward & Wara, *supra* note 2, at 1460. It is commendable that emissions trading systems established after the controversy over CDM offsets have paid more attention to the environmental integrity of these instruments. But in attempting to prevent the problems of the past, California policymakers did not fully anticipate the challenges they faced as a jurisdiction that is the only state in a regional electricity transmission grid to price greenhouse gas emissions. *See id.* One wonders whether the next generation of sub-national markets will instruct agencies to monitor both offsets and resource shuffling.

86. The example still holds if California had adopted a flexible approach to resource shuffling that contained the leakage impacts of resource shuffling. *See* discussion *supra* note 62.

A. *The Review Process*

Formally, the independent review process begins with the OAG's consideration of the proposed link. In practical terms, however, it is important to note that the OAG lacks in-house technical expertise on the design and operation of carbon markets; lawyers in the OAG will actually be reviewing the technical material ARB provides concerning the proposed link with State X. This will include a report from ARB summarizing its case for the four findings it needs the governor to make,[87] informed by a public notice-and-comment process about the prospective link.[88] Should the OAG find no problems in the administrative record or in ARB's summary thereof, the governor will next make an independent assessment of the issues. Accordingly, in discussing this hypothetical example, I begin with ARB's assessment of the situation and then discuss the OAG review. For simplicity, I assume that the governor will issue the necessary findings if there are no significant concerns expressed by either ARB or the OAG. In reality, the governor's role offers one final opportunity to revisit disputed issues.

1. The Stringency Requirement

In order to assess how the review process would apply the stringency requirement to State X, I begin with ARB's analysis of the prospective link with Québec. There, ARB evaluated the stringency requirement by looking at three aspects of its prospective partner's market. First, ARB compared the legally binding targets for greenhouse gas emissions. Second, ARB evaluated the role of the cap-and-trade program in meeting the overall emissions target. Finally, ARB discussed the rules and regula-

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87. *See generally* DISCUSSION OF SECTION 12894 REQUIRED FINDINGS, *supra* note 33.

88. *See generally* CAL. AIR RES. BD., PROPOSED LINKAGE OF CALIFORNIA'S CAP-AND-TRADE PROGRAM WITH THE CANADIAN PROVINCE OF QUÉBEC'S CAP-AND-TRADE PROGRAM: GENERAL SUMMARY OF COMMENTS AND PRELIMINARY AGENCY RESPONSES (2013), *available at* http://www.arb.ca.gov /cc/capandtrade /linkage/summary-comments-prelim-response.pdf (issued February 21, 2013).

tions of its prospective linking partner, comparing these provisions with their parallel requirements in the California market.[89] I discuss each finding below in the context of the link with Québec and generalize a rule that might be applied to a prospective link with State X.

First, ARB concluded that the emissions reduction goal in Québec is equivalent to, or stricter than, that of California law. Specifically, Québec has set a goal of reducing emissions to 20% below its 1990 levels by the year 2020; in contrast, California law requires only that its emissions reach 1990 levels by the year 2020.[90] Thus, the comparison is made on the basis of a headline program target. Because State X shares the same target as California, it will satisfy this criterion.

Second, ARB concluded that Québec gives its carbon market a comparable role in meeting its overall emissions reduction target. Perhaps because this particular issue is relatively inconsequential, ARB did not explore the reasoning in great depth, but rather cited the common history and standard market design resulting from participation in the WCI.[91] Thus, participation in the WCI should be sufficient in the future. Because State X also participated in the WCI, it will satisfy this criterion.

Third, ARB provided a detailed comparison of the major market design provisions in California and Québec. This included parallel citations to each market's regulations on issues including verified emissions reporting, greenhouse gases regulated in the market, government control of the total number of allowances, regulated entities' use of compliance instruments, and the use of carbon offsets from outside each market's jurisdiction.[92] No generally applicable rule can be made here, as ARB's evaluation of Québec rests on technically complex details in both programs' respective regulations. Thus, whether State X will meet this standard cannot be anticipated in advance.

Despite this ambiguity, it is worth noting that, while the com-

89. *See* DISCUSSION OF SECTION 12894 REQUIRED FINDINGS, *supra* note 33, at 3-8.

90. *Id.* at 3.

91. *Id.* at 4.

92. *See id.* at 4-8.

parisons ARB made in the case of Québec include parallel citations to the relevant regulations, none of the issues—with the single exception of carbon offsets—receives more than a few sentences' worth of analysis. ARB's report is also silent on leakage and resource shuffling concerns. Presumably this reflects the significantly lower risks of resource shuffling in Québec, which obtains most of its electricity supplies from clean hydropower. As a result, one cannot anticipate how ARB would view leakage risks in the context of a prospective linking partner—or whether this issue is a priority for agency leaders at all. Even if its failure to address this issue was justified in this case, however, ARB's formalist approach to analyzing the risks associated with linking markets raises some important concerns. Carbon markets are financial markets, not traditional regulatory structures. By design, they are decentralized instruments. Failing to provide significant economic analysis of a prospective link at this stage is a major oversight, since both the OAG and governor's office are unlikely to have the ability or capacity to do any such work independently.

In its review of ARB's findings with respect to the link with Québec, the OAG provided little additional analysis. (Again, there is little a talented lawyer can add in the absence of deep technical experience with carbon market design and operation, nor is any reason to believe that Québec's market is less strict than California's.) The OAG agreed that ARB's report offered a "well considered and well supported comparison" of the Californian and Québécois markets.[93] But while the OAG expressed general agreement with ARB's findings, it did not simply defer to the agency. It conducted an independent review of the in-state administrative record, concluding that it was "not aware of any facts asserted or arguments made in public comments in response to the proposed ARB linking regulations that provide a basis for finding in the negative on any of the four required stat-

93. Letter from Christopher S Crook to Cliff Rechtschaffen, *supra* note 34, at 3. One minor exception was to note minor differences in the way the two programs handled invalidated carbon offsets, but ultimately the OAG rightly concluded that both programs were comparable in this respect. *Id.*

utory findings."[94]

Thus, should members of the public submit credible comments in ARB's administrative process concerning leakage in State X's program, the OAG review might exert additional pressure to investigate these claims in more detail before issuing positive findings, either at the agency level or in the formal OAG review process. This potentially provides an additional layer of protection, but only to the extent that the OAG can highlight areas where experts disagree. Fundamentally, the OAG is unlikely to be prepared to adjudicate these disputes in its review. Therefore, ARB is likely to have additional leeway to pursue a link that might, when viewed in a more neutral light, raise legitimate questions about the integrity of a prospective partner jurisdiction.

To recap how California would address the stringency requirement in the future, ARB is likely to continue to wield significant influence in the decision-making process over a prospective link with State X. Despite the involvement of other government offices, ARB is the only entity with the technical expertise necessary to address complex market issues like leakage. If lawyers at the OAG thoroughly review the administrative record, they are likely to uncover any major points of disagreement between agency staff and public stakeholders. But the OAG's ability to independently evaluate any disputes is limited due to the relative lack of technical expertise available within the OAG and reliance on public stakeholders to communicate their concerns about State X's regulatory shortcomings in ARB's administrative proceedings. This suggests that in the future, if ARB wants to link with State X and downplays the associated leakage risks, the opportunity for other parts of the state government to reach and express a different conclusion will be limited.

2. The Enforceability Requirement

As with the stringency requirement, I begin with ARB's analysis of the link with Québec to anticipate how it would view the link with State X. There, ARB reviewed the Québécois government's authority to impose penalties and the environmental reg-

94. *Id.* at 7.

ulator's option to refer specific instances of abuse for prosecution.[95] Citing the generally higher penalties and expansive options for injunctive relief in Québec, ARB concluded that its Canadian counterparts enjoy "superior" enforcement powers.[96] The OAG agreed that both systems have adequate enforcement powers, finding that both regulatory structures "contain provisions dealing with fraudulent and manipulative conduct."[97] Thus, both ARB and the OAG found that the enforceability requirement was readily satisfied.

Nevertheless, it is notable that both reports were limited to looking at basic enforcement powers and options for relief. No analysis was provided as to whether the foreign jurisdiction's existing powers could, in practice, be used to deter or penalize a market actor who appears to violate one of the core market rules. This distinction is critical in the case of California's resource shuffling amendments. Even after ARB adopted its safe harbor policy, it left in place the prohibition against resource shuffling.[98] But ARB modified the definition of resource shuffling to exclude a series of previously impermissible activities.[99] In turn, those exemptions are so broad that nearly any transaction could, with the proper legal advice, be structured to fit within them.[100]

As a result, there are two ways to look at ARB's final approach to resource shuffling. Formally, ARB maintains that it has a firm and enforceable prohibition against resource shuffling. Functionally, however, the safe harbors were structured to provide extremely generous and loosely worded exemptions, with several offering near-blanket permission to engage in activities that would otherwise be considered resource shuffling under the un-

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95. *See* DISCUSSION OF SECTION 12894 REQUIRED FINDINGS, *supra* note 33, at 9-11.

96. *Id.* at 10.

97. Letter from Christopher S Crook to Cliff Rechtschaffen, *supra* note 34, at 5.

98. *See* CAL. CODE REGS. tit. 17, § 95852(b)(2) (2014).

99. *See* CAL. CODE REGS. tit. 17, § 95802(a)(338).

100. See CAL. CODE REGS. tit. 17, § 95852(b)(2)(A). For explicit criticisms of the structure and breadth of the safe harbor exemptions, *see* Letter from Danny Cullenward to Cal. Air Res. Bd., *supra* note 52, at 3-5; Cullenward & Weiskopf, *supra* note 50, at 21-26.

modified definition of that activity. Thus, once State X had adopted a similar approach to resource shuffling, ARB and the OAG might be prone to mistake the apparent prohibitions as a strong enforcement policy if they adopt a formalist approach to the review. Only by analyzing the structure of these specific regulations in significant detail could an outsider appreciate their practical function.[101] Yet to go beyond a formal review requires deep technical expertise that the OAG is unlikely to have on staff.

Thus, future application of the enforceability standard is likely to focus on questions of jurisdiction and regulatory authority. To be fair, this is an area where independent review from the OAG draws on a core area of that office's expertise, suggesting that the state review process will deliver additional safeguards in this instance. Nevertheless, the practical operation of a linked market will have as much to do with the enforcement culture and actual practices in State X as it will the written statutes and regulations.

B. *Administrative Law to the Rescue?*

California law requires that ARB, the OAG, and the governor each make four independent findings that support linking the state carbon market with a new jurisdiction. Without suggesting that any of these findings were inappropriate in the case of the link with Québec, I argue that the analysis conducted for that process would have been unlikely to anticipate technically complex concerns like resource shuffling.

In theory, California's linking process provides additional checks and balances on ARB's authority to link with other jurisdictions' markets. But in practice, only ARB has the technical capacity to evaluate the full spectrum of risks in sufficient detail. In the hypothetical scenario where California considers a link to a jurisdiction with weaker leakage provisions, ARB might very

101. Again, I am not suggesting ARB or the OAG failed to do this with respect to Québec. The point is that we know there are market implementation problems, like leakage and resource shuffling, that are unlikely to be properly identified with even the most thorough formalist analysis of the legal provisions in each system.

well be more concerned with these issues and therefore more receptive to expert advice and public comments on these points. That receptivity would only be increased if the legal requirements for linking explicitly mandated an examination of leakage, raising the threat of resource shuffling (and other types of leakage) to the level of scrutiny carbon offset standards currently enjoy. But better linking standards are of limited use. If ARB fails to identify the leakage problem in State X, it is unlikely that others in the process will do a better job, due to the technical complexity involved. Similarly, if ARB wishes to underemphasize those risks in order to pursue other goals—like working with politically important partner jurisdictions or increasing the prominence of the agency's role in national or global climate policy—then there is little hope that others involved in the administrative process will have the necessary expertise to independently address these concerns.

For the same reasons, independent legal review from the OAG, although somewhat helpful, is unlikely to uncover issues not already raised in the administrative process. If the OAG takes responsibility for reviewing the public comments and agency responses in the administrative linking process, this could provide a modest procedural safeguard. Knowing that the OAG would flag any significant public comments for review might encourage ARB to address them more seriously. On the other hand, if there were any unresolved issues in the administrative record, it is not clear the OAG would be in the best position to evaluate whether the technical claims have any merit—particularly because any agency faced with public opposition to its preferred course of action would be careful to dispute these allegations in detail. Moreover, these kinds of concerns would only arise in the OAG review if they were articulated in ARB's administrative record in the first place. Thus, to the extent this procedural safeguard is helpful, it relies on the public notice-and-comment process in California to identify practical concerns about the function of State X's market operations. But this seems somewhat speculative. I have argued in this article that the administrative process was insufficient to identify and publicly discuss the leakage implications of a purely domestic regulatory reform. As a result, I am even more skeptical that the same process can effectively be used to monitor the performance of outside jurisdictions.

Finally, it bears repeating that the legal process in California for reviewing prospective linking partners is a one-time affair. In this sense, it resembles due diligence in contractual negotiations. Done well, it is an important pre-requisite for establishing a collaborative partnership. But even the most careful initial review is no substitute for the development of clear standards for the mutual operation of linked markets, which must remain subject to public participation, transparent oversight, and the rule of law.[102]

VI.
CONCLUSIONS

Rather than demonstrate a successful model for sub-national climate policy harmonization, the link between carbon markets in California and Québec exemplifies the difficult legal and institutional challenges facing implementation of complex policy regimes. In my view, California's domestic carbon market reforms do not minimize leakage, directly contradicting an important statutory requirement. That ARB concluded otherwise, despite the well-documented opinion of its expert economic advisers to the contrary, raises questions about the ability of public interest stakeholders to use the notice-and-comment process to sustain the integrity of carbon markets.

In turn, California's regulatory shortcomings are all the more pressing in light of the simultaneous regulatory processes that produced the link with Québec. Under the Bilateral Agreement signed by the two governments, California must discuss the expected impacts of its domestic reforms with regulators in Québec. But if ARB properly disclosed the leakage implications of its

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102. *See generally* Danny Cullenward, *How California's Carbon Market Actually Works*, 70 BULL. OF ATOMIC SCIENTISTS 35 (2014), *available at* http://thebulletin.org/2014/september/how-californias-carbon-market-actually-works7589 (criticizing the California Air Resources Board for enacting its resource shuffling safe harbor reforms without seriously addressing the leakage risks documented in its administrative record, despite procedural and substantive legal standards that required a more significant analysis).

safe harbor policy on resource shuffling to its Canadian colleagues, this would demonstrate that its position in its own administrative record was less than truthful. Presumably ARB would not withhold critical information from its market partners. However, if ARB did not disclose any risks because it did not appreciate the leakage implications of its actions, this would illustrate the failure of market regulators to anticipate a well-publicized issue that speaks directly to the integrity of carbon markets as climate policy instruments.

California's experience also offers a cautionary lesson about its ability to avoid similar problems in future market links. When state policymakers apply their own strict standards for evaluating prospective links with other jurisdictions, it is not clear that they will be able to anticipate the kinds of leakage risks that followed Québec's decision to link with California. While California law provides some important safeguards prior to affecting a link, those safeguards rely primarily on oversight from lawyers and politicians, not environmental economists. Independent legal review may very well highlight technical disputes in state administrative records for further review, but the lawyers tasked with the review are not particularly well equipped to anticipate counterproductive economic outcomes. Requiring that the review process explicitly address leakage and resource shuffling would help avoid these problems in the future; yet if carbon markets are going to work, they must be able to anticipate new challenges, not merely avoid known pitfalls.

More generally, avoiding problems like leakage and resource shuffling requires ongoing review and oversight, not a single episode of administrative due diligence. Thus, a jurisdiction that cares about controlling leakage—a prerequisite for producing real benefits for the global climate—must go beyond a formal analysis of its prospective linking partner's laws by regularly reviewing regulators' informal guidance documents, formal regulations, and enforcement regimes as they are implemented in practice. Simply relying on the existence of official prohibitions against undesirable market behavior is no guarantee of an effective financial market.

Collectively, these problems suggest that linking sub-national carbon markets will be much harder than most proponents of this strategy suggest. With every link, the administrative complexity of the system increases; as the complexity increases, so too does the burden of effective regulatory oversight. Even in the simple case of two markets with a common design and shared history, significant challenges remain. Expanding this system to include more linked partners will only increase the risks of unintended consequences—which, due to the mutual recognition of compliance instruments, would propagate throughout the entire linked market.

RETHINKING THE GEOGRAPHY OF LOCAL CLIMATE ACTION: MULTILEVEL NETWORK PARTICIPATION IN METROPOLITAN REGIONS

Hari M. Osofsky*

Abstract

As the United States and the world become increasingly urbanized, cities are a key site for addressing the problem of climate change. However, urban climate change action is not simply about local officials making decisions within their cities. In major U.S. urban areas, "local" involves multiple layers of government, including county and metro-regional entities. Moreover, many of the cities taking action on climate change also participate in and shape networks of local governments based at state, regional, national, and international levels.

This Article argues that multilevel climate change networks could be more effective by embracing this geography of local action and the pressing need to foster action by suburban cities. Most emissions take

 Professor, University of Minnesota Law School; 2014-15 Julius E. Davis Chair in Law; Faculty Director, Energy Transition Lab; Director, Joint Degree Program in Law, Science & Technology; Faculty Member, Conservation Biology Graduate Program; Adjunct Professor, Department of Geography, Environment and Society; and Fellow, Institute on the Environment. Research for this project has received invaluable funding from the University of Minnesota Center for Urban and Regional Affairs through the 2013–2014 Fesler-Lampert Chair in Urban and Regional Affairs and from the University of Minnesota Law School's summer research support. I am grateful to Myron Orfield for allowing me to reproduce his maps of Atlanta, Chicago, Denver, New York City, San Francisco, and the Twin Cities organized by city type. The maps in the print version of this Article are edited versions of his color maps and have been converted to greyscale. The PDF version of this Article uses his original color maps. This Article has been significantly improved by feedback during presentations at N.Y.U. School of Law, Washington University School of Law, University of Arizona College of Law, Florida State University College of Law; and the University of Minnesota, Department of Geography. I am particularly indebted to Professors Kirsten Engel, Carol Rose, and Katrina Wyman for their thoughtful feedback on the draft. Thomas Burman, Sarah Schenck, and Brandon Wheeler provided invaluable research assistance on climate networks and local participation in them; they also helped to develop the charts of network participation for the major cities and analyze patterns emerging from them. The Twin Cities chart in the accompanying appendix, which was updated by Joseph Dammel and Brandon Wheeler, was originally developed by research assistant Kenzie Johnson. The Law Library at the University of Minnesota Law School, and particularly Suzanne Thorpe, was extremely helpful, especially in locating interdisciplinary sources on suburbs and climate change. I also appreciate the thoughtful editorial work of the *Utah Law Review*, particularly Mitch Longson, Gregory Gunn, Ashley Walker, and Elise Walker. As always, I am grateful for the love, support, and patience of Josh, Oz, and Scarlet Gitelson.

place in the suburban areas of metro regions, but these networks generally do not focus on the particular needs of different types of suburban cities. This Article provides a novel analysis of patterns of participation in climate change networks by cities in six major U.S. metropolitan regions—Atlanta, Chicago, Denver, New York, San Francisco, and the Twin Cities—as a basis for proposing practical strategies and areas for future research. It considers what types of cities participate in which networks and where stronger and weaker network interlinkages occur. The Article concludes that networks inadequately (1) differentiate by city and metro-regional type and (2) coordinate resources and strategies. It suggests ways in which networks could do so to maximize the number of cities participating in them and the participation level of those cities.

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I. INTRODUCTION

Urban action is critical to addressing climate change. Over half the world's population and more than 82% of the U.S. population lives in cities.[1] Cities and their power plants are the largest human-created sources of greenhouse gas emissions, producing at least 70% of the world's fossil fuel carbon dioxide emissions.[2] No effective strategy for controlling emissions or adapting to impacts can ignore such a substantial part of the population. Many important climate change policy decisions are made at a local level as part of urban land use planning.

However, what the local level means can be complex in the urban context. Major center cities that lead the charge on climate change are part of metropolitan regions in which action on climate change is quite varied. For example, in the Twin Cities, the center cities of Minneapolis and St. Paul contain less than a quarter of the metropolitan region's population of almost three million people.[3] An effective local strategy for addressing climate change depends not only on those center cities taking action, but also smaller suburban ones doing so as well, ideally in a manner coordinated at county and metro-regional local scales.

This need for local action and its complexity has not been lost on mayors, city and county officials, and members of metropolitan regional councils. As international climate change negotiations continue to fail to solve this problem, a growing number of cities around the world play increasingly critical roles in multilevel efforts to address climate change. They influence the language in the climate change treaty negotiations, form their own transnational agreements, and use their local governmental power to make commitments that often exceed those of their nation-states. Multilevel networks—at local, state, regional, national, and international levels—help to foster local action. These networks provide models and frameworks for cities to use in developing their policies and opportunities for local climate change leaders to connect with one another.[4]

But such networks face limitations that constrain their impacts. First, not enough cities participate in them, especially in the suburbs. For example, the 1,060

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[1] *See* U.S. Cent. Intelligence Agency, *Urbanization*, THE WORLD FACTBOOK, https://www.cia.gov/library/publications/the-world-factbook/fields/2212.html, *archived at* http://perma.cc/YE39-T87R (last visited Oct. 5, 2014).

[2] *Megacities Carbon Project, Why Are Cities Important?*, CAL. INST. OF TECH. NASA JET PROPULSION LAB., https://megacities.jpl.nasa.gov/portal/page/motivation/cities-matter, *archived at* http://perma.cc/TX86-HE57 (last visited Feb. 15, 2015).

[3] In 2013, the Twin Cities Metropolitan Region had a population of 2,951,000; Minneapolis had a population of 401,000, and St. Paul had a population of 296,500. The population of Minneapolis and St. Paul together was therefore 23.6% of the overall metro region's population. Metro. Council, *Population Growth Across the Region: The Twin Cities in 2013*, METROSTATS (July 2014), http://metrocouncil.org/getattachment/b09e532c-ca54-4452-b913-34116bfec037/.aspx, *archived at* http://perma.cc/JTN2-WFH4.

[4] For examples of these networks and a discussion of their development, see *infra* Part II.

U.S. mayors that have joined the U.S. Mayors Climate Protection Agreement (Mayors Agreement) represent only about 5% of U.S. cities and 28% of the total U.S. population.[5] Second, the networks often have insufficient connection with one another. Many networks offer overlapping, but uncoordinated, resources that create inefficiencies for cities joining multiple networks. While the Mayors Agreement cities made parallel commitments in the Copenhagen City Climate Catalogue, this type of interlinking is rare. Even leader cities—which take early action on climate change and collaborate with other cities in doing so—will join some transnational local agreements, but not others, and participate unevenly in international, national, regional, and state networks.[6] Third, many networks differentiate among types of cities insufficiently. While some networks will highlight small versus large cities, they generally do not consider the diversity of cities within a metropolitan region or how to align climate change policies with cities' varying needs; center cities, stressed inner suburbs, affluent and developed job-center suburbs, and outer-ring and often rapidly growing developing job centers and bedroom communities vary in multiple ways that affect their mitigation and adaptation possibilities and trajectories.[7]

This Article provides a novel empirical analysis of multilevel climate network participation in six geographically diverse U.S. metro regions—Atlanta, Chicago, Denver, New York, San Francisco, and the Twin Cities—to consider how these networks could overcome such limitations.[8] Theoretically, the Article interweaves

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[5] As of October 24, 2013, 1,060 mayors, representing a total population of 88,962,982 citizens, had joined the Mayors Agreement. Mayors Climate Prot. Ctr., *List of Participating Mayors*, U.S. CONFERENCE OF MAYORS [hereinafter Mayors Climate Prot. Ctr., *List of Participating Mayors*], http://usmayors.org/climateprotection/list.asp, *archived at* http://perma.cc/WL5-FWPU (last visited Oct. 5, 2014). The U.S. Census Bureau estimated that the total U.S. population on that date was 316,911,323. U.S. Census Bureau, *U.S. and World Population Clock*, POPULATION CLOCK, http://www.census.gov/popclock/, *archived at* http://perma.cc/M97H-G526 (last visited Oct. 5, 2014) (under "The United States population on [date]" click "Select a Date" link and select "October 24, 2013").

[6] *See infra* Part III.

[7] *See* Hari M. Osofsky, *Suburban Climate Change Efforts: Possibilities for Small and Nimble Cities Participating in State, Regional, National, and International Networks*, 22 CORNELL J. L. & PUB. POL'Y 395, 439–40 (2012) [hereinafter Osofsky, *Suburban Climate Change Efforts*]; *see also infra* Part II.

[8] *See* Hari M. Osofsky, *Is Climate Change "International"? Litigation's Diagonal Regulatory Role*, 49 VA. J. INT'L L. 585 (2009); Hari M. Osofsky, Symposium, *Local Approaches to Transnational Corporate Responsibility: Mapping the Role of Subnational Climate Change Litigation*, 20 PAC. MCGEORGE GLOBAL BUS. & DEV. L.J. 143 (2007); Hari M. Osofsky, *Multiscalar Governance and Climate Change: Reflections on the Role of States and Cities at Copenhagen*, 25 MD. J. INT'L L. 64 (2010); Hari M. Osofsky, *Scaling "Local": The Implications of Greenhouse Gas Regulation in San Bernardino County*, 30 MICH. J. INT'L L. 689 (2009); Osofsky, *Suburban Climate Change Efforts*, *supra* note 7; Hari M. Osofsky & Janet Koven Levit, *The Scale of Networks?: Local Climate Change Coalitions*, 8 CHI. J. INT'L L. 409 (2008).

scholarship from law and geography to produce a model for understanding these networks' geographic and governance roles. The model draws particularly from the work of geographer Kevin Cox to argue that these networks not only help to construct the nature of climate change action at a local scale, but also are constructed by the localities that participate in them and the levels of governance at which they operate.[9] This complex geography allows them to affect mitigation and adaptation efforts at multiple scales: the local scale at which their members operate; the governance level at which they are constituted; and other scales, such as the global one, that they work to influence.

Practically, the Article considers how these networks could be more effective in encouraging additional local action on climate change. It provides an innovative assessment of what these networks do and of patterns of urban participation in them—by city type—in the six exemplar U.S. metropolitan regions. Using an approach that combines urban geography with network analysis, this Article outlines particular strategies for how networks could overcome the three limitations highlighted above by developing additional resources targeted at different types of cities and by increasing coordination and collaboration.

Part II serves as the conceptual core of the Article, providing a theory for understanding the multiscalar aspects of local climate action. Part III then considers the roles that multilevel climate change networks play in fostering local action through an examination of key networks at each level. Part IV analyzes local network participation in the Atlanta, Chicago, Denver, New York City, San Francisco, and Twin Cities metro regions. It considers patterns of participation both in terms of city type and cross-network interaction. Part V concludes by proposing strategies based on this analysis for networks to reach more cities and encourage more action in participating cities.

II. THE SCALE OF "LOCAL" CLIMATE CHANGE ACTION

This Part provides the conceptual framework for the Article by exploring what "local" is and how that should shape law and policy strategies on local climate change action. It focuses on the multiscalar character of local action to develop principles for addressing the participation gap more effectively. The Part brings together law with the discipline of geography, especially urban and critical geography, to provide a tool for understanding patterns of local behavior and how they might relate to cities' decisions on mitigation and adaptation.

In so doing, this Part builds upon the conceptual analysis of my prior article, *Suburban Climate Change Efforts: Possibilities for Small and Nimble Cities Participating in State, Regional, National, and International Networks*.[10] That paper

[9] *See* Kevin R. Cox, *Spaces of Dependence, Spaces of Engagement and the Politics of Scale, or: Looking for Local Politics*, 17 POL. GEOGRAPHY 1, 2 (1998) [hereinafter Cox, *Spaces of Dependence*].

[10] *See* Osofsky, *Suburban Climate Change Efforts, supra* note 7.

brought together scholarship on localities and climate change, metro-regional demography, international network theory, and polycentric/pluralist governance theory to explore how to encourage more suburban action on climate change.[11] It then applied this framework to twelve Twin Cities' suburbs in different demographic categories that were all taking some action on climate change.[12]

This Part adds to that analysis by showing how a deeper understanding of localities and the networks in which they participate can help to shape a geographically sensitive model for local climate action. It considers three dimensions of local geography: its multiple scales, its organization into metro regions, and the network dynamics that help constitute "local." The Part draws from these dimensions to propose principles for analyzing local climate action. The rest of the Article then applies this conceptual approach to data from cities in six major metropolitan regions to propose strategies for encouraging a greater number of cities to do more.

A. Why "Local" Action Is Not Just Local

With the vast majority of the U.S. population living in cities and such a low percentage of cities actively participating in climate change networks, more local action is clearly needed. Fostering local action, however, requires first understanding what "local" is.

Answering this question is complicated for two primary reasons. First, the category of local includes a diverse set of entities. Cities, counties, and metropolitan councils are all local government units, and the larger-scale of them have other local government units within them. Moreover, these local governments vary greatly in physical size, population, and demographic characteristics. Understanding how these local structures intersect and the particular needs of each type of entity and the people within it is critical to effective mitigation and adaptation planning.[13]

Second, local decisions are not made purely within that locality. Localities have to balance between their local autonomous control and the constraints that other levels put upon them. For example, the law varies from state to state on whether cities can mandate energy efficiency standards that exceed state ones. Local entities also participate in local, state, regional, national, and international networks—the subject of this Article—some of which focus on topics relevant to climate change.

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[11] *See id.* at 401–11.

[12] *See id.* at 411–41.

[13] Gerald E. Frug and David J. Barron describe cities "as simultaneously subordinate domestic governments and independent international actors." *See* Gerald E. Frug & David J. Barron, *International Local Government Law*, 38 URB. LAW. 1, 2 (2006); *see also* Keith Aoki, et al., *(In)visible Cities: Three Local Government Models and Immigration Regulation*, 10 OR. REV. INT'L L. 453, 472–78 (2008) (analyzing Frug and Barron's ideas' applicability to immigration).

Those interactions among localities shape decisionmaking deeply, even if agreements made through such networks tend to be voluntary.[14]

Effective strategies for fostering local climate change action need to take these complexities of scale into account. Each local entity has core local-scale powers relevant to climate change and particularized local needs tied to socioeconomics, culture, and geography. Understanding these powers and needs can help shape strategies for motivating climate action. At the same time, these local entities make choices through interactions with governmental and nongovernmental actors at other levels, including climate networks. Increasing conscious interconnectivity of and synergy among networks would maximize their impact.

B. Implications of the Evolving Geography of Metro Regions

This Article focuses on a particular aspect of this multiscalar local geography: metro regions and the diverse characteristics and spatiality of the cities within them. Although the climate change literature often focuses on major center cities,[15] metro regions that surround and contain them have a much broader urban footprint than their core well-known cities. Geographers such as Peter Muller have traced the evolution of urban regions into polycentric, multinodal complex systems in which suburban minicities and technopoles participate in global economic networks.[16]

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[14] I have explored some of these dynamics in the sources cited *supra* note 8. *See also* Judith Resnik et al., *Ratifying Kyoto at the Local Level: Sovereigntism, Federalism, and Translocal Organizations of Government Actors (TOGAs)*, 50 ARIZ. L. REV. 709, 726–33, 764 (2008) (analyzing the many TOGAs working on climate change and their current and potential roles in shaping federal policy).

[15] *See, e.g.*, Melissa Powers, *US Municipal Climate Plans: What Role Will Cities Play in Climate Change Mitigation?*, *in* LOCAL CLIMATE CHANGE LAW: ENVIRONMENTAL REGULATION IN CITIES AND OTHER LOCALITIES 134, 140–44 (Benjamin J. Richardson ed., 2012) (comparing the efforts of several U.S. localities); David Dodman, *Blaming Cities for Climate Change? An Analysis of Urban Greenhouse Gas Emissions Inventories*, 21 ENV'T & URBANIZATION 185, 189 (2009) (comparing greenhouse gas emissions of eleven cities in Europe, North America, South America, and Asia); Osofsky & Levit, *supra* note 8, at 414–15 (comparing the development of climate change efforts in Portland and Tulsa); Heike Schroeder & Harriet Bulkeley, *Global Cities and the Governance of Climate Change: What Is the Role of Law in Cities?*, 36 FORDHAM URB. L.J. 313, 351–59 (2009) (comparing urban climate change governance approaches in London and Los Angeles).

[16] For discussion of the classic U.S. urban geography literature on this issue, see generally John R. Borchert, *America's Changing Metropolitan Regions*, 62 ANNALS ASS'N AM. GEOGRAPHERS 352 (1972) (citing ROBERT E. DICKINSON, CITY REGION AND REGIONALISM (1947); ROBERT E. DICKINSON, CITY AND REGION (1964); OTIS DUDLEY DUNCAN, ET AL., METROPOLIS AND REGION (1960)); and BEVERLY DUNCAN & STANLEY LIEBERSON, METROPOLIS AND REGION IN TRANSITION (1970)). Peter Muller has discussed the complex spatial evolution of urban metropolitan regions as they have become polycentric participants in globalization. *See* PETER O. MULLER, CONTEMPORARY SUBURBAN AMERICA (1981) [hereinafter MULLER, CONTEMPORARY SUBURBAN AMERICA] (analyzing the

Muller has described the ways in which suburban development roughly tracks transportation technology development from the Walking-Horsecar Era through the 1880s, to the Electric Streetcar Era through 1920, to the Recreational Automobile Era through 1945, to the modern Freeway Era.[17] He also has explained that the Freeway Era has resulted in five growth stages of the suburbs: (1) bedroom community, (2) independence, (3) catalytic growth, (4) high rise/technology, and (5) mature urban centers.[18] Each of the six metropolitan regions that are the focus of this Article is a mature urban center that has gone through its own variation of these stages of development.[19]

This Article argues that understanding a city's positionality within a metro region can help shape strategies for encouraging it to do more on climate change. As noted in my prior article *Suburban Climate Change Efforts*, most analyses of local climate action, particularly ones focused on suburbs, do not incorporate the variation among cities within metro regions into their approaches.[20] There is a wide variety of scholarship analyzing the types of actions cities can take and are taking,[21] many of

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development of suburbs and metro regions); Peter O. Muller, *The Suburban Transformation of the Globalizing American City*, 551 ANNALS AM. ACAD. POL. & SOC. SCI. 44 (1997) (examining the complex spatial evolution of urban metropolitan regions as they have become polycentric participants in globalization); Peter O. Muller, *Transportation and Urban Form: Stages in the Spatial Evolution of the American Metropolis*, *in* THE GEOGRAPHY OF URBAN TRANSPORTATION 59 (Susan Hanson & Genevieve Giuliano eds., 3d ed. 2004) [hereinafter Muller, *Transportation and Urban Form*] (considering stages in the interrelated development of urban transportation and metro regions). Other scholars have also addressed the complex spatial evolution of urban metropolitan regions. *See, e.g.*, David J. Barron, *Reclaiming Home Rule*, 116 HARV. L. REV. 225. (2003) (analyzing possibilities for innovation in scaling and structuring governance in metropolitan regions; Gerald E. Frug, *Beyond Regional Government*, 115 HARV. L. REV. 1763 (2002) (same).

[17] *See* MULLER, CONTEMPORARY SUBURBAN AMERICA *supra* note 16, at 26–49.

[18] *See* Muller, *Transportation and Urban Form*, *supra* note 16, at 80–81; *see also* Audrey Singer, *Twenty-First-Century Gateways: An Introduction*, *in* TWENTY-FIRST CENTURY GATEWAYS: IMMIGRANT INCORPORATION IN SUBURBAN AMERICA 15 (Audrey Singer et al. eds., 2008) (analyzing the evolving spatial distribution of immigrants in suburbs).

[19] Muller, *Transportation and the Urban Form*, *supra* note 16, at 80–81; *see* MULLER, CONTEMPORARY SUBURBAN AMERICA, *supra* note 16, at 26–49.

[20] Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 411.

[21] *See* REID EWING ET AL., GROWING COOLER: THE EVIDENCE ON URBAN DEVELOPMENT AND CLIMATE CHANGE 27–31, 35–36 (Urban Land Institute eds., 2008); Kirsten Engel, *State and Local Climate Change Initiatives: What Is Motivating State and Local Governments to Address a Global Problem and What Does This Say About Federalism and Environmental Law?*, 38 URB. LAW. 1015, 1023–25 (2006); Alice Kaswan, *Climate Change, Consumption, and Cities*, 36 FORDHAM URB. L.J. 253, 280–83, 296 (2009); Katherine A. Trisolini, *All Hands on Deck: Local Governments and the Potential for Bidirectional Climate Change Regulation*, 62 STAN. L. REV. 669, 735, 743–45 (2010); Michael Burger, *Empowering Local Autonomy and Encouraging Experimentation in*

which focus on what major center cities are doing. Those pieces that address the suburbs largely treat them as an undifferentiated category[22] and critique their unsustainable land use patterns and larger carbon footprints.[23] Their solutions tend

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Climate Change Governance: The Case for a Layered Regime, 39 ENVTL. L. REP. NEWS & ANALYSIS 11161, 11164–65 (2009).

[22] *See, e.g.*, EWING ET AL., *supra* note 21, at 67–73 (exploring possibilities for compact development can reduce vehicle miles traveled, including in a suburban context); Edna Sussman et al., *Climate Change Adaptation: Fostering Progress Through Law and Regulation*, 18 N.Y.U. ENVTL. L.J. 55, 109–10 (2010) (discussing New York suburbs' initiatives on smart growth, California's efforts at regional planning, and adaptation implications of them); Dan Tarlock, *Fat and Fried: Linking Land Use Law, The Risks of Obesity, and Climate Change*, 3 PITT. J. ENVTL PUB. HEALTH L. 31, 39 (2009) (examining possibilities for land use strategies to work in both cities and suburbs); Trisolini, *supra* note 21, at 715–16 (indicating that many of the cities choosing to adapt Smart Code were suburbs and exurbs in the South). Although there have long been more nuanced analyses of suburbs, see for example, Darcy Seaver, *Conference Explores Older Suburbs as Regional Pivot Points*, THE FREE LIBRARY, http://www.thefreelibrary.com/Conference+Explores+Older+Suburbs+as+Regional+Pivot+Points.-a054032273, *archived at* http://perma.cc/Z6N8-S5V5 (last visited Oct. 20, 2014) (a 1999 conference at the University of Minnesota on first-ring suburbs), these are rarely incorporated into the legal literature on suburbs and climate change.

[23] For examples of the literature on cities, suburbs, and sustainable land use, see John R. Nolon, *The Land Use Stabilization Wedge Strategy: Shifting Ground to Mitigate Climate Change*, 34 WM. & MARY ENVTL. L. & POL'Y REV. 1, 3 n.16, 8–9 (2009) (citing EWING ET AL., *supra* note 21) (relying on Ewing's work demonstrating the lower carbon footprint of Chicago's center city as compared to its suburbs and suggesting strategies urban areas can use to reduce their carbon footprint); J.B. Ruhl, *Taming the Suburban Amoeba in the Ecosystem Age: Some Do's and Don'ts*, 3 WIDENER L. SYMP. J. 61, 75, 78–86 (1998) (proposing ten principles for law's role in fostering sustainable suburban development with suburban development in Austin, Texas as a case example); Patricia E. Salkin, *Sustainability and Land Use Planning: Greening State and Local Land Use Plans and Regulations to Address Climate Change Challenges and Preserve Resources for Future Generations*, 34 WM. & MARY ENVTL. L. & POL'Y REV. 121, 124–25 (2009) (exploring various approaches that state and local governments can use to increase sustainability and mitigate climate change). For examples of articles looking at the nexus of suburbs, racial segregation, and climate change, see Alice Kaswan, *Climate Change, Consumption, and Cities*, *supra* note 21, at 253 (considering the role of land use measures and federal measures in addressing the city-suburb divide and reducing vehicle miles traveled and the need to integrate the socioeconomic and environmental concerns in local land use planning); James A. Kushner, *Affordable Housing as Infrastructure in the Time of Global Warming*, 43 URB. LAW. 179, 182, 197–200 (2010) (presenting an approach to smart growth that would address both climate change and segregation simultaneously); Bekah Mandell, *Racial Reification and Global Warming: A Truly Inconvenient Truth*, 28 B.C. THIRD WORLD L.J. 289, 304–05, 335–42 (2008) (analyzing the contribution of city-suburb to climate change); Florence Wagman Roisman, *Sustainable Development in Suburbs and Their Cities: The Environmental and Financial Imperatives of Racial, Ethnic, and Economic Inclusion*, 3 WIDENER L. SYMP. J. 87 (1998) (exploring how racial and ethnic segregation undermine sustainability).

to focus on how to limit sprawl or approach smart growth,[24] strategies that apply to some types of suburbs well but not others. Even some of the most spatially sophisticated scholarship, which maps emissions patterns throughout metropolitan regions, does not explore how a more finely grained focus on city type might illuminate possibilities for greater action. These studies focus on physical spatial variation without considering the ways legally constructed jurisdictional divisions within metro regions define the geography of climate change action.[25]

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[24] For a few interesting examples from the voluminous literature on sprawl, see generally William W. Buzbee, *Urban Sprawl, Federalism, and the Problem of Institutional Complexity*, 68 FORDHAM L. REV. 57 (1999) (exploring sprawl as a multilevel governance challenge and how conditional federal funding might help ameliorate it); Reid Ewing & Fang Rong, *The Impact of Urban Form on U.S. Residential Energy Use*, 19 HOUSING POL'Y DEBATE 1 (2008) (analyzing how urban form effects residential energy use); Nicole Stelle Garnett, *Save the Cities, Stop the Suburbs?*, 116 YALE L.J. 598 (2006) (reviewing recent books that focus on debates over urban growth restrictions); Christian Iaione, *The Tragedy of Urban Roads: Saving Cities from Choking, Calling on Citizens to Combat Climate Change*, 37 FORDHAM URB. L.J. 889, 896–905 (2010) (arguing for market-based approaches and demand-side approaches, rather than supply expansion, as a better strategy for addressing traffic congestion); Christine A. Klein, *The New Nuisance: An Antidote to Wetland Loss, Sprawl, and Global Warming*, 48 B.C. L. REV. 1155 (2007) (surveying the impact of *Lucas v. South Carolina Coastal Council* on regulations restricting wetland filling, sprawling development, and greenhouse gases emissions); Alexandra Lampert, *California's Fight Against Global Warming: Finally Getting Smart About Sprawl?*, 20 STAN. L. & POL'Y REV. 193 (2009) (describing California's Senate Bill 375 as a small step forward in curbing urban sprawl); Mary D. Nichols, *Sustainable Communities for a Sustainable State: California's Efforts to Curb Sprawl and Cut Global Warming Emissions*, 12 VT. J. ENVTL. L. 185 (2010) (discussing California's Senate Bill 375 as an example of addressing sprawl and climate change through metro-regional land use planning approaches); J.B. Ruhl & James Salzman, *Climate Change, Dead Zones, and Massive Problems in the Administrative State: A Guide for Whittling Away*, 98 CALIF. L. REV. 59 (2010) (discussing how complex sprawl is to understand and address).

[25] For examples of metropolitan-focused analyses in climate change mitigation, see MARILYN A. BROWN ET AL., SHRINKING THE CARBON FOOTPRINT OF METROPOLITAN AMERICA, 7–11 (Brookings Inst. ed., 2008), *available at* http://www.brookings.edu/~/media/research/files/reports/2008/5/carbon%20footprint%20sarzynski/carbonfootprint_brief.pdf, *archived at* http://perma.cc/XJ59-TZCQ (arguing that federal policy leadership is needed to complement state and local efforts on metropolitan emissions); PATRICK M. CONDON ET AL., URBAN PLANNING TOOLS FOR CLIMATE CHANGE MITIGATION 20–42 (Lincoln Inst. of Land Policy ed., 2009), *available at* http://www.dcs.sala.ubc.ca/docs/lincoln_tools%20_for_climate%20change%20final_sec.pdf, *archived at* http://perma.cc/YAD9-EVH2 (illustrating how various modeling tools can help in the planning process to reduce carbon footprints of new development); Yonn Dierwechter, *Metropolitan Geographies of US Climate Action: Cities, Suburbs, and the Local Divide in Global Responsibilities*, 12 J. ENVTL. POL'Y & PLAN. 59, 79 (2010) (analyzing city-suburb dynamics in six U.S. metropolitan regions, but without detailed comparison of individual suburban cities); Edward L. Glaeser & Matthew E. Kahn, *The Greenness of Cities: Carbon Dioxide Emissions and Urban Development* 8–25 (Taubman Ctr. for State & Local Gov't, WP-2008-07),

In *Suburban Climate Change Efforts*, I demonstrate how the work of Myron Orfield—at times in collaboration with Thomas Luce—on the demography of metro regions might be brought to bear on analyses of local climate change action.[26] Their work maps the different types of cities in metro regions by combining Geographic Information Systems (GIS) technology with demographic data.[27] This type of mapping could be useful in identifying how climate change action might be paired with other local priorities—such as urban redevelopment or growth management—and what kinds of support particular cities likely need to take action. Using examples of action by different types of leader suburbs in the Twin Cities, that article showed how efforts seemed to vary by city type and how that variation could be used strategically.[28]

This Article takes the next step in that analysis by considering how climate change networks could be more effective in metro regions. It explores the types of climate change networks in which cities within major metro regions in different U.S. regions participate and how membership varies across different types of cities within these metro regions. It then uses this assessment to consider where opportunities lie for networks to be more effective in the way in which they target different types of cities and in which they collaborate with one another. In so doing, this extended case study provides a model for how metro-regional data can be used to inform local climate strategies.

C. The Role of Multiscalar Networks in Local Action

The urban geography literature discussed in the prior sections reinforces the importance of creating a multiscalar model of urban climate action that identifies (1) the particular characteristics of different types of localities and (2) the core relationships that help to constitute these localities and their choices. Each city within a metro region is both its own contained urban space with a relatively autonomous governing entity and part of this larger landscape of metro-regional evolution. Thinking locally requires simultaneously understanding each of the local scales—from city to county to metro region—and how they interact with each other and with state, national, international, and regional scales.

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available at http://www.hks.harvard.edu/var/ezp_site/storage/fckeditor/file/pdfs/centers-programs/centers/taubman/working_papers/glaeser_08_greencities.pdf, *archived at* http://perma.cc/J3XN-9LSE (exploring how metropolitan emissions patterns vary across metropolitan areas and the differences between city-suburb dynamics). For an example of a study focusing on suburban climate change action, see Sarah E. Knuth, *Addressing Place in Climate Change Mitigation: Reducing Emissions in a Suburban Landscape*, 30 APPLIED GEOGRAPHY 518, 520–29 (2010) (providing a case study of efforts by a wealthy suburban county to develop a climate change mitigation plan in a wealthy suburban county).

[26] *See* Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 406–12.

[27] MYRON ORFIELD, AMERICAN METROPOLITICS: THE NEW SUBURBAN REALITY 46–48 (Brookings Inst. ed., 2002).

[28] *See* Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 452–54.

This section focuses in particular on Cox's analysis of the nature of the local scale because its unpacking of intra- and inter-level spatial networks provides an especially helpful lens through which to view local climate action and network participation.[29] Cox envisions core local functions interacting across multiscalar networks by introducing what he terms "spaces of dependence" and "spaces of engagement."[30] Cox's "[s]paces of dependence are defined by those more-or-less localized social relations upon which we depend for the realization of essential interests and for which there are no substitutes elsewhere; they define place-specific conditions for our material well being and sense of significance."[31] In the context of local climate action, such spaces include the local bodies that decide the myriad of land use planning, energy, environmental, and water policy questions related to mitigation and adaption, as well as the more informal community forums and gatherings that take place on a regular basis within local places.[32]

Spaces of engagement, in contrast, are "the space[s] in which the politics of securing a space of dependence unfold[]."[33] In this context, these would include—among others—the real and virtual meetings of the various climate networks described in Part III, the Conference of the Parties negotiations of the United Nations Framework Convention on Climate Change, and the other interactions that the same cities have in networks and organizations unrelated to climate change. They also would include press coverage of those events, governmental reactions to them, etc. Cox explains that these many spaces of dependence and engagement interact: "[p]eople, firms, state agencies, etc., organize in order to secure the conditions for the continued existence of their spaces of dependence but in so doing they have to engage with other centers of social power: local government, the national press, perhaps the *inter*national press, for example."[34] This organizing and use of polycentric power sources is evident throughout the Article.

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[29] I have drawn heavily from Cox in earlier scholarship on scalar issues in climate change regulation.

[30] Cox, *Spaces of Dependence*, *supra* note 9, at 2. For scholarship reviewing Cox's approach, see Katherine T. Jones, *Scale as Epistemology*, 17 POL. GEOGRAPHY 25 (1998); Dennis R. Judd, *The Case of the Missing Scales: A Commentary on Cox*, 17 POL. GEOGRAPHY 29 (1998); Michael Peter Smith, *Looking for the Global Spaces in Local Politics*, 17 POL. GEOGRAPHY 35 (1998); Lynn A. Staeheli, *Globalization and the Scales of Citizenship*, 19 GEOGRAPHY RES. F. 60 (1999). Cox responded to those reviews. *See* Kevin R. Cox, *Representation and Power in the Politics of Scale*, 17 POL. GEOGRAPHY 41 (1998).

[31] *See* Cox, *Spaces of Dependence*, *supra* note 9, at 2.

[32] Who or what the regulators are can also have an important impact on the spaces. In a very different substantive context, for example, Professor Steven Ratner explores the differential legal and political treatment of occupation by states and administration by international organizations. *See* Steven R. Ratner, *Foreign Occupation and International Territorial Administration: The Challenges of Convergence*, 16 EUR. J. INT'L L. 695 (2005).

[33] Cox, *Spaces of Dependence*, *supra* note 9, at 2.

[34] *Id.*

Network dynamics, in particular, play a crucial role in this Article's analysis, and Cox's work provides a helpful way to envision complex scalar dynamics in network terms. Cox describes the ways in which networks move through the traditional boundaries of governments. He explains:

> Networks signify unevenness in the penetration of areal forms. They are also rarely entirely contained by areal forms; boundaries tend to be porous. The territorial reach of state agencies is imperfect. Even in the case of the most totalitarian of states, there are always spaces of resistance. The same applies to other agents with territorially defined powers like the utilities, political parties and labor unions. To be sure, they all enjoy power, in the sense of rights, with respect to particular bounded areas or enclosures, but it is a *formal* power which is affected in its actual application by contingent conditions. Conversely, agents, in the associations that they can form and indeed do form, are by no means limited by particular enclosures. Local government policies can be appealed to higher levels of authority. Networks of association are created across national boundaries, as in the fight against apartheid.[35]

Seen in these terms, local climate action involves a constant push and pull among formal and informal associational networks within and across scales. Cox's work helps to illuminate the complexity of each scale and interactions across them in each of the metro regions that this Article examines.

The Article draws from Cox's approach throughout its analysis, which is guided by key principles introduced in the following section. In Part III, it describes the multidimensional, and often multiscalar, ties of each of the exemplar networks. Then, Part IV's exploration of metro regions and networks considers (1) how each metro region is constituted and (2) the network ties of different types of cities within it. These two parts then become the basis for the Article's proposal for increasing network penetration in major metropolitan regions.

D. Conceptualizing the Geography of Local Climate Change Network Participation

The rest of this Article analyzes the role of multilevel climate change networks in local climate action. This section draws from the previous three to provide a framework for doing so. The insights from geography scholarship reveal the scalar complexity of localities and the ostensibly local decisions that they are making about climate change. For the purposes of this Article's more specific focus on network participation, it is important to understand the geography of the networks and of the localities that comprise them as put forward in this Article's two core principles.

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[35] Cox, *Spaces of Dependence*, *supra* note 9, at 2–3.

Principle 1 (Network Geography): Translocal climate change networks have geographic characteristics that influence how they operate and the effectiveness of their efforts. Understanding these characteristics is critical to enhancing their role in fostering local action.

The climate change networks studied in this Article are all multiscalar, but they constitute themselves at particular levels ranging from local to international. All of the networks have local participants (and some have sublocal participants), but the geography of which cities participate in each network varies. Regardless of the level at which they are constituted, many of the networks also frame themselves explicitly within international and national climate change negotiations and debates. This Article analyzes the geography of these networks and their participants in order to consider possible synergies that might help foster more local climate change action.

Principle 2 (Local Geography): The cities participating in translocal climate change networks often are based in local metropolitan regions and have varying geographic characteristics and roles within those regions. Understanding this positionality is crucial to fostering more action by individual cities.

Although individual cities are signing up for each of the networks discussed in this Article, they are located within local metropolitan regions and vary significantly in their geographic characteristics and roles in those regions. The model that this Article develops also focuses on understanding this local geography. Exploring these characteristics can help identify which groups are participating less and what kind of appeals might be more effective. The Article delineates participation patterns across six major U.S. metropolitan regions to display that geography and to provide the basis both for getting those already participating to do more and for adding new network participants.

The Parts that follow use these principles to consider the multiscalar patterns of network development and participation and their implications. These patterns provide the basis for turning from theory to practice, and the Article provides practical strategies for fostering local action on climate change by using these networks more effectively.

III. THE ROLES OF MULTILEVEL CLIMATE CHANGE NETWORKS

Localities and the networks in which they participate are the core focus of this Article. In order to understand their multiscalar interactions, it is critical to first identify key networks and their priorities. This Part explores some of the climate change networks relevant to the six metro regions that have developed international, national, state, and local scales. Its detailing of networks is not intended to be comprehensive, but rather aims to give a sense of the types of networks that exist at each scale and some of their major activities. In so doing, the Part illuminates the ways the various networks, though constituted at one level, interact with many actors at multiple levels, along the lines of Cox's network theory of scale.

Although the networks described in this section operate at different levels and have diverse core activities, they share in common a focus on assisting localities in efforts to do more to address climate change. Much of that "more" takes place at a local scale. The networks provide toolkits, examples, and recognition for local leaders who want to take additional steps, as well as a supportive network of similarly committed leaders. Participating leaders in some of these programs have indicated that these mechanisms provide a helpful framework for their activities.[36]

As becomes clear in this Part's descriptions, however, many of these voluntary local networks—even smaller-scale ones—also interact significantly with the international climate negotiations between nation-states. Some networks formed in reaction to failures by nation-states generally, and the United States in particular, to commit to action at international negotiations. In fact, many of the international-scale agreements among cities are made in parallel with annual Conference of the Party (COP) negotiations among nation-state parties to the United Nations Framework Convention on Climate Change. This interactivity helps reinforce the polycentric nature of climate change governance in general and the multiscalar character of local action in particular that Cox helps outline.[37]

A. International-Level Climate Change Networks

International-level networks of localities focus on changing behavior at multiple scales. A big part of their efforts involves trying to influence nation-state behavior and the course of international negotiations among them. Intertwined with that large-scale goal are local-level commitments made in international contexts by participating localities using their governmental powers. This section explores activities at all of these scales. It begins by describing the goals and activities of some of the most significant international-level networks, then turns to the ways in which these networks have influenced international negotiations, and concludes with a discussion of the agreements among localities that these networks have fostered.

1. Leading Networks

This section focuses on three of the international-level networks most active on local climate change action: the International Council for Local Environmental Initiatives (ICLEI), World Mayors Council on Climate Change (WMCCC), and United Cities and Local Governments (UCLG). Because ICLEI has the most extensive programs of the group, the section provides an in-depth analysis of ICLEI's work and a briefer summary of the other two networks.

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[36] Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 447.
[37] Cox, *Spaces of Dependence*, *supra* note 9, at 4–21.

(a) International Council for Local Environmental Initiatives

ICLEI is the most active of the international networks working on climate change.[38] ICLEI aims "to build and serve a worldwide movement of local governments to achieve tangible improvements in global sustainability with [specific] focus on environmental conditions through cumulative local actions."[39] It works to: (1) connect leaders of "cities to other organizations on a local, national and international level"; (2) accelerate local government action by supporting campaigns and programs and forging partnerships with academics, businesses, and government leaders; and (3) serve as a gateway to solutions through "technical consulting, information services and training to build capacity, shar[ing] knowledge and support[ing] local governments in the implementation of sustainable development at the local level."[40] Although ICLEI's overall focus is more broadly on sustainability,[41] its climate change efforts include a wide range of programs that influence international treaty negotiations, create agreements among localities, and guide activities within localities. ICLEI claims that its Cities for Climate Protection (CCP) Campaign has eliminated more than 60 million tons of carbon-dioxide-equivalent emissions annually.[42]

ICLEI emerged from the first World Congress of Local Governments for a Sustainable Future in 1990 in New York, where it was founded by 200 local governments from forty-three countries.[43] It has grown in the over two decades since to include over 1,000 local governments of different sizes in eighty-four countries.[44] From the start, its programs have often paralleled international-level efforts by nation-states. For example, two of ICLEI's earliest initiatives were Local Agenda 21, "a program promoting participatory governance and local sustainable

[38] ICLEI claims to be "the world's leading association of cities and local governments dedicated to sustainable development." Int'l Council for Local Envtl. Initiatives, *Who We Are*, ICLEI, http://www.iclei.org/iclei-global/who-is-iclei.html, *archived at* http://perma.cc/MZJ3-UU8S (last visited Oct. 20, 2014).

[39] *Id.*

[40] Int'l Council for Local Envtl. Initiatives, *Frequently Asked Questions*, ICLEI, http://www.iclei.org/iclei-global/who-is-iclei/faq.html, *archived at* http://perma.cc/NLJ2-7CG2 (last visited Sept. 11, 2014).

[41] ICLEI advances eight agendas: sustainable cities, resource-efficient cities, biodiverse cities, low-carbon cities, resilient cities, green urban economies, smart urban infrastructures, and healthy and happy communities. *See* Int'l Council for Local Envtl. Initiatives, *Our Activities*, ICLEI, http://www.iclei.org/our-activities/our-agendas/sustainable-city.html, *archived at* http://perma.cc/MUE7-LH47 (last visited Sept. 10, 2014).

[42] Int'l Council for Local Envtl. Initiatives, *Who We Are*, *supra* note 38.

[43] *Id.*

[44] ICLEI describes itself as "a powerful movement of 12 mega-cities, 100 super-cities and urban regions, 450 large cities as well as 450 medium-sized cities and towns in 86 countries." *Id.*

development planning," and CCP,[45] "the world's first and largest program supporting cities in climate action planning using a five milestone process including greenhouse gas emissions inventories to systematically reduce emissions."[46] Its sustainability focus and toolkit approach have since been used in different variations by many other organizations, including much smaller-scale initiatives such as Minnesota's Greenstep Cities program.

ICLEI has numerous programs for cities that work to achieve its emissions-reduction goals. It launched the carbon*n* Cities Climate Registry at the 2010 World Mayors Summit on climate change, which allows cities to voluntarily report their mitigation and adaptation targets, actions, and achievements.[47] This registry aims to make local governments more transparent and accountable and to help inform national governments and the broader global community of the local role in climate change action.[48] ICLEI claims that this registry, which collects data from 422 local and subnational governments in forty-four countries responsible for 2.25 gigatons of carbon dioxide equivalent emissions annually, is the world's largest global database for local climate action.[49] The registry pairs with other international initiatives and compacts to increase participation and its impacts.[50]

ICLEI's registry is complemented by toolkit oriented programs, as well as software and services, which assist local governments with making step-by-step progress on climate change. For example, ICLEI's GreenClimateCities program provides a three-phase model for local governments to take action that includes

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[45] *Id.*

[46] *Id.*

[47] Int'l Council for Local Envtl. Initiatives, *Low-carbon City*, ICLEI, http://www.iclei.org/our-activities/our-agendas/low-carbon-city.html#c2282, *archived at* http://perma.cc/7RKR-TT9X (last visited Sept. 10, 2014).

[48] CARBON*N* CLIMATE REGISTRY, *Mission*, http://citiesclimateregistry.org/about/mission/, *archived at* http://perma.cc/B3UR-FXYP (last visited Sept. 10, 2014).

[49] LUCAS DE MONCUIT, 2013 ANNUAL REPORT: LOCAL RESPONSE TO MEASURABLE, REPORTABLE, VERIFIABLE GLOBAL CLIMATE ACTION 1, 5, 13 (2014), *available at* http://citiesclimateregistry.org/fileadmin/user_upload/cCCR/cCCR_2014/cCCR-2013-annual-report.pdf, *archived at* http://perma.cc/E5JV-VUVD.

[50] For example, "Article 4 of the Mexico City Pact envisages that signatories report their climate commitments, performance and actions regularly through the carbon*n* Cities Climate Registry (cCCR)." The Mex. City Pact, *The Mexico City Pact*, http://www.mexicocitypact.org/en/the-mexico-city-pact-2/, *archived at* http://perma.cc/N3XN-MS52 (last visited Sept. 11, 2014). Likewise, the World Wildlife Fund's Earth Hour City Challenge (EHCC) will partner with cCCR in 2014. The EHCC 2014 participating cities will report to cCCR, and their reports will be evaluated by an international jury. CARBON*N* CLIMATE REGISTRY, *Earth Hour City Challenge*, CARBON*N*, http://citiesclimateregistry.org/partnerships/wwf-earth-hour-city-challenge/, *archived at* http://perma.cc/SD85-3DBH (last visited Sept. 11, 2014). The cCCR is also one component of ICLEI's Green Climate Cities Program. Int'l Council for Local Envtl. Initiatives, *What Is Green Climate Cities?*, ICLEI, http://www.iclei.org/our-activities/our-agendas/low-carbon-city/gcc.html, *archived at* http://perma.cc/NQ9N-E6QH (last visited Sept. 11, 2014).

numerous tools and opportunities for guidance and networking.[51] Its Urban Low Emission Development Strategies—implemented in conjunction with UN-Habitat and founded by the European Commission—helps selected local governments in Brazil, India, Indonesia, and South Africa with implementing its GreenClimateCities approach.[52] Covenant capaCITY provides a training program for European local governments to assist them with developing a Sustainable Energy Action Plan.[53] ICLEI also has developed software and online tools to support its efforts: (1) the "Climate and Air Pollution Planning Assistant" assists local governments with developing emissions reduction strategies as they participate in ICLEI's programs;[54] (2) the Harmonized Emissions Analysis Tool Plus "helps cities to account and report greenhouse gas (GHG) emissions[and] develop an emissions forecast and climate action plan";[55] and (3) the Online Toolbox of Methodologies on Climate And Energy, which provides examples of methodologies and tools.[56] It also created a Global Protocol for Community-Scale GHG Emissions, which attempts to address the wide variation in how GHG inventories are conducted by providing a standardized approach for cities to quantify their emissions.[57] Local leaders interviewed as part of this project described the modeling tools as particularly helpful for completing their greenhouse gas emissions inventories.[58]

(b) World Mayors Council on Climate Change

The World Mayors Council on Climate Change was founded in 2005 by the mayor of Kyoto just after the international-scale Kyoto Protocol came into force in

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[51] Int'l Council for Local Envtl. Initiatives, *What Is Green Climate Cities?*, *supra* note 50.

[52] Int'l Council for Local Envtl. Initiatives, *Low-carbon City*, *supra* note 47.

[53] Covenant CapaCITY, *Introducing Covenant capaCITY*, http://www.covenant-capacity.eu/eu/about-capacity/, *archived at* http://perma.cc/EES2-G2V3 (last visited Oct. 19, 2014).

[54] Int'l Council for Local Envtl. Initiatives USA, *Climate and Air Pollution Planning Assistant (CAPPA) Trainings*, ICLEI USA, http://www.icleiusa.org/action-center/skills-training/climate-and-air-pollution-planning-assistant-cappa-trainings, *archived at* http://perma.cc/4NQM-UQ94 (last visited Aug. 9, 2014).

[55] Int'l Council for Local Envtl. Initiatives, *Low-carbon City*, *supra* note 47. (follow "More" hyperlink under "Our Tools and Services").

[56] *Id.*; Toolbox of Methodologies Climate and Energy, *About the Toolbox*, http://toolbox.climate-protection.eu/about-the-toolbox/, *archived at* http://perma.cc/5LRY-4L8D (last visited Oct. 20, 2014).

[57] YUNUS ARIKAN ET AL., GLOBAL PROTOCOL FOR COMMUNITY-SCALE GREENHOUSE GAS EMISSIONS (GPC): PILOT VERSION 1.0 – MAY 2012 (2012), *available at* http://carbonn.org/fileadmin/user_upload/carbonn/Standards/GPC_PilotVersion_1.0_May2012_20120514.pdf, *archived at* http://perma.cc/D34F-Q8X9.

[58] Confidential Meeting with Local Leaders, (Feb. 7, 2014) [hereinafter Osofsky, Confidential Meeting with Local Leaders] (notes on file with author).

parallel with the Montreal Conference of the Parties.[59] WMCCC's goals include (1) "strengthening political leadership on global sustainability by building a group of committed local sustainability leaders"; and (2) "being the prime political advocacy force of cities and local governments on global sustainability matters."[60] WMCCC implements this mission by (1) "showcasing local leaders' climate and sustainability actions that contribute to policy change at local and global levels"; (2) "supporting its members to enhance their climate and sustainability leadership capacities"; (3) "addressing global climate and sustainability policy makers as a global body of leaders from diverse local governments"; and (4) "politically steering the development and implementation of mechanisms that support local climate and sustainability action."[61] Although the Council was constituted separately from ICLEI and functions independently, ICLEI provides technical and strategic support for it and often collaborates with it.[62]

(c) United Cities and Local Governments

United Cities and Local Governments has a broader focus than ICLEI or the World Mayors Council on Climate Change, with its stated mission of serving as "the united voice and world advocate of democratic local self-government, promoting its values, objectives and interests, through cooperation between local governments, and within the wider international community."[63] It is relevant to this Article's analysis, however, because of its active participation in the international climate change negotiations and its partnership with both of the other networks highlighted in this section. It formed the UCLG Climate Negotiation Group at its 2009 World Council, and that group has been actively participating in the climate change negotiations and in developing the transnational agreements among localities since then.[64] For example, the UCLG spokesperson played a leadership role in the creation

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[59] World Mayors Council on Climate Change, *History*, WMCCC, http://www.worldmayorscouncil.org/about/history.html, *archived at* http://perma.cc/K86P-WSSF (last visited Oct. 20, 2014).

[60] World Mayors Council on Climate Change, *Mission and Method*, WMCCC, http://www.worldmayorscouncil.org/about/mission-and-method.html, *archived at* http://perma.cc/ZUB6-S4JB (last visited Oct. 20, 2014).

[61] *Id.*

[62] *Id.*

[63] United Cities and Local Governments, *About Us*, UCLG, http://www.uclg.org/en/organisation/about, *archived at* http://perma.cc/DBZ8-YLPZ (last visited Oct. 20, 2014).

[64] United Cities and Local Governments, *Climate Change*, UCLG, http://www.uclg.org/en/issues/climate-change, *archived at* http://perma.cc/3H3Y-V5SG (last visited Oct. 20, 2014).

of the 2013 Nantes Declaration of Mayors and Subnational Leaders on Climate Change discussed below.[65]

2. Influence on and Agreements Parallel to International Treaty Negotiations

The international negotiations have provided a primary site for networks of localities to gather and attempt to push nation-states both to do more and to recognize the local role in the treaties being negotiated.[66] These efforts have been organized since the 2007 Conference of the Parties in Bali under the auspices of a Local Government Climate Roadmap by ICLEI and UCLG. This effort was originally supposed to finish by the Copenhagen COP, but has continued through the more recent Conferences of the Parties.[67] At each COP negotiation, this coalition has made progress in getting more language on cities, localities, and subnational government into the international agreements and initiatives taking place under them. With the adoption of the Nantes Declaration of Mayors and Subnational Leaders on Climate Change in fall 2013, the climate roadmap entered a new phase.[68] The gathered localities created the Friends of the Cities group to bring together "national governments who wish to collaborate with local and subnational governments."[69]

While ICLEI and UCLG use their status as observers to influence the text at COP negotiations, their efforts are augmented by the side meetings among localities (and other subnational governments) often taking place parallel to the COPs. The participating governments create agreements in which they voluntarily commit to taking steps within their local control. These agreements have become more detailed over time, and have evolved from initially focusing primarily on mitigation to increasingly including adaptation. However, as detailed in depth in the following

[65] United Cities and Local Governments, *Mayors and Subnational Leaders Meet in Nantes and Renew Commitment to Upscale Climate Change Actions*, UCLG (Oct. 10, 2013, 1:34 PM), http://www.uclg.org/en/node/20653, *archived at* http://perma.cc/HRR6-K2LB.

[66] Press Release, Int'l Council for Local Envtl. Initiatives, Durban Outcomes: Nations Invest in Time, World Must Invest in Cities, (Dec. 12, 2011), *available at* http://www.iclei-europe.org/fileadmin/templates/iclei-europe/files/content/ICLEI_IS/Press_releases/2011/12.12.11_COP17_Outcomes.pdf, *archived at* http://perma.cc/GQ8N-FVAR.

[67] *See* LOCAL GOV'T CLIMATE ROADMAP, FROM COPENHAGEN TO CANCÚN TO SOUTH AFRICA: COP15 - COP16 - COP17 (2010), [hereinafter LOCAL GOV'T CLIMATE ROADMAP], *available at* http://www.iclei.org/fileadmin/template/project_templates/climate-roadmap/files/Communication_Material/Towards_COP16/Concept_towards_COP16_Final_8September2010.pdf, *archived at* http://perma.cc/GMA3-VMUY.

[68] Gino Van Begin, *Comment: Look to Cities for Genuine Low Carbon Progress*, RESPONDING TO CLIMATE CHANGE (Oct. 11, 2013, 7:22 AM), http://www.rtcc.org/2013/10/10/comment-look-to-cities-for-real-progress-in-low-carbon-investment/, *archived at* http://perma.cc/P86N-LK9F.

[69] *Id.*

Part, the participation rate of cities in key U.S. metropolitan regions has been low other than in the Copenhagen City Climate Catalogue.

A sampling of agreements made from 2009 to the present exemplifies these trends. The 2,903 localities registered with the Copenhagen City Climate Catalogue—created in conjunction with the 2009 negotiations—made climate change commitments, often a percentage reduction in CO_2 equivalents by a certain date.[70] The 2010 Mexico City Pact, which ICLEI facilitates, built on the types of commitments localities made at Copenhagen, adding more substance to them. The 250 signatories to the pact—substantially fewer than those making commitments in the Catalogue—"voluntarily commit to 10 action points to advance local climate action, including the reduction of emissions, adaptation to the impacts of climate change and fostering city-to-city cooperation,"[71] with an emphasis on "globally measurable, reportable, and verifiable (MRV) local climate action."[72] Signatories are encouraged to report their climate actions on the cCCR network, discussed above, and the Pact's website also includes narrative reports of city efforts.[73]

The agreement among localities parallel to the 2011 Durban negotiations moved the focus to adaptation.[74] As of November 1, 2013, the 1200 signatories to the Durban Adaptation Charter had committed to a variety of initiatives around

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[70] Int'l Council for Local Envtl. Initiatives, *City Climate Catalogue: Over 1700 Communities Making a Point*, ICLEI (Oct. 30, 2009), http://climate-catalogue.org/index.php?id=6905, *archived at* http://perma.cc/UA5V-FQ2K; The City Climate Catalogue, *How Does the Catalogue Work?*, http://climate-catalogue.org/index.php?id=7507, *archived at* http://perma.cc/A4M8-84TH (last visited Sept. 10, 2014). As of the website's most recent update, 2,903 communities have listed 3251 targets. The City Climate Catalogue, *List of Commitments*, http://climate-catalogue.org/index.php?id=6870, *archived at* http://perma.cc/ES88-N6EM (last visited Sept. 10, 2014).

[71] Int'l Council for Local Envtl. Initiatives, *Low-carbon City*, *supra* note 47; *see also* INT'L SECRETARIAT, GLOBAL CITIES COVENANT ON CLIMATE: THE MEXICO CITY PACT, SECOND ANNUAL REPORT 2012 (Sandra Strikovsky Vestel ed., 2012) [hereinafter INT'L SECRETARIAT, GLOBAL CITIES COVENANT ON CLIMATE], *available at* http://www.mexicocitypact.org/wp-content/uploads/2013/09/Second-Anual-Report-2012-English.pdf, *archived at* http://perma.cc/RU7A-XADW.

[72] *Global Cities Covenant on Climate Change – The Mexico City Pact*, WORLD MAYORS COUNCIL ON CLIMATE CHANGE [hereinafter WMCCC, *Global Cities*], http://www.worldmayorscouncil.org/the-mexico-city-pact.html, *archived at* http://perma.cc/B6A4-5CYQ (last visited Sept. 10, 2014); *see also* Global Cities Covenant on Climate, *Strategic Importance of the Pact*, http://www.mexicocitypact.org/docs/importancia-estrategicaEN.php (last visited Feb. 13, 2014) (describing the Pact's strategic importance).

[73] WMCCC, *Global Cities*, *supra* note 72.

[74] *See* eThekwini Municipality, *Implementation of the Durban Adaptation Charter*, http://www.durban.gov.za/City_Services/development_planning_management/environmental_planning_climate_protection/Projects/Pages/11.Implementation-of-the-Durban-Adaptation-Charter.aspx, *archived at* http://perma.cc/69AK-K8R4 (last visited Sept. 11, 2014).

adaptation—including integrating it into their local planning, preparing adaptation strategies, aligning adaptation and mitigation goals, and promoting multilevel, integrated governance and partnerships.[75] In addition, the Charter "offers cities a channel of opportunity to leverage funding sources and partnerships, an ever growing need in cities in emerging economies."[76] Ninety-four percent of those who had signed by July 31, 2012 were located in developing nations—with the majority coming from the southern hemisphere[77]—a point of concern—though recent signatories include, among others, Bonn, Germany; Fort Lauderdale, Florida; North Vancouver, Canada; Linkping, Sweden; and Seferihisar, Turkey.[78]

Although not in conjunction with a COP, the 2013 Nantes Declaration of Mayors and Subnational Leaders on Climate Change[79] is interesting because of its

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[75] DURBAN LOCAL GOV'T CONVENTION, DURBAN ADAPTATION CHARTER FOR LOCAL GOVERNMENTS AS ADOPTED ON THE 4TH DECEMBER 2011 OF THE OCCASION OF THE "DURBAN LOCAL GOVERNMENT CONVENTION: ADAPTING TO A CHANGING CLIMATE" – TOWARDS COP17/CMP7 AND BEYOND 2-3 (2011) [hereinafter DURBAN LOCAL GOV'T CONVENTION, DURBAN ADAPTATION CHARTER], *available at* https://unfccc.int/files/meetings/durban_nov_2011/statements/application/pdf/111209_cop17_hls_iclei_charter.pdf, *archived at* http://perma.cc/6X5P-W2ZQ; Press Release, Durban Adaptation Charter, Momentous DAC Signing Ceremony by 120 African Leaders (Nov. 1, 2013), *available at* http://durbanadaptationcharter.org/news, *archived at* http://perma.cc/TJ2G-KR9P.

[76] Int'l Council for Local Envtl. Initiatives, *Global Climate Change Adaptation Charter Gains Momentum with 11 New Signatories*, ICLEI (June 6, 2013) [hereinafter Int'l Council for Local Envtl. Initiatives, *Global Climate Change*], http://www.iclei.org/details/article/global-climate-change-adaptation-charter-gains-momentum-with-11-new-signatories.html, *archived at* http://perma.cc/YB6R-UQSB; *see* DURBAN LOCAL GOV'T CONVENTION, DURBAN ADAPTATION CHARTER, *supra* note 75.

[77] ETHEKWINI MUNICIPALITY, DURBAN ADAPTATION CHARTER 3 (2012), *available at* http://www.durban.gov.za/City_Services/development_planning_management/environmental_planning_climate_protection/Projects/Documents/DAC__Pamphlet.pdf, *archived at* http://perma.cc/N84R-FHE6.

[78] *See* Int'l Council for Local Envtl. Initiatives, *Global Climate Change*, *supra* note 76. According to the Adaptation Charter's website, two localities from the United States are signatories. Durban Adaptation Charter, *Signatories of the Durban Adaptation Charter*, http://www.durbanadaptationcharter.org/signatories, *archived at* http://perma.cc/VC8P-88PY (last visited Feb. 14, 2015).

[79] *See* INT'L COUNCIL FOR LOCAL ENVTL. INITIATIVES, NANTES DECLARATION OF MAYORS AND SUBNATIONAL LEADERS ON CLIMATE CHANGE LOCAL GOVERNMENT CLIMATE ROADMAP 2013-2015 1 [hereinafter INT'L COUNCIL FOR LOCAL ENVTL. INITIATIVES, NANTES DECLARATION], *available at* http://archive.iclei.org/fileadmin/user_upload/documents/Global/initiatives/2013_Nantes_Summit/WorldMayorsSummit2013_Nantes_EN_Declaration_only.pdf?utm_content=katrina.borromeo@iclei.org&utm_source=VerticalResponse&utm_medium=Email&utm_term=The%20Nantes%20Declaration%20of%20Mayors%20and%20Subnational%20Leaders%20on%20Climate%20Change&utm_campaign=Nantes%20Declaration%20refuels%20hopes%20for%20local%20governments%2

focus on the multiscalar dimensions of local action. Adopted "with the support of over 50 mayors from 30 countries, and more than 20 regional and global networks of local and subnational governments,"[80] the Nantes Declaration aims to increase connections between the local and global levels. It emphasizes scaling up local climate action and engaging with government and members of the private and financial sector at multiple levels.[81]

B. National-Level Climate Change Networks

The United States contains numerous national-level groups that bring local officials together. As Judith Resnik, Joshua Civin and Joseph Frueh have explored in depth in their work on translocal organizations of governmental actors (TOGAs), these groups include the following, among others (in order of founding year): the International City/County Management Association, U.S. Conference of Mayors, the National Association of Counties, the National League of Cities, and the National Association of Towns and Townships.[82] These organizations have been involved with issues of climate change in a variety of ways. For example, during the 2008 election, the U.S. Conference of Mayors called upon the federal government to "empower local elected officials, especially in metropolitan areas, to make the decisions on how federal transportation resources are invested, a shift this [sic] is especially crucial to change energy demand and greenhouse gas emissions in this sector."[83]

While all of these interactions among localities have the potential to influence their climate change mitigation and adaptation choices, two networks stand out at a national level as particularly important for purposes of this study: the U.S. Conference of Mayors Climate Protection Agreement (Mayors Agreement) and the Urban Sustainability Directors Network (USDN). As described in depth below, these two networks differ substantially from one another in their focuses, activities,

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C%20as%20science%20calls%20for%20urgent%20climate%20actionscontent, *archived at* http://perma.cc/5Q8S-N5SK.

[80] Int'l Council for Local Envtl. Initiatives, *Nantes. World Mayors Summit on Climate Change 2013*, LOCAL GOV'T CLIMATE ROADMAP, http://www.iclei.org/worldmayorssummit.html, *archived at* http://perma.cc/S9ZV-VCML (last visited Oct. 20, 2014).

[81] *See* INT'L COUNCIL FOR LOCAL ENVTL. INITIATIVES, NANTES DECLARATION, *supra* note 79 at 2–3; Van Begin, *supra* note 68.

[82] *See* Resnik et al., *supra* note 14, at 709, 726–33, 764.

[83] U.S. CONFERENCE OF MAYORS, NATIONAL ACTION AGENDA ON ENVIRONMENT AND ENERGY FOR THE NEXT PRESIDENT OF THE UNITED STATES 10 (2008), *available at* http://www.usmayors.org/maf/documents/20090105-Environment.pdf, *archived at* http://perma.cc/E47H-HKA7. Such pushes have also taken place in the clean energy context. *See, e.g.*, CLEAN ENERGY STATES ALLIANCE, ECONOMIC STIMULUS AND A FEDERAL/STATE CLEAN ENERGY PARTNERSHIP: CESA POSITION PAPER 1–3 (2009), *available at* http://www.cesa.org/assets/Uploads/Resources-pre-8-16/CESA-SLICE-position-paper-FedState-partnershipjan2009.pdf, *archived at* http://perma.cc/49JV-YLZW.

and membership; comparing them highlights the varying ways national networks work to influence climate change action. The Mayors Agreement focuses specifically on climate change and is highly inclusive; any city can join that takes its pledge. USDN, in contrast, focuses more broadly on sustainability, with climate change as an important component, and includes a limited number of key people from North American leader cities—in the six metro regions studied, center cities were overrepresented compared to suburbs—to provide a safe space for collaboration.

1. U.S. Conference of Mayors Climate Protection Agreement

By far the most significant U.S. domestic climate-focused network that has emerged from the many TOGAs is the Mayors Agreement in which mayors pledge to meet what the U.S. commitments under the Kyoto Protocol would have been—reducing emissions to seven percent below 1990 levels by 2012—and to encourage larger-scale governments to do the same.[84] Specifically, signatories commit to taking the following three actions:

- Strive to meet or beat the Kyoto Protocol targets in their own communities, through actions ranging from anti-sprawl land-use policies to urban forest restoration projects to public information campaigns;
- Urge their state governments, and the federal government, to enact policies and programs to meet or beat the greenhouse gas emission reduction target suggested for the United States in the Kyoto Protocol—7% reduction from 1990 levels by 2012; and
- Urge the U.S. Congress to pass the bipartisan greenhouse gas reduction legislation, which would establish a national emission trading system.[85]

Seattle Mayor Greg Nickels launched this network in 2005 in response to the U.S. decision not to participate in the Kyoto Protocol. He worked with other mayors to organize an initial group of 141 mayors to pledge to those Kyoto Protocol targets.

[84] Mayors Climate Prot. Ctr., *About the Mayors Climate Protection Center*, U.S. CONFERENCE OF MAYORS, http://www.usmayors.org/climateprotection/about.htm, *archived at* http://perma.cc/5ZZC-98KL (last visited Oct. 21, 2014); Mayors Climate Prot. Ctr., *List of Participating Mayors*, *supra* note 5.

[85] Mayors Climate Prot. Ctr., *U.S. Conference of Mayors Climate Protection Agreement*, U.S. CONFERENCE OF MAYORS, http://usmayors.org/climateprotection/agreement.htm, *archived at* http://perma.cc/C3V5-KUWX (last visited Oct. 21, 2014).

The U.S. Conference of Mayors unanimously endorsed the Mayors Agreement and has encouraged cities to sign on since then.[86]

In 2007, Douglas H. Palmer, then-Mayor of Trenton and President of the U.S. Conference of Mayors, in collaboration with Conference Executive Director Tom Cochran, launched the U.S. Conference of Mayors Climate Protection Center. The Center provides mayors with guidance and assistance with the goal of "increas[ing] the number of cities involved in the effort, and to equip[ping] all cities with the knowledge and tools that ultimately will have the greatest impact on undo [sic] the causes of global warming."[87] The Center provides best practices models[88] and gives awards to leader cities in large and small categories.[89]

2. Urban Sustainability Directors Network

USDN emerged from networking among a small group of municipal sustainability directors in 2008. These directors began communicating to share ideas and experiences, and decided that they wanted to create a more formal network that created a safe space for doing so. The Global Philanthropy Partnership agreed to sponsor this effort, and each director reached out to five others around the country. The initial group of 35 directors expanded to 70 by their first meeting in 2009, and then to 120 by 2013.[90] It has three primary functions: (1) providing its members with peer-to-peer networking opportunities, (2) funding a collaborative innovation system to create solutions that can scale, and (3) using regional networks to expand access and address specific issues.[91] Through those functions, USDN involves city officials beyond its core director members and encourages its member cities to lead regional initiatives in their area.[92]

Regarding its first function, an important role that USDN has played among its members is increasing their connectivity. In its annual mapping of member connections, USDN shows a growth from an average of eight connections per member in 2009 to an average that is consistently over thirty since 2012.[93] The

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[86] Mayors Climate Prot. Ctr., *About the Mayors Climate Protection Center*, *supra* note 84.

[87] *Id.*

[88] Mayors Climate Prot. Ctr., *Best Practices*, U.S. CONFERENCE OF MAYORS, http://www.usmayors.org/climateprotection/bestpractices.htm, *archived at* http://perma.cc/795L-5ZV64YCS-4HFF (last visited Oct. 15, 2014).

[89] Mayors Climate Prot. Ctr., *Awards*, U.S. CONFERENCE OF MAYORS, http://www.usmayors.org/climateprotection/climateawards.htm, *archived at* http://perma.cc/6EU9-8FZQ (last visited Oct. 15, 2014).

[90] Urban Sustainability Dirs. Network, *About Us*, USDN, http://usdn.org/public/About-us.html, *archived at* http://perma.cc/5F3W-3UPJ (last visited Oct. 20, 2014).

[91] *Id.*

[92] *Id.*

[93] Nils Moe & Mia Arter, Urban Sustainability Dirs. Network, PowerPoint: About USDN: A Project of GPP (Feb. 2014) (on file with the Utah Law Review).

members form user groups focused on mutual interests to learn from one another and avoid reinventing the wheel in their urban area. These interest groups focused on many issues relevant to climate change mitigation and adaptation, including the following:

- Expanding support and funding streams for bike sharing
- Integrating climate-preparedness planning into city departments
- Exploring the benefits of neighborhood scale approaches
- Building urban food systems
- Improving communication about sustainability
- Implementing best practices for tracking and reporting of metrics and outcomes[94]

This first networking function is complemented by USDN's collaborative innovation system. The system works in the following manner:

> USDN's programs mobilize members to pursue collaborative projects that address urgent challenges and timely opportunities facing multiple cities. The project's members work together to allow us to assess which innovation areas are the most strategically important and yield the most effective outcomes. USDN aggregates data from these projects to generate a valuable picture of the current urban sustainability innovation market.[95]

USDN has two funds that support this process, an innovation fund and a local sustainability matching fund.[96] Innovation fund projects have focused on many issues relevant to climate change, such as electric vehicles, commercial building energy disclosures, employee energy saving campaigns, adaptation lessons, switching streetlights, and an energy efficiency wedge tool.[97]

Finally, while USDN currently has 126 member directors serving cities that contain 53 million people, it works to reach additional cities through its eight regional networks: New England, Cascadia, Heartland, Western Adaptation Alliance, Southeast, Michigan, OKI (Ohio, Kentucky, Indiana), and Green Cities California. These eight networks collaborate with one another through the USDN Regional Network Coordinating Committee. USDN aims to use these regional

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[94] Urban Sustainability Dirs. Network, *About Us*, *supra* note 90.

[95] *Id.*

[96] *Id.*

[97] *See* Urban Sustainability Dirs. Network, *Innovation Products*, USDN, http://www.usdn.org/public/innovation.html, *archived at* http://perma.cc/7TDY-RMN7 (last visited Oct. 15, 2014).

networks to create access to a peer network for all North American local government sustainability leaders.[98]

The network appears to have had a significant impact on its member directors, who are also optimistic about its broader potential to address metro-regional climate change. One member director from the Southwest described it as the most significant of all of the climate networks.[99] This director explained that it has helped the participating directors in many tangible ways and that its regional networks could perpetuate this process throughout many more cities.[100]

C. Regional, State, and Local-Level Climate Change Networks

In addition to these international- and national-level efforts, many states, cities, and regions have developed relevant networks. This section details examples of networks in each of the metropolitan regions that are the focus of this Article: Atlanta, Chicago, Denver, New York, San Francisco, and the Twin Cities. Together, they highlight the ways smaller scale networks complement efforts at a national and international scale. Because many of these smaller-scale networks achieve greater participation than the larger-scale networks in particular metro regions, as Part IV details in more depth, these become an important gateway for encouraging local mitigation and adaptation.

These networks vary in their focus and geographic scale. Some of these networks focus directly on climate change, while others have a broader focus, such as sustainability, but do substantial work related to climate change. The networks range from interstate regional to statewide to metro regional, and many of them have linkages to other levels of government or key public and private actors. In their strategic approaches, a number of them employ variations on the toolkit approach described above with respect to ICLEI.

1. EPA Regional Networks

Although the Environmental Protection Agency has a national scope overall, it also is divided into regions. This Article uses an example network from Region 5 that covers Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin and thirty-five tribes, and thus includes the Chicago and Twin Cities metro regions.[101] In addition to having a climate action plan, EPA Region 5 has created a network and aimed resources at local governments. The EPA Region 5 Community Climate Change Network "provides information and opportunities about energy efficiency and

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[98] *See* Urban Sustainability Dirs. Network, *About Us*, *supra* note 90.

[99] Osofsky, Confidential Meeting with Local Leaders, *supra* note 58.

[100] *Id.*

[101] *See* U.S. Envtl. Prot. Agency, *Region 5 Climate Change*, http://www.epa.gov/r5climatechange/, *archived at* http://perma.cc/7SKU-CA8U (last visited Oct. 16, 2014). The other EPA regions are also involved in various forms of climate change action, but this Article focuses on Region 5 as an exemplar.

greenhouse gas reduction to municipalities, as well as access to a network of other like-minded communities that are taking action on climate change."[102] Region 5 also has established energy-efficiency and climate-partnership programs that assist municipalities with buildings, waste, combined heat and power, clean energy purchasing, water and energy conservation, and obtaining energy from landfills.[103] Region 5's 2009 Community Climate Change Initiative has encouraged communities to join one of the above programs and the number of municipalities involved has grown to seventy-six.[104] Region 5 also assists communities with municipal energy, specifically with using the negotiation of their franchise agreements with utilities to increase energy efficiency and promote renewable energy.[105]

2. Atlanta

The Atlanta Regional Commission Certified Green Communities provides voluntary sustainability certifications for local governments in the ten-county Atlanta metropolitan region.[106] Local governments earn points by implementing sustainable practices in ten different areas, and can obtain gold, silver, or bronze certification.[107] Although the program focuses on sustainability, a number of areas relate directly to climate change issues, such as Green Building,[108] Energy

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[102] *See* U.S. Envtl. Prot. Agency, *Municipalities*, http://www.epa.gov/r5climatechange/municipalities.html, *archived at* http://perma.cc/NDA9-MM2F (last visited Oct. 16, 2014).

[103] *Id.*

[104] *See id.*

[105] *Id.*

[106] Atlanta Reg'l Comm'n, *Certified Green Communities Program*, http://www.atlantaregional.com/environment/green-communities, *archived at* http://perma.cc/LP2M-JU3Y (last visited Oct. 20, 2014). The stated benefits of certification are that it "[f]osters civic pride[,] [c]reates a positive image of a place to live or conduct business[,] [s]ets an example for businesses and organizations seeking to reduce their environmental impact[, and] [l]eads to a greater quality of life." *Id.*

[107] *Id.* The stated goals of the program are

> To promote measures that encourage local governments to work towards reducing the environmental footprint of the government through its policies, practices, buildings and fleets; To promote measures that assist local governments in encouraging their community to reduce its environmental impact; To provide assistance in public education and outreach on sustainability.

Id; *see* ATLANTA REG'L COM'N NATURAL RES. DIV., CERTIFICATION MANUAL (2012), *available at* http://www.atlantaregional.com/File%20Library/Environment/Green%20Communities/2013_MANUAL_Green_Communities_December2012.pdf, *archived at* http://perma.cc/E8R9-5FZP.

[108] Examples of policies and practices within the "Green Building" category include adopting a government policy that all new large buildings are LEED certified; requiring new

Efficiency,[109] Green Power,[110] and Transportation and Air Quality.[111] While cities vary in which measures they take, some are more widespread. For instance, almost every community has synchronized their traffic lights, but no community has agreed to retrofit their government vehicles.[112]

3. Chicago

Like the Atlanta Regional Commission Certified Green Communities, Chicago Wilderness has a broader focus than climate change.[113] The regional alliance, with membership that includes "local, state and federal agencies, large conservation organizations, cultural and education institutions, volunteer groups, municipalities,

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or renovated buildings to be ENERGY STAR, EarthCraft Light Commercial, or LEED certified; offering incentives for green building such as expedited planning development or reduced development fees; offering incentives for affordable housing entities to have certified energy efficient housing; and others. ATLANTA REG'L COM'N NATURAL RES. DIV., *supra* note 107, at 7–15.

[109] Examples of policies and practices within the "Energy Efficiency" category include conducting energy audits of government buildings, becoming an ENERGY STAR partner community, agreeing to purchase at least ENERGY STAR rated equipment, installing LED traffic lights, having a "lights out/power down" policy, having a demonstration cool roof, encouraging replacement of inefficient light bulbs, establishing an inspection program to enforce Georgia's residential- and commercial-energy codes, and incentivizing or requiring efficient outdoor lighting. *Id.* at 17–27.

[110] Examples of policies and practices within the "Green Power" category include operating a demonstration renewable energy project, becoming a US EPA Green Power Partner, and incentivizing community solar. *Id.* at 29–34.

[111] Examples of policies and practices within the "Transportation and Air Quality" category include incentivizing a carpool program or subsidizing public transit costs for their employees; adopting a green fleet policy that requires the purchase of only the most fuel efficient and least polluting government vehicles; adopting a government no-idling policy; retrofitting government vehicles; producing or purchasing alternative fuels for government vehicles; adopting a complete streets policy or ordinance for multipurpose use of streets by bicycles, pedestrians, motorists and bus riders; synchronizing traffic lights to reduce idling and congestion; implementing a "safe routes to school" program to encourage walking and bicycling to school; requiring end-of-trip bicycle facilities at all community facilities; adopting bike and pedestrian friendly policies; and encouraging shared, joint, and/or reduced parking. *Id.* at 59–74.

[112] *See* ATLANTA REG'L COMM'N NATURAL RES. DIV., SUMMARY OF GREEN COMMUNITIES ACHIEVEMENTS (2012), *available at* http://www.atlantaregional.com/File%20Library/Environment/Green%20Communities/GC_Summary Achievements _2012.pdf, *archived at* http://perma.cc/XZE8-X7NV.

[113] Chi. Wilderness, *What We Do*, http://www.chicagowilderness.org/what-we-do, *archived at* http://perma.cc/4UUX-AYYY (last visited Oct. 17, 2014).

corporations, and faith-based groups,"[114] works to connect people with nature.[115] However, one of Chicago Wilderness's four primary initiatives is to mitigate climate change.[116] It also builds networks around these issues beyond the Chicago area: "Chicago Wilderness helped create, and chairs, the Metropolitan Greenspaces Alliance," which is "a national network of urban conservation coalitions working to promote [a] collaborative approach, sharing knowledge and best practices across major metropolitan areas."[117]

With respect to climate change, Chicago Wilderness provides a variety of resources and has developed a plan and tools for biodiversity recovery and adaptation.[118] Its "Climate Action Plan for Nature" is "the first plan of its kind to link climate change specifically to issues of biodiversity conservation."[119] Chicago Wilderness identifies high priority actions[120] and specific mitigation,[121]

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[114] Chi. Wilderness, *Who We Are*, http://www.chicagowilderness.org/who-we-are/, *archived at* http://perma.cc/35GB-5HGZ (last visited Oct. 19, 2014).

[115] *Id.*

[116] *Id.*

[117] *Id.*; *see also* Chi. Wilderness, *Metropolitan Greenspaces Alliance*, http://www.chicagowilderness.org/who-we-are/metropolitan-greenspaces-alliance/, *archived at* http://perma.cc/2875-C78C (last visited Oct. 20, 2014).

[118] *E.g.*, CHICAGO WILDERNESS, BIODIVERSITY RECOVERY PLAN (1999), *available at* http://www.chicagowilderness.org/files/3413/3034/7640/biodiversity_recovery_plan.pdf, *archived at* http://perma.cc/U4Q-T2Z2; Chi. Wilderness, *Climate Action*, http://www.chicagowilderness.org/what-we-do/climate-action/, *archived at* http://perma.cc/893B-F63R (last visited Oct. 20, 2014); Chi. Wilderness, *Climate Change Impacts on Regional Biodiversity*, http://www. chicagowilderness.org/what-we-do/climate-action/climate-change-and-regional-biodiversity/, *archived at* http://perma.cc/45SY-QCJE (last visited Oct. 20, 2014).

[119] Chi. Wilderness, *Climate Action*, *supra* note 118.

[120] The plan identifies "three main strategies [as] high priority actions": "(1) mitigate the future impact of climate change; (2) adapt to those that are inevitable; and (3) engage the Chicago Wilderness community in action." CHICAGO WILDERNESS, CHICAGO WILDERNESS CLIMATE ACTION PLAN FOR NATURE 4, *available at* http://www.chicagowilderness.org/files/2213/3035/6961/Climate_Action_Plan_for_Nature.pdf, *archived at* http://perma.cc/P429-S3PZ (last visited Sept. 23, 2014).

[121] Mitigation strategies include recognizing the value of conservation and ecosystem restoration in combatting climate change, conducting a CO2 inventory and reducing the carbon footprint of all members, "help[ing] Chicago Wilderness conservationists take advantage of new finance opportunities related to the carbon market," and "advanc[ing] climate science to increase the efficacy of mitigation strategies in the Chicago Wilderness region." *Id.*

adaptation,[122] and engagement strategies.[123] One of its projects with the City of Chicago, the Nature Conservancy, University of Notre Dame, and the Field Museum is the Climate Considerations Guidebook,[124] which assists with natural area and green space management and focuses particularly on adaptation and species.[125] Six sites are piloting the Guidebook.[126] Chicago Wilderness also provides links to other resources, such as the "Climate Adaptation Guidebook for Municipalities in the Chicago Region" developed by the Chicago Metropolitan Agency for Planning (CMAP), and "[t]he Nature Conservancy Climate Change Adaptation Case Study."[127]

4. Denver

The Colorado Climate Network aims to support mitigation and adaptation efforts by local governments and allied organizations in the state.[128] It focuses primarily on legislation and on providing workshops and conferences.[129] The Network's legislative tracker service informs members about state policy actions that will have a significant impact on the success of local efforts.[130] Its annual

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[122] Adaptation strategies include (1) "assess[ing] the vulnerability of priority Chicago Wilderness terrestrial and aquatic conservation targets to climate change," (2) "promot[ing] and maintain[ing] larger landscapes for biodiversity resiliency with connectivity of green space," (3) "integrat[ing] stormwater management policy with information on how climate change is expected to impact the region," and (4) "develop[ing] monitoring programs to evaluate adaptation strategies." *Id.* at 5.

[123] Engagement strategies include (1) "establish[ing] a Climate Clinic program to engage conservation practitioners in learning, thinking critically and applying knowledge of climate science to natural area conservation"; (2) "build[ing] on existing climate change education programs and tools for educators"; and (3) "us[ing] outcomes from mitigation actions to inform key decision makers of the role land conservation plays in climate change action." *Id.*

[124] Chi. Wilderness, *Climate Action*, *supra* note 118; *see* A. DERBY LEWIS, ET AL., ADVANCING ADAPTATION IN THE CITY OF CHICAGO: CLIMATE CONSIDERATIONS FOR MANAGEMENT OF NATURAL AREAS 1–3 (2012), *available at* https://adapt.nd.edu/resources/1107/download/Climate_Considerations_Chicago_FINAL.pdf, *archived at* http://perma.cc/DCB9-CKCW.

[125] LEWIS, ET AL., ADVANCING ADAPTATION IN THE CITY OF CHICAGO: CLIMATE CONSIDERATIONS FOR MANAGEMENT OF NATURAL AREAS, *supra* note 124 at 1–3.

[126] *Id.*

[127] Chi. Wilderness, *Climate Action*, *supra* note 118; *Climate Adaptation Toolkit*, CMAP, http://www.cmap.illinois.gov/climate-adaptation, *archived at* http://perma.cc/88W9-R3F6 (last visited Sept. 9, 2014).

[128] Colo. Climate Network, *What We Do*, http://www.coclimatenetwork.org/, *archived at* http://perma.cc/QAP4-LAYU (last visited Sept. 9, 2014).

[129] *Id.*

[130] Colo. Climate Network, *Colorado Climate Network Programs*, http://www.coclimatenetwork.org/programs/index.html, *archived at* http://perma.cc/Y82J-4CPC (last visited Sept. 11, 2014).

conferences and periodic workshops provide opportunities for information, skill-building, and networking.[131] These workshops at times assist with creating needed harmonization. For instance, a workshop held in April of 2013 discussed the range of methods Colorado local governments use to inventory GHGs and ways to make state and local inventories more consistent.[132] The Network's website also provides links to grant opportunities and to state, local, and national programs run throughout the country.[133]

5. New York City

New York's Climate Smart Communities is a "state-local partnership."[134] The statewide network, which is cosponsored by several relevant state agencies,[135] provides a variety of services to local governments, including community coordinators, a communities listserv, webinars, and a local-action guide.[136] The community coordinators assist with the selection, development, and implementation of local climate action programs; some of them work with specified geographic regions and others on a statewide basis.[137] The listserv alerts local governments to

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131 *Id.*

132 *Id.*

133 *Id.*

134 N.Y. Dep't of Envtl. Conservation, *Community Sustainability*, http://www.dec.ny.gov/energy/76483.html, *archived at* http://perma.cc/R6MZ-FTRL (last visited Sept. 11, 2014).

135 "The Climate Smart Communities program is jointly sponsored by the following six New York State agencies: Department of Environmental Conservation; Energy Research and Development Authority; Public Service Commission; Department of State; Department of Transportation; and the Department of Health." N.Y. Dep't of Envtl. Conservation, *Climate Smart Communities*, http://www.dec.ny.gov/energy/50845.html#Climate, *archived at* http://perma.cc/DZM6-SJVL (last visited Sept. 9, 2014).

136 *Id.*

137 Climate Action Assocs. LLC, *Company Overview*, http://climatetools.com/about.html, *archived at* http://perma.cc/K7PG-7C8P (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Capital District CSC Coordinator*, http://www.dec.ny.gov/energy/85100.html, *archived at* http://perma.cc/Y7QC-TZP6 (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Climate Smart Community Coordinators*, http://www.dec.ny.gov/energy/84508.html, *archived at* http://perma.cc/SHS4-553X (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Land Use and Transportation Planning Support CSC Coordinator*, http://www.dec.ny.gov/energy/85125.html, *archived at* http://perma.cc/MEL8-YADV (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Long Island CSC Coordinator*, http://www.dec.ny.gov/energy/85115.html, *archived at* http://perma.cc/N8KL-Q6ND (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Mid-Hudson CSC Coordinator*, http://www.dec.ny.gov/energy/85110.html, *archived at* http://perma.cc/JX74-DLUE (last visited Sept. 9, 2014); N.Y. Dep't of Envtl. Conservation, *Statewide (Outside of Pilot Regions) CSC Coordinator*, http://www.dec.ny.gov/energy/85120.html, *archived at* http://perma.cc/VE2V-LHHU (last visited Sept. 9, 2014).

funding, educational, and networking opportunities.[138] Webinars provide governments with information on a broad range of climate-relevant topics.[139] The *Climate Smart Communities Guide to Local Action* provides comprehensive information for localities interested in becoming a Climate Smart Community.[140] The guide includes technical and policy support for setting and measuring emissions goals, decreasing energy demands for government facilities and transportation, encouraging renewables for local government operations, implementing climate friendly waste management practices, and adapting to climate change.[141] The program also allows special access to some state assistance programs for communities that sign the Climate Smart Pledge.[142]

6. San Francisco

The Institute for Local Government, the research and education affiliate of the California State Association of Counties and the League of California Cities, focuses broadly on supporting good government at a local level.[143] Like other state and regional networks described in this section, it has extensive programs and resources on climate change for California local governments that make it appropriate for inclusion in this study.[144] Specifically, its sustainable communities program provides information to local officials on greenhouse gas inventories, climate action plans, and adapting to climate change.[145] It also gives out a "Beacon Award" to recognize California cities and counties "that are working to reduce greenhouse gas emissions, save energy and adopt policies and programs that promote sustainability."[146] The Statewide Energy Efficiency Collaborative—a "collaboration between three statewide non-profit organizations and California's four Investor Owned

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[138] N.Y. Dep't of Envtl. Conservation, *Community Sustainability*, http://www.dec.ny.gov/energy/50845.html, *archived at* http://perma.cc/3UJ5-RGKH (last visited Sept. 9, 2014).

[139] N.Y. Dep't of Envtl. Conservation, *Climate Smart Webinar Presentations*, http://www.dec.ny.gov/energy/84359.html, *archived at* http://perma.cc/TMC7-RET2 (last visited Sept. 9, 2014).

[140] N.Y. Dep't of Envtl. Conservation, *Climate Smart Communities*, *supra* note 135.

[141] *Id.*

[142] N.Y. Dep't of Envtl. Conservation, *Adopt the Climate Smart Communities Pledge*, http://www.dec.ny.gov/energy/53013.html, *archived at* http://perma.cc/884Y-A9HF (last visited Sept. 9, 2014).

[143] Inst. for Local Gov't, *About ILG*, http://www.ca-ilg.org/about-institute-local-government, *archived at* http://perma.cc/ZJG6-AYFJ (last visited Sept. 9, 2014); Inst. for Local Gov't, *Beacon Award: Local Leadership Toward Solving Climate Change*, http://www.ca-ilg.org/beacon-award-local-leadership-toward-solving-climate-change, *archived at* http://perma.cc/ZZM2-9LYS (last visited Sept. 9, 2014); Inst. For Local Gov't, *About ILG*, http://www.ca-ilg.org/about-institute-local-government, *archived at* http://perma.cc/ZJG6-AYFJ (last visited Sept. 9, 2014).

[144] Inst. for Local Gov't, *Beacon Award*, *supra* note 143.

[145] *Id.*

[146] *Id.*

Utilities"—cosponsors the Beacon Award, which is funded by California utility ratepayers and administered by several California utilities under the auspice of its public utilities commission.[147] Participants may receive a Silver, Gold, or Platinum Beacon Award based on their efforts to increase energy efficiency, reduce greenhouse gas emissions, or implement designated activities in ten different "Best Practice Areas."[148]

7. Twin Cities

For the Twin Cities, the Article includes two different statewide networks because of their different emphases and opportunities for participation. Greenstep Cities, like some of the other programs described in this section, is a statewide sustainability program targeting local governments that includes categories relevant to climate change.[149] Cities are recognized for implementing best practices in buildings and lighting, land use, transportation, environmental management, and economic and community development.[150] As discussed in more depth in *Suburban Climate Change Efforts*, Greenstep Cities emerged out of the implementation of state legislation.[151] It is administered by a state agency, but it includes a number of

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[147] Inst. for Local Gov't, *Beacon Award: Local Leadership Toward Solving Climate Change*, http://www.ca-ilg.org/overview/beacon-award-local-leadership-toward-solving-climate-change, *archived at* http://perma.cc/8HAW-PPK9 (last visited Nov. 14, 2014).

[148] INST. FOR LOCAL GOV'T, BEACON AWARD: LOCAL LEADERSHIP TOWARD SOLVING CLIMATE CHANGE 3, *available at* http://www.ca-ilg.org/sites/main/files/file-attachments/beacon_award_brochure.pdf, *archived at* http://perma.cc/DDY9-ST3A (last visited Sept. 23, 2014). To win a Beacon Award, participating agencies are required to complete each of the following six elements: "(1) Agency Greenhouse Gas Reductions; (2) Agency Electricity Savings; (3) Agency Natural Gas Savings; (4) Community Greenhouse Gas Reduction; (5) Activity Promoting Energy Efficiency in the Community; [and] (6) Activities in each of the Institute's ten Sustainability Best Practice Areas." Inst. for Local Gov't, *Beacon Award Winners*, http://www.ca-ilg.org/post/beacon-award-winners, *archived at* http://perma.cc/8FUK-8ZV6 (last visited Oct. 13, 2013). While a Silver Award winner may focus its activities on education and outreach, an example of a Platinum Award activity would be "[a]dopting a green building ordinance" or "[s]ponsoring home energy audit and efficiency retrofit programs." INST. FOR LOCAL GOV'T, GUIDELINES FOR PARTICIPATION & RECOGNITION 12 (2013), *available at* http://www.ca-ilg.org/sites/main/files/file-attachments/beacon_program_guidelines_june_2013_revise_final_0.pdf, *archived at* http://perma.cc/36UN-4AY2. For the winners, see Institute for Local Government, *Beacon Award Winners*, *supra*.

[149] Minn. Pollution Control Agency, *Minnesota GreenStep Cities*, http://greenstep.pca.state.mn.us/index.cfm, *archived at* http://perma.cc/G6CN-YVPW (last visited Oct. 15, 2014).

[150] MINN. POLLUTION CONTROL AGENCY, MINNESOTA GREENSTEP CITIES 1, *available at* http://www.pca.state.mn.us/index.php/view-document.html?gid=17370, *archived at* http://perma.cc/PQ4W-X5T7.

[151] Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 415–17.

partner organizations—including nonprofits, city advocacy organizations, and government agencies—in its bimonthly working committee and receives foundation funding in addition to government funding.[152]

The Minnesota Energy Challenge is a statewide program run by the nonprofit organization Center for Energy and the Environment.[153] It maintains an online action guide to help Minnesotans reduce energy waste and allows communities—including local governments, schools, businesses, nonprofits, neighborhood organizations, and other community groups—to form teams that compete for energy savings.[154] This network differs from some of the others studied because it focuses not just on local governments but on other community-based, often sublocal, entities. The teams track both their dollar and carbon savings on the Minnesota Energy Challenge website.[155] In addition to the action guide and teams, the website provides a link to a personal carbon footprint calculator and other information to help people reduce energy use.[156] The Minnesota Energy Challenge's statewide coordinator also organizes educational events and other outreach efforts at local schools, churches, neighborhood organizations, and other community groups.[157]

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[152] Minn. Pollution Control Agency, *The Minnesota GreenStep Cities Program*, http://greenstep.pca.state.mn.us/aboutProgram.cfm, *archived at* http://perma.cc/VN3T-NENC (last visited Oct. 15, 2014); *see* Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 15–16.

[153] Emma Shriver, *Minnesota Energy Challenge*, MINN. CTR. FOR ENERGY & ENV'T (Oct. 2006), http://www.mncee.org, *archived at* http://perma.cc/4V82-LGZ2 (follow "Innovation Exchange: Resource Center" hyperlink; then "Data & Reference" hyperlink, then "Minnesota Energy Challenge" hyperlink); MN Energy Challenge, *About the Challenge*, http://www.mnenergychallenge.org/About-the-Challenge.aspx, *archived* http://perma.cc/FG2-5K4P (last visited Oct. 15, 2014).

[154] MN Energy Challenge, *Start a Team*, http://www.mnenergychallenge.org/Teams/Create.aspx, *archived at* http://perma.cc/8XBV-GGL8 (last visited Oct. 25, 2014).

[155] MN Energy Challenge, *Challenge FAQs*, http://www.mnenergychallenge.org/About-the-Challenge/Challenge-FAQs.aspx, *archived at* http://perma.cc/FG2-5K4P (last visited Oct. 15, 2014) ("Three people live in their 2,000 ft2 home, and spend $850 a year on electricity and $1,185 a year on natural gas. They have two cars, which get an average of 22 miles per gallon, and are driven about 12,500 miles a year. In total, they're spending over $4,300 every year on energy and have a carbon footprint of more than 51,900 pounds of carbon dioxide emissions annually.").

[156] MN Energy Challenge, *How Do You Measure Up?*, http://www.mnenergychallenge.org/Actions/How-Do-You-Measure-Up-.aspx, *archived at* http://perma.cc/BHK5-YVQ9 (last visited Oct. 15, 2014).

[157] MN Energy Challenge, *About Emma*, http://www.mnenergychallenge.org/About-the-Challenge/About-Neely.aspx, *archived at* http://perma.cc/4A45-S4QU (last visited Sept. 12, 2014).

IV. NETWORK PARTICIPATION PATTERNS BY CITIES IN U.S. MAJOR METROPOLITAN REGIONS

While all of the example networks described in Part III have goals and programs that could help with mitigation and adaptation, participation is critical. Localities must actually commit to take these steps and follow through for these networks to make a significant aggregate difference beyond influencing international negotiations. Moreover, numbers alone only give a partial picture. Given the organization of most major U.S. cities into metropolitan regions, patterns of participation within those regions are crucial to understanding where the biggest gaps and opportunities are.

This Part takes on that challenge. It considers how different types of cities are participating in international, national, state, and regional networks by examining six major U.S. metropolitan regions in different parts of the country. Understanding these participation patterns is an important first step for planning strategies to increase a network's effectiveness in getting more localities to do more. As described in depth in Part V, I will build on this analysis in future qualitative research by exploring why cities join these networks and how participating in networks changes the cities' behavior.

As Table 1 indicates, an initial overall look at participation in international and national networks in six metropolitan regions is rather concerning. While some of the metro regions show significant participation in the Mayors Agreement, ICLEI, and the Copenhagen City Climate Catalogue, and most have cities involved with USDN and the carbon*n* registry, very few cities in the metropolitan regions have participated in the more recent international agreements. Moreover, even the Copenhagen City Climate Catalogue commitments may not be a strong signifier of broader international participation because the cities making those commitments generally were members of the Mayors Agreement and simply repeated their Mayors Agreement commitment in the Catalogue.

Table 1: Overall Participation of Cities in Six Sample Metropolitan Regions in International and National Climate Change Related Networks[158]

	Atlanta (109)	**Chicago (181)**	**Denver (68)**	**New York City (327)**	**San Francisco (104)**	**Twin Cities (322)**
ICLEI	2 (1.8%)	8 (4.4%)	2 (2.9%)	31 (9.5%)	55 (52.9%)	8 (2.5%)
Nantes Declaration	0	0	1 (1.5%)	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0
Mexico City Pact	0	0	1 (1.5%)	0	0	1 (0.3%)
Copenhagen City Climate Catalogue	0	28 (15.5%)	3 (4.4%)	59 (18%)	51 (49%)	21 (6.5%)
carbon*n* Cities Climate Change Registry	1 (0.9%)	2 (1.1%)	0	1 (0.3%)	8 (7.7%)	1 (0.3%)
Mayors Agreement	2 (1.8%)	32 (17.7%)	4 (5.9%)	64 (19.6%)	60 (57.5%)	22 (6.8%)
Urban Sustainability Directors Network	2 (1.8%)	3 (1.7%)	2 (2.9%)	4 (1.2%)	4 (3.8%)	1 (0.3%)

The sections that follow take a more detailed look at each of the metropolitan regions—including these international- and national-level networks, but also state and regional ones—to see how participation patterns vary by city type within the region. In particular, drawing from the categorizations and maps created by Myron Orfield in *American Metropolitics: The New Suburban Reality*,[159] they examine participation by central cities,[160] at-risk segregated communities,[161] at-risk older

[158] *See* Hari M. Osofsky, Appendix: Patterns of Network Participation in Major Metropolitan Areas (2014) (on file with Utah Law Review), *archived at* http://perma.cc/L2PG-VSTU.

[159] ORFIELD, *supra* note 27.

[160] These are the core center cities upon which these metropolitan regions are based: Atlanta, Chicago, Denver, New York, San Francisco and Oakland, and Minneapolis-St. Paul. *Id.* at 23–28.

[161] These cities have "very low tax capacity, slow tax-capacity growth, high municipal costs, and high concentrations of minority children in public schools." *Id.* at 37. Many of them are inner-ring suburbs. They often have a higher non-Asian minority population than the center cities with a "fraction of the resources of the central cities they surround." *Id.* They "are some of metropolitan America's worst places to live." *Id.*

communities,[162] at-risk low-density communities,[163] bedroom developing communities,[164] affluent job centers, and very affluent job centers.[165] To the extent that some types of cities tend to participate in particular networks more than others, these patterns may point a way forward to involving a greater number of cities in more climate action. Also, as I found in my initial sample of cities in *Suburban Climate Change Efforts*, the types of actions taken vary by city type and so targeting models by city type and pairing other needs with climate change mitigation and adaptation—rather than just providing a general toolkit for local action—may help encourage greater participation.[166]

A. Atlanta

Founded in 1837, Atlanta is the capital of Georgia and the state's largest city.[167] According to the 2012 census data, Atlanta is the eleventh largest metropolitan region in the United States.[168] It serves as a major commercial, financial, and transportation center in the southeastern United States.[169] As with all of the metropolitan regions studied, however, the Atlanta region's center city represents

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[162] These cities are "very high-density suburbs that had relatively low poverty rates, low tax capacity, slower-than-average growth in fiscal capacity, and slow population growth . . . . The group comprises mostly older, inner-ring suburbs and small, outlying cities that have been swallowed up by metropolitan growth." *Id.* at 38.

[163] These cities are "relatively low-density localities with low tax capacities that are growing more slowly than their regions and with higher-than-average poverty and population growth rates. These communities, home to about a fourth of the population in . . . [many] metropolitan areas, are typically located in the metropolitan areas' outer portions." *Id.* at 41.

[164] These cities are "what many would regard as the prototypical suburb. The population—mostly white—is growing more quickly in the suburbs in this group than in any other. Density is low, housing is new, and tax capacity is just below average and growing at an average rate." *Id.* at 42.

[165] These cities "have moved well beyond their traditional role as bedroom communities for large cities and are now major players in their regional economy." *Id.* at 44.

[166] *See* Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 452–54.

[167] Andy Ambrose, *Atlanta*, NEW GA. ENCYCLOPEDIA, http://www.georgiaencyclopedia.org/articles/counties-cities-neighborhoods/atlanta, *archived at* http://perma.cc/5R3D-AN7R (last updated June 5, 2014).

[168] U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, CENSUS.GOV, http://www.census.gov/popest/data/metro/totals/2012/, *archived at* http://perma.cc/9PN4-Y7F4 (last visited Sept. 12, 2014) (follow "Annual Estimates of the Population of Metropolitan and Micropolitan Statistical Areas: April 1, 2010 to July 1, 2012 (CBSA-EST2012-01) [XLS – 153k]" hyperlink; then in Excel, sort metropolitan regions, largest to smallest by the 2012 population estimates).

[169] Ambrose, *Atlanta*, *supra* note 167.

only a fraction of the metropolitan region's population—less than 10% in this case.[170]

Atlanta's growth pattern has followed the path Muller outlined for metropolitan regions.[171] The expansion of intersecting rail lines allowed it to emerge as a regional center before and after the Civil War.[172] In the early twentieth century, Atlanta's economy diversified, but its development patterns remained deeply impacted by segregation.[173] The advent of the automobile allowed Atlanta's suburban expansion, and the building of its airfield in the 1920s ensured Atlanta's continuing importance as a regional hub.[174] Atlanta experienced massive growth following World War II, which it responded to through annexation and building more roads.[175] This massive suburban expansion continued during the rest of the century; the metropolitan region doubled in population from two million to more than four million between 1980 and 2000.[176] Atlanta was the second-fastest growing metropolitan region in the United States during the 1990s.[177] Although Atlanta remains quite segregated, distribution patterns have changed as more African-Americans have moved into its suburbs.[178]

Atlanta metropolitan regional governance takes place through the Atlanta Regional Commission, which has been designated by state law as both a Metropolitan Area Planning and Development Commission and a Regional

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170 "According to the 2010 U.S. census, the population of Atlanta is 420,003, although the metropolitan area (comprising twenty-eight counties and more than 6,000 square miles) has a population of more than 5.2 million." *Id.*

171 *See* MULLER, CONTEMPORARY SUBURBAN AMERICA, *supra* note 16, at 26–49; Muller, *Transportation and Urban Form*, *supra* note 16, at 80–81.

172 Ambrose, *Atlanta*, *supra* note 167.

173 *Id.*

174 *Id.*

175 *Id.*

176 *Id.*

177 *Id.*

178 *Id.* For additional resources on Atlanta's metro-regional development, see generally 1 FRANKLIN M. GARRETT, ATLANTA AND ENVIRONS: A CHRONICLE OF ITS PEOPLE AND EVENTS, 1820S–1870S (2011) (providing comprehensive history of Atlanta from the 1820s to the 1870s); 2 FRANKLIN M. GARRETT, ATLANTA AND ENVIRONS: A CHRONICLE OF ITS PEOPLE AND EVENTS, 1880S–1930S (1969) (providing comprehensive history of Atlanta from the 1880s to the 1930s); 3 HAROLD M. MARTIN, ATLANTA AND ENVIRONS: A CHRONICLE OF ITS PEOPLE AND EVENTS, 1940S–1970S (2011) (providing comprehensive history of Atlanta from the 1940s to the 1970s); SPRAWL CITY: RACE, POLITICS, AND PLANNING IN ATLANTA (Robert D. Bullard et al. eds., 2000) (analyzing the development of Atlanta's worsening urban sprawl problem, with particular emphasis on its link to race and class); William Campbell, *Urban Holism: The Empowerment Zone and Economic Development in Atlanta*, 26 FORDHAM URB. L.J. 1411 (1999) (explaining how Atlanta has reduced violent crime while increasing its population through holistic development); James E. Kundell & Margaret Myszewski, *Urban Sprawl*, NEW GA. ENCYCLOPEDIA, http://www.georgiaencyclopedia.org/articles/geography-environment/urban-sprawl, *archived at* http://perma.cc/EP7D-VGV4 (last edited on Oct. 2, 2014) (summarizing environmental impacts of urban sprawl in Atlanta metro region).

Commission.[179] Initially created as the Metropolitan Planning Commission in 1947—when it included two counties and the city of Atlanta—the Atlanta Regional Commission now engages in intergovernmental coordination and regional planning for ten counties and the city of Atlanta.[180]

The metro region also has more specialized structures functional at that regional level to address transportation concerns. For example, the Metropolitan Atlanta Regional Transit Authority (MARTA) has worked since it was statutorily authorized in the 1960s to create regional-level solutions to transportation.[181] The Georgia Regional Transportation Authority was established by state statute in 1999 to address air quality and transportation mobility across a thirteen-county region.[182]

Map 1 displays the current Atlanta metropolitan region, organized by city type. Both the at-risk segregated and affluent-job center suburbs are physically located in the inner rings, close to the center city. The bedroom-developing suburbs and at-risk, lower-density suburbs comprise the outer rings, where more of the expansion takes place.

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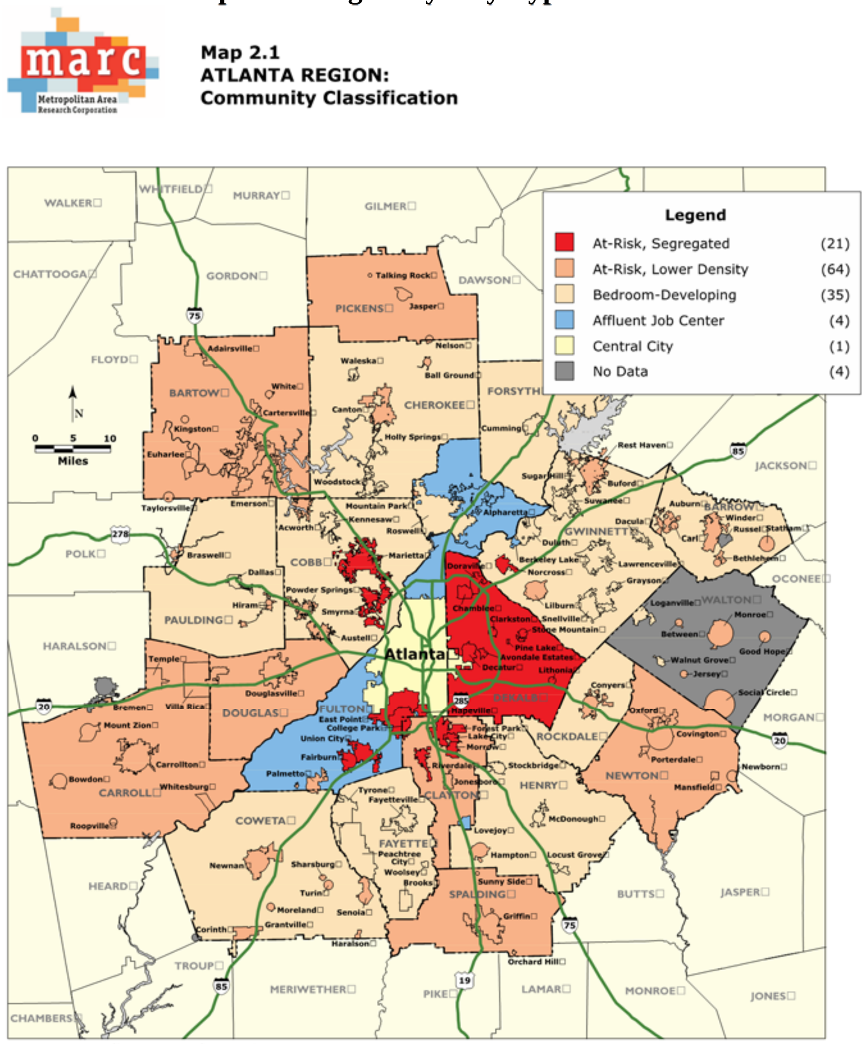
[179] Atlanta Reg'l Comm'n, *About ARC*, http://www.atlantaregional.com/about-us/overview, *archived at* http://perma.cc/BP6B-MEU9 (last visited Sept. 12, 2014).

[180] *Id.*; Atlanta Reg'l Comm'n, *ARC History, Funding and Membership*, http://www.atlantaregional.com/about-us/overview/history-funding--membership, *archived at* http://perma.cc/XTM6-6T7Z (last visited Sept. 12, 2014).

[181] Metro. Atlanta Rapid Transit Auth., *MARTA's Past and Future*, http://www.itsmarta.com/marta-past-and-future.aspx, *archived at* http://perma.cc/6BRE-3BLQ (last visited Sept. 12, 2014).

[182] GA. REG'L TRANSP. AUTH., OVERVIEW, *available at* http://www.grta.org/about_us/pdf/GRTA_Fact_Sheet.pdf, *archived at* http://perma.cc/8P3Q-AWFH (last visited Feb. 1, 2014). A report by The Brookings Institution Center on Urban and Metropolitan Policy discussed the creation of the Georgia Regional Transportation Authority as a positive step in the metro region's efforts to address sprawl. BROOKINGS INST. CTR. ON URBAN & METRO. POLICY, MOVING BEYOND SPRAWL: THE CHALLENGE FOR METROPOLITAN ATLANTA 36 (2000), *available at* http://www.brookings.edu/~/media/research/files/reports/2000/3/atlanta/atlanta.pdf, *archived at* http://perma.cc/E74N-J7SL.

Map 1: Atlanta Metropolitan Region by City Type



Data Source: Metropolitan Area Research Corporation.

As displayed in Table 2 below, although the center city in the Atlanta metropolitan region is active in climate change networks at every level, its suburbs generally show very low levels of participation in any network. Its affluent job centers and bedroom-developing communities are the most active group, but the sample size of affluent job centers is very low and the participation rate of bedroom-developing communities is still under 20% in any network. Overall, the Atlanta metro region's cities are more active in the metropolitan regional network than in national and international networks.

Table 2: Atlanta Metropolitan Region: Participation in Climate Change Related Networks by City Type[183]

	Central City (1)	**At-Risk, Segregated (20)**	**At-Risk, Lower Density (56)**	**Bedroom-Developing (24)**	**Affluent Job Center (2)**	**No Data/ Recently Incorporated (6)**
ICLEI Member	1 (100%)	1 (5%)	0	0	0	0
Nantes Declaration	0	0	0	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0
Mexico City Pact[184]	0	0	0	0	0	0
Copenhagen City Climate Catalogue	1 (100%)	0	0	0	1 (50%)	0
carbon*n* Cities Climate Registry[185]	1 (100%)	0	0	0	0	0
Mayors Agreement	1 (100%)	2 (10%)	0	1 (4.2%)	1 (50%)	0
Urban Sustainability Directors Network	1 (100%)	1 (5%)	0	0	0	0
Atlanta Regional Commission Certified Green Communities	1 (100%)	3 (15%)	1 (1.8%)	4 (16.7%)	1 (50%)	2 (33%)

[183] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.

[184] *See* The Mex. City Pact, *Signatories*, http://www.mexicocitypact.org/en/the-mexico-city-pact-2/list-of-cities/, *archived at* http://perma.cc/W2PX-699P (last visited Oct. 11, 2014).

[185] *See* carbon*n* Climate Registry, *City Search*, http://citiesclimateregistry.org/data/, *archived at* http://perma.cc/9VZT-Q6SR (last visited Oct. 27, 2014).

B. Chicago

Chicago, the third-largest metropolitan region in the United States,[186] also has a history of growth and development tied to transportation.[187] Its combination of water and railroad access with its central location made it an early economic hub that included agricultural products, stockyards, and industry.[188] Streetcars, elevated rail lines, and the interurban railroad allowed population expansion into suburban areas in the late nineteenth and early twentieth century, an expansion which was at times motivated by communities forming around the prohibition of liquor.[189] Segregation also shaped Chicago's patterns of development; racially restrictive covenants limited where new minority residents could live.[190]

Chicago's evolution into a mature metropolis took place over the course of the mid-to-late twentieth century.[191] The development of interstate freeways, paired with state and county highways, allowed for greater suburbanization in the mid-twentieth century.[192] At the same time, urban renewal projects reshaped existing communities.[193] Deindustrialization and the emergence of technology and service industries at the end of the twentieth century further shaped Chicago's pattern of metropolitan development.[194] New urban centers emerged in the suburbs, with many white-collar workers no longer commuting into the center city, but instead from suburb to suburb.[195]

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186 U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, *supra* note 168.

187 *See* Ann Durkin Keating, *Metropolitan Growth*, ENCYCLOPEDIA OF CHI., http://www.encyclopedia.chicagohistory.org/pages/821.html, *archived at* http://perma.cc/Z3ME-RRR6 (last visited Oct. 27, 2014).

188 *Id.*

189 *Id.*

190 *Id.*

191 *See id.*

192 *See id.*

193 *Id.*

194 *See id.*

195 *See id.* For additional resources on the Chicago metropolitan region's development, see GLEN E. HOLT & DOMINIC A. PACYGA, CHICAGO: A HISTORICAL GUIDE TO THE NEIGHBORHOODS, THE LOOP AND SOUTH SIDE (1979); DOMINIC A. PACYGA, CHICAGO: A BIOGRAPHY (2009); DOMINIC A. PACYGA, POLISH IMMIGRANTS AND INDUSTRIAL CHICAGO, WORKERS ON THE SOUTH SIDE, 1880–1922 (1991); Ann Durkin Keating, *Chicagoland: More than the Sum of Its Parts*, 30 J. URB. HIST. 213 (2004); Jon B. DeVries & D. Bradford Hunt, *Chicago in Plan: An Insiders' Discourse on City's History*, *Challenges Ahead*, URB. LAND, Oct. 10, 2013, *available at* http://urbanland.uli.org/planning-design/chicago-in-plan-insiders-discourse-on-citys-history-challenges-ahead/, *archived at* http://perma.cc/86VB-R3XG; Arnold R. Hirsch, *Urban Renewal*, ENCYCLOPEDIA OF CHI., http://www.encyclopedia.chicagohistory.org/pages/1295.html, *archived at* http://perma.cc/HST-69YM (last visited Oct. 27, 2013); Carl Smith, *The Plan of Chicago*,

Chicago's metro-regional governance takes place under the auspices of the Chicago Metropolitan Agency for Planning (CMAP).[196] CMAP serves as the official regional planning organization for the seven northeastern Illinois counties that comprise the metro region.[197] It was created in response to 2005 state legislation that united the functions of the metro region's two primary regional planning organizations, the Chicago Area Transportation Study (transportation planning) and the Northeastern Illinois Planning Commission (land use planning).[198] CMAP was tasked with developing and guiding the implementation of a comprehensive regional plan—Chicago's first since its 1909 *Plan of Chicago*—which it completed in 2010.[199] This plan, GO TO 2040, focuses on coordinated strategies that will assist the efforts of the region's 284 communities on transportation, housing, economic development, open space, the environment, and other quality-of-life issues.[200]

Map 2 displays the metropolitan region's current pattern of development. Its first-ring suburbs largely consist of at-risk segregated and older communities plus some of its developed job centers. With limited exceptions, the affluent and very affluent job centers form the next ring, and the at-risk low-density communities and bedroom-developing communities comprise its outer perimeter.

ENCYCLOPEDIA OF CHI., http://www.encyclopedia.chicagohistory.org/pages/10537.html, *archived at* http://perma.cc/KEK3-E2MZ (last visited Oct. 27, 2013).

[196] Chi. Metro. Agency for Planning, *About*, http://www.cmap.illinois.gov/about, *archived at* http://perma.cc/7MZT-4PVK (last visited Feb. 2, 2014); Chi. Metro. Agency for Planning, *GO TO 2040*, http://www.cmap.illinois.gov/about/2040, *archived at* http://perma.cc/LJS8-DELE (last visited Sept. 23, 2014).

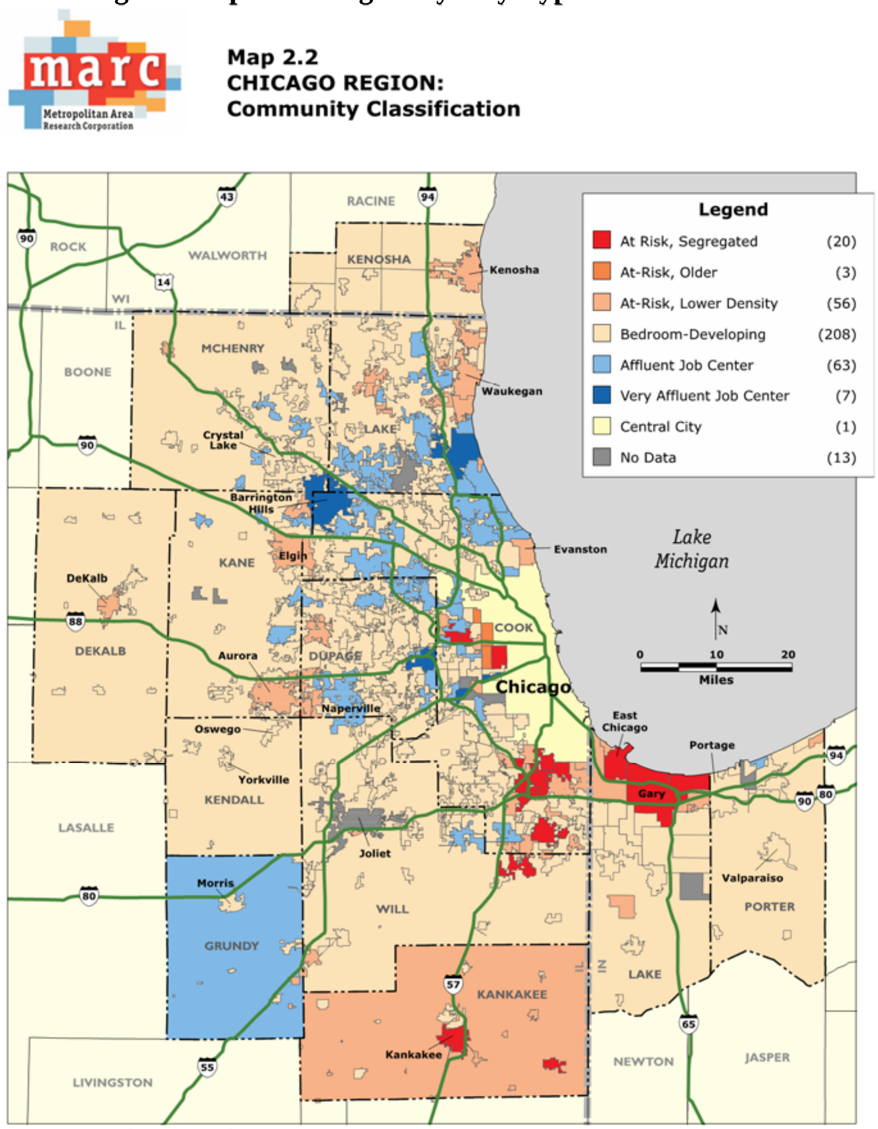
[197] Chi. Metro. Agency for Planning, *About*, *supra* note 196.

[198] KAREN SAVAGE ET AL., CORRIDOR APPROACHES TO INTEGRATING TRANSPORTATION AND LAND USE 4 (June 2009), *available at* http://onlinepubs.trb.org/onlinepubs/archive/notesdocs/NCHRP08-36(86)_FR.pdf, *archived at* http://perma.cc/GUP9-6RY2.

[199] Chi. Metro. Agency for Planning, *Fact Sheet: The Chicago Metropolitan Agency for Planning and GO TO 2040*, http://www.cmap.illinois.gov/about/for-media/ipk-10-13-10/fact-sheet, *archived at* http://perma.cc/B7T3-7GYQ (last visited Sept. 11, 2014).

[200] Chi. Metro. Agency for Planning, *GO TO 2040*, *supra* note 196.

Map 2: Chicago Metropolitan Region by City Type



Data Source: Metropolitan Area Research Corporation.

As Table 3 indicates, Chicago's center city—like Atlanta's—shows a much higher participation rate than its suburbs. However, its suburbs overall show more involvement in climate change networks than ones in Atlanta. Interestingly, the highest levels of involvement are in the national-scale Mayors Agreement and corresponding commitments in the Copenhagen City Climate Catalogue. Chicago's at-risk older suburbs show especially high activity levels, but they are a small sample group. There is enough participation by each of the city types in many of the networks that those cities could potentially be used as models for other cities of their type.

Table 3: Chicago Metropolitan Region: Participation in Climate Change Related Networks by City Type[201]

	Central City (1)	At-Risk, Segregated (18)	At-Risk, Lower Density (18)	At-Risk, Older (3)	Bedroom-Developing (89)	Affluent Job Center (41)	Very Affluent Job Center (7)	No Data (4)
ICLEI Member	1 (100%)	0	1 (5.6%)	1 (33.3%)	3 (3.4%)	1 (2.4%)	1 (14.3%)	0
Nantes Declaration	0	0	0	0	0	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0	0	0
Mexico City Pact[202]	0	0	0	0	0	0	0	0
Copenhagen City Climate Catalogue	1 (100%)	2 (11.1%)	4 (22.2%)	2 (66.7%)	13 (14.6%)	5 (12.2%)	1 (14.3%)	0
carbon*n* Cities Climate Registry Reporting Cities[203]	0	0	1 (5.6%)	1 (33.3%)	0	0	0	0
Mayors Agreement	1 (100%)	2 (11.1%)	4 (22.2%)	2 (66.7%)	15 (16.9%)	6 (14.6%)	1 (14.3%)	1 (25%)
Urban Sustainability Directors Network	1 (100%)	0	1 (5.6%)	1 (33.3%)	0	0	0	0
EPA Region 5 Community Climate Change Initiative Partner	1 (100%)	2 (11.1%)	1 (5.6%)	1 (33.3%)	7 (7.9%)	3 (7.3%)	0 (14.3%)	0
Chicago Wilderness	1 (100%)	0	0	1 (33.3%)	5 (5.6%)	9 (22%)	1 (14.3%)	0

[201] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.
[202] *See* The Mex. City Pact, *Signatories*, *supra* note 184.
[203] *See* carbon*n* Climate Registry, *City Search*, *supra* note 185.

C. Denver

Denver's history began later than some of the other metropolitan regions in this study and follows a somewhat different pattern that is tied to its physical geography. It emerged not because of its location near railroads or water, but because gold was discovered near there in 1858.[204] Denver's early years were somewhat precarious, as prospectors rushed to gold in the nearby mountain town of Central City, only to return to Denver's more hospitable climate.[205] Denver also experienced the Civil War, and fires and floods devastated it in its first decade.[206] Denver's place as a regional hub was solidified by citizens building their own rail line to join the Union Pacific when Denver was bypassed and by the discovery of silver in Leadville.[207]

Denver experienced economic crisis in the late nineteenth and early twentieth century when the price of silver collapsed and the agricultural and ranching industries experienced a severe drought.[208] Denver remained highly dependent on mineral, agricultural, and ranching industries until after World War II when gasoline rationing ended and the oil business began to boom in and around Denver.[209] Investments by private industry and federal government—paired with the expansion of roads, wider accessibility of automobiles, and a major airport—allowed for significant suburban expansion.[210] Continued population expansion paired with limited public transportation has led to problems of sprawl and congestion, which Denver has tried to alleviate with recent transportation projects.[211] As of the 2012 census estimates, Denver is the sixteenth largest metropolitan area in the United States.[212]

Denver's efforts at metro-regional governance began in 1955, when thirty-nine officials agreed to create a planning entity, the Inter-County Regional Planning Association, for what was then a four-county region.[213] This entity changed its name

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[204] CARL ABBOTT ET AL., COLORADO: A HISTORY OF THE CENTENNIAL STATE 44 (4th ed. 2005); Denver Convention & Visitors Bureau, *Denver History*, http://www.denver.org/metro/history, *archived at* http://perma.cc/FMR6-3X25 (last visited Oct. 27, 2014).

[205] *See* ABBOTT ET AL., *supra* note 204, 51–54.

[206] *Id.* at 59–60, 63.

[207] *See id.* at 79–83, 92.

[208] *Id.* at 102–03.

[209] *See id.* at 315, 322.

[210] *See id.* at 333–36, 323–25.

[211] For a discussion of the sprawl and smog problems and progress in addressing them, see David Olinger, *We Caused Sprawl Ourselves*, DENVER POST.COM (Feb. 7, 1999), http://extras.denverpost.com/news/gro0207a.htm, *archived at* http://perma.cc/E4VG-U3KH; *Decade After 'Brown Cloud,' Denver Air Clears*, USA TODAY (Aug. 10, 2002), http://usatoday30.usatoday.com/weather/news/2002/2002-08-10-denver-smog.htm, *archived at* http://perma.cc/B77K-M4E8.

[212] U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, *supra* note 168.

[213] DENVER REG'L COUNCIL OF GOV'TS, SHAPING THE REGION WITH ONE VOICE (2005), *available at* https://drcog.org/sites/drcog/files/resources/50th%20DRCOG%20history

in 1968 to its current one, the Denver Regional Council of Governments.[214] This Council is a nonprofit association of local governments that covers the now nine-county Denver region with representation from its member cities and counties.[215] It has developed several long-range regional plans over the years. The Council's regional plan "provides policies designed to guide where, how much and when growth and development occur in the region, addressing development, transportation needs and environmental quality."[216] Its current iteration, *Metro Vision*, plans through the year 2035 and includes a 921-mile voluntary urban growth boundary/area.[217]

Map 3 shows the Denver Metropolitan Region's development pattern. It looks very different from the other urban areas studied because it has very few developed job centers and city types are more clustered. At-risk segregated and older suburbs are closest to the center and form most of the suburban area. There is a limited zone of bedroom-developing communities south of the urban core.

%20.pdf, *archived at* http://perma.cc/PU3P-9NX7.

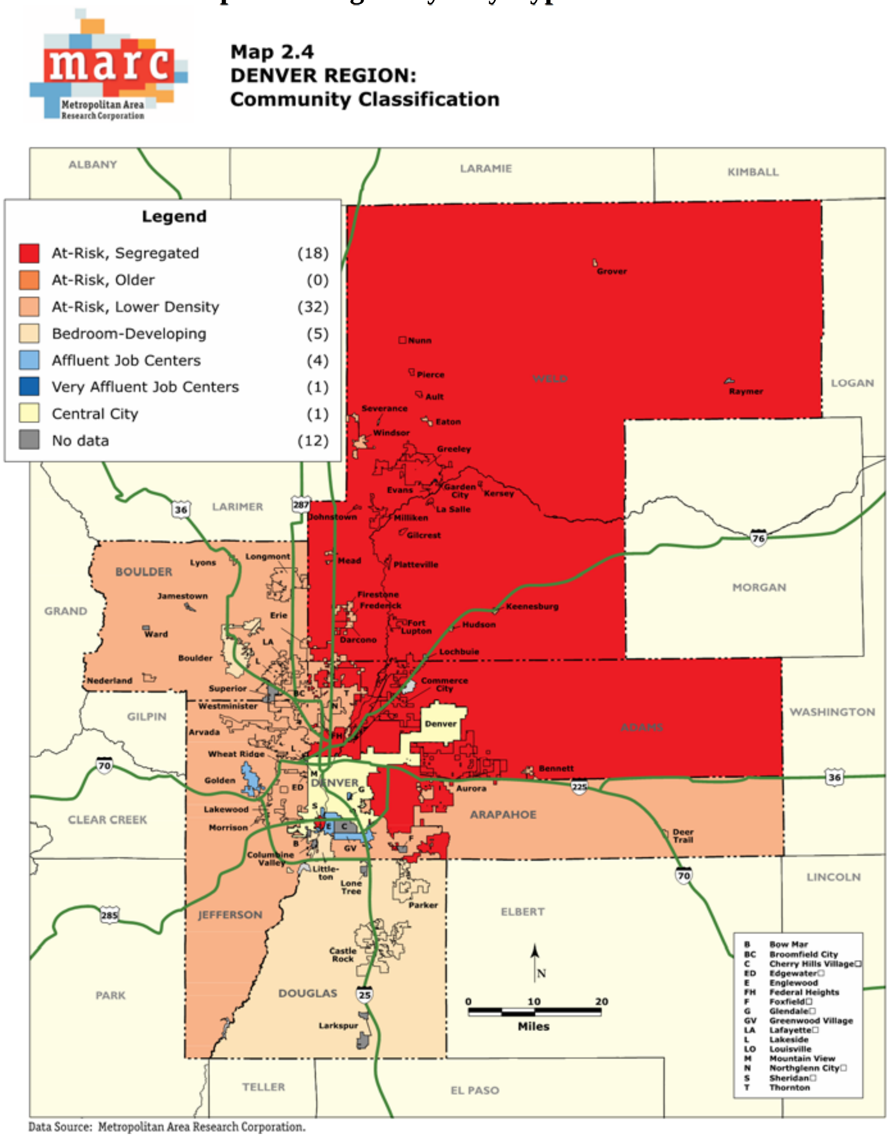
[214] *Id.*

[215] *See* Denver Reg'l Council of Gov'ts, *About DRCOG*, http://drcog.org/about-drcog/about-drcog, *archived at* http://perma.cc/XB3F-CERW (last visited Sept. 23, 2014); Denver Reg'l Council of Gov'ts, *Member Governments*, http://drcog.org/about-drcog/member-governments, *archived at* http://perma.cc/TN4D-XSRZ (last visited Sept. 23, 2014).

[216] DENVER REG'L COUNCIL OF GOV'TS, WITH ONE VOICE: ENHANCING AND PROTECTING THE QUALITY OF LIFE IN OUR REGION (2013), *available at* http://www.drcog.org/documents/2009%20With%20One%20Voice%20Brochure%204%20web.pdf, *archived at* http://perma.cc/E6BQ-6BZL.

[217] *Id.*

Map 3: Denver Metropolitan Region by City Type



As indicated in Table 4, like the other metro regions, Denver's center city has more overall participation than its suburban cities. The Denver metro region, however, has fewer total cities than some of the other metropolitan regions, and some recently incorporated cities make especially large data gaps. Also, while Boulder—categorized as a bedroom-developing community—has similar participation rates to Denver, boosting that category, participation by other cities in the region is sporadic. These networks, even at the statewide level, seem to be playing a very limited role in local behavior in this metro region beyond Denver and Boulder.

Table 4: Denver Metropolitan Region: Participation in Climate Change Related Networks by City Type[218]

	Central City (1)	At-Risk, Segregated (17)	At-Risk, Lower Density (28)	Bedroom-Developing (4)	Affluent Job Center (4)	No Data/Recently Incorporated (14)
ICLEI Member	1 (100%)	1 (5.9%)	0	0	0	0
Nantes Declaration	0	0	0	1 (25%)	0	0
Durban Adaptation Charter	0	0	0	0	0	0
Mexico City Pact[219]	0	0	0	1 (25%)	0	0
Copenhagen City Climate Catalogue	1 (100%)	0	1 (3.6%)	1 (25%)	0	0
carbon*n* Cities Climate Registry[220]	0	0	0	0	0	0
Mayors Agreement	1 (100%)	0	2 (7.1%)	1 (25%)	0	0
Urban Sustainability Directors Network	1 (100%)	0	0	1 (25%)	0	0
Colorado Climate Network	1 (100%)	1 (5.9%)	0	1 (25%)	0	0

[218] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.

[219] *See* The Mex. City Pact, *Signatories*, *supra* note 184.

[220] *See* carbon*n* Climate Registry, *City Search*, *supra* note 185.

D. New York City

New York was first settled in the 1600s and became the largest U.S. city by 1820.[221] Its next massive expansion occurred in 1898 when five counties merged to become the five boroughs that still comprise New York City.[222] The New York City metropolitan region is the largest by population in the United States according to the 2012 census estimates.[223]

New York's metro-regional governance was deeply influenced by the above-mentioned early Chicago efforts.[224] Dr. Marc Weiss, Chairman and CEO of Global Urban Development, explains:

> The famous 1909 Plan of Chicago was essentially a regional plan, and two of the leading business patrons of that plan, Charles Norton and Frederic Delano, moved to New York City a decade later and helped spearhead an even more ambitious effort, the Regional Plan of New York and its Environs. This plan, completed at the end of the 1920s, served as a blueprint for urban investment and development in the tri-state region for a generation. New York City, which was reinvented in 1898 by consolidating five separate counties to instantly become the world's largest city, was encompassed by the world's largest urban region that crossed three different states, New York, New Jersey, and Connecticut.[225]

Metro-regional planning in present-day New York takes place through both governmental and non-profit auspices. New York's official metropolitan planning organization is the New York Metropolitan Transportation Council, which focuses

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[221] Tim Lambert, *A Brief History of New York City*, http://www.localhistories.org/newyork.html, *archived at* http://perma.cc/VF2V-CQ6X (last visited Sept. 23, 2014); *A History of New York City*, NEWYORK.COM, http://www.newyork.com/resources/history-new-york-city/, *archived at* http://perma.cc/JZ3N-YN34 (last visited Oct. 27, 2014).

[222] *The 100 Year Anniversary of the Consolidation of the 5 Boroughs into New York City*, NEW YORK CITY, http://www.nyc.gov/html/nyc100/html/classroom/hist_info/100aniv.html, *archived at* http://perma.cc/63G4-6LW3 (last visited Oct. 27, 2014).

[223] U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, *supra* note 168.

[224] For a discussion of the Chicago efforts, see *supra* text and accompanying notes 196–200.

[225] MARC A. WEISS, METROPOLITAN GOVERNANCE AND STRATEGIC PLANNING IN THE US: A REPORT TO THE STRATEGIC METROPOLITAN PLAN OF BARCELONA 1–2 (2003), *available at* http://www.globalurban.org/metro_governance.htm, *archived at* http://perma.cc/LH54-PXTU.

primarily on transportation issues in its planning and coordinating role.[226] However, the Regional Plan Association, a non-profit entity that emerged from New York's first regional planning process, continues to play a critical role in broad long-range and issue-specific planning.[227] It has produced three regional plans, the latest in 1996, and works on a range of land use, transportation, environmental, and economic development and opportunity issues.[228]

Map 4 displays New York City's metro-regional development pattern, including the organization of different city types. New York's development pattern is similar to that of most other metro regions, but its physical geography, especially the water that constrains its growth in places, and the differences among the five boroughs alter that pattern somewhat. For the most part, at-risk older and segregated suburbs tend to form the inner core, followed by a ring of affluent and very affluent job centers, and an outer ring of low-density at-risk and bedroom developing suburbs. But some of the affluent and very affluent job centers abut the center city, especially on the Queens side, and others are at the very edge of the metropolitan region.

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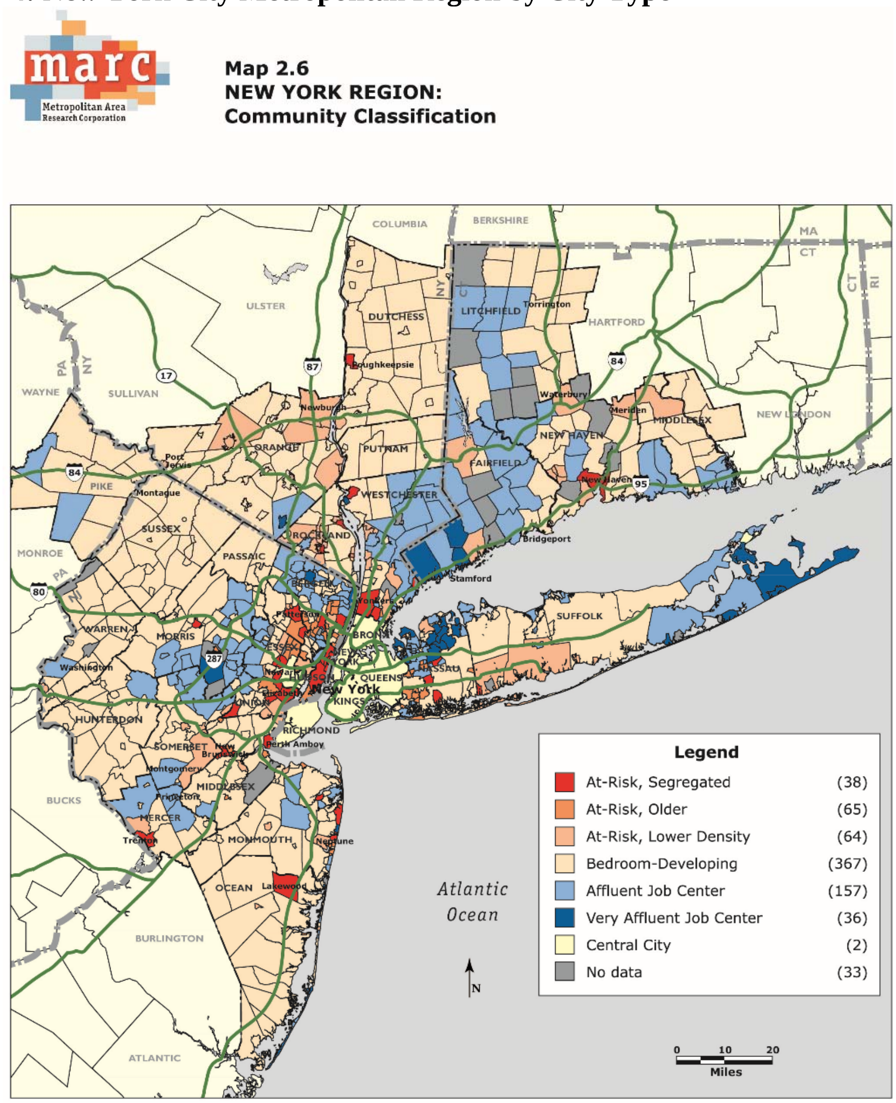
[226] *See* N.Y.C. Metro. Transp. Council, *About NYMTC*, http://www.nymtc.org/, *archived at* http://perma.cc/9T7P-F8FJ (follow "About NYMTC" hyperlink) (last visited Sept. 23, 2014).

[227] *See* Reg'l Plan Ass'n, *Our History*, http://www.rpa.org/about/history, *archived at* http://perma.cc/YW9F-TJCZ (last visited Sept. 23, 2014).

[228] *See id.*

Map 4: New York City Metropolitan Region by City Type



Data Source: Metropolitan Area Research Corporation.

As Table 5 displays, like in other metropolitan regions, New York's center city is participating more in networks than other city types. However, similar to Chicago, there is some participation in many networks across the suburban categories, with the most participation happening in the Mayors Agreement and the associated commitments in the Copenhagen City Climate Catalogue rather than in the state-based network. This pattern suggests cities in each category may serve as models for other cities in that category, which might boost participation.

Table 5: New York Metropolitan Region: Participation in Climate Change Related Networks by City Type[229]

	Central City (2)	**At-Risk, Segregated (29)**	**At-Risk, Lower Density (33)**	**At-Risk, Older (53)**	**Bedroom-Developing (93)**	**Affluent Job Center (84)**	**Very Affluent Job Center (22)**	**No Data (11)**
ICLEI Member	2 (100%)	2 (6.9%)	4 (12.1%)	3 (5.7%)	9 (9.7%)	10 (11.9%)	0	1 (9.1%)
Nantes Declaration	0	0	0	0	0	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0	0	0
Mexico City Pact[230]	0	0	0	0	0	0	0	0
Copenhagen City Climate Catalogue	2 (100%)	9 (31%)	10 (30.3%)	7 (13.2%)	19 (20.4%)	10 (11.9%)	1 (4.5%)	1 (9.1%)
carbon*n* Cities Climate Registry[231]	0	0	0	0	1 (1.2%)	0	0	0
Mayors Agreement	2 (100%)	9 (31%)	12 (36.4%)	8 (15.1%)	20 (21.5%)	12 (14.3%)	0	1 (9.1%)
Urban Sustainability Directors Network	2 (100%)	1 (3.4%)	0	0	0	0	0	0
New York Climate Smart Communities	0	3 (10.3%)	5 (15.2%)	1 (1.9%)	12 (12.9%)	12 (14.3%)	0	1 (9.1%)

[229] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.

[230] *See* The Mex. City Pact, *Signatories*, *supra* note 184.

[231] *See* carbon*n* Climate Registry, *City Search*, *supra* note 185.

E. San Francisco

San Francisco began as a colonial mission in the 1700s, but did not become part of the United States until the 1848 Treaty of Guadalupe.[232] It expanded in the middle of the nineteenth century due to the California Gold Rush and the resulting influx of Chinese immigrants, but then faced a devastating cholera epidemic.[233] Its transformation into a major U.S. metropolitan region took place in the second half of the nineteenth century.[234] It then faced devastating setbacks at the turn of the twentieth century, however, due to a plague epidemic and major earthquake.[235] San Francisco's post-earthquake rebuilding helped create the modern scheme of its center city.[236]

In the early twentieth century, San Francisco considered following New York's example by annexing surrounding counties as boroughs, but that Greater San Francisco movement was ultimately defeated.[237] However, the construction of the Bay and Golden Gate bridges in the 1930s helped to create greater physical regional interconnection.[238] Post-World War II expansion and urban renewal provided further redefinition of the metro region; the mayor used eminent domain to raze and rebuild numerous neighborhoods and a revolt against freeways limited their expansion.[239]

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[232] *See* S.F. Ctr. for Econ. Dev., *A Brief History*, http://sfced.org/case-for-business/a-brief-history/, *archived at* http://perma.cc/XBA8-VAMJ (last visited Oct. 27, 2014); *Arrival of Europeans and Early Settlement*, SF-INFO.ORG, http://www.sf-info.org/history/d3/arrival-of-europeans-and-early-settlement, *archived at* http://perma.cc/CF9C-MJEX (last visited Sept. 23, 2014).

[233] *San Francisco Gold Rush*, SF-INFO.ORG, http://www.sf-info.org/history/d4/gold-rush, *archived at* http://perma.cc/6YQN-5HBJ (lasted visited Sept. 23, 2014).

[234] *See* S.F. Ctr. for Econ. Dev., *supra* note 232.

[235] *1906 San Francisco Earthquake and Fire*, SF-INFO.ORG, http://www.sf-info.org/history/d7/1906-earthquake-and-fire, *archived at* http://perma.cc/V2JG-HTTR (lasted visited Sept. 24, 2014); *Paris of the West*, SF-INFO.ORG, http://www.sf-info.org/history/d5/paris-of-the-west, *archived at* http://perma.cc/DDZ4-NQBC (lasted visited Sept. 24, 2014).

[236] *See Rebuilding San Francisco Following the 1906 Earthquake*, SF-INFO.ORG, www.sf-info.org/history/d8rebuilding, *archived at* http://perma.cc/RQQ6-DPEA (last visited Sept. 24, 2014).

[237] *"Greater San Francisco" Movement of 1912*, SF-INFO.ORG, http://www.sf-info.org/history/d9/greater-movement, *archived at* http://perma.cc/6LDL-3DY6 (last visited Sept. 24, 2014).

[238] *See* Golden Gate Bridge Highway Transp. Dist., *Frequently Asked Questions About the Golden Gate Bridge*, http://goldengatebridge.org/research/facts.php#Name, *archived at* http://perma.cc/WP7Z-KX79 (last visited Sept. 24, 2014); The S.F.-Oakland Bay Bridge Seismic Safety Projects, *Bay Bridge History*, http://baybridgeinfo.org/history, *archived at* http://perma.cc/7N9N-3SN4 (last visited Sept. 24, 2014).

[239] *See* David Habert, *Fifty Years of Redevelopment*, SPUR (Mar. 1, 1999), http://www.spur.org/publications/library/article/50yearsredevelopment03011999, *archived at* http://perma.cc/G7VB-H6ZV; *San Francisco After World War II*, SF-INFO.ORG,

In the 1980s, many skyscrapers were built, but as with the freeways, popular outcry led to land use restrictions that limited this building movement.[240] Since then, additional earthquakes and the dot com booms and crashes have helped to provide further redevelopment, expansion, and gentrification.[241] The San Francisco metropolitan region is the fifth largest in the United States as of the 2012 census estimates.[242]

San Francisco's metro-regional governance entity, the Bay Area Association of Governments, was established in 1961 and produced its first regional plan in 1970.[243] Its members include nine counties and 101 cities and towns in the San Francisco metro region.[244] The Association focuses on a wide range of planning issues—including "land use, environmental stewardship, energy efficiency, hazard mitigation, water resource protection, and hazardous waste management"—and has received state, national, and international recognition for its efforts.[245] Especially relevant to the focus of this Article, the Association is collaborating with the Metropolitan Transportation Commission to develop "the region's first Sustainable Communities Strategy (SCS) pursuant to state legislation.[246] The SCS, known as Plan Bay Area, will tackle pressing issues such as accommodating population growth while keeping the region affordable for all residents, preserving open space, protecting the environment, accommodating transportation needs, and reducing greenhouse gas emissions."[247]

Map 5 displays the metro region and the organization of the city types within it. Like Denver, its patterns show some of the typical urban form, but less so than some of the other metro regions. Many of the older and segregated at-risk suburbs are clustered around San Francisco and Oakland, the affluent job centers form a second ring, and at-risk lower density and bedroom communities are further out. But as the map shows, there are a number of exceptions to this pattern, in part due to the physical geography of the metro region's interaction with water and in part because

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http://www.sf-info.org/history/d11/wwii, *archived at* http://perma.cc/WH6H-DZL6 (last visited Sept. 9, 2014).

[240] *1980s: "Manhattanization" and Homelessness*, SF-INFO.ORG, http://www.sf-info.org/history/d13/homeless, *archived at* http://perma.cc/QKE5-FYWL (last visited Sept. 9, 2014).

[241] *1989 Loma Prieta Earthquake*, SF-INFO.ORG, http://www.sf-info.org/history/d14/1989-loma-prieta-earthquake, *archived at* http://perma.cc/VAS3-M484 (last visited Sept. 9, 2014); *Dot-Com Bubble*, SF-INFO.ORG, http://www.sf-info.org/history/d15/dot-com-bubble, *archived at* http://perma.cc/AM6J-S38A (last visited Sept. 9, 2014).

[242] U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, *supra* note 168.

[243] ASS'N OF BAY AREA GOV'TS, ABOUT ABAG, *available at* http://www.abag.ca.gov/overview/overview.pdf, *archived at* http://perma.cc/RP4U-Q4DR (last visited Sept. 9, 2014).

[244] *Id.*

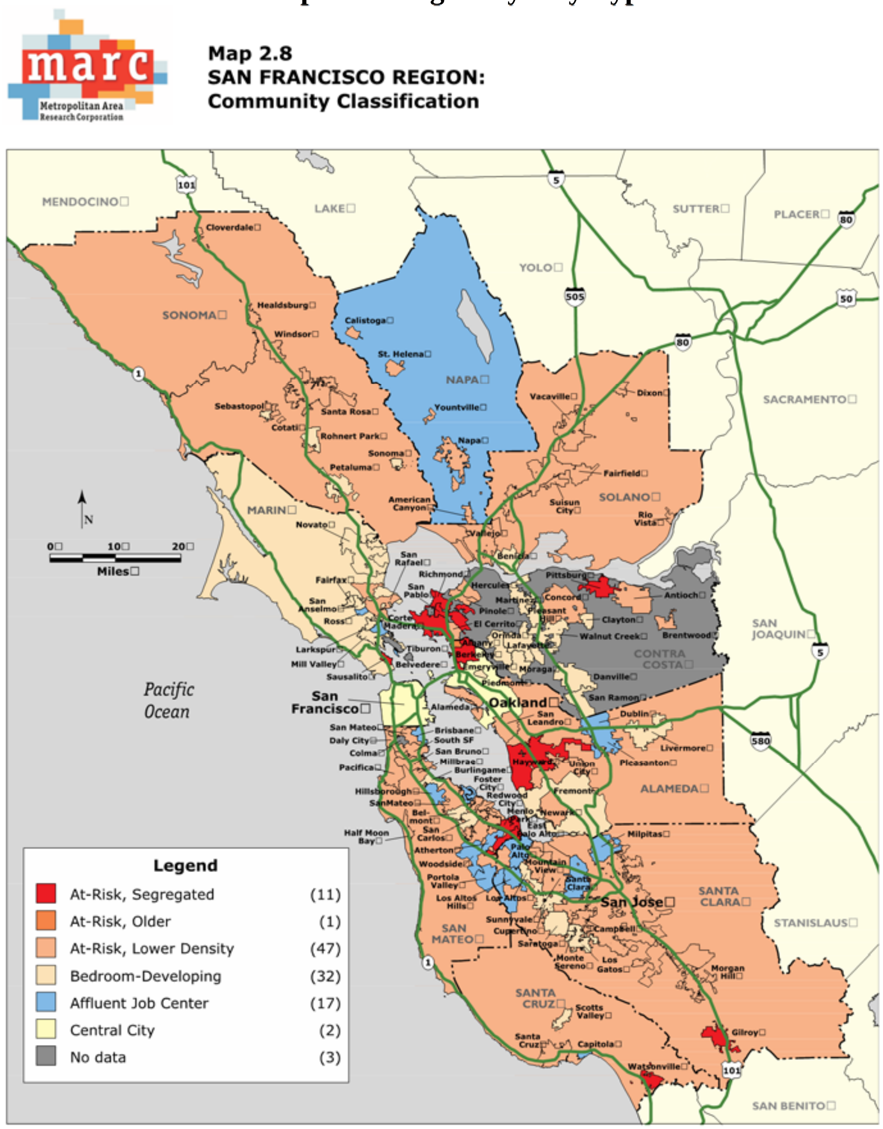
[245] *Id.*

[246] *Id.*

[247] *Id.*

one of the outer areas labeled as an affluent job center in the metro region is Napa Valley—a unique area with a well-established wine industry and related tourism.

Map 5: San Francisco Metropolitan Region by City Type



Data Source: Metropolitan Area Research Corporation.

As Table 6 illustrates, the San Francisco Metropolitan Region shows the highest level of participation of any of the metropolitan regions studied. Not only do its center cities, Oakland and San Francisco, both participate in many networks at national and international levels, but also every category of its suburbs show significant participation in networks at every level as well. This high level of participation may not be replicable in other metropolitan regions, as it may relate more to the unique environment of California and this metropolitan region than to steps by the networks themselves. But, at the very least, there are many model cities in each category that could be used to encourage more participation.

Table 6: San Francisco Metropolitan Region: Participation in Climate Change Related Networks by City Type[248]

	Central City (2)	**At-Risk, Segregated (11)**	**At-Risk, Lower Density (41)**	**At-Risk, Older (1)**	**Bedroom-Developing (32)**	**Affluent Job Center (15)**	**No Data (2)**
ICLEI Member	2 (100%)	7 (63.6%)	22 (53.7%)	1 (100%)	14 (43.8%)	8 (53.3%)	1 (50%)
Nantes Declaration	0	0	0	0	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0	0
Mexico City Pact[249]	0	0	0	0	0	0	0
Copenhagen City Climate Catalogue	2 (100%)	3 (27.2%)	22 (53.7%)	1 (100%)	13 (40.6%)	9 (60%)	1 (50%)
carbon*n* Cities Climate Registry[250]	2 (100%)	0	3 (7.3%)	0	2 (6.3%)	1 (6.7%)	0
Cities for Climate Protection Campaign	2 (100%)	2 (18.2%)	4 (9.8%)	0	7 (21.9%)	0	0
Mayors Agreement	2 (100%)	5 (45.5%)	26 (63.4%)	1 (100%)	16 (50%)	9 (60%)	1 (50%)
Urban Sustainability Directors Network	1 (50%)	1 (9%)	1 (2.4%)	0	0	1 (6.7%)	0
Institute for Local Government-Beacon Award Participants	0	3 (27.3%)	5 (12.2%)	0	4 (12.5%)	2 (13.3%)	0

[248] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.

[249] *See* The Mex. City Pact, *Signatories*, *supra* note 184.

[250] *See* carbon*n* Climate Registry, *City Search*, *supra* note 185.

F. Twin Cities

As geographer John Borchert has explored in depth, the Twin Cities followed an urbanization pattern much like many of the other major metropolitan regions in the United States.[251] His *Atlas of Minnesota Resources and Settlement*, prepared for the Minnesota State Planning Agency with Donald Yaeger in 1968, explains that St. Paul, St. Anthony, and Minneapolis emerged due to their strategic locations for pioneer steamboat navigation and hydropower.[252] Prior to the post-World War II Freeway Era described by Muller, the Twin Cities urban area expanded along rail and streetcar transportation routes.[253] The widespread use of the automobile allowed for low-density settlement via paved roads to the countryside "over the high-amenity, rolling wooded, lake and moraine lands," physical attributes that also limited population density.[254] As the broader region transitioned from a natural-resources-based economy to one more focused on manufacturing and nationally-oriented services, the Twin Cities became "a 'hinge' area which combines access to the human resources of the region with access to the mid-western and national markets";[255] the Twin Cities experienced a significant population concentration in their metropolitan region—containing nearly half of Minnesota's population and one-quarter of the Upper Midwest's population according to a 1963 report—even as the population within that region decentralized.[256] Borchert noted that in the forty-year period preceding the 1980s, for example, the urban field—its urban circulation system defined by level of accessibility—of the Twin Cities increased from less than one thousand square miles to over fifteen thousand square miles.[257] This "expansion of metropolitan circulation systems, with accompanying decentralization, has weakened the historic regional center—the monumental downtown of the central city."[258]

The present day Twin Cities region—the fourteenth largest metropolitan region by 2012 census estimates[259]—shows a maturation of these patterns. Orfield and Luce documented in their in-depth study of the Twin Cities that the region contains 172 cities and ninety-seven townships and ranks as the fifth most fragmented among the

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[251] *See* JOHN R. BORCHERT & DONALD P. YAEGER, ATLAS OF MINNESOTA RESOURCES AND SETTLEMENT 187–88 (1968).

[252] *Id.*

[253] *Id.* at 188.

[254] *Id.*

[255] *See* JOHN R. BORCHERT & RUSSELL B. ADAMS, PROJECTED URBAN GROWTH IN THE UPPER MIDWEST: 1960–1975, at 24 (1964).

[256] *See id.* at 2; JOHN R. BORCHERT, THE URBANIZATION OF THE UPPER MIDWEST: 1930–1960, at iii, 36–37 (1963).

[257] *See* Borchert, *America's Changing Metropolitan Regions*, *supra* note 16, at 365.

[258] *Id.* at 368.

[259] U.S. Census Bureau, *Metropolitan and Micropolitan Statistical Areas*, *supra* note 168.

United States' fifty largest metropolitan areas.[260] Like in most major metropolitan areas, jobs and population in the Twin Cities have decentralized significantly over the last thirty years, with current growth concentrated in the outer suburbs; from 1990 to 2004, Minneapolis grew at 1.3% and St. Paul grew at 3.0%, as compared to the region's overall growth rate of 22.5%.[261] As this growth has occurred, suburban differentiation has taken place, with some suburbs, especially inner ones, increasingly reflecting the fiscal stresses and racial and poverty concentrations of the central cities, and other suburbs, especially outer ones, facing the complexities of rapid growth with inadequate infrastructure.[262] Only a small percentage of the region's suburban cities fit the traditional model of wealthy residents who commute into the central city.[263]

The Twin Cities area has one of the most extensive metro-regional governance structures in the United States.[264] Minnesota's experiment in metropolitan regional governance in its most significant urban area—the Twin Cities—began in 1967 when its legislature established the Met Council to meet new federal requirements for regional governance.[265] The Met Council was intended to build upon decades of ad hoc collaboration among the cities and to address concerns over land use planning, wastewater coordination, and transit funding.[266] Even before the Met Council's formal creation, the regional planning efforts in the Twin Cities formed an important part of state-wide land use planning approaches; for example, Borchert used regional governance in the Twin Cities as an example of why more regional planning was needed in Minnesota in his 1963 report.[267] As of January 2012, the Met Council listed 183 communities in its seven-county metro area.[268] The state legislature gradually expanded the Met Council's powers over time, and the council has played and continues to play a significant role in regional planning.[269] The Met Council also began in 2013 to consider new metro-regional efforts on climate change. As part of its ThriveMSP 2040 initiative, Met Council adopted a goal related

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[260] MYRON ORFIELD ET AL., REGION: PLANNING THE FUTURE OF THE TWIN CITIES 2 (2010).

[261] *Id.* at 14.

[262] *See id.* at 43–49.

[263] *Id.* at 46.

[264] *See id.* at 52–53. For other examples of well-developed metropolitan regional governments, see Nashville, Tennessee, Greater Nashville Regional Council, https://www.gnrc.org/, *archived at* http://perma.cc/WQY8-FBHV (last visited Oct. 29, 2014) and Portland, Oregon, Metro, http://www.oregonmetro.gov/, *archived* at http://perma.cc/A4KX-RNK2 (last visited Oct. 29, 2014).

[265] *See* ORFIELD, *supra* note 260, at 52–53.

[266] *See id.* at 52–80.

[267] BORCHERT, *supra* note 256, at 43.

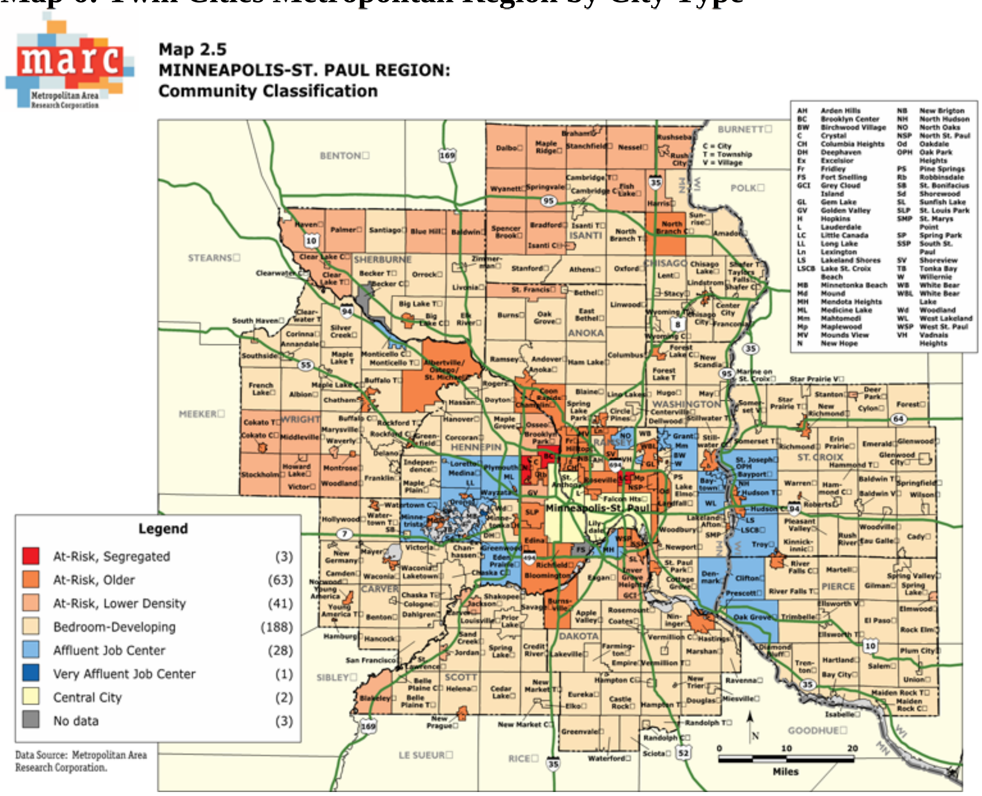
[268] Metro. Council, *List of Community Profiles*, http://stats.metc.state.mn.us/profile/list.aspx, *archived at* http://perma.cc/5UJB-ZHWM (last visited Sept. 11, 2014).

[269] Metro. Council, *Who We Are*, http://www.metrocouncil.org/About-Us/The-Council-Who-We-Are.aspx, *archived at* http://perma.cc/VYN2-H59G (last visited Sept. 9, 2014).

to climate change—"[a] resilient region minimizes its contributions to climate change and is prepared for the challenges and opportunities of a changing climate"—and is currently exploring a variety of approaches to implementation.[270]

Map 6 displays the Twin Cities metro-region organized by city type. With some exceptions, it follows a relatively typical pattern of suburban development rings. At-risk segregated and older suburbs form the first ring, affluent job centers the middle ring, and low-density at risk and bedroom developing suburbs the outer one.

Map 6: Twin Cities Metropolitan Region by City Type



[270] *See* Ethan Fawley, *Metropolitan Council: Addresses Climate Change in the Twin Cities*, FRESH ENERGY (July 19, 2013), http://fresh-energy.org/2013/07/metropolitan-council-address-climate-in-the-twin-cities/, *archived at* http://perma.cc/593D-TE6G.

As illustrated in Table 7, the Twin Cities follows the pattern of most of the other metropolitan regions in having significantly higher network participation in its central cities than suburbs. However, unlike some other regions, the participation rates are higher in state-wide networks than international and national ones. The only larger-scale network with significant participation from suburbs is the Mayors Agreement and the parallel commitments in the Copenhagen City Climate Catalogue that those cities made. The Twin Cities metropolitan region has enough participation in each city category to have some models for other cities of that type, but overall it shows less participation in larger-scale networks than other regions. Its comparatively high participation levels in state-wide networks suggest an opportunity for those networks to become feed-in points for involvement in larger-scale networks. A key question is whether those statewide networks focused on sustainability and energy produce equivalent results through their toolkits and step-by-step processes such that larger-scae networks are less important for these cities.

Table 7: Twin Cities Metropolitan Region: Participation in Climate Change Related Networks by City Type[271]

	Central City (2)	At-Risk, Segregated (3)	At-Risk, Lower Density (39)	At-Risk, Older (60)	Bedroom-Developing (184)	Affluent Job Center (30)	Very Affluent Job Center (1)	No Data (3)
ICLEI Member	2 (100%)	0	1 (2.6%)	3 (5%)	2 (1.1%)	0	0	0
Nantes Declaration	0	0	0	0	0	0	0	0
Durban Adaptation Charter	0	0	0	0	0	0	0	0
Mexico City Pact[272]	0	0	0	1 (1.7%)	0	0	0	0
Copenhagen City Climate Catalogue	2 (100%)	1 (33.3%)	2 (5.1%)	6 (10%)	6 (3.3%)	4 (13.3%)	0	0
carbon*n* Cities Climate Registry[273]	0	0	0	1 (1.7%)	0	0	0	0
Mayors Agreement	2 (100%)	1 (33.3%)	2 (5.1%)	8 (13.3%)	6 (3.3%)	3 (10%)	0	0
Urban Sustainability Directors Network	1 (50%)	0	0	0	0	0	0	0
EPA Region 5 Community Climate Change Initiative Partner	1 (50%)	0	0	4 (6.7%)	1 (0.5%)	0	0	0
GreenStep Cities	1 (50%)	0	0	13 (21.7%)	11 (6%)	2 (6.7%)	0	0
Municipalities with MN Energy Challenge Participants	2 (100%)	3 (100%)	14 (35.9%)	55 (91.7%)	75 (40.8%)	22 (73.3%)	0	1 (33.3%)

[271] Osofsky, *Appendix: Patterns of Network Participation in Major Metropolitan Areas*, *supra* note 158. Unless otherwise cited within the Table, all information can be found in the Appendix on file with the Utah Law Review, *archived at* http://perma.cc/L2PG-VSTU.

[272] *See* The Mex. City Pact, *Signatories*, *supra* note 184.

[273] *See* carbon*n* Climate Registry, *City Search*, *supra* note 185.

V. CONCLUSIONS: STRATEGIES FOR STRENGTHENING THE ROLE OF MULTILEVEL URBAN NETWORKS

A comparative assessment of climate change network participation by city type in these six metro regions indicates different patterns in each place. While center cities tended to be the most active in each metro region, suburban participation was inconsistent. In particular, metro regions varied in the overall level of participation by suburbs, the types of suburbs participating most actively, and whether cities were more active in smaller-scale or larger-scale networks.[274] This variation suggests the need for metro-regional-based analysis and approaches to increasing network participation.

This Part provides strategies for using the principles from Part II and the network and participation data from Parts III and IV to enhance the effectiveness of the multilevel climate networks. It focuses in particular on how this data could assist further development of two strategies introduced in *Suburban Climate Change Efforts*: (1) creating differentiated toolkits and models and (2) multiscalar network collaboration and coordination.[275] In its analysis, this Part maps next steps for implementation and research.

A. Creating Differentiated Toolkits and Models

In *Suburban Climate Change Efforts*, I argued that the divergent needs and opportunities in different city types made it critical to create more differentiated models and toolkits.[276] In particular, stressed inner suburbs are expanding less and have more urban redevelopment needs. Affluent job centers have the capacity to take actions similar to central cities. Outer-ring developing job centers and bedroom communities tend to be less connected to climate networks and free resources, but they have the most opportunities for growth-related land use planning.[277]

Like the networks I examined in my initial study of the Twin Cities region, however, none of the networks at any level in this broader study appear to be differentiating their toolkits or models in this way.[278] At most, they distinguish by city size or substantively. For example, USDN has a smaller-cities group, and the Mayor's Agreement awards and best-practices models differentiate between large and small cities.[279] Similarly, a number of the networks have specific subgroups

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[274] *See supra* Part III.

[275] *See* Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 452–57.

[276] *See id.*

[277] *See id.*

[278] *See supra* Part II.

[279] *Mayors and Climate Protection Best Practices*, MAYORS CLIMATE PROTECTION CENTER (June 2009), http://www.usmayors.org/pressreleases/uploads/ClimateBestPractices061209.pdf, *archived at* http://perma.cc/VLY6-RU3A; Urban Sustainability Directors Network, *About USDN*, *supra* note 93.

focused on issues relevant to some of their members, such as the USDN Western adaptation group.[280]

The participation data for the six metropolitan regions suggest that greater differentiation by city type in networks' toolkits and examples could be implemented on a metro-regional basis. For most of the networks examined, there was at least one city participating from most types of cities in these six metropolitan regions. This pattern indicates the possibility for focused metro-regional approaches that include exemplar cities in each of the regions providing geographically specific models for other cities of their type. If one groups the suburbs into broader categories of stressed inner suburbs (including segregated and older at-risk suburbs), developed job centers (including affluent and very affluent job centers), and developing communities (including low-density at risk suburbs and bedroom developing suburbs) for an initial set of models, exemplar cities are even easier to establish on a metro-regional basis.[281]

Network staff and local officials interviewed concur that this type of differentiation could be valuable.[282] I plan to collaborate with networks and local officials, beginning in the Twin Cities metro region, to develop such differentiated toolkits and exemplars and assist in implementing them. My hope is that creating such exemplar cities for six major geographically diverse urban areas can help to serve as a model for additional metro regions to take similar steps nationally.

B. Multiscalar Network Collaboration and Coordination

This broader study also reinforces the need for greater collaboration and coordination among networks. Like in the Twin Cities example introduced in *Suburban Climate Change Efforts*,[283] the many networks examined in Part III have substantial overlap in their functions but appear to have limited direct coordination. For example, the models, toolkits, and recognition provided by numerous networks at different levels address many similar steps that cities could take, but framed in various ways. This variation means that a city participating in more than one network would need to spend time reframing similar actions multiple times. If networks collaborated to create more consistency in what they ask of cities, they might increase their individual impact and the ability to measure across networks their impact on what their members are doing.[284]

This strategy has its limits, and full consistency is likely not possible or even desirable. Some networks have a broader focus on sustainability, which may be important for political reasons, whereas others have focused climate change goals. However, there are enough similarities across networks that some greater

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[280] Urban Sustainability Directors Network, *About Us*, *supra* note 92.
[281] *See supra* Part III.
[282] Osofsky, Confidential Meeting with Local Leaders, *supra* note 58.
[283] Osofsky, *Suburban Climate Change Efforts*, *supra* note 7, at 411–40.
[284] *See supra* Part II.

consistency seems both possible and desirable.[285] Moreover, the networks often have informal linkages that could be formalized. For instance, local officials in an urban area not included in this study have described how a center city joining the Mayor's Agreement asked the regional planning entity for assistance with its required greenhouse gas inventory.[286] The regional planning entity then asked the county for access to its ICLEI models, and in the process, agreed to do an inventory for the county and the smaller urban entities within that metro region's equivalent of suburbs.[287] I plan to work with networks to understand better where consistency could be achieved and how to build on such existing informal synergies.

Beyond consistency questions, the differentiation by scale of network penetration across the six metropolitan regions provides an opportunity for analysis and action. Specifically, further research is needed regarding why local and state networks seem to get better participation in some metro regions, while national and international networks do in others. It would be helpful to know if those differentiated choices are conscious and economic/political or instead reflect patterns of exposure and networking among cities in the region. As part of interviews on this question, I also plan to explore when and how networks spur or support action that would not otherwise have happened in participating cities.

An important question for this qualitative research is the extent to which the cost of joining a network influences participation rates. Networks in this study vary significantly in whether and how much they charge member cities. For example, at an international level, while both ICLEI and UCLG charge their members sliding scale fees based on population, the World Mayors Council on Climate Change is free.[288] Some local government representatives have described the cost of ICLEI as prohibitive, but its modeling tools as very useful;[289] as a consequence, within a metro region, governmental entities have sometimes shared resources from networks of which one of the entities is a member.[290] At a national level, both the Mayors Agreement and USDN charge dues.[291] However, at regional, state, and metro-

[285] *See id.*

[286] Osofsky, Confidential Meeting with Local Leaders, *supra* note 58.

[287] *Id.*

[288] Global Network of Cities, Local & Reg'l Gov'ts, *Join UCLG*, UCLG, http://www.uclg.org/en/join-uclg, *archived at* http://perma.cc/5USG-DUY2 (last visited Sept. 11, 2014); Int'l Council for Local Envtl. Initiatives USA, *Membership Dues*, ICLEI USA, http://www.icleiusa.org/join/process-of-joining/iclei-usa-membersip-dues, *archived at* http://perma.cc/5N4N-DX9H (last visited Sept. 11, 2014); World Mayors Council on Climate Change, *Registration Form*, http://www.worldmayorscouncil.org/join/registration-form.html, *archived at* http://perma.cc/V6B5-RAD8 (last visited Sept. 11, 2014).

[289] Osofsky, Confidential Meeting with Local Leaders, *supra* note 58.

[290] *Id.*

[291] Urban Sustainability Dirs. Network, *Join USDN*, USDN, http://usdn.org/public/Join.html, *archived at* http://perma.cc/EY8G-FP7M (last visited Sept. 11, 2014); U.S. Conference of Mayors, *Dues for the U.S. Conference of Mayors*, U.S.

regional levels, there is more variation that may affect participation decisions. For instance, the Chicago and Denver state and metro-regional networks charge for membership, but the Atlanta, New York, San Francisco, Twin Cities, and regional EPA ones are free.[292]

In addition, I plan to consider in this further research how localities' political affiliations influence their network participation. In the Twin Cities, both Democratic- and Republican-leaning communities were joining climate change networks, even ones with explicit climate focus like the Mayors Agreement, though participation in the sustainability-focused statewide Greenstep Cities program was more bipartisan than in the Mayors Agreement. This initial data is a hopeful sign that progress may be possible across party lines in a local context, but it would be helpful to understand both bipartisan participation patterns across metro regions and, through interviews, the extent to which local leaders are influenced by polarized national politics in their network participation and climate action.[293]

In places where political and economic barriers are not insurmountable, the underrepresented networks might make some targeted efforts to increase participation. In others, the networks that are more politically palatable might redouble their efforts to involve more cities, using the many participants as models. Finally, to the extent that participation divergence is likely to continue in some metro regions, those networks with greater penetration or ability to penetrate might collaborate with those facing more barriers to maximize their impact.[294]

CONFERENCE OF MAYORS, http://www.usmayors.org/about/dues.asp, *archived at* http://perma.cc/6QQK-6FK8 (last visited Sept. 11, 2014).

[292] Chi. Wilderness, *Chicago Wilderness Member Application*, https://docs.google.com/file/d/0B6P8pYIRd5wIYmNTOEZYeHFrNkU/edit, *archived at* http://perma.cc/N2YF-7DMP (last visited Sept. 11, 2014); Colo. Climate Network, *About the Colorado Climate Network*, http://www.coclimatenetwork.org/about/index.html, *archived at* http://perma.cc/3987-Z938 (last visited Sept. 11, 2014); Atlanta Reg'l Comm'n, *Certified Green Communities Program*, http://www.atlantaregional.com/environment/green-communities, *archived at* http://perma.cc/LP2M-JU3Y (last visited Oct. 20, 2014) (providing no indication of cost); Inst. for Local Gov't, *About ILG*, *supra* note 143; Minn. Pollution Control Agency, *Minnesota GreenStep Cities*, *supra* note 149; MN Energy Challenge, *About the Challenge*, *supra* note 153; N.Y. Dep't of Envtl. Conservation, *Adopt the Climate Smart Communities Pledge*, *supra* note 142.

[293] For a discussion of these patterns and the ways in which nonpartisan elections and other factors, such as community connection, might make the local context less partisan, see Hari M. Osofsky & Jacqueline Peel, *Energy Partisanship*, 65 EMORY L.J. (forthcoming Jan. 2016) (manuscript at 48) (on file with Utah Law Review) (citing NAT'L LEAGUE OF CITIES, *Partisan vs. Nonpartisan Elections*, http://www.nlc.org/build-skills-and-networks/resources/cities-101/city-officials/partisan-vs-nonpartisan-elections, *archived at* http://perma.cc/JN65-XZPM (last visited Feb. 28, 2015)); Brian F. Schaffner, et al., *Teams Without Uniforms: The Nonpartisan Ballot in State and Local Elections*, 54 POL. RES. Q. 7 (2001); Douglas D. Perkins & D. Adam Long, *Neighborhood Sense of Community and Social Capital: A Multi-Level Analysis*, *in* PSYCHOLOGICAL SENSE OF COMMUNITY: RESEARCH, APPLICATIONS, AND IMPLICATIONS 291 (Adrian T. Fisher et al. eds., 2002)).

[294] *See supra* Part III.

Overall, the new data presented in this Article provides important information on how network participation varies across metro regions and where gaps are most pronounced. While analyzing participation in networks is only one component of fostering urban climate change, understanding these patterns can help to inform strategies and further research projects. Given both the high level of urbanization and the low level of overall participation, especially in the suburbs, rethinking the geography of urban climate action in this way is critical.

THE ENERGY-ENVIRONMENT TENSION AND RESTRICTIONS ON SUBNATIONAL ADMINISTRATIVE DISCRETION: NAVIGATING THE CLEAN POWER PLAN

PROFESSOR STEVEN FERREY[1]

ABSTRACT

The "indirect" secondary impacts of regulatory policy can be as great as the "direct" intended result. With the administration's new Clean Power Plan (CPP), the indirect impacts could be substantial in those 2/3 of the states which are part of an independent system operator (ISO) to manage their energy markets. Whether or not to participate in an ISO also is a subnational decision – no state is forced.

The indirect effects of the CPP will be to: (1) monetize power plant carbon emissions even outside of the 9 states in RGGI and California; and (2) cause substantial indirect effects limiting coal-fired power and carbon emissions in conjunction with several other regulatory changes, including a tightening of the 8-hour ozone standard, the Supreme Court upholding the CSAPR interstate pollution transport rule, and more stringent air sampling standards. Both the means to generate power, as well as its distribution, will be affected.

There is an immediate tension between CPP environmental requirements and grid reliability, which has been highlighted by FERC Commissioners in Congressional testimony as "a jurisdictional train wreck." The relatively recent creation and growth of ISOs also create another federally-created layer of authority which will interfere with state governance and discretion. These points of friction make implementation less certain and multi-dimensional. How this will unfold in the U.S. has major international implications for other major CO_2 emitting countries with strong subnational governance, including Canada, India, Germany, and other nations.

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DRAFT

State and Local Carbon Tax Initiatives in Western North America: Blueprint for Global Climate Change Policy

Professor Nancy Shurtz*

Abstract: In the absence of effective international and federal initiatives to combat the effects of global climate change, many state and local jurisdictions are passing or proposing measures to curb carbon dioxide (CO_2) emissions. The province of British Columbia, Canada, as well as the cities of San Francisco, California and Boulder, Colorado have carbon taxes in place, and similar actions have been proposed in the Oregon and Washington state legislatures. This Article will examine the fundaments of carbon taxation, including identification of the tax base (the pollutant) and taxpayer (consumer, manufacturer, etc.), rates of taxation, measurement standards for tax assessment, exemptions, and use of revenue, and then compare them to cap-and-trade systems. It will assess this family of market initiatives based on the following criteria: (1) administrability, (2) political feasibility (3) revenue generation, (4) efficiency, (5) equity, and (6) efficacy. Lastly, the Article considers the challenges to reform, including constitutional, practical, and political issues. The Article concludes that all states and provinces in North America should link together in a strict cap and trade system while local jurisdictions within the region should pass broad-based carbon taxes. Any revenue generated from these market mechanisms can be recycled to low-income taxpayers and used for carbon sequestration and other "green" purposes. Although the urgency for comprehensive policy actions on a national and international scale is apparent but not immediately forthcoming, regional, state and municipal initiatives can serve as blueprints for innovative and effective climate policy change.

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INTRODUCTION

Even though "no serious scientist" would disagree about the fact of climate change,[1] the countries of the world have been unable to successfully address this pressing problem.[2] Despite nineteen United Nation summit meetings, no global initiative has resulted in any hard-law agreements on greenhouse gas (GHG) reductions.[3] On the U.S. federal level, Congress has passed no cap-and-trade or carbon tax legislation.[4] A few countries have been successful in their market-based initiatives to combat global warming, but most have failed.[5]

In the Western North America many promising regional, state and local initiatives have been passed or have been proposed.[6] At the regional level, California and Quebec have a cap-and-trade system in place and the British Columbia carbon tax has been effective at reducing carbon emissions with only minimal impact on the economy. At the state and local level, carbon taxes exist in both Boulder and San Francisco and have been proposed in Oregon and Washington. However, much more needs to be done to combat climate change.[7] In the absence of federal and international action, regional, state and local market initiatives can serve as models, giving other governments the opportunity to learn from these local laboratories.[8]

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[1] *See* Intergovernmental Panel on Climate Change, 2007: Summary for Policymakers, in S. Solmon, et. al, eds, Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (Cambridge University Press 2007), *available* at http://www.ipc.ch/pdf/assessment-report/ar4wgl/ar4-wgl-spm.pdf; Intergovernmental Panel on Climate Change, 2013, Summary for Policymakers, Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the IPCC with Fifth Assessment; Stephen Sewalk, *Europe Should Dump Cap-and-Trade in Favor of Carbon Tax with Reinvestment to Reduce Global Emissions*, 5 WASH. & LEE J. ENERGY CLIMATE & ENV'T. 355 (2014) n. 1-18 and accompanying text; *Climate Impact on Coast Areas and Climate Impacts on Agriculture and Food Supply,* U.S. ENVTL. PROTECTION AGENCY, at http://www.epa.gov/climate change/impacts; "Study Predicts Huge Sea Level Rise if All Fossil Fuels Are Burned," The New York Times, reported in Register Guard Sept. 12, 2015 at A9.

[2] Even Pope Francis has been discussing this issue. *See* "Why Can't the Left Govern," Daniel Henninger, Wall St. at A15 (March 27, 2014).

[3] *See* Sewalk, *supra* note 1, at n. 57.

[4] In the absence of mandates, the administration efforts have been limited to updating EPA standards, climate-related research, and voluntary emission reduction programs relating to GHG emissions. *See* discussion *infra* in Part I.B. On March 28, 2014 Obama initiated regulations on methane, etc.

[5] *See* discussion *infra* in Part I.C.

[6] *See* discussion *infra* in Part III.

[7] I guess I would put myself into the "transformative" school of thought when it comes to environmental taxation. I view that environmental harms are "regrettable consequences of economic development that can be minimized by different attitudes and concerted efforts at environmentally sensitive practices." "The main purpose of environmental taxes is not to internalize costs or assign blame for environmental harms, but to encourage environmental awareness and shared responsibility for creating a better environmental future." *See q*uotes at 2070 in David G. Duff, *Tax Policy and Global Warming,* 51 CAN. TAX J. 2063 (2003). (Duffy contrasts this transformative view with the economic and justice/morality views). In addition, I believe that our outlook should be the "blueprint" model, as opposed to the "scramble model." "Blueprint" is an optimistic viewpoint, stressing that change can come from the bottom up by focusing on local actions that can address environmental challenges. "Scramble" is reactive, where events outpace actions, change only comes when nature forces it, and policy makers pay little attention to the problems. *See* Chapter Two "Shell Games," McKenzie Funk's WINDFALL: THE BOOMING BUSINESS OF GLOBAL WARMING, (The Penguin Press, 2014) (hereinafter WINDFALL).

[8] This article just focuses on energy, but for local green building initiatives, *see* Nancy E. Shurtz, *Eco-Friendly Building from the Ground Up: Environmental Initiatives and the Case of Portland, Oregon*, 27 J. OF ENVT. L. & LIT. 237-262 (2012).

Local initiatives[9] are important in at least three key respects. First, many of the problems causing climate change stem from local problems.[10] Thus, it is within the local jurisdiction's authority to plan and solve these problems.[11] Second, changing the behavior of people and businesses is often more effectively accomplished when done at the local level, [12] and may have a cumulative and thus a national (and international) impact.[13] Third, in the absence of effective federal and international initiatives, state and local governments pursuing unique policies can serve as a petri dish for the federal government and ultimately the international community by offering innovative ideas that can translate into national and international initiatives.[14]

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[9] "Local" from now on means regional, state and local.

[10] Climate change will affect different places in different ways, so the specific tax and other policies used to manage impacts must be tailored to respond to each locality's unique local conditions. When local governments create climate change policies, they should be evaluated within the context of their specific environments on a case-by-case basis and should establish a mix of strategies that reflect local priorities and the specific vulnerabilities of the community. For example, in areas such as California, which are not prone to hurricanes, but are prone to drought and high traffic congestion, innovative transportation policies aimed at mitigating congestion, and GHGs that creates, as well as fortifying road infrastructure. Alternatively, in areas that are prone to frequent hurricanes or typhoons, land use policies that promote redevelopment with green buildings that are often more energy efficient and cost effective to begin with, would contribute to a reduction in GHG's and ultimately reduce climate change. *See* Evan Mills, Climate Change, *Insurance and the Buildings Sector: Technological Synergisms Between Adaptation and Mitigation*, 31 BUILDING RES. & INFO. 257, 271 (2003).

[11] Local initiatives referred to as "corporate welfare" or "perverse incentives" are used by local governments to attract new business. The focus of these incentives is to promote economic growth. However, the incentives are destructive to the environment because they often provide no incentives for the new businesses to pursue sustainable practices. To have an effective local climate change initiative, these local policies must be eliminated or made contingent upon green initiatives. When local governments offer large corporations income and property tax breaks to relocate within the city or state, but make no restrictions on the corporation's environmental activities, such unsustainable policies cause a strain on local resources. Thus, local governments must steer economic growth and urban development towards GHG reductions when they offer corporate welfare packages to new businesses or completely curb this practice. *See See* Gawain Kripke & Brian Dunkiel, *Taxing the Environment—Corporate Tax Breaks to Promote Environmental Destruction*, 1998 WL 12638860; Beverly I. Moran, Chapter 8: Economic Development: Taxes, Sovereignty, and the Global Economy in Taxing America (edited by Karen B. Brown and Mary Louise Fellows) (N.Y. University Press, 1997) (Moran questions "why localities continue to provide incentives, given the tremendous economic risks," at 198).

[12] *Id.* Also see Yair Listokin and David M. Schizer, *I Like to Pay Taxes: Taxpayer Support for Government Spending and the Efficiency of the Tax System,"* 66 TAX. L. REV. 179 (2013). Since most people now live in urban areas and even more are expected to move there in the future, changing behaviors in just a few city sectors such as transportation, land use, waste and energy consumption, could make a considerable impact on climate change.

[13] Katherine A. Trisolinial, *All Hands on Deck: Local Governments and the Potential for Bidirectional Climate Change Regulation*, 62 STAN. L. REV. 669 (2010) *available at* http://www.stanfordlawreview.org/ sites/default/files/articles/Trisolini.pdf.

[14] *See* Patricia M. Dechristopher, *Flexibility, Efficiency, Integration: Local Lessons in Sustainable Development*, 16 COLO. J. INT'L ENVTL. L. & POL'Y 157 (2005); Myanna Dellinger, *Localizing Climate Change Action*, 14 MINN. J. L. SCI. & TECH. 603 (2013); Joe Loper, *Evaluating Existing State and Local Tax Codes from an 'Environmental Tax' Perspective: The Case of Energy-Related Taxes*, 12 PACE ENVTL. L. REV. 61 (1994); Robert B. McKinstry, Jr., *Laboratories for Local Solutions for Global Problems: State, Local, and Private Leadership in Developing Strategies to Mitigate the Causes and Effects of Climate Change*, 12 PENN. ST. ENVTL. L. REV. 15 (2004); Hari M. Osofsky & Janet Koven Levit, *The Scale of Networks?:Local Climate Change Coalitions*, 8 CHI. J. INT'L L. 409, (2008) ("A growing scholarly and public policy dialogue examines. . .the role of localities in climate change regulation. To date, however, analyses of cities' participation in climate policy have largely focused on some combination of law and policy initiatives, urban theory, and the intersection of international law with political science.")

Tax initiatives in particular can provide a price signal that can direct investment into new technologies or provide a motivation for people to change their behavior.[15] Thus, tax initiatives can have a triple-effect on curbing climate change. First, tax deductions and credits can incentivize good behavior.[16] Second, environmental taxes can punish bad behavior.[17] Third, the revenue generated from environmental taxes can be used to promote environmental practices that can combat carbon emissions and climate change.[18] New and innovative local tax policies, in combination with other initiatives, such as cap-and trade, should be instituted that allow us to move forward in the fight against climate change.[19]

Part I of this Article examines International and U.S. federal climate change initiatives, as well as those in several Scandinavian and European countries. Part II of this Article compares carbon tax to cap and trade and assesses these market initiatives based on economic, equitable, and other criteria. Part III explores regional, state and local carbon reduction initiatives in the Western North America and urges these types of initiatives be expanded throughout the U.S. and Canada. Part IV makes some general assessments and addresses the challenges to reform, such as constitutional, practical, and political issues. Lastly, the Article concludes with a call for the federal U.S. and international communities to take note of the innovative policies that have been implemented in Western North American. A state/province lead multilateral cap and trade program expanding throughout North American combined with local carbon taxes would be the best way to combat global warming.[20] Such a plan might "nudge" the federal government into passing needed legislation, but would at least give a message to the world that it is possible to address the problems of climate change.[21]

PART I: INTERNATIONAL & U.S. FEDERAL CLIMATE CHANGE INITIATIVES

International and U.S. federal climate change initiatives have proven to be inadequate at preventing climate change. UN Conventions and international treaties have failed to stop global warming. The U.S. has also failed in its passage of a carbon tax and cap-and-trade regime. Very few countries have been successful at harnessing market initiative into effective global change policy.

[15] Kenneth R. Richards, *Framing Environmental Policy Instrument Choice*, 10 DUKE ENV'L & POL'Y F. 221-285 (2000); Jonathan Baert Wiener, *Global Environmental Regulation: Instrument Choice in Legal Context*, 108 YALE L. REV. 677-800 (1999)

[16] Janet Milne, *Environmental Taxation, Why Theory Matters*_____ ; *also see* Stanley S. Surrey, *Tax Incentives as a Device for Implementing Governmental Policy: A Comparison with Direct Government Expenditures*, 83 HARV. L. REV. 705, 713-38 (1970) (Surrey is of the view that direct subsidies are as good as, if not better than, tax subsidies); Charles D. Patterson, III, *Environmental Taxes and Subsidies: What is the Appropriate Fiscal Policy for Dealing with Modern Environmental Problems?* 24 WILLIAM & MARY ENVTL. L & POL'Y REV. 121-159 (2000).

[17] Janet Milne, *Environmental Taxation in the United States: The Long View*, __

[18] *See* Stephen Sewalk, *Carbon Tax with Reinvestment Trumps Cap-and-Trade*, 30 PACE ENVTL. L. REV. 580 (2013); Marie Al Kirk & Christian L. Wade, *A Taxing Problem for Environmental Justice: The Tax Money From Hazardous Waste Facilities, Where It Goes, and What It Means*, 16 STAN. ENVTL. L. J. 201 (1997).

[19] See *infra* notes 273-275 and accompanying text.

[20] *See States and Trends of Carbon Pricing,* World Bank Group, (hereinafter World Bank) at 22 (stating market instruments can "co-exist in harmony and complement each other effectively.")

[21] Richard H. Thaler & Cass. R. Sunstein, NUDGE: IMPROVING DECISIONS ABOUT HEALTH, WEALTH, AND HAPPINESS. (Yale University Press 2008) (describing "libertarian paternalism" as a way to try to influence people's behavior in a direction that will benefit them.); *Also see* Annabelle Jaeger, *Five Reasons Why Local Government Should Influence Climate Change Plans*, THE GUARDIAN, (Jan. 6, 2015) *available at* http://www.theguardian.com/public-leaders-network/2015/jan/06/local-government-climate-change-plans.

A. International Climate Change Initiatives Have Failed

At the Rio Earth Summit in 1992, the first major international agreement on climate change—the United Nations Framework Convention on Climate Change (UNFCCC)—was drafted.[22] The UNFCCC states as its ultimate objective is to achieve[23]

> Stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, ensure that food production is not threatened, and enable economic development to proceed in a sustainable manner.

UNFCCC sets forth a framework of guiding principles and includes general commitments applicable to all parties. This framework was significant because it represented a solid collaborative commitment from all corners of the globe to prevent GHG concentrations in the atmosphere.

Five years after the original Rio Earth Summit, the first international protocol was passed in 1997, at Kyoto Japan, and entered into force in 2005.[24] The Protocol set forth national emission reduction targets for developed nations to meet in two commitment periods between 2008-2012 and 2013-2020, as well as a flexible mechanism to meet them.[25] By 2009, the Protocol had been adopted by 192 countries.[26] However, the United States, along with many other nations who signed the Protocol, refused to ratify it.[27] Canada signed and ratified the Treaty, but withdrew in 2011.[28] In the second commitment period, only 12% of the world's GHG emissions were covered and only 9 countries had ratified the Treaty.[29] Russia, Japan, and New

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22 CHECK THIS and get cite

23 UNFCCC, Article 2: Objective, *available at* http://unfccc.int/essential_background/convention/background/items/1353.php

24 See Kyoto Protocol to the United Nations Framework Convention on Climate Change (1997) (herein referred to as "Protocol" or "Kyoto Protocol" or "Treaty.") and United Nations Framework on Climate Change (UNFCC) (1992), *available at* http://unfccc.int/index.html.; *Also see* UNFCCC, Status of Ratification of the Kyoto Protocol (2014), *available at* http://unfccc.int/kyoto_protocol/ status_of_ratification/items/2613.php. The Protocol set forth specific limitations on annual GHG emissions. The limit could be satisfied by reducing GHG emissions, investing in carbon "sinks" that remove GHG from the atmosphere, or by acquiring emission reduction units from other parties.

25 The protocol was amended in 2012 to accommodate the 2013-2020 commitment period in what was known as the Doha Amendment of the Kyoto Protocol. However, as of February 2015, the Doha Amendment was not yet in force. *See August Update on Doha Amendment Ratification*, CLIMATE CHANGE POLICY & PRACTICE, (Aug. 15, 2015) *available at* http://climate-l.iisd.org/news/august-update-on-doha-amendment-ratification/.

26 The UNFCCC was initially signed by 155 States and came into force on May 21, 1994 -- the 19th day after 50 States had signed and ratified it, *available at* http://unfccc.int/kyoto_protocol/ status_of_ratification/items/2613.php-But World Bank still says 192 parties. (Check this)

27 *See* Sewalk, *supra* note 1, at n. 51. Star Tribune, *Canada Formally Pulls Out of Kyoto Protocol on Climate Change*, (December 12, 2011), *available at* http://www.startribune.com/world/135469408.html.

28 Trisolini *supra* note 13, at 671. David G. Duff, *Carbon Taxation in British Columbia*, 10 VT. J. ENVTL. L. 87, 88 ("GHG emissions in Canada increased substantially throughout the 1990s and early 2000s reaching 747 million tones in 2005-over 25% higher than 1990 level and almost 34% higher than Canada's commitment under the Kyoto Protocol.")

29 World Bank, *supra* note 20, at 14.

Zealand, three major carbon emitters, officially pulled out during this second commitment period.[30] Therefore, while the Kyoto Protocol initially seemed like a significant step in the right direction, in recent years it has been a disappointing failure. At best, it has resulted in non-binding, soft targets from most participants.[31]

The lack of binding participation on the international level became apparent in 2007 at the Intergovernmental Panel on Climate Change (IPCC), when the Panel released its Fourth Assessment Report.[32] This report indicated that global emissions would need to be reduced by 80-90% or more by 2050.[33] In the same year, the comprehensive Stern Review on the Economics of Climate Change carried out by the U.K. Treasury concluded that economic cost of delayed greenhouse gas reductions would be far greater than previously projected.[34] Yet, in 2009, at the UNFCCC's 15th Conference of the Parties (COP15) in Copenhagen, a binding agreement had still not been created. The agreement that was created at COP15 in 2009, the "Copenhagen Accord," provided a "soft" commitment to keep the global temperature increase below two degrees and a scheme to protect tropical rainforests known as Reding Emissions from Deforestation and Forest Degradation (REDD).[35] While the COP18 in 2013 in Warsaw modified REDD (REDD+)[36] and focused on "urbanization, and specifically buildings and transport, and on the role of local government to enhance global mitigation efforts,"[37] nothing binding was passed.[38]

Yet, despite these efforts, REDD+ has failed.[39] In addition, the United Nations Convention to Combat Desertification has failed.[40] This convention's "emphasis on a bottom-up approach" to stop land degradation and desertification "suggests that a different approach may lead to more meaningful results."[41] Recent United Nations data "suggest that fifty percent of drylands currently under agricultural cultivation are moderately or severely degraded, and 12 million hectares of productive land become barren each year due to desertification and

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[30] World Bank, *supra* note 20, at 16.
[31] As of this writing 9 (CHECK—is there more?) countries have accepted the Protocol including, Algeria, Azerbaijan, Bangladesh, Barbados, Bhutan, Brunei Darussalam, China, Comoros, Congo, Djibouti, Ecuador, Ethiopia, Grenada, Guyana, Honduras, Hungary, Indonesia, Kenya, Liberia, Lichtenstein, Madagascar, Maldives, Marshall Islands, Mauritius, Mexico, Micronesia, Monaco, Morocco, Namibia, Nauru, Norway, Palau, Panama, Peru, Republic of Korea, Samoa, San Marino, Seychelles, Singapore, Solomon Islands, South Africa, Sudan, Switzerland, Thailand, Trinidad and Tobago, Tuvalu, Uganda, United Arab Emirates, and Viet Nam, *available at* https://treaties.un.org/pages/ViewDetails.aspx?src=TREATY&mtdsg_no=XXVII-7-c&chapter=27&lang=en.
[32] *See* IPCC, Climate Change 2007: Mitigation Contribution of Working Group III to the Fourth Assessment Repot of the Intergovernmental Panel on Climate Change, (Cambridge University Press, 2007). *Also see* 2007: Synthesis Report. Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change in Pachauri, R.K. and Reisinger, A. (Core Writing Team eds), 2007 IPCC, Geneva Switzerland.
[33] *Id.*
[34] Nicholas Stern, The Economics of Climate Change: The Stern Review, (Cambridge University Press, 2007).
[35] United Nations, The Copenhagen Accord (FCCC/CP/2009?l.7) Dec. 18, 2009.
[36] World Bank, *supra* note 20, appendices.
[37] World Bank, *supra* note 20, at 37. Although the climate change initiatives
have failed, the Mediterranean Action Plan and Montreal Protocol on ozone depletion were a success. *See* Paul G. Harris, *Collective Action on Climate Change: The Logic of Regime Failure,* 47 NAT. RESOURCES J. 195 (2007).
[39]Chris Lang, *The Dismal Failure of the REDD+ Partnership,* REDD MONITOR, (Nov. 20, 2014) *available at* http://www.redd-monitor.org/2014/11/20/the-dismal-failure-of-the-redd-partnership/.
[40] Stephen Emmott, TEN BILLION, (Vintage Books, 2013) at 188.
[41] Alon Tal & Jessica A. Cohen, *Bringing "Top-Down" to "Bottom-Up":A New Role for Environmental Legislation in Combating Desertification,* 31 HARV. ENVTL. L. REV. 163, 218 (2007).

drought."[42] Lastly, the Convention on Biological Diversity has failed.[43] With no compliance mechanism, this Convention is very weak and thus fails to stop "monstrous projects."[44] If global temperatures rise by more than 3.5°C "70% of the world's known species risk extinction."[45]

Much attention is now being focused on the upcoming Paris Climate Change Conference in December 2015.[46] It is hoped that the countries of the world will enter into a new globally binding agreement.[47] However, the first draft of the proposed UN agreement is out and is already being criticized as it "relies on dangerous and unneeded forms of energy such as nuclear power and natural gas, and fails to emphasize renewable energy."[48] Unfortunately, the consensus is that global climate change initiatives have failed in the past and are unlikely to succeed in the future.[49]

B. U.S. Federal Climate Change Policies Have Failed

The U.S. federal government's climate change policies have been largely ineffective at reducing GHG emissions and preventing climate change. In the absence of federal mandates for a cap-and-trade system or a carbon tax, the federal government's climate change policies have largely revolved around new EPA rules and a limited number of tax policies.[50] In general, the U.S. federal climate change policies have mostly failed.

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[42] Selley Weton, Michela Biasutti, and Michael B. Current Legal & Scientific Integrity in Advancing a "Land Degradation Neutral World," 40 COLUM J. ENVTL. L. 39, 39 (2015).
[43] Emmott, *supra* note 40, at 188
[44] Rachael Waxler Ruiz,*The Convention on Biological Diversity: An Affectation of Conservation Exposed by the Interoceanic Chinese-backed Nicaraguan Canal*, 28 TUL. ENVTL. L. J. 455,479 (2015); *Also see* Rachelle Adam, *Missing the 2010 Biodiversity Target: A Wake-up Call for the Convention on Biodiversity?*, 21 COLO. J. INT'L ENVTL. L. & POL'Y 123 (2010).
[45]Anup Shah, *Loss of Biodiversity and Extinctions*, (Jan. 19, 2014) *available at* http://www.globalissues.org/article/171/loss-of-biodiversity-and-extinctions.
[46] For conference information and presentation, *see* http://waset.org/conference/2018/10/paris/ICCCGW. *Local Government Climate Roadmap Paris Dialogues*, LOCAL GOVERNMENT CLIMATE ROADMAP, (Aug. 9, 2015) *available at* http://www.iclei.org/fileadmin/user_upload/ICLEI_WS/Documents/advocacy/COP21/LGCR_-_Paris_Dialogues_atCOP21_v1_20150809.pdf
[47] World Bank Group, *supra* note 20, at 22 (stating an aspiration of "much needed international partnerships."); *A Conference of the Parties with Higher Stakes than Ever*, 2015 PARIS CLIMATE CONFERENCE, (2015) *available at* http://www.diplomatie.gouv.fr/en/french-foreign-policy/climate/2015-paris-climate-conference-cop21/.
[48] Bob Doppelt, "Reorganize Economy to Run on Renewables," The Register-Guard, at A9, (Oct. 22, 2015)
[49] Harris, *supra* note 37, at 197. ("Despite the Kyoto Protocol entering into force in February 2005, the climate regime has been a failure."); *See Failure to Constrain Climate Change Will Create 'Climate Chaos', Secretary-General Says at High-Level General Assembly Event Aimed at Inspiring Ambitious Accord*, UNITED NATIONS, (June 29, 2015) *available at* http://www.un.org/press/en/2015/ga11658.doc.htm http://www.un.org/press/en/2015/ga11658.doc.htm
[50] Thomas M. Gremillion, *Setting the Foundation: Climate Change Adaptation at the Local Level*, 41 ENVTL. L. 1221, 1247 (2011). ("existing state and federal regulatory programs are ill-prepared to adapt to the direct effects of climate change"); See also, Robert L. Glicksman, Climate Change Adaptation: A Collective Perspective on Federalism Considerations, 40 ENVTL. L. 1159, 1163 (2010) ("Despite the critical need for the development of adaptive response to climate change, the federal government has done little to stake out its turf on adaptation policy or to coordinate the response of lower levels of government."); J.B. Ruhl, Climate Change Adaptation and the Structural Transformation of Environmental Law, 40 ENVTL. L. 363, 412 (2010). ("The United States has compiled close to zero in the way of coordinated anticipatory adaptation policy for managing the risk in the United States of climate change catastrophe and crisis.").

Creating an effective climate change policy at the federal level has proven difficult for political reasons.[51] During the 2008 presidential election, president-elect Obama espoused his support for use of a cap-and-trade system to cut greenhouse gas emissions by 80% by 2050 and in doing so, made his intention known that he wanted the U.S. to become a leader in climate change.[52] The cap-and-trade system that President Obama supported was a federal environmental policy that imposed a mandatory cap on omissions while providing flexible compliance options.[53] The program aimed to reward innovation, efficiency, and early action without inhibiting economic growth.[54] Once elected, President Obama issued Executive Order 13514 on Oct. 5, 2009, requiring federal agencies to undertake various measures to reduce GHG emissions[55] and to identify climate change strategies in conjunction with the interagency Climate Change Adaptation Task Force.[56] As of the writing of this Article however, most agencies have only made promises.[57] Some have argued that federal policy failed to encourage coordination with state and local authorities while others even argued federal policy inhibited best practices of local jurisdictions.[58] However, what is clear is that the policy got bogged down in the political doldrums and was never successfully fully implemented.

An equally exciting, but ultimately unsuccessful, attempt by a U.S. federal agency to control climate change came from the National Oceanic and Atmospheric Administration (NOAA). NOAA had proposed a reorganization to create a national Climate Service, centralizing federal sources of information on climate change strategies.[59] Congressional

[51] Many prominent Republicans do not even believe in global warming or climate change or do not believe it is an immediate threat. Ashley Parker, Day After Fed Uproar, Perry Tones It Down, N.Y. Times, Aug 18, 2011, at 12 (quoting Governor Rich Perry of Texas), *available at* http://www.nytimes.com/2011/08/18/us/politics/18perry.html?_r=0.

[52] FIND

[53] FIND

[54] U. S. Environmental Protection Agency, *Cap and Trade,* (May 10, 2012), http://www.epa.gov/captrade/.

[55] Pursuant to the Executive Order, all federal agencies were required by June 2011 to issue "an agency-wide climate change adaptation policy statement . . . which commits the agency to adaptation planning to address challenges posed by climate change risks to the agency's mission, programs and operations." The White House President Barack Obama, Implementing Climate Change Adaptation Planning in Accordance with Executive Order 13514, *Federal Agency Climate Change Adaptation Planning Support Document*, p. 23 §A (March 4, 2011), *available at* http://www.whitehouse.gov/sites/default/files/microsites/ceq/ adaptation_support_document _3_3.pdf.

[56] The White House President Barack Obama, Council on Environmental Quality, *Climate Change Resilience*, *available at* http://www.whitehouse.gov/administration/eop/ceq/initiatives/ resilience.

[57] For example, the Department of Transportation pledged to incorporate considerations of climate change resilience in its planning process and to try to encourage coordination with state and local authorities. U.S. Dep't of Transp., Strategic Sustainability Performance Plan 24 (2014), *available at* https://www.transportation.gov/sites/dot.gov/files/docs/2014-DOT-Strategic-Sustainability-Performance-Plan.pdf.

[58] Alejandro E. Camacho, *Adapting Governance in Climate Change: Managing Uncertainty Through a Learning Infrastructure*, 59 EMORY L. J. 1, 26 (2009); Robert L. Glicksman, *Climate Change Adaptation: A Collective Perspective on Federalism Considerations,* 40 ENVTL. L. 1159, 1163 (2010); J.B. Ruhl, Climate *Change Adaptation and the Structural Transformation of Environmental Law*, 40 ENVTL. L. 363, 412 (2010).

[59] Emily Yehle, *Appropriations: House Votes to Slash Climate Research, Block New Red Snapper Fishing Plan* (the spending bill cuts climate research by $30 million) (June 4, 2015) *available at* http://wwweenews.net/stories/106001948; *also see* ,Examining NOAA's Climate Service Proposal: Hearing Before the H. Comm. on Sci., Space, & Tech, 112th Cong. 1-3 (201) (statement of Jane Lubchenco, Adminstrator, NOAA), *available at* http://science.house.gove/sites/ republicans.science.house.gov/files/documents/hearing/062211_lubchencopdf; Maybe the U.S. climate resilience toolkit is similar? http://toolkit.climate.gov/.

Republicans, unfortunately, have targeted NOAA's revenue-neutral reorganization in recent spending bills and cut off funding to the Climate Service.[60]

The latest attempt to combat climate change has been the EPA's initiative to treat greenhouse gas emissions as pollution under the Clean Air Act.[61] The EPA recently set forth clean energy guidelines (the Clean Power Plan or CPP) for fuel-fired electric plants. [62] The CPP requires each state to submit an implementation plan for EPA approval by June 16, 2016 and authorizes the states to use market-based programs to meet emission targets. [63] Issues surrounding whether the CPP is within the scope of EPA authority has been tied up in litigation.[64] The Supreme Court is expected to hear the case in 2018 or 2019.[65] Unfortunately, the regulatory approach is often slow, complex and inefficient. [66]

In the federal tax law area, environmental taxes and income tax incentives have largely failed to combat climate change.[67] Very few environmental initiatives exist; and, the ones that do have a very small effect on climate change.[68] Environmental taxes are imposed on crude oil and petroleum products (oil spill liability), the sale or use of ozone-depleting chemicals (ODCs), imported products containing or manufactured with ODCs,[69] and gas guzzling cars.[70] These taxes are antiquated, too narrowly tailored, and as a result, are ineffective in combatting climate change.[71] Tax incentives have often subsidized bad environmental activities, such as oil and gas exploration, with minimal benefits for renewable energy and conservation.[72] Much more reform is needed in this area. Federal tax policy should incentive clean and renewable energy, preserve and protect carbon sinks, promote efficient and clean-full vehicles, subsidize energy-efficient buildings and appliances, and reduce methane and other harmful GHG gas emissions. *See* summary Chart I below.

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[60] Press Release. H Comm. on Sci., Space &Tech., Republicans Raise Concerns with NOAA Climate Service, EPA Science Activities (Mar. 10, 2011), *available at* science.house.gov/press-release/republicans-raise-concerns-noaa-climate-service-epa-science-activities.

[61] 42 U.S. C. §7411(d)(2014).

[62] *Clean Power Plan for Existing Power Plants*, U.S. EPA., *available at* http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants#additional-resources.

[63] *See* Craig Gannett, *Implementing Section 111(D) of the Clean Air Act: The Pathway to Regional Cap-and-Trade Programs?2015 No. 1 RMMLF-Inst Paper No. 8,* ROCKY MOUNTAIN MINERAL LAW FOUNDATION, at 8-3 (Jan. 22-23, 2015 (noting the allowance of "market-based trading programs.") *Also* see *EPA, Office of Air and Radiation, Projecting EGU C)2 Emission Performance instate Plans (June 2014), available at* http:///www2epa.gov/carbon-pollution-standard/clen-poer-plan-proposed-rule-proujecting-egu-c02-emission-performance*; EPA. Office of Air and Regulation, Clean Power plan Proposed rule: Translation of the State-Specific Rate=Based Co2 Goals to Mass-Based Equivalents, available at* http://www2epa.gov/carbon-pollution-standards/clean-ppower-plan-proposed-rule.

[64] *Mass. v. EPA* 549 U.S. 497 (2007); *UARG v. EPA*, 134 S.Ct. 2427 (2014).

[65] Gannett, *supra* note 63, at 8-9 ("To make matters more complicated, the current demographics of the Court suggest that the outcome of this case may turn on the 2016 Presidential election."

[66] Find cite.

[67] Roberta Mann, *Waiting to Exhale?: Global Warming and Tax Policy*, 51 AM. UNIV. L. REV. 1135-1222 (2002).

[68] *See* Janet E. Milne, Environmental Taxation in the United States: Retrospective and Prospective, 113 in GREEN TAXATION IN EAST ASIA.

[69] IRS, Environmental Taxes, *available at* http://www.irs.gov/publications/ p510/ch03.html.

[70] See Milne, *supra* note 68, at 122.Gas Guzzler Tax, 26 U.S.C. A.§ 4064 (2005) (Passed in 1978). (Milne explains that the Gas Guzzler Tax has been largely ineffective because of the exception for non-passenger vehicles like SUVs and the thx rates have not been increased since 1990.) 40 C.F.R. § 600.306.

[71] Margalioth, Yoram, *Tax Policy Analysis of Climate Change*, 64 TAX L. REV. 63-98 (2010).

[72] Mona L. Hymel, *The Population Crisis: The Stork, The Plow, and the IRS*, 177 N. CAROLINA L. REV.18 (1998); *But see* John A. Bogdanski, *Reflections on the Environmental Impacts of Federal Tax Subsidies for Oil, Gas, and Timber Production*, 15 LEWIS & CLARK L. REV. 323 (2011).

Chart I: Environmental Tax Incentives

Sector	The Bad	The Good	Reform
Energy[73]	Coal-fired Oil-fired Nuclear?	Renewable: Wind, solar, hydroelectric, geothermal Energy conservation Increasing efficiency Reducing waste	Reduce or eliminate the current oil, gas and coal subsidies. • Percentage depletion • Intangible drilling cost • Enhanced oil recovery credits Pass new energy law extending and adding tax incentives • Extend and modify the renewable energy production tax credit; • Extend and modify the solar energy and fuel-cell investment tax credit; • Remove the caps on credits for residential solar property and residential fuel-cell property; • Create a tax credit for plug-in hybrid vehicles; • Create a credit for cellulosic alcohol production; • Extend the credit for biodiesel production; • Extend and increase the credit for alternative refueling stations; • Eliminate the "SUV loophole," which allows business to claim a tax break for buying less-efficient heavy vehicles; and

[73] Richard Westin, *What to Do With Proceeds of a Carbon Tax?* 115 TAX NOTES 191-193 (2007).)
Shi-Ling Hsu, *Reducing Emissions From the Electricity Generation Industry: Can We Finally Do It?"* 14 TUL. ENVTL. L. J. 427 (2001).

			• Create renewable energy bonds for public power providers and electric cooperatives
Forestry[74]	Clear-cutting Logging Soil erosion Nonsustainable forest practices	Preserve existing forests Increase carbon sequestration by planting new forests Increase wildlife habitat and biodiversity Prevent soil erosion Improve watershed management Harvest forests sustainably Preserve spiritual respite and scenic beauty for humans	Eliminating below-cost timber sales and other subsidies on public lands End preferential timber-tax treatment • Capital gains for timber sales • Expanding timber production Continue incentives for conservation and reforestation Allow tax credits for carbon sequestration
Industry[75]	Low energy efficiency Non or low recyclable content	High energy High recyclable content[76]	Limit the advertising deduction[77] Eliminate policies favoring debt and consumption Impose pollution tax on SO_2, NO, noise, air and water pollution
Agriculture[78]	Erosion of Wetlands Nitrogen fertilizer High transportation costs Eutrophication	Organic farming Local production Sustainable farming	Eliminate or reduce bad tax incentives • Capital intensive subsidies • Capital gains preferences on sale of cattle • Cash method for farmers Impose tax on fertilizer

[74] Janet E. Milne, *Timber Taxes: A Critique of the Northern Forest Land Council's Tax Recommendations,* 19 VT. L. REV. 423 (1995); *Celeste M. Black*, The Use of Market Based Mechanisms to Bolster Forest Carbon," 150- 163, ENVIRONMENTAL TAXATION AND CLIMATE CHANGE: ACHIEVING ENVIRONMENTAL SUSTAINABILITY THROUGH FISCAL POLICY (Edward Elgar 2011).
[75] Mona Hymel, *The United States' Experience With Energy-Based Tax Incentives: The Evidence Supporting Tax Incentives for Renewable Energy*, 38 LOY. U. CHI. L.J. 43 (2006).
[76] Britt Anne Bernheim, *Can We Cure Our Throwaway Habits by Imposing the True Social Cost on Disposable Products?* 63 COLO L. REV. 953 (1992)
[77] Mona Hymel, *Consumerism, Advertising, and the Role of Tax Policy,* 20 VIR. TAX REV. 348 (2000).
[78] Mona, *supra* note 72, at ___.

Transportation	Fuel-inefficient cars Airplane travel Parking	Fuel-efficient cars Public transportation Walking/biking	Eliminate the tax preferences for commuting • Tax the parking provided by the employer • Reduce expensing of light trucks (SUVs) • Eliminate light truck exception to gas-guzzle tax Continue to promote hybrids and electric cars, car pooling, and bkiking Increase gasoline tax
Housing[79]	Urban sprawl Erosion of wetlands Large new and/or inefficient homes in open areas Low energy Inefficient appliances	High-density housing/multifamily Renovated homes Energy efficient High energy-efficient appliances	Limit mortgage interest deduction on low energy-efficient homes or on large homes Disallow mortgage deduction on vacation homes Tax inefficient appliances
Population[80]	Over population Over consumption	Limit population Limit consumption	Limit dependency exemption Eliminate or limit the per-child credit Tax consumption (VAT or national sales tax)
Other[81] Reduce methane and other GHG emissions			

The main reason for the environmental climate change conundrum in America is political.[82] Therefore, like the failed attempts to prevent climate change on the international

[79] Mark Andrew Snider, *The Suburban Advantage: Are the Tax Benefits of Home Ownership Defensible?* 32 N. KY. L. REV. 157-187 (2005).
[80] Hymel,,*supra* note 72, at ___.
[81] *See* Duff, *supra* note 7, at 2107,
[82] A majority of the population think the economy, not the environment, is the most important problem the country faces today. *See* Yale Project on Climate Change Commc'n &George Mason Univ. Cir. For climate change comm.. Public Support for Climate and Energy Policies in May 2011, at 2 (May 1, 2011), *available at* http://www.climatechangecomuunication.org/images/files/PolicySpportMay2011pdf.

level, a large-scale solution to climate change at the U.S. federal level is unlikely in the near future. [83] Therefore, from a federal policymaking standpoint, the U.S. federal government's promises to reduce climate change have followed the global climate change trend – with a bunch of hot air.

C. A Few Countries Have Had Successes But Most Have Failed

Some Scandinavian and European countries have passed effective carbon taxes, usually in combination with other forms of energy and pollution taxation and tax subsidies.[84] In addition, many of these countries are also part of the regional emissions trading system (the EU ETS).[85] Some countries, like Australia, have passed carbon taxes and then repealed them.[86] Other countries have proposed carbon taxes, but never passed them.[87] Most countries of the world, however, have never even contemplated a carbon tax.[88]

1. The Scandinavian Success Stories

The Scandinavian countries of Sweden, Denmark, Finland and Norway have been the pioneers in carbon taxation. Perhaps the most successful country has been Sweden, followed by Denmark and Finland. In contrast, Norway's carbon tax has been largely ineffective at reducing GHG emissions. The lessons learned here are that the effectiveness of the carbon tax depends on a number of factors, such as the scope of the tax, its rate, exemptions, and where the revenue from the tax goes.

The Swedish carbon tax, passed in 1991, has the highest rate of all countries in the world.[89] Like most successful carbon tax initiatives the initial rates were to increase over time.[90]As of 2014, the rate was equivalent to US \$168/tCO_2.[91] The tax is broad based in its scope, covering all fossil fuels used for heating and all motor fuels for transport – about 25% of the GHG emissions in the country.[92] To enhance business competitiveness and support economic

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[83] *See* Roberta Mann, *The Case for the Carbon Tax: How to Overcome Politics and Find Our Green Destiny*, ------- (stating that "it appears inevitable that Congress will enact some sort of federal climate change legislation in the next few years."

[84] Carbon Tax Center, *Where Carbon is Taxed*, April 11, 2011, http://www.carbontax.org/progress/wereh-carbon-is-taxed/; Also *see*, Duff, supra note 7, at 2092, 2094 (mentioning how Scandinavian countries use a combination of tax and subsidy approaches and pointing out the fertilizer tax in Sweden). Denmark also has a sulfur tax, *infra* note 105.

[85] Denmark, Finland, France, Finland, Germany, Ireland, Italy, the Netherlands Portugal, Sweden, and the UK are part of the EU. *See* EU Member Countries, European Union, *available at* http://europa.eu/about-eu/countries/member-countries/index_en.htm.

[86] Which countries?

[87] Which countries?

[88] *See* Progress Towards 200802012 Kyoto Target in Europe. European Environmental Agency, A Technical Report/No 18/2014).

[89] World Bank, *supra* note 20, at 17 (stating that the rates range from the high in Sweden to the low in Mexico of US \$1/tCO2.)

[90] Jacqueline Cottrell, *Carbon Taxes: Fiscal Policies Towards an Inclusive Green Economy*, Green Budget Europe, Exhibit 3 UNEP-IMP-GIZ Workshop (10/8/2012).

[91]World Bank, *supra* note 20, at 17 .

[92] World Bank, *supra* note 20, at 82 citing 254.

efficiency, the tax is higher on households and the service sector[93]and lower in sectors subject to international competition.[94] The tax is compatible with EU ETS as fossil fuels regulated there are fully exempt and even non-ETS industry and agriculture are partially exempt.[95] Instead of directly providing exemptions to all GHG emissions covered under the EU cap and trade system, exemptions gradually increased over time.[96] Administrative costs have been low, less than 0.1% of the revenue collected,[97] and revenue from the tax has been steady from 1993 to 2000 and then increased to $3.65 billion annually in 2005-2007.[98] Sweden directs the revenues to the general budget.[99] In other words, Sweden has mainly recycled the revenues to lower income taxes, specifically the tax on labor.[100] Swedish studies have indicated that GHG emissions fell about 15% between 1995 and 1990 and have fallen by more than 40% since the mid-1970s.[101] At the same time, between 1990 and 2007, the Swedish economy has grown over 20%.[102] Interestingly, all political parties were willing to implement this tax.[103] A key ingredient of a successful tax is political leadership and population acceptance.

Denmark is "one of the carbon tax proponents' favorite case studies."[104] Passed in 1991, the carbon tax "was part of a larger environmental tax package, which included energy taxes," a sulfur tax, and subsidies for wind and energy efficiency.[105] The tax was broad-based covering all consumption of fossil fuels (oil, natural gas, coal and electricity) and thus approximately 45% of the total GHG emissions in the country.[106] Designed to minimally impact industry, the rates varied depending on energy use and phased-in over time.[107] Tax rates increased each year between 2008 and 2015 and now stand at US $31/t$CO_2$ equivalence.[108] Like Sweden, industries

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[93] Cottrell, *supra* note 90, at Exhibit 3(EU27 in 1991 to E114 in 2011); Mikael Skou Andersen, *Europe's Experience with Carbon-Energy Taxation.* 3 S.A.P.I. E.N. S. 6-7 (2010) *available at* http://sapiens.revues.org/index1072.html. (The "large increase in electricity taxes depressed real incomes in the short run.")

[94] Cottrell, *supra* note 90, at Exhibit 3. (EU 7 in 1991 and EU34 outside EU, zero within EUETS, 2011); *Also see* World Bank, *supra* note 20, at 82.

[95] World Bank, *supra* note 20, at 82.

[96] *Id.* For example, "District heating plants participating in the EU ETS and heat from EU ETS plants not used for manufacturing purposes now have to pay 80% of the tax rate compared to 94% before 2014."

[97] Cottrell, *supra* note 90, at Exhibit 3.

[98] Jenny Summer, Lori Bird, and Hilary Smith, *Carbon Taxes: A Review of Experience and Policy Design Considerations,* Technical Report NREL/Tp-6A2-47312 at 11 (December 2009) *available at* NREL.com (hereinafter NREL)

[99] *Id.*

[100] Andersen, *supra* note 93, at 6 ("It would have been difficult for Sweden (and Finland) to follow the recommendations from the fiscal literature to aim reductions at employers' social security contributions, because such contributions are relatively small in both countries.")

[101] NREL, *supra* note 98, at 11. *See* Sierra Rayne, *The Devil and the Details of National Carbon Tax Experiments*, at American Thinker, *available at* http://www.thinker.com/blog/2015/02/the-devil-and-the-detils-of-national-carbon-tax-experiments.html. ("From 1991 to 3003, emissions declined just 0.9 percent. Since 3003, emissions have declined 19 percent and there has been only 19 percent real economic growth during the decade.")

[102] *Id.* But *see* Cottrell, *supra* note 90, at Exhibit 4 states GDP gone from100 to 143. However, the consumer price index has increased. *See* Anderson, *supra* note 93, at 7. "The Swedish experience suggests that combining carbon-energy taxes on households with reductions in income taxes could cause inflation rates at a level triggering a possible tax interaction effect, but further analysis is required to corroborate this.") (Consumer price index is weighted average of average price of products, including energy.)

[103] Cottrell, *supra* note 90, at Exhibit 3.

[104] Rayne, *supra* note 101, at 1.

[105] World Bank, *supra* note 20, at 84-85. *See* Rayne, *supra* note 101, at 11.

[106] World Bank, *supra* note 20, at 79.

[107] *Id.* When the carbon tax passed, the tax on energy was reduced to maintain an overall even tax rate.

[108] *Id.*

subject to the EU ETS are generally exempt, however fuels for the production of district heating are subject to the tax even though covered in the cap-and-trade.[109] Energy-intensive sectors not in the cap-and-trade are given exemptions similar to free allowance in the EU ETS,[110] and up until 2014, these sectors could negotiate voluntary agreements to be exempt if covered under the EU ETS.[111]

In 2008, the revenues from the carbon tax were $903 million.[112] Unlike its fellow Scandinavian states, 40% of the revenue from the carbon tax is used for environmental subsidies while the other 60% is returned to industry.[113] Studies showed that industrial emissions "decreased by 23% during the 1990s, after adjusting for growth and market-induced industry restructuring." [114] However, unlike Sweden, the Danish economy has "contracted in real terms by 3 percent since 2006."[115]

Finland was the first country to adopt a carbon tax in 1990.[116] This tax was broad-based and imposed on gasoline, diesel, light fuel and heavy fuel oil, jet fuel, aviation gasoline, coal natural gas and electricity.[117] The tax covers all consumers of fossil fuels, except for fuels for electricity production, commercial aviation and commercial yachting.[118] Its scope was limited to covering only 15% of the total GHG emissions in the country.[119] Like Sweden and Finland, the rates varied on type of fuel and gradually increased over time.[120] In 2013, the liquid traffic fuel rate was US $83/t$CO_2$, whereas the rate for heating fuels increased to US $48 from $41.[121]

Like Sweden, all revenues from the tax went directly to the general budget without any earmarking. By lowering income taxes on labor, the impact on lower-income taxpayers was made more equitable.[122] In 2000, the Finnish government determined that the tax resulted in a reduction of roughly 4 million metric tons of CO_2 (or 7% of emissions) between 1990 and 1998.[123] Between 2007 and 2012 emissions declined 23 percent.[124] On the other hand, unlike Sweden, the Finnish national economy "shrunk almost 4 percent in real terms."[125]

Like Sweden and Denmark, Norway passed a carbon tax in 1991.[126] The taxed sectors include gasoline, light and heavy fuel oil, and oil and gas in the North Sea. Certain industries pay a reduced rate (pulp and paper, fishmeal, domestic aviation, domestic shipping and continental

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[109] World Bank, *supra* note 20, at 79.
[110] *Id.* From 2013 incineration plants are included in both so are doubly regulated.
[111] *Id.*
[112] Can you get recent amount?
[113] *Id.* at 12.
[114] Rayne, *supra* note 101, at 1. ("[B]etween 1992 and 2006, there was absolutely no reduction in Denmark's carbon dioxide emissions – actually, there was a slight increase. Since 2006, there has been a large decrease in emissions (by about one-third.))
[115] *Id.*
[116] NREL, *supra* note, 98, at 9.
[117] *Id.* (Coal is subject to a rate of $73.97 per metric ton, natural gas is subject to a reduced tax rate of $3.02 per MWh, and liquid fuels are taxed between $-.07 and $0.09 per liter. (citing European Environmental Agency).
[118] World Bank, *supra* note 20, at 79.
[119] *Id.*
[120] World Bank, *supra* note 20, at 79.
[121] World Bank, *supra* note 20, at 79.
[122] Anderson, *supra* note 93, at 6.
[123] *Id.* citing Prime Minister's Office, Finland 2000.
[124] Rayne, *supra* note 101, at 1.
[125] *Id.*
[126] World Bank, *supra* note 20, at 10

shelf fleet) while some industries (foreign shipping, fishing, and external aviation) are exempt.[127] Industry "included in the EU ETS are (partially) exempted from the carbon tax, except for the offshore petroleum industry. [128] The tax covered 50% of the GHG emissions in the country.[129] Like its sister states of Finland and Sweden, revenue from the tax goes into the general government budget.[130] However, the funds were to be used to finance a special pension fund.[131] Unfortunately, studies have shown that GHG emissions have increased by 15% from the time the tax was first implemented.[132] Thus, the Norway carbon tax has mostly failed.

2. Other Countries Carbon Taxes

Several European countries have also passed carbon taxes: France,[133] Iceland,[134] Ireland,[135] Italy,[136] Netherlands,[137] Portugal,[138] Switzerland,[139] and the United Kingdom.[140] (See Appendix A) Under these systems, price signals vary, ranging from low tax rates of $10t/$CO_2$ in Iceland to $68t/$CO_2$ in Switzerland. The taxes are generally broad-based. UK's tax covers approximately 25% of GHF emissions,[141] whereas Iceland's covers 50%.[142] Exemptions, or partial exemptions, are given for firms included in the EU ETS. The use and amount of the revenue collected from the tax have also varied. In the United Kingdom the tax was intended to be revenue neutral with offsetting cuts to the National Insurance Contributions, but ended up being revenue negative.[143] In contrast, the Netherlands tax revenues were substantial—over

127 *Id*. at 10.
128 World Bank, *supra* note 20, at 80.
129 World Bank, *supra* note 20, at 81
130 *Id*.
131 *Id*.
132 *Id.* Norway also experienced an increase in GD of 70% since 1990 and that is the excuse used to explain the failure of the carbon tax.
133 *See S*ewalk, *supra* note 1, at ___. France proposed a carbon tax in 2009. The tax was imposed per ton of carbon dioxide emissions on fossil fuels, such as gasoline, gas, or coal. Electricity was exempt as it was covered by the EU cap-and-trade system. Unlike other European countries, the revenue was to be returned to households and business in the form of a "green check".
134 World Bank, *supra* note 20.
135 *Also see* World Bank, *supra* note 20, at 80. In 2010 Ireland passed a carbon tax on emissions from fossil fuels, including kerosene, diesel fuel, liquid petroleum, fuel oil and natural gas. In 2012, the tax was expanded to solid fuels such as peat and coal. The tax only applies to sectors not part of the EU ETS. The tax slowly phased in at higher amounts. The tax is estimated to generate 500 million pounds of revenue in 2013 and be potentially offset Irish income tax. Ireland's Environmental Protection agency estimates that overall GHG emissions dropped 6.7% and energy GHG emissions dropped by 10/5%. This was all done with slight growth in the Irish economy. *Also see* Carbon Tax and Shift: How to Make it Work for Oregon's Economy, Northwest Economic Research Center, College of Urban an Public Affairs.
136 *Italy to Introduce Carbon Tax to Fund Green Energy*, (April 17, 2012) *available at* http://www.reuters.com/article/2012/17/italy-carbontax-idUSL6E8FHALR20120417.
137 World Bank, *supra* note 20.
138 *See* http://www.worldbank.org/content/dam/Worldbak/document/Climate/background-notex_carbon-tax.pdf.
139 World Bank, *supra* note 20.
140 World Bank, *supra* note 20.
141 World Bank, *supra* note 20, at 83.
142 *Id.* at 80.
143 The United Kingdom passed a limited carbon tax in 2001. The tax covered electricity, natural gas supplied by gas utilities, liquefied gas supplied in a liquid state for heating, and solid fuel, such as coal and coke, lignite. The sectors covered include industrial, commercial, agricultural, public and service sectors and the rates vary depending on the sector. Residential sectors were excluded. A study estimated that the tax would reduce energy demand my 15%.

$4.819 billion and the revenues are used to shift the tax burden off individuals and business as well as recycle a portion for the purchase of environmental equipment.[144] More often the revenue goes into the general fund and is used to shift taxes off individuals and businesses. As far as effectiveness, the taxes vary, as does the impact on the country's economy.[145] (*See* Chart 4 in Appendix B).

Only a few countries outside Europe have passed carbon taxes. For example, South Africa and Kazakhstan have a carbon tax.[146] The countries in South America are just starting to implement carbon taxes.[147] Both Chili and Brazil have proposed a carbon tax. [148] Australia passed a carbon tax in 2012 and then repealed it in 2014.[149] African countries and Middle Eastern countries including Russia have not enacted any such taxes.[150] Asian countries have generally preferred cap-and-trade although the Republic of Korea has a carbon tax. [151] (See Appendix A)

3. <u>The EU ETS Has Failed</u>

In 2005, the EU implemented the EU Emissions Trading System (EU ETS) encompassing 27 countries. [152] The EU ETS program covered the electric power sector and the major energy-intensive industrial sector.[153] Many of the Scandinavian and European countries discussed above are part of the EU, so in addition to their state carbon taxes, their carbon emitters are subject to a cap and trade regime. [154] Usually these industries are exempt or partially exempt from the carbon tax, which could present an issue of effectiveness because the EU ETS had been ineffective.[155]

This cap and trade regime has been criticized on several grounds. First, the cap was set at a too high level and thus was too generous for polluters. In fact, no reduction of emissions occurred because the price of allowances collapsed.[156] Second, the allowances were not

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[144] *Id.* Netherlands passed a carbon tax in 1990. The tax is broad-based, covering natural gas, electricity, blast furnaces, coke ovens, refinery and coal gas, coal gasification gas, gasoline, diesel, and light fuel. The Netherlands Ministry of Housing, Spatial Planning and the Environment estimated that the tax would be effective in reducing annual emissions by 5%.

[145] Rayne, *supra* note 101, at 1.

[146] World Bank, *supra* note 20, at 83.

[147] Costa Rica passed a carbon tax in 1997 but no data since 2005. *See* Rayne, *supra* note 101, at 1.

[148] World Bank, *supra* note 20, at 8?.

[149] The price was $23 per ton of carbon emissions and this was "extraordinarily high by international standards and [it] lacked the phased-in-approach of other programs such as the EU ETS or the British Columbia carbon tax." Michael Wara, *Instrument Choice, Carbon Emissions, and Information,* 4 MICH J. ENVTL. & ADMIN. L. 261,299 (2015) When the conservative party won the election, the tax was repealed. Since it was enacted by a simple majority of the parliament, repeal was easy with the election changes. *Id.*at n. 107 this did not operate as a fixed price tax "but was not actually a carbon *tax*." *Also see* Gannett, *supra* note 63, at n 12..

[150] *Id.*

[151] World Bank, *supra* note 20, at 8?.

[152] World Bank, *supra* note 20, at 83.

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[155] Refer to earlier footnote saying this when describing individual state plan.

[156]

auctioned but grandfathered to existing industries.[157] The EU ETS ended up distributing 95% of the allowances for free.[158] Thus, the EU failed to meet its goals under the Kyoto Protocol.[159]

Several other jurisdictions outside the EU have passed cap-and-trade systems. Switzerland, New Zealand, Japan, and Kazakhstan have a cap and trade, as does Alberta and Quebec in Canada.[160] The U.S. has the California cap-and-trade and the Northeastern Regional one[161] A growing number of countries are considering cap-and-trade, more so than carbon taxes.[162] When added to carbon taxes, about "40 countries and over 20 sub-national jurisdictions are putting a price on carbon" and together these carbon pricing instruments cover around "12% of the annual global GHG emissions."[163] Of course, this is not enough and more needs to be done.[164] *See* Appendices A and B at the end of this article.

PART II: CARBON TAXES VS. CAP AND TRADE

A heated battle currently is being fought as to whether a cap and trade or carbon taxes will be better to solve our climate change problem. Many commentators and authors of law reviews have advocated that a cap and trade is better,[165] whereas many others have argued that a carbon tax is best.[166] My thesis is that both carbon taxes and cap and trade should be used on the local and regional level, particularly for Canada and the U.S., two of the largest contributors to climate change and two of the biggest beneficiaries of climate change.[167] If designed properly, these market mechanisms can work together and be effective.

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[157] Andrew J. O'Connell, *A Critical Analysis of Allowance Allocation in Cap-and-Trade and Its Effect on Linked Carbon Markets*, 44 TEX. ENVTL. L. J. 339 (2014).360-361 (In the first two periods allowances were grandfathered but in the later period they were auctioned and benchmarked.)

[158] Reuven S. Avi-Yonah & David M. Uhlmann, *Combating Global Climate Change: Why a Carbon Tax is Better Response to Global Warming than Cap and Trade*, 28, 42 Stan. Envtl.L. J. 3 (2009); Stan. *supra* note ___at 42.

[159] *Id.* at 42. *See* European Environmental Agency, *Progress Towards 2008-2012 Kyoto Targets in Europe*, EUROPEAN ENVIRONMENTAL AGENCY TECHNICAL REPORT, (Oct. 28, 2014) *available at* http://www.eea.europa.eu/publications/progress-towards-2008-2012-kyoto.

[160] *See* Duff, *supra* note 28, at 90. (discussing Alberta).

[161] *See* discussion *infra* in Part IIIA.

[162] Ann E. Carlson, *Designing, Effective Climate Policy: Cap-and-Trade and Complementary Policies,* 49 HARV. J. ON LEGIS. 207 (2012) (stating that the cap-and-trade system is "the dominant policy choice to date."); Dr. Haifeng Deng, *Improving The Legal Implementation Mechanisms for a Carbon Tax in China,* 32 PACE ENVTL. L. REV. 665 (2015).

[163] World Bank, *supra* note 20, at 14.

[164] Sewalk, *supra* note 18 at 580 .

[165] AviYonah & Uhlmann, *supra* note 158; Carlson, *supra* note 162; Harris, *supra* note 37; Alex Rice Kerr, *Why We Need a Carbon Tax,* 34 FALL ENVIRONS ENVTL L. & POLICY J 69 (2010); Joshua Meltzer, *A Carbon Tax As a Driver of Green Technology Innovation and the Implications for International Trade,* 35 ENERGY L. J. 45 (2014); Mann, *supra* note 83; Sewalk, *supra* note 18; Wara, *supra* note 149.

[166] Paul J. Lee, Rahmat O. Tavallali, Hai Sook Kwon & John T. Geekie, *Comparisons Between The Cap and Trade System and Carbon Taxation: Is the USA Ready for a Carbon Tax?* 35-43, Environmental Taxation and Climate Change: Achieving Environmental Sustainability Through Fiscal Policy (Edward Elgar 2011); David P. Warren & Scott Tomashefsky, *The Western Climate Initiative*, 41 STATE & LOCAL GOV'T REV. 55-60 (2009).
Melinda Harm Benson, *Regional Initiatives: Scaling the Climate Response and Responding to Conceptions of Scale*, 100 ANNALS OF THE ASSOCIATION OF AMERICAN GEOGRAPHERS, 1025-1035 (2010).

[167] *See* discussion *infra.* Carlson, *supra* note 162, (talking about cap-and-trade and complimentary policies); Andrew J. O'Connell, *A Critical Analysis of Allowance Allocation in Cap-and-Trade and Its Effect on Linked Carbon Markets,* 44 Tex. Envtl. L. J. 339 (2014) (talks about different cap-and-trade features and problems when they are linked).

A. A Heated Debate

Most economists prefer carbon taxes. According to most economists, price instruments, such as carbon taxes, can be expected to be more efficient and effective than quantity instruments, such as tradable allowances.[168] Economists favor taxes because "they provide the clearest price signal, unencumbered by factors like baselines, allowance allocation, and use of credits." [169] Price instruments are thought to perform better under uncertainty, to raise valuable revenues and to avoid transaction costs.[170] Economists say a viable market for tradable pollution rights can rarely exist unless the government makes the right decision and clears all market barriers to free trade.[171] Furthermore, tradable allowances may lead to environmental hot spots in low-income communities and diminish the pressure on emitting companies to make technological changes to restrict GHG emissions.[172]

On the other hand, most environmentalist and politicians favor cap and trade.[173] Environmentalists want a certain cap on emissions to assure environmental benefits.[174] Politicians hate taxes and have even signed pledges not to raise them.[175] Furthermore, cap and trade systems allow politicians to allocate original allowances to favored constituents.[176]

Business groups can go either way. Businesses usually like a certain price so they can accurately determine their profit and calculate whether they can pass on the increased cost to their consumers.[177] Cost certainty "enables business to plan ahead, secure in the knowledge that raising the tax rate beyond any automatic adjustment, which can be planned for, requires another vote" in the legislature.[178] Nonpolluting companies might support a carbon tax if they do not pollute and the revenues from the tax will reduce their corporate tax. [179] Of course, if the exiting industry can be grandfathered into the cap and trade without paying for the initial allowance,

[168] For example, former Treasury Secretary Larry Summers, Nobel laureate Joseph Stiglitz and Republican economist N. Gregory Mankiw all are in favor of a carbon tax. David Driesen notes that cap-and-trade can stifle innovation and result in concentrated local pollution.

[169] Avi-Yonah & Uhlmann, *supra* note 158, at 34 citing in 120N. Gregory Mankiw, One Answer to Global Warming: A New Tax, N.Y. Times, Sept. 16, 2007, at 6 ("Economists tend to favor taxes because they provide the clearest price signal, unencumbered by factors like baselines, allowance allocation, and use of credits.")

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[172] Industry groups can lobby to essential continue to pollute. AviYonah & Uhlmann, *supra* note 158, at 44. The cap-and-trade sends an "ambiguous message" that government allows you to pollute as long as you pay, essential signaling that "it a purchase price for right to pollute." In contrast to taxes that "send a clear signal."

[173] John Dingell, Democrat from Michigan and powerful chair of the Energy and Commerce Committee is one of the few politicians that favor carbon taxes. He says it is easy to 'rig' a cap-and-trade system. He says "Europe has shown that this is hell to make work. They are going back to the drawing board again, with not assurance they won't make the same mistakes they did before."

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[175] Most politicians like cap-and-trade because it is a hidden tax but is not called a tax. Most Republicans have signed on to the Norquist Pledge.

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[177] Avi-Yonah & Uhlmann, *supra* note 158, at 46 citing note 154. *Also see* Mann, *supra* note 83, at (stating "Businesses ……

[178] Avi-Yonah & Uhlmann, *supra* note 158, at 42.

[179] Wara, *supra* note 149 at 297. Walmart may support high carbon tax if carbon tax will reduce its corporate income tax. ("once Walmart has received benefit of reduction in tax, will be loath to return a higher rate so that 'American Electric Power can face a lower carbon tax liability.") AviYonah & Uhlmann, *supra* note 158, at 46.

they would favor the cap and trade.[180] In addition, business groups that can sharply reduce their emissions will prefer cap-and-trade as they can profit from selling their excess allowances to others. Lastly, Wall Street would also most likely support cap and trade as "hefty fees" can be charged "for arranging trades in allowances and futures trading."[181]

B. A Comparison

Both the carbon tax and the cap and trade are market-based mechanisms so both can encourage cost-effective technological innovation.[182] Both can be superior to the regulatory approach, which specifically mandates emissions, tends to be complicated, and is slow to be fully implemented.[183] In addition, these mechanisms can be better than tax incentives for renewable energy as they "incentivize efficiency improvements, reduction in energy use, and fuel switching from higher-to-lower emissions fuels."[184] Since greenhouse gas emissions occur throughout the world, a market-based instrument, such as cap-and-trade, when linked with other countries, could prove the best approach to solve the climate change problem. [185] Nevertheless, both of these market mechanisms can work together and be administered, politically feasible, revenue generating, efficient, equitable, and effective.

1. Administerability

Whether a carbon tax or cap-and-trade system is adopted at the regional or national level, the administerability issues are similar. Thus, both can be effectively designed with a broad base, a low cap/or high tax, and few exemptions. Both carbon taxes and cap-and-trade schemes can be imposed "upstream" or "downstream." Upstream measures usually hit emissions from fossil fuel production (oil, coal and natural gas), such as refineries and power plants. [186] Such a system could be effective because it would ensure that all sources of carbon dioxide at the point entering economy is affected and would cover fewer entities than downstream. [187] The upstream approach also reduces complexity because it covers large sources. Downstream would work better locally as it hits consumption, such as motor vehicle drivers, electricity users, and arguably all sectors of the economy emitting heat. [188] However, this might impact political feasibility as it

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181 Avi-Yonah & Uhlmann, *supra* note 158; *Also see* Wara, *supra* note 149.

182 Richard B. Stewart, *A New Generation of Environmental Regulation,* 29 CAP. U. L. REV. 21 (2001).

183 Avi-Yonah & Uhlmann, *supra* note 158, at 28-29 (pointing out the "inherent complexity of the Clean Air Act and the delays that would face any regulatory system to reduce carbon dioxide emissions. Indeed, if past experience under the Clean Air Act is any guide, litigation would ensue once a new regulatory regime was established leading to even greater delays in carbon dioxide reductions."

184 These mandates and market initiatives often beat out voluntary agreements, all of these mechanisms have a place. *See* Stewart, *supra* note 182. Implementing Carbon Taxes: Considerations, Realities and Lessons Learned. *Bureau of National Affairs,* at 6, 2013.

185 *See* Weiner, *supra* note 15.

186 Avi-Yonah & Uhlmann, *supra* note 158, at

187 *Id.*

188 *Id.*

more directly effects the consumer.[189] In addition, the broader range of sources could make administration more complex, because of the necessity to increase the monitoring.

In general, a cap and trade tends to be more administrative complex.[190] First, a baseline must be set to establishing an emissions cap. If this is set too high, than the system will be ineffective in reducing carbon emissions. If the cap is set too low, the costs to the emitters will be too high and make carbon allowances more expensive on the market. Once a cap is set, a mechanism must be instituted to determine how allowances will be created and distributed. Free allowances will benefit the current industries or polluters and no money will be raised. In the alternative, a charge can be made for the allowance or the allowance can be auctioned off. [191] Third, the trading in allowances must be established, creating a market for purchases and sales. Fourth, monitoring of the trading must occur, to prevent fraud and punish violators.[192] Fifth, to prevent cost uncertainty banking and borrowing need to be established. Banking will allow a holder to save its allowances for use in the future. Borrowing allows the holder to emit now and pay back later by emitting less. However, these very mechanisms can prevent the desired certainty of benefit. Sixth, offsets must be established for carbon sequestration. Offsets allow the emitter to invest in forest conservation and other projects that absorb carbon.[193] Finally, to be internationally effective, the cap-and-trade program needs to be coordinated with other cap-and-trade regimes,[194] and it is often difficult, both politically and design-wise, to coordinate with other systems.[195]

For a carbon tax, one must decide whether to tax upstream or downstream, then set a tax rate, decide on any exemptions or credits, and monitor. Unlike cap and trade, carbon taxes can be enforced by an existing revenue departments. Thus, carbon taxes are generally simpler than the cap-and-trade, but do not work as well on the international level.

Chart 2: Comparison of Cap and Trade and Carbon Tax

Cap and Trade	Carbon Tax
Upstream/downstream	Upstream/downstream
Set level of emissions	Set tax
Determine quantity of allowances	Determine Exemptions
Determine allocation of allowances (free/fee/auction)	Determine Credits
	Monitor emissions

[189] Miln ,Vt. L. Rev.
[190] Avi-Yonah & Uhlmann, *supra* note 158 (One extra step here).
[191] *See* Mann *supra* note 83. .
[192] "To prevent the same allowances from being used twice." Sewalk, *supra* note 18, at 605 (Some have said that "our current monitoring technologies are not sufficient to take on such an expansive pollutant as carbon.".Avi-Yonah & Uhlmann, *supra* note 158, at 39. Others have said that "an elaborate mechanism would need to be set up to distribute and collect allowances and to ensure that allowances are real and that polluters are penalized if they emit gasses without an allowance."
[193] Mann, *supra* note 83 (talking about problems of accurate measurement of these offsets giving the example of a tropical forest in Brazil.)
[194] O'Connell, *supra* note 167. Avi-Yonah & Uhlmann, *supra* note 158, at 38-39.
[195] *See* later discussion *infra* at IVB.

Create a market

Monitor emissions

Monitor market

Banking, borrowing, credits and offsets

Cap-and trade programs take a long time to get passed and implemented,[196] whereas, a carbon tax "can be enacted and enforced practically tomorrow."[197] Most cap and trade bills are long and complicated, whereas carbon tax proposals are shorter and simpler. [198] The longer the text the more likely it will not be understood—and the greater possibly of loopholes.[199]

Allowances under cap-and -trade raise interesting securities, tax, and international trade issues.[200] Securities issues arise with the regulation of futures trading in allowances. Tax issues arise when allowances are free, upon trading and selling of allowances, and when banking borrowing and offsets are involved. World Trade Organization compliance issues also arise with cap-and-trade.[201] Carbon taxes, on the other hand, do not raise securities or tax issues and do not pose international trade problem because it can be collected on imports and rebated on exports and not imposed on domestic production.[202]

2. Political Feasibility

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[196]Wara, *supra* note 149, at 295 and 300. If Waxman-Markley cap-and-trade passed than "stuck in a situation in which relatively little abatement was occurring, allowance price were very low, and the prospect of report ….was a remote possibility. By contrast if carbon tax passed much greater abatement than anticipated. Thus carbon taxes offer a much greater likelihood that all sides in a climate regulation negotiation enjoy the benefit of the bargain." Designing real cap-and-trade programs may require information that regulators currently do not possess and are unlikely to ever possess. Given weakness in forecast models, likely cap-and-trade not achieve the objectives that environmentalists want. Not likely that there will be change. Can be a phase in. At least two examples (CA RELAIM and and CA Bill 32 "evidence exist s that cap-and-trade programs are vulnerable to weakening in the face of higher than expected allowance prices.)

[197] Avi-Yonah & Uhlmann, *supra* note 158, at . "probably take at least two years to get the [cap-and-trade] program passed in Congress and set up for implementation."

[198]Avi-Yonah & Uhlmann, *supra* note 158, at 38 "A carbon tax is inherently simple: a tax is imposed at X dollars per ton of carbon content on the main sources of carbon dioxide emissions in the economy.".

[199] Sewalk, *supra* note 18, at 603, citing Liebermann-Warner Climate Security Act of 2008 at over 300 pages and the Waman-Markey at 500. In contrast, the John B. Larson carbon tax was only 17 pages.

[200]*Id.* at 38-39.

[201] *Id.*

[202] *Id.*at 49 at n. 160. Keith Kendall, *Carbon Taxes and the WTO: A Carbon Charge Without Trade Concerns?* 29 ARIZ. J. INT' & COMP. L. 49, 50 (2012) (under a border tax adjustment (BTA), "exports have the tax rebated, so they enter the world market free of the carbon charge, with imports being subjected to the same imost as domestically produced goods. In this way, the domestic policy has a neutral effect on a domestic industry's international competitiveness." (and at 87) "The major hurdle for a carbon tax to be legitimate under the WTO is its uncertain status as an indirect tax—that is, as a tax on a produce rather than on the producer (or the PPB). There are strong arguments in both directions, making this the major hurdle in terms of introducing an economically appropriate carbon tax. There is strong potential, though, that even if a carbon tax BTA were found to violate the substantive provisions of the WTO, it may qualify for one of the exceptions under article XX."

At the local level, just as at the federal level, differences arise between the traditional values of Republicans and Democrats. In general, Republicans are reluctant to pass a tax, so a cap-and-and trade regime is probably more politically feasible.[203] The public might also not like a tax, although a cap-and-trade will also result in higher gas and gas bills. In general, polls have shown that citizens have a "strong public resistance to new taxes." [204] Since a tax is more transparent, it is more likely to have citizen complaints. [205] For example, a July 2014 poll showed that taxpayers in California would not support the cap-and-trade if their gas and electric bills would go up.[206] On the other hand, the British Columbia carbon tax has had sustained popularity even with the recession and several administrations. [207]

It is possible that a cap-and-trade may be more politically acceptable because the U.S. has already experienced a very successful permit system under the Acid Rain Program, implemented under the Clean Air Act Amendments of 1990.[208] This program offered a successful model in the trading system of sulfur-dioxide and nitrogen oxide—pollutants that cause acid rain and smog.[209] This success at the federal level could translate into a more politically feasible regional cap-and-trade system.[210]

A cap-and-trade is probably more consistent with pre-existing government environmental regulations.[211] The new EPA rules under the Clean Power Plan specifically cover "market-based trading programs."[212] Nothing is said about carbon taxes.[213] In addition, cap-and-trade can "more easily dovetail with similar existing and proposed regimes" in other regions. [214] Thus, cap-and-trade can be regionally connected. Commentators have favored cap-and-trade for a similar reason in the international realm.[215]

There is also a difference in political economy between a cap-and-trade and a carbon tax. The legislative, administrative, and budgetary considerations for a tax can be quite different. Taxes are passed in the legislature by a finance, not an energy or environment committee, and

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[203] *See supra* note 175.
[204] *Id.* British Columbia and Sweden, *but see* Keibun Mori, WASHINGTON STATE CARBON TAX, Fiscal and Environmental Impacts, 13 (July 2011). (A disadvantage of carbon taxes is "the strong public resistance to new taxes.)
[205] Avi-Yonah & Uhlmann, *supra* note 158, at n 151.
[206] Madhu Ravi, *Making Sense of California's Cap-and-Trade System* at 8 (May 4, 2015) *available at* http://cacs.org/researc/californias-cap-and-trade-and-what-will-invluence-its-future/.
[207] For example, the "British Columbia carbon tax was introduced by the province's finance minister at the time, Carole Taylor, and was considered alongside other revenue measures, including changes in numerous other taxes. Wara, *supra* note 149 at 297,300. The status quo, once established, is very difficult to alter.
[208] Clean Air Act Amendment of 1990, Pub. L. no. 101-549, Title IV s401, 104 Stat. 2584 (codified and amended at 42 U.S.C. ss7651-7651o)
[209] Avi-Yonah & Uhlmann, *supra* note 158, at 34. The program "focused on 111 facilities in the Midwest (the so-called "Big Dirties"
[210] Union of Concerned Scientists: Science for a Healthy Planet and Safer World, (These results "were achieved at a significantly lower cost than originally assumed.") *available at* http://www.ucsusa.org/global_warming/solutions/reduce-emissions/cap-and-trade.html#.VeRxX-vEGfR.
[211] Claudia O'Brien, Miles Farmer, Michael Dreibelbis, & C. Genevieve Jenkins, *Implementing Carbon Taxes: Considerations, Realities, and Lessons Learned*, Bloomberg BNA: Energy and Climate Report 87 ECR at 5, n.56 (05/06/2013).
[212] Gannett, *supra* note 63, at 8-3, n.15.
[213] Discussed *infra* at
[214] Avi-Yonah & Uhlmann, *supra* note 158, at 38-39.
[215] *See* Wiener, *supra* note 15.

are administered by the department of revenue.[216] In addition, different requirements exist for how the funds are distributed.[217] These differences were illustrated by the recent cases challenging the California cap-and-trade regime.[218] In August 2013, the courts held the cap-and-trade system was a fee and not a tax.[219] As the court said, a tax has to be passed by supermajority of the California state legislature, a voting requirement in the state constitution.[220] Fees only need a majority in the state agency authorized in the statute, which was not a problem here.[221] Another important difference is that revenue from taxes can be spent on anything, such as rebates to the poor, whereas a fee must go into programs closely aligned with the fee itself.[222] Because the purpose of the California cap-and-trade is to reduce GHG, the fees from the auctions of the permits must go into the Greenhouse Gas Reduction Fund.

This political difference between a tax and a fee could be significant for the states in the western United States. Oregon, like California, has a similar supermajority rule for new revenue.[223] However, Washington does not have such a requirement.[224] Therefore, Washington has tremendous flexibility in what carbon mechanism to choose. Furthermore, if they join the California cap-and-trade system, they can use the revenues to reduce the regressive effects of the cap-and-trade system or in any manner they so desire.

3. Revenue Generation

Both carbon tax and cap-and-trade can generate revenue —in money from selling permits and with funds raised from carbon taxes. However, if the initial permits are given away and not auctioned, then no money will be generated. A carbon tax, however, will always result in revenue.[225]

Most states have to balance their budget so any new revenue could be desirable from the state's viewpoint.[226] However, the use of the revenue can determine the impact on efficacy, economic growth and equity. To accomplish efficacy, the revenues would go to fund research into low-emission technologies or recycled into green practices,[227] or to mass transit, research and development, carbon sequestration, and other greenhouse-gas reducing efforts.[228] To promote economic growth, economists often favor a reduction in capital taxes or reduction in

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[216] *See* Surrey *supra* note 16 at 728-730.
[217] *Id.*
[218] Alan Durning & Yoram Bauman, *17 Things to Know About California's Carbon Cap*, Sightline Institute, at 8 (May 22, 2014), *available at* http://daily.sightline.org/2014/05/22/17-things-to-know-about-california-cap-and-trade.
[219] Superior Court of California, County of Sacramento, Joint Ruling on Submitted matters Case No: 34-2012-80001313 and Related Case No. 34-2013-80001464, August 28, 2013.
[220] Durning & Bauman, *supra* note 218, at 8.
[221] *Id.* at 7 (."AB 32 passed by a simple majority in 2006, granting power to ARB to establish cap and trade.")
[222] *Id.* at 7.
[223] *Id*. at 8.
[224] *Id.*
[225] Sewalk, *supra* note 18, at 607. For example, a $10 per ton carbon tax should generate $50 billion.
[226] Every state but Vermont has to balance its budget.
[227] Sewalk, *supra* note 18, at 614 (stating the revenue could go to "building a new energy economy" and the creation "new jobs.)"
[228] Avi-Yonah & Uhlmann, *supra* note 158, at 41.

deficits.[229] To ensure equity, the money could be used to shift the tax burden off labor or sales taxes, lessen the tax on small businesses and low-income taxpayers, or used for lump sum rebates or refundable credits to poor households.[230]

Or the revenue can be used for multiple purposes. Many of the state economic studies have run models using various percentages for reinvestment.[231] They conclude that there will be no serious impact on the economy with minimal reinvestment of the funds into green initatives.[232] The studies show that the greater the reinvestment the more adverse the impact on the economy; whereas, a greater percent going to a tax shift, the on the economy and the more equitable and the more environmentally effective the mechanism.[233]

4. Efficiency or Economic Growth

One of the biggest issues with a carbon tax is the impact on business and industry. The companies that will suffer the most from a carbon fee or tax are those in cement, chemicals, car manufacturing, iron and steel, aluminum, mining and oil.[234] If the cost of doing business goes up this could cause businesses to move to other jurisdictions, known as "leakage" and this can have an adverse impact on the economy and employment of the state or region.[235] However, to eliminate the negative economic effects, the carbon systems can exempt industries (allocate free permits to them) and/or the revenue can be returned to them in reduced taxes.

The rate of the carbon tax or the cap set on the cap-and-trade will impact the criteria of efficiency or economic growth. In general, the higher the rate of carbon tax or lower the emissions cap, the more adverse impact on the economy. For example, the Congressional Budget Office estimates that in order to decrease CO_2 levels by 20% below 1990 levels, a $250 per ton tax would be needed.[236] However, if even a $100 per ton tax is imposed, estimates are that U.S. gross national product will decline by as much as 2%.[237] With a moderate carbon tax of $20 or $30, economic studies in several European Countries, British Columbia, and Oregon have all shown no significant adverse impact on the economy.[238]

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231 *See* Oregon study on Tax Shift.

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234 Mark J. Perry, *Caron Tax Would Kill Major Industries, Hurt U.S. Consumers*, Investors Business Daily (Oc. 16, 2012) *available at* http://news.investors.com/ibd-editorials-on=the-right/101612-629540-carbon-tax-would-kill-off-growth-in-american-eoncomy.htm.

235 Bloomberg, *supra* note 211, at 5.

236 http://www.finance.senate.gov/imo/media/doc/Testimony%20-%20David%20Kreutzer.pdf .
Or this
http://www.skepticalscience.com/print.php?r=299l

237 FIND CITE. David Kreutzer, PhD, *The Impacts of Carbon Taxes on the U.S. Economy*, U.S. Senate Finance Committee, (Sept 16, 2014) *available at* http://www.finance.senate.gov/imo/media/doc/Testimony%20-%20David%20Kreutzer.pdf

238 Cite earlier and later footnotes discussing this. David Kreutzer, PhD, *The Impacts of Carbon Taxes on the U.S. Economy*, U.S. Senate Finance Committee, (Sept 16, 2014) *available at* http://www.finance.senate.gov/imo/media/doc/Testimony%20-%20David%20Kreutzer.pdf

Where the revenue from the carbon tax or cap-and-trade goes will also impact the criteria of efficiency or economic growth. One study concluded that using pollution tax revenues to lower other distortionary tax burdens can even improve economic performance, [239] and no decline in GNP would result.[240] A study by the Economic Policy of the Center for a Sustainable Economy even concluded that over 2 million jobs could be created over the next twenty years with a fifty percent reduction in U.S. carbon emissions under alternative market approaches.[241] Other economic studies[242] have shown that the most economically efficient use of the tax revenue would be to cut taxes on capital, followed by reducing payroll taxes[243] and that recycling the revenues with lump-sum rebates to lower-income households would have the worst economic efficiency outcomes.[244]

5. Equity or Incidence

The incidence, and thus the equity, of the carbon tax or cap-and-trade will also depend on how much revenue is generated and how the revenue is used.[245] Both mechanisms will increase the energy costs to consumers and thus could have some inequitable impacts on lower-income taxpayers. An American Enterprise Institute paper estimates that a tax of $15 per ton of carbon dioxide emitted would increase the cost of a gallon of gas by 24 cents and the price of coal-fired

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[239] Avi-Yonah & Uhlmann, *supra* note 158, at 41. Charles Komanoff, *Carbon Tax Polling Milestone: 2/3 Support if Revenue-Neutral*, CARBON TAX CENTER, (Apr. 15, 2015) *available at* http://www.carbontax.org/blogarchives/2015/04/15/carbon-tax-polling-milestone-23-support-if-revenue-neutral/; Oren Cass, *Carbon Taxes in Revenue Fantasyland*, THE WALL STREET JOURNAL, (Apr. 30, 2015) *available at* http://www.wsj.com/articles/carbon-taxes-in-revenue-fantasyland-1430436869; Jared Carbone, et al., *Getting to an Efficient Carbon Tax: How the Revenue is Used Matters*, RESOURCES FOR THE FUTURE, (Jan. 13, 2014) *available at* http://www.rff.org/research/publications/getting-efficient-carbon-tax-how-revenue-used-matters

[240] *Id.*

[241]

?????? Bill Dougherty, Steve Bernow, and James Barrett, *Clean Energy and Jobs*, ECONOMIC POLICY INSTITUTE, (Feb. 2002) *available at* http://www.epi.org/publication/studies_cleanenergyandjobs/ http://www.epi.org/publication/studies_cleanenergyandjobs/

[242] Dale W. Jorgenson, Richard J. Goettle, Mun S. Ho, and Peter J. Wilcoxen, *Carbon Taxs and Fiscal Reform in the united States*, 68 NAT'L TAX J. 121 (2015); Warwick J. mcKibbin, Adele C. Morris, Peter J. Wilcoxen, and Yiyong Cai, *Carbont Taxes and U.S. Fiscal Reform*, 68 NAT'L TAX J. 139 (2015); Sebastian Rausch and John Reilly, *Carbon Taxes, Deficits and Energy Policy Interactions*, 68 NAT'L TAX J. 157 (2015); Sugandha D. Tuladhar, W. David Montgomery, and Noah Kaufman, *Environmental Policy for Fiscal Reform: Can a Carbon Tax Play a Role?* 68 NAT'L TAX J. 179 (2015); Roberton C. Williams III, Hal Gordon, Dallas Burtraw, Jared C. Carbone, and Richard D. Morgenster, *The Initial Incidence of a Carbon Tax Across Income Groups,* 68 NAT'L TAX J. 195 (2015).

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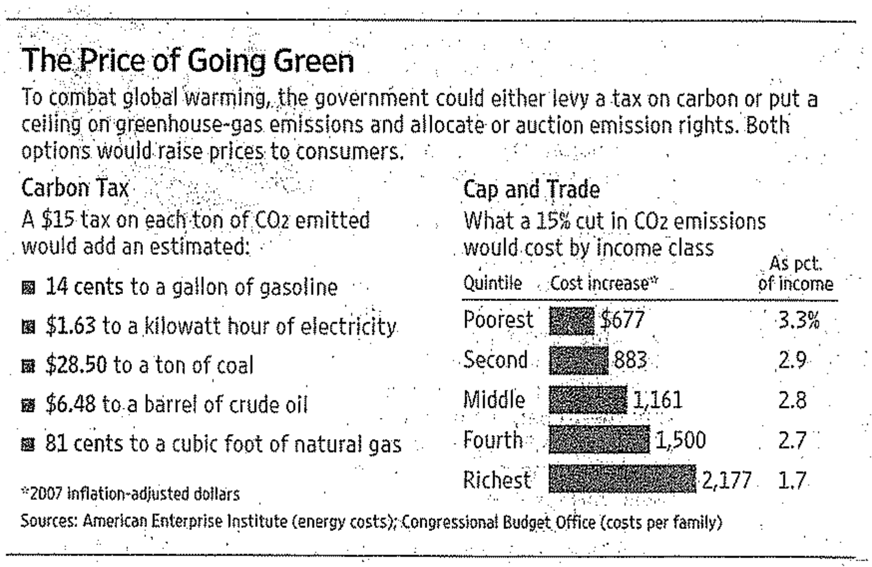
[244] *Id.* A lump sum transfer or a cut in sales tax would benefit older generations at the cost of younger generations, whereas a cut in labor taxes would have the opposite effect.

[245] *Id.* National carbon taxes may have uneven regional impacts due to vastly differing energy structures and energy consumption patterns from region to region. The Northeast opposes taxes because they could increase the price of heating oil. The West dislikes increase in gasoline taxes because of greater than average driving distances. The Corn-belt states are sensitive to diesel fuel price increases due to agricultural use. The Midwest and Southeast are energy-producing and oppose any form of energy taxes. In addition, the Midwest uses electricity generated primarily by coal-fired power plants.

electricity by $1.63 per kilowatt-hour.[246] The Congressional Budget office estimates a 15% cut in emissions would cost the poorest households an additional $677 a year in current dollars.[247] Other studies[248] also demonstrate that low-income households spend greater percentage of their income on energy and that the distribution of the tax revenues from a carbon tax can make the tax less regressive.[249] If the consumer can substitute public transportation for driving then the carbon mechanism will have less impact. However, electricity tends to be inelastic and could have a larger impact on the consumer.[250]At least a carbon tax guarantees revenue that can be used to alleviate the burden on the poor, whereas there is no such guarantee when the a cap-and-trade constitutes a fee.

[246] Aparna Mathur, and Adele Morris, *Distributional Effects of a Carbon Tax in Broader U.S. Fiscal Reform*, AMERICAN ENTERPRISE INSTITUTE, (Dec. 16, 2013) *available at* https://www.aei.org/publication/distributional-effects-of-a-carbon-tax-in-broader-us-fiscal-reform/.
[247]*Who Pays for Cap and Trade?*, THE WALL STREET JOURNAL, (Mar. 9, 2009) *available at* http://waysandmeans.house.gov/wsj-who-pays-for-cap-and-trade/
[248] *Id.* Bill Dougherty, Steve Bernow, and James Barrett, *Clean Energy and Jobs*, ECONOMIC POLICY INSTITUTE, (Feb. 2002) *available at* http://www.epi.org/publication/studies_cleanenergyandjobs/.
[249] Burtraw, et al. Resources for the Future, The Incidence of U.S. Climate Policy: Were You Stand Depends on Where You sit 92008), available at http://www.mistra-research.se/download/18.87749a811cbd4c4fb480001008/Burtraw=et=al=2--8=a.pdf ; *also see* Sewalk, *supra* note 18, n.175.
[250] Andersen, *supra* note 93.

Chart 3: The Incidence or Equity Factor



6. Efficacy

Regional or local cap-and-trade initiatives alone will not enough to solve the climate change problem. Scientists say that emissions of greenhouse gasses must be cut by at least 60% to stabilize global warming.[251] Limiting the average global temperature rise to less than 2°C "is commonly regarded as a prerequisite to avoid dangerous climate change."[252] The investment needed, however, in the energy sector alone, to accomplish this objective is "estimated to be US $910 billion per annum during 2010-2050."[253] Obviously, state and local governments are not prepared to make that kind of investment. In addition, tax rates would have to be prohibitively high and the caps prohibitively low to get these emissions under control.[254]

In terms of efficacy, the key difference between a carbon tax and a cap-and-trade is that a cap-and-trade places a cap on emissions so there is what is called "benefit certainty," whereas carbon taxes set an exact price on emissions or a cap on the costs of abatement, so there is "cost certainty."[255] The benefit certainty of the cap, however, is not an advantage if the cap us not set accurately.[256] This is the "Acheilles heel" of the cap-and-trade system.[257] Once the price is set,

[251] *See* Harris, *supra* note 37, at 197 n.8 citing World Resources Inst., The Difficulty of Stabilizing Emissions, in World Resources, 199601997: The Urban Environment, *available at* http://population.wri.org/pubs_content_text.cfm?ContentID-792. Concerned Scientists, *supra* note 210.
[252] World Bank, *supra* note 20, at 22.
[253] *Id.*
[254] *See* Congressional Budget Office *infra* note
[255] Avi-Yonah & Uhlmann, *supra* note 32, at _____
[256] See earlier discussion on the EU.
[257] Rita Chandiok. *Climate Change Law In California and Massachusetts: Lessons for State Policymakers*, 21 HASTINGS W.N.W. J. ENVTL. L. & POLICY 249, at 284 (referring to the measuring of the additionality of carbon emissions.)

it may not be effective, as the market (such as low gas prices) might depress the price.[258] Furthermore, changing the cap might be difficult –unless of course, it is somehow phased-in incrementally over the years in the initial legislation.

The only way to prevent cost uncertainty in a cap and trade is to have safety value mechanisms. If the market price allowances become too high, businesses can receive or purchase at a fixed price additional allowance at a set price from the government.[259] If the cap amount "begins to seriously hurt business and the price allowances spikes," the cap can be lowered.[260] These mechanisms, however, frustrate the efficacy or benefit of the cap-and-trade.

Similarly, a carbon tax cannot guarantee a certain benefit, it can just set a price. Again, the tax rate may not be effective to impact behavior.[261] If the tax is set too low, it will not cause a reduction in carbon consumption and if the tax is set too high, it may have adverse equity or economic repercussions.[262] Like cap-and-trade, the rates can be increased over time with a phase-in. Arguably, the tax could be set to accomplish the benefit desired.[263] However, exemptions can also make the tax ineffective, and credits can be given to carbon sequestration projects and other projects that reduce greenhouse gas emissions, thus diluting the price signal.[264] In the end, carbon taxes, like cap-and-trade, leave environmental outcomes uncertain.[265]

Even if the revenues from the tax or cap-and-trade program go back and are 100% reinvested in lower-carbon alternatives, such as renewable energy, or into energy efficient, "the efficacy of those projects is similarly uncertain."[266] And any revenue used in this way would not be available to mitigate the regressive impacts of such policies.[267] In the end, there is no authoritative evidence that putting a price on carbon by itself will effectively reduce emissions.[268]

C. Conclusion

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[258] Dingell says the cap-and-trade system alone does not convey the real cost of climate change and that companies would be allowed under cap-and-trade to spew a certain amount of carbon dioxide into the air.

[259] Avi-Yonah & Uhlmann, *supra* note 32, at 46. The fundamental problem is that the reduction in the cap that is build into the cap-and-trade would necessarily make allowances more expensive. How much more expensive depends on the development of future technologies, which cannot be predicted with an accuracy over the longer time period require for cap-and-trade to achieve its goals."

[260] *Id.*

[261] *Id.*

[262] Bloomburg, *supra* note 211, at 4.

[263]

[264] Kenneth C. Johnson, Beware of the Dogmatist: A Consensus Perspective on the Tax-Versus Cap Debate (Working Paper Series 2008), *available at* http://ssrn.com/abstact=1154638. ("The price stability of a carbon tax could prove as much as five times more cost-efficient than cap-and –trade.")

[265] Bloomberg, *supra* note 211, at 4.

[266] Bllomberg, *supra* note 211, at 4.

[267] *Id.*

[268] Sewalk, *supra* note 18, at 609 "[B]oth carbon tax and cap-and-trade bills have failed to give proof of any real emission reductions." "(T)ere is no firm data to show that putting a price on carbon will reduce emissions.") The EU-ETS has crated a carbon market, but the successes are economical rather than environmental." (citing in n. 188 EU study the Peter Heindl study)

Both carbon tax and cap-and-trade systems can be designed to be effective.[269] Both can have strict cost-containment mechanisms: setting a stringent cap, including all economic sources of emissions, covering all heat-trapping gas emission, and excluding loopholes.[270] Allowances can be auctioned off and revenue used for the public good. Although emissions have been reduced by these market mechanism, they have not been reduced enough. [271]A cap-and-trade program is thus alone "not sufficient to meet the challenges of climate change."[272] Therefore, we need a carbon tax in addition to a cap-and-trade. Other policies are also needed. We should require utilities to provide a greater percentage of their electricity from renewable energy sources, require automakers and producers of appliances to increase performance standards, and mandate stronger energy efficiency for new and existing buildings. [273] and In addition, policies should be established to create positive tax incentives for good behavior. We should promote conservation, encourage smart growth, and provide incentives for investment in low-carbon or renewable technologies. [274] Lastly, we need to eliminate the bad policies, such as the removal of fossil fuel subsidies, at the federal level and the perverse corporate welfare subsidies at the local level.[275] A comprehensive approach is what is needed to solve our climate change crisis.

III. WESTERN NORTH AMERICAN CLIMATE CHANGE INITIATIVES

Because of the failures of the climate change initiatives at the international and U.S. federal government levels, the market-based initiatives at the regional, state and local level can offer some hope to solve our climate change problems. The part of the Article looks at regional cap-and-trade systems, then examines state and local carbon taxes, focusing on British Colombia, Oregon, Washington, and several cities.

A. Regional Cap-and-Trade Initiatives

The history of regional cap-and-trade programs in the U.S. has been rather tumultuous. California set up a cap-and-trade system which originally included six Western states and two Canadian provinces but now includes only California and Quebec. [276] The Chicago Climate

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[269] The effectiveness of MMs depends on: the number of regulated sources, the physical and chemical nature of a regulated pollutant, the range of technology option available, the existence of cost-effective monitoring, reporting and verification systems, adaptive decision-making process, etc.

[270] These would include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbones, and sulfur hexafluoride.

[271]See Concerned Scientist, *supra* note 210, (note their recommendations).

[272] *Id.*

[273] *See* Shurtz, *supra* note 8.

[274] Conerned Scientist, *supra* note 210 (energy efficiency certificate trading are also needed.") For example, Union of Concerned Scientist say "the government must implement parallel policies alongside a cap-and-trade regime to ensure development and deployment of the full range of clean technologies". "Studies have shown that a comprehensive approach including these parallel policies would lower the price for allowances, cut emissions, and save consumers money by lowering their electric and gasoline bills." Id.

[275] *See supra* note 11. *Also see* World Bank, *supra* note 20, at 23.

[276] *Multi-State Climate Initiatives*, Center for Climate and Energy Solutions, *available* at http://www.c2es.org/print/us-states-regions/reginal-climate-initatives. (hereinafter CCES); Micheal Hiltzik, *Emissions Cap-and-Trade Program is Working Well in California*, The Economy Hub, *available at* hhttp://www.latimes.com/business/hilzik/la-fihilzik-20150513-column.html.

Exchange founded in 2003 boasted big company participants like Ford, Amtrak, but went defunct in 2010.[277] The Regional Greenhouse Gas Initiative (RGGI), established in 2005, has had New Jersey withdraw, and had to shrink its cap by 45%.[278]

1. The Western Climate Initiative Has Failed

The Global Warming Solutions Act of 2006 set goals for California to reduce its greenhouse gas.[279] In 2007 Gov. Schwarzenegger, Richardson of New Mexico, Kulongosky of Oregon and Gregoire of Washington signed an agreement, called the Western Climate Initiative (WCI).[280] Later the governors of Utah and Montana and the premiers of British Columbia, Manitoba, Ontario and Quebec joined as partners.[281] An additional 14 jurisdictions joined including Alaska, Colorado, Idaho, Kansas, Nevada, Wyoming and the Canadian provinces of Nova Scotia and Sakatchewan and even Mexican states of Baja Chihuahua, Coahula Nuevo Leon, Sonaro and Tamaulipas.[282] In September 2008, the WCI released a document calling for economy-wide emission program covering "nearly 90% of the region's greenhouse gas emissions."[283] The program was to reduce emissions 15% below 2005 levels by 2020 and start mandatory emission monitoring starting January 2010.[284] Under the WCI, each state and province agreed to set up their own cap-and-trade regime and link with the other systems. Each jurisdiction could verify the other jurisdiction's program. In addition, they agreed to share information and management in support of such a system.[285] Nevertheless, unresolved issues arose, "including allowance apportionment between the states and among the sectors, percentages of allowances to be auctioned, design and structure of both the auction market and the market oversight and enforcement mechanisms to address market manipulation, and the use of offsets."[286]

From 2008 to 2011, the WCI began to fall apart.[287] First, elections occurred in Arizona, New Mexico, and Utah, whose new governors opposed cap-and-trade.[288] Second, state legislatures in Washington, Oregon, and Montana failed to enact carbon trading schemes.[289] Then, the Great Recession occurred. Finally, in November 2011, six states withdrew.[290] In that

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[277] Beeeter World Club News. & Ian Gutherz, *Current Developments in Carbon & Climate Law North America: United States*, 8 CARBON & CLIMATE L. REV. 69, 70 (2014).
[278] *Id.* (RGGI "announced that it would reduce the available number of GHG allowances for 2014 by 45 percent to correct for a significant oversupply in the market. The cap will be reduced by 2.5% annually through 2020.")
[279] Ch. 488, 2006 Cal. Stat 3419 (codified at CAL HEALTH & SAFETY CODE s 38500)
[280] *Western Regional Climate Action Initiative*, at 2 (Feb. 26, 2007), *available at* http://www.westernclimateinitiative.org/component/remository/generl/WCI-Governors-Agreement/.
[281] *Id.*
[282] *Id.*
[283] *Id*. at 3. Also s*ee* CCES, *supra* note 276, at 2. *Also see* Western Climate Initiative, *Design for the WCI Regional Program* [hereinafter WCI Design] (Jul. 2010*) available at* http://www.westernclimateinitative.org/the-wci-cap-and-trad-program/program-design.
[284] WCI Design, supra note 283 at 5.
[285] Gannett, *supra* note 63, at 8-4.
[286] Warren &Tomashefsky, *supra* note 166, at 57.
[287] Gannett, *supra* note 63, at 8-5.
[288] Geoffrey Craig, *Six U.S. States Leave the Western Climate Initiative,* Platts (Nov. 18, 2011), *available at* http://www.[;atts.com/latest-news/electric-power/washingtop/six-us-states-leave-the-western-climate-initiative-6695863.
[289] *I*d.
[290] *Id.*

same month, in an attempt to salvage the plan, the Western Climate Initiative (WCI) a nonprofit corporation was formed.[291] It "provides administrative and technical support to state and provincial governments" implementing cap-and-trade programs.[292] On the whole, however, the Western Climate Initiative has failed.

2. It is Too Early to Pronounce the California Cap-and-Trade Program a Success

The current California Cap-and-Trade program was implemented under the Global Warming Solutions Act under AB32, the states landmark carbon dioxide legislation of 2006.[293] The Air Resources Board, a branch of the California Environmental Protection agency, is in charge of its design and implementation.[294] The cap-and-trade covers the "broadest range of industries of any such program in North America," including transportation.[295] Over 85% of California's GHG emissions are covered by the regime.[296] Because of interstate commerce issues the program does not cover planes or ships with destinations beyond the state border. It does cover "carbon by wire"—emissions form out-of-state coal and natural gas plants that sell electricity into the state's grid.[297] Leakage also occurs for agricultural and food producers.[298]

The cap-and-trade system is fairly straightforward and simple. It is imposed upstream on some 600 companies.[299] It provides for banking but not borrowing.[300] The trading is tightly regulated so gaming is unlikely.[301] The ARB carefully restricts and monitor offsets, which have to be third-party verified.[302] Firms can substitute offsets for reforestation programs and methane recapture from livestock manure for 8% of their emissions permits.[303]

Allocation of permits were not grandfathered, but based on a combination of free allowances and auctioned ones. In 2013 and 2014, ARB distribution about 90% of the permits free of charge.[304] These free permits were given to large industrial firms whose products compete with products from outside of California and to large electric and natural gas utilities.[305] In addition, extra permits were given to companies that had been the most successful in reducing their emissions.[306] When the cap expands in 2015, most of the new permits—those for

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[291] Western Climate Initiative Inc. *Program Design* (2014), *available at* http://www.wei-inc.org/program-desig.php.
[292] *See* CCES *supra* note 276, at 2.
[293] Get Cite
[294] The California Air Resources Boards' Climate Change Scoping Plan Updates the past five years and outlook. Looking ahead—collaborative efforts with others, allocation rules, market program and offset program implementation. World Bank, *supra* note 20, at 57. *See* Hiltzik, *supra* note 276. (This legislation included mandates for renewable fuels and emissions standards for new vehicles).
[295] *Id*. *See* Durning & Bauman, *supra* note 218 ("cap will be the most comprehensive, though not the most aggressive, carbon-pricing regime in the world."
[296] Durning & Bauman, *supra* note 218, at 9-10
[297] *Id.* at 10 (Points out the comparison between BC, which only covers only fossil fuel, and Northeast Regional and EU that only cover electricity, but that CA covers both plus "carbon by wire.")
[298] Durning & Bauman, *supra* note 218, at 4.
[299] *Id.* at 10.
[300] *See* earlier discussion at *infra* Part IIB1.
[301] Durning & Bauman, *supra* note 218.
[302] *Id.* at 12.
[303] *Id.*
[304] *Id.*
[305] Might want to elaborate.
[306] *Id.*

petroleum and other fuels, will be auctioned.[307] CA cap-and-trade does not allow waivers and exemptions but has a price containment reserve that holds back a few percent of permits in reserve so that if the carbon prices rise too high, these permits can go to auction.[308]

It is too early to make statements as to the regime's effectiveness.[309] Although some consumers may be able to reduce their use of cars and substitute mass transportation, electricity is inelastic and consumers cannot easily change their behavior and substitute another product.[310] The aim of the cap-and-trade is to reduce the state's carbon emissions to 1990 levels by 2020.[311] To meet these 1990 levels emissions must be cut by almost 16%.[312] However, the cap was initially set too high and the prices remained exceptionally low.[313] The cap is restricted to a ceiling of approximately $40-50 so as not to harm the California economy.[314] In addition, a price floor exists ($11,34 in 2014 dollars). A floor price is set which rises slightly each year and the total supply of emissions permits will decline by 2-3 % per year until 2020.[315] Governor Brown is advocating more stringent targets for 2020-2030. He issued a nonbinding executive order to reduce emissions an additional 80% by 2050.[316]

Another aim of the cap-and-trade system is "to encourage other governments to act to combat rising GHG."[317] California produces 1% to 1.5% of the world's greenhouse gases,[318] so even if California reduces its emission, other governments need to join them to make an effective difference in the world. As of January 2014, only Quebec and California have linked their programs. [319] Allowances in California are expected to drive the price in the two jurisdictions.[320]

Thus far, the system has had no adverse impacts on the economy, although the price of gas did go up around 10 cents.[321] The revenues collected through 2014 were $969 million and an estimated $3.4 to $10.3 billion more could be collected by 2020.[322] All funds from the auctions go into the Greenhouse Gas Reduction Fund,[323] which focuses on (1) sustainable communities

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[307] *Id.*
[308] *Id.* at 13.
[309] *Id*. ("At $12 a ton, it signals to industries to make investments in clean energy technology". statement by California Air Resources Board Nichols (but disputed by Borenstien in the same article.) *Id*. at 3.(State's emission rose from 1996 to 2007 and then dropped during the Great Recession. To return to 1990 levels by 2020 will require a 5 percent drop below the 2011 levels. Because California's population continues growing quickly, emissions per capital will have to be reduced even more.
[310] *Warren* and Tomashefsky, *supra* note 166, at 59.
[311] *Id.*
[312] *Id.*
[313]
[314] Ravi, *supra* note 206, at 8
[315]
[316] Durning & Bauman, *supra* note 218, at 2.
[317] Ravi, *supra* note 206, at 2.
[318]*Hilzik*, *supra* note 276. (says 1% but Ravi, *supra* note 206, at 9 says 1.5%)
[319] Ilan Gutherz, *Current Developments in Carbon & Climate Law North America: United States*, 8 CARBON & CLIMATE L. REV. 69,70 (2014).*See*, Beeeter World Club, *supra* note 277. *Also see* World Bank, *supra* note 20, at 57.
[320] *See* Gutherz, *supra* note 319, at 70. ("Quebec's carbon market is significantly smaller than California's, the demand for allowances in the California market is expected to drive price in the two jurisdictions.")
[321]*Id*. The state's oil and gas industry predicted that it would drive up gas prices 16 to 76 per gallon. Chandiok, *supra* note 257, 265-266 ("California's successes…..are a guide for other states who are trying to design a climate change law that will survive the inevitable legal challenges.")
[322] Ravi, *supra* note 206, at 7. Durning & Bauman, *supra* note 218, at 9 (study states $2 billion a year for the rest of this decade.)
[323] Durning & Bauman, *supra* note 218, at 7. ("AB 32 passed by simple majority in 2006, granting power to ARB to establish a cap and trade." Thus a state agency can impose fess authorized by simple majorities.)

and clean transportation, (2) energy efficiency and clean energy, and (3) natural resource and waste diversion.[324] Twenty-five percent of the funds are to go into the high-speed rail from L.A. to San Francisco, 35% into disadvantaged communities and some mass-transit, and 40% to the state legislature to decide where the remaining funds should go.[325]

A July 2014 poll found that the majority of Californians would not support a cap-and-trade if it meant paying more for electricity or gas.[326] The program will inevitably cause a rise in utility bills. The California Legislative Analyst's Office estimates that gas prices will rise "between 13 and 50 cents per gallon by 2020" and electric bills "could rise between 5% and 12%."[327] And because this is a fee and not a tax, no rebates or tax shifting off labor are allowed.[328] If enough voters oppose the cap-and-trade, it could be repealed. Thus, it is too soon to declare this program a success.

3. <u>The Midwestern Greenhouse Gas Reduction Accord Has Failed</u>

The Midwestern Greenhouse Gas Reduction Accord (MGGRA) or Midwestern Accord, was established in 2007 and covered six U.S. states (Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin) and one Canadian province (Manitoba). [329] Another three U.S. states and one Canadian province were formally observing this process.[330] Under the Accord, the members agreed to set up a multi-sector cap-and trade system and meet targets of 60 to 80 percent below 2007 emission levels.[331] In early 2008, participating jurisdictions appointed an Advisory Group comprised of representatives from environmental groups, industry and participating jurisdictions to develop recommendations on a regional cap-and-trade program.[332] In May 2009, the Advisory Group released their draft of final design recommendations.[333] After releasing their draft in April 2010, "the states and province in MGGRA did not continue pursuing their green house gas goals under the Accord." [334] Thus, the Midwestern initiative has failed

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4. <u>The Regional Greenhouse Gas Initiative Has Been a Success</u>

The Regional Greenhouse Gas Initiative (RGGI) was established in 2005 and has been the most successful cap-and-trade in North America.[335] It initially covered ten Northeast and

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[324] World Bank, *supra* note 20, at 114.
[325] Ravi, *supra* note 206, at 8.
[326] *Id*.
[327] *Id.*
[328] Durning & Bauman, *supra* note 218, at 7. Still the California Public Utility Commission ordered Pacific Gas and Electric to give "climate credits" averaging $35 to residential customers for several months a years. *Id* at 5.
[329] *See* CCES, *supra* note 276, at 5.
[330] *Id.* at 5.
[331]*Id*.
[332]Chris Lau and Nicholas Bianco, *bottom Line on Regional Cap-and Trade Programs*, World Resources Institute, at 2 (July 2009) *available at*http://www.wri.org/publication/bottom-line-regional-cap-and-trade-program.
[333]*CCCS*.
[334]*Id*.
[335] *Id.* See Chandiok,*supra* note 257, at n. 197 (GET THE ORIGINALS OF THESE: REG'L GREENHOUSE GAS INITIATIVE, OVERVIEW OF RGGI CO2 BUDGET TRADING PROGRAM 2 (2007), *available at* http://www.rggi.org/doc/program_summer_10_07.pdf; Reg'l GGreenhouse Gas Intiative, RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants (Jan. 13 2014), *available at*

Mid-Atlantic States (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont). It aims to reduce emissions from electric power and thus applies only to emission from regulated fossil fuel power plants that "together produce 95% of the region's electric-generation carbon emissions."[336] Importantly, it did not include the transportation, agriculture, commercial and residential sectors of the economy. Thus, it is more limited in scope than the California/Quebec cap-and-trade.

Under the RGGI, each state limits emissions, issues allowances and encourages participation in regional auctions.[337] Thus, state programs are integrated into a single regional market for carbon emissions. RGGI, like the California program, included banking allowances and soft price ceilings and a minimum auction price.[338]

Unlike EU cap-and-trade program, the majority of the allowances were auctioned off in 2008.[339] Subsequent auctions have occurred quarterly. So far, these auctions have earned more than $1.5 billion since 2009 and over 80% of the revenue has gone back to programs in renewable energy projects, energy efficiency programs and other initiatives to benefit the consumer.[340]

RGGI can be applauded for its flexibility in making changes to its cap. The cap was criticized because it was set too high and thus the prices were seen as too low. [341] Thus, RGGI updated and reduced the cap by 45% in January 2014.[342] The cap was set at 188 million short tons of carbon for the first control period (2009-2011) and then reduced to 91 million short tons.[343] The cap will be reduced by 2.5% each year from 2015 to 2020. [344]Some say this "increase in stringency is dramatic and represents evidence" that cap-and-trade systems can be subsequently modified.[345] Others might say the cap is too low—that by 2020, we must cut 15 to 20% off current levels, and the RGGI decline does not meet that standard. [346] Empirical studies have shown that the emissions were 40% lower than in 2005; however, many factors have contributed to this reduction.[347]

The RGGI economies have grown. An independent study by the Analysis Group projected positive economic outcomes including $1.6 billion in net economic benefits, $1.1

http://www.rri.org/docs/PresReleases?PR011314_AutionNotice23.pdf; *Regulated Sources*, RGGI.ORG, http://www.rggiorg/design/overview/regualted_sources. Massachusetts regulations implementing RGGI at 225 MASS. CODE REGS. Sec 13.01 *et. seq*

[336] Gannett, *supra* note 7 B-5 n. 14.

[337] *Id.* at n 8.

[338] *Id.*

[339] *Id.*

[340] *Id. Also see* Chandiok, *supra* note 257*, n.* 198.

[341] *See Gutherz*, supra, note 319, at n. 8 citing Regional Greenhouse Gas Initiative*, The RGGI CO2 Cap, available at* http??www.rggiorg/desing/overview/cap.

[342] World Bank, *supra* note 20, at 58. "The new 2014 cap is 91 million short tons of CO2, representing a 45% reduction form the previous cap."

[343] Id.

[344] *Id.* The cost containment reserve CR was triggered for the first time in March 2014. World Bank, *supra* note 20, at 58.

[345] Wara, *supra* note 149 at 292.

[346] Concerned Scientists, *supra* note 210.

[347] *Id.* This includes "energy efficiency measures, a broad switch from coal and oil to natural gas use in power plants, carbon price signals, and regulatory predictability are factors contribution to this reduction."

billion in electricity bill savings for consumers, 16,000 additional jobs, and $765 million retained in local economies due to reduced fossil fuel demand.[348]

Despite this favorable economic outcome, New Jersey, with the urging of Governor Christie, withdrew from the program in 2011.[349] In New Hampshire, the House tried to end the state participation in RGGI by 2015 and a compromise was passed in the Senate stating that if two other New England states withdraw then New Hampshire will withdraw.[350] A conservative group tried to block New York's participation but this failed.[351] Despite these minor glitches, the RGGI seems to be going strong and must be considered a success.[352]

4. Conclusion

What we can learn from these emissions trading programs is their success will largely depend on the political will of the state, the administrative details of the program (its scope, the cap, the allocation approach, use of offsets, price stabilization mechanisms, and enforcement) its performance and effectiveness, its ability to be flexible given the need for change based on competitiveness or efficacy concerns, and its ability to link to other systems.

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[348]Paul Hibbard, Andrea Okie, Susan Tierney, and Pavel Darling, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States*, ANALYSIS GROUP, 11, 19 (July 14, 2015) *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_july_2015.pdf see pages 11 and 19.

[349] Chris Christie stated that "our analysis of the Regional Greenhouse Gas Initiative or RGGI reveals that this program is not effective in reducing greenhouse gases and is unlikley to be in the future." "East Coast Cap-and-Trade Program Reports Success. http://www.betterworldclub.com/news/story.cfm?title=East%20Coast%20Cap-and-Trade%20Program%20Reports%20 Success&article-id =948 The governor called it a "failure" because of low auction prices and industry's ease of compliance. Several environmental groups challenged the governors actions and still unresolved. UPDATE THIS. Being sued by two environmental defense groups, *available at* http://www.nj.com/politics/index.ssf/2015/03/rep_pallone_says_christies_withdrawal_from_regiona.html, *see also* http://thinkprogress.org/climate/2014/03/25/3418873/court-christie-rggi/ and http://www.northjersey.com/news/appeals-panel-christie-administration-improperly-pulled-n-j-out-of-program-to-cut-greenhouse-gas-emissions-1.750770
Jonathan Salant, *Christie's Withdrawal From Air Pollution Compact has Cost N.J. $114M, Pallone Says*, NJ.COM, (Mar. 17, 2015) *available at* http://www.nj.com/politics/index.ssf/2015/03/rep_pallone_says_christies_withdrawal_from_regiona.html; Scott Fallon, *Appeals Panel: Christie Administration Improperly Pulled N.J. Out of Program to Cut Greenhouse Gas Emissions*, NORTHJERSEY.COM, (Mar. 25, 2015) *available at* http://www.northjersey.com/news/appeals-panel-christie-administration-improperly-pulled-n-j-out-of-program-to-cut-greenhouse-gas-emissions-1.750770.

[350] Beetter world club news.

[351] United States: Making the States Full Partners in a National Climate Change Effort: A Necessary Element for Sustainable Economic Development at http://www.mondaq.com/unitedstates/x/103786/Climate+Change/Making+the+States+Full+Partners+in+a+National+Climate+Change+Effort+A+Necessary+Element+for+Sustainable+Economic+Development+

[352] Wara, *supra* note 149, at 293. "(O)verallocation and a general lack of stringency are serious concerns in many cap-and-trade programs." However, if they become too stringent then evidence exists that programs will be weakened---See RECLAIM and CA Assembly Bill 32 as examples. World Bank, *supra* note 20, at 58. The RGGI states have submitted comments to the EPA in relation to the clean Air Act. Advocating flexibility in how states approach carbon pollution, emphasizing market-based approach over a regulatory approach and emphasizing the need to reward early actors

What is needed is for the original signers of the Western Climate Change to join the California and Quebec cap-and-trade systems. Then, the Midwestern initiative should be revived. RGGI should be expanded to cover transportation. All systems should be coordinated with similar auction allowances, sector coverage, and cap limits.[353] North America needs be the leader in the reduction of carbon dioxide emissions.[354] Canada and the U.S. have been the largest polluters of carbon and will also be the biggest beneficiaries from the melting ice. Since the impact of climate change will fall mainly on poor countries, it is imperative that the richer countries take the lead.

B. State and Province Carbon Tax and Other Initiatives

Some states in the U.S. and provinces in Canada have established creative climate change initiatives. Some of these are merely aspirational in tone. However, others, such as carbon taxes in British Columbia, Boulder and San Francisco, have been effective in reducing CO_2 emissions with minimal economic impact. This section examines those initiatives.

1. Many State and Local Initiatives Are Merely Aspirational

Climate change initiatives at the local level have tended to focus on GHG mitigation.[355] Cities work with International Council for Local Environmental Initiatives (ICLEI), [356] the Mayors Climate Protection Agreement (MCPA), [357] and C40 Cities (a climate leadership group),[358] to inventory emissions, develop climate action plans, and pursue sustainable development goals. States and regions have also signed agreements to fight climate change. All of these initiatives are voluntary and thus do not by themselves guarantee effective climate change policies.[359] However, because our federal government has failed to use its collective bargaining power to instigate change on the international level, local governments can band together with other cities become agents for change in the world war against climate change.

The Council for Local Environmental Initiatives (ICIEI) "serves as a clearinghouse on sustainable development and environmental protection policies, programs, and techniques, initiates joint projects or campaigns among groups of local governments, organizes training programs, and publishes reports and technical manuals on the art of environmental management

[353] Wold Bank, *supra* note 20 at 58. Fifty percent of the total GHG emiisoninAlberta are coverd by the Alberta Greenhouse Gas Reduction Program. Facilites that emit more than0.1Mt Co2e per year are required to reduc their emiisons by 12% or buy permits.
[354] *Id.* Alberta Greenhouse Gas Reduction Program could also be linked. Other challenges include political aversion to "new taxes," the powerful fossil fuel interest groups, and divergent and diffuse interests of the public. However, looming deficits and real environmental concerns could result in change. *See* discussion infra____.

[355] *See, Trisolini, supra* note 2 at 679.
[356] http://www.iclei.org/ ; http://www.usmayors.org/climateprotection/revised/ ;
[357] This initiative should be contrasted with the EU Covenant of Mayors which has "a more binding nature." See Dellinger, *supra* note 14, at 632. ("But whereas the Covenant appears to e both procedurally and substantively successful, more action needs to be demonstrated by the MCPA and Green Climate Cities before these can reasonably be determined to be effective." *Also see* Chicago at FN 5.
[358] http://www.c40cities.org/.
[359] *See* Duff, *supra* note 7. (stating that these voluntary agreements have their place in the global warming fight.)

practices."[360] As of October 2015, more than one thousand cities were members of ICLEI, including Portland, Seattle, San Francisco and other major cities in Western North America and around the globe.[361]

ICLEI's first initiative was the Cities for Climate Protection (CCP) campaign that focused on the following five "milestones": (1) require a "baseline emissions inventory and forecast," (2) set forth "an emissions reduction target for the forecast year," (3) develop a local plan of action by involving community stakeholders, and (4) implement the plan and policies.[362] Unfortunately, these last steps are still lacking in many places.[363] ICLEI's newest initiative, launched in June 2012, is the GreenClimatCities program.[364] Here, a three-step approach is adopted: (1) analyzation (again doing a GHG inventory, identify opportunities for emissions reduction, etc.) (2) action (develop a mitigation and adaptation action plan, identify finances for projects, etc.) and (3) acceleration (measure progress and report on achievements).[365] As a result of their effort, "232 cities from 25 countries . . . reported 561 climate and energy commitments, 557 GHG inventories, and a total of 2092 mitigation and adaptation actions."[366] The problem is that all of this is voluntary with no enforcement method to assure compliance, other than the "threat of potential public scorn."[367] To conclude: ICLEI is just "too new to demonstrate any substantive success."[368] However, in the absence of global and federal initiatives, it is definitely a promising program.

The Mayors Climate Protection Agreement (MCPA) has been adopted by over one thousand mayors, within all 50 of the states (plus the District of Columbia and Puerto Rico.)[369] Again, the mayors of Seattle, Portland, and San Francisco have signed this simple one-page agreement. The agreement strives to beat the Kyoto Protocol target of 7% GHG reduction within the city and urges the mayors to try to get their state and federal governments (including the U.S. Congress) to enact GHG reduction legislation.[370] Unfortunately, the 7% target reduction now needs to be increased "tenfold."[371] Thus, the MCPA "appears to have become more of a political public relations tool than an agreement with much real bite."[372]

The C40 Cities Climate Leadership Group is also a voluntary group of cities concerned with climate change. Now in tis 10th year, it includes over 75 cities in its membership, covering

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[360]GreenClimateCities, ICLEI 1-3 (2012), *available* at http://www.iclei.org/fileadmin/user-uplad/documents/Global/About-ICLEI/brocres/GCC_final_Brochure.pdf. Sustainable Communities Online, International Council for Local Environmental Initiatives (ICLEI), (2014). Available online at http://www.sustainable.org/creating-community/inventories-and-indicators/149-international-council-for-local-environmental-initiatives-iclei.
[361] UPDATE ICLIEI-Local Governments for Sustainability USA, FAQ: About ICLEI-Local Governments for Sustainability,. Available online at http://www.icleiusa.org/ablout-iclei/faqa/faq-about-iclei-local-governments-for-sustainability.
[362] The Five Milestone Process, ICLEI Global, *available at* http://www.iciei.org/index.php?id=810.
[363]*See* Dellinger, *supra* note 14.
[364]*Id.* at 635.
[365] *Id.*
[366]*Id.* at 636.
[367] *Id.*
[368] *Id* at 637.
[369] List of Participating Mayors, mayors Climate Proetection Center, *available at* http://www.usmayors.orgclimateprotection/list.asp.
[370] The U.S. Conference of Mayors climate Protection Agreement—Signature Page, USMAYORS.org,http://wwww.usmayors.org/climateprotection/documents/signaturepage.pdf.
[371] Dellinger, *supra* note 14, at 633.
[372] *Id.* at 633.

over 500 million people and one quarter of the world's economy.[373] It focuses on "tackling climate change and driving urban action that reduces greenhouse gas emissions and climate risks, while increasing the health wellbeing and economic opportunities of urban citizens.[374] As a primer to the meeting in Paris, C40 is "showcasing research and stories that help explain why a global agreement on climate change matters, and why cities are so important to the success of any agreement." [375]

In addition to the aspirational city initiatives, many state and regional initiatives exist at the state and regional level in the western North America. For example, in 2008, The Pacific Coast Collaborative (PCC), was established and signed by Alaska, British Columbia, Washington, Oregon and California.[376] The aim here is to promote clean energy innovation and low-carbon developments to reduce climate change in the region. Through the PCC, jurisdictions hope to "coordinate, propose, and adopt policy frameworks aimed at generating investment in renewable energy, climate resilience, low-carbon transportation infrastructure, and environmental conservation."[377] Then, in 2009, California, Washington and Oregon signed a climate change pact with British Columba stating their intent to implement cap-and-trade programs, and achieve long-term reductions in GHG emissions.[378] While not binding, this pact represents a commitment to multilateral cooperation and, like the other initiatives, is hopeful but not binding.[379] Thus, it appears that many cities are following the global approach, which is just to enter into nonbinding "soft" agreements that can easily by avoided.

2. <u>Some Carbon Taxes Have Been Successful</u>

Luckily, some initiatives are more binding. Those would include the provincial carbon tax in British Columbia and the local carbon taxes in Boulder, Colorado and San Francisco, California. This section also highlights the proposed carbon taxes in Oregon and Washington, which at this point are only aspirational in nature

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a. British Columbia

In July 2008, British Columbia introduced its carbon tax. [380] The BC carbon tax is just one of the key parts of the Climate Action Plan to reduce BC's GHG emissions by 33% below 2007 levels by 2020.[381] The BC tax has at least six core features that have remained the same as when first enacted and have contributed to its success.[382]

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[373] http://www.c40.org/about
[374] http://www.c40.org/about
[375] http://www.c40.org/about
[376] CCES
[377] *See* CCES *supra* note --- at 4.
[378] strive for zero-emissions vehicles to account for ten percent of vehicle purchases in 2016 Fn 10 in Carbon and Climate: *Pacific Coast Action Plan on Climate and Energy*, *available at* http://www.pacifccoastcollaborative.org/Documents/Pacific%20Coast%C20Action %20 Plan.pdf.
[379] Sta Clara 225-226. SEE FN 67 here.
[380] Quebec and Alberta have similar taxes but they are limited. Cite WA Study British Columbia combines several policies to reduce GHG emissions by 33% by 2020 and by 80% by 2050, compared to 2007 levels.British Columbia, Ministry of Transportation and Infrastructure, *Taking Action on Climate Change*, (accessed Feb, 16, 2014). Available online at http://www.th.gov.bc.ca/climate_action/index.html.
[381] World Bank, *supra* note 20, at 86. British Columbia successfully implemented the GHG reduction initiative in the transportation sector by imposing a parking fee, the proceeds of which are used to offer incentives to City

First, the tax is broad based--taxing nineteen carbon-based fossil fuels, each at different rates.[383] It covers "approximately 70% of all the GHG emissions in the province."[384] Some legitimate leakage occurs with exemptions in the agriculture sector and for marine and aviation fuels.[385] Essentially the tax exempts fuel in interstate commerce and exported out of the province and taxes fuels coming in and being used in the province.[386] Despite its broad base, the tax has been criticized as it does not apply to certain industrial processes[387] and all GHG gases, such as methane and nitrous oxide.[388] These exemptions were based on the prospect of the implementation of a cap-and-trade system covering these industries, but that initiative has failed.[389] Thus, the tax is not as comprehensive as it could be.

Second, the BC tax started at a low rate, varied depending upon the carbon content of the fuel, and increased gradually over the years.[390] This gave consumers a warning of increased prices and certainty.[391] It started at a relative low rate of CAD $10 per ton of carbon dioxide

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employees to encourage them to carpool, walk or bike, or take public transportation to work. British Columbia's Sustainable Commuting Program offers:

1. Rebates on transit passes,
2. Monthly incentives and access to reserved paring for staff who share rides,
3. Incentives for biking, walking, skateboarding, and rollerblading, such as gift cards for rain gear,
4. Cycling skills courses and subsidized bike tune-ups, and

A "guaranteed ride home" program in the event of emergency or sickness. The University of British Columbia, Emergency Ride Home, (accessed February 16, 2014). *available at* http://planning.ubc.ca/vancouver/transportation-planning/transportation-options/emergency-ride-home.

5, British Columbia, Live Smart on the Road

British C olumbia has also recently created a program called LiveSmart on the Road. The LiveSmart on the Road program provides incentives for people with inefficient to scrap old, inefficient cars instead of selling them and provides additional incentives for people who buy clean energy vehicles under a component program called the Clean Energy Point of Sale Incentive Program. As part of the LiveSmart on the Road program, British Columbia also offers rebates of up to $500 on residential electric car charging stations and in January 2013, invested $1.3 million in 13 new direct current (DC) fast-charging stations throughout Vancouver to help electric vehicle owners charge their cars.[381] The cumulative effect of British Columbia's combined public transportation, ride share, cycling, guaranteed ride home program, LiveSmart on the Road program, and Clean Energy Point of Sale Incentive Program is fewer individual fossil fuel burning commuters on the road, thus fewer GHGs being released into the atmosphere.

(February 14, 2014), *available at* http://www.livesmartbc.ca/road/.

[381] *Id.*

[382] *Id.* World Bank at 86.*Also see*, Rodney L. Brown, Jr., *State-by-State or Regional Solutions?*, Rocky Mountain Mineral Law Foundation, (2015 No. 1 RMMLF-INST paper).

[383] *Id.*

[384] World Bank, supra note 20, at 79.ist them and the rates.

[385] These are considered the "trade-exposed" sectors (MORE) WA study Also World Ban at 79 "Exported fuels and fuel consumption by aviation and shipping also travelling outside British Columbia are not covered by th carbon tax. Non-combustion GHG emissions such as industrial process emissions, venting an fugitive emissions ae not covered either." From 2014, "80% exemption to the carbon tax on natural gas and propane for heting and CO2 production for green house growers, and exemption for colored gasoline and colored disel purchased by farmers." World bank at 79.

[386] Vt at94.

[387] See Vermont at 94 (:such as the productionof ol, gas, aluminum, or cement"0

[388] *Id.* "from the diposal of solid waste and agricultural sector.

[389] Vt. 95 at footnote 52. FN "The tax will be integrated withother measuers. World bank at 86.

[390] *INSERT CHART*

[391] *Id.* at 98. The tax started at $10 per metric tonne of carbon dioxide-equivalent in 2008 and ramped up by $5 each year to reach $30 a tonne by 2012. In 2008 that meant a 2.4 cents per litter (US $.09/gallon) increase in the price of

equivalent emissions and progressively increased each year by $5 until 2012, when it reached the final and current price of CAD$30 per ton. [392] In 2008, that meant a 2.4 cents per liter increase in the price of gasoline and an increase of 6.7 cents per liter by 2012.[393] The problem here is that the rate is now frozen and should probably increase to further GHG reductions. The BC government has said it might increase those rates if it does not meet its emissions targets or if other jurisdictions pass similar carbon pricing instruments.[394]

Third, the BC tax was simple, piggybacking on an existing fuel tax paid mostly by wholesalers,[395] (although natural gas was paid at the retail level.)[396] This upstream approach meant that the tax needs to be collected only from a limited number of companies,[397] and it did not require any additional administration or enforcement resources.[398] And the taxes are transparent, as consumers see it itemized on their receipts at the pump, or on their gas bills.[399]

Fourth, the carbon tax was designed to be economically efficient, politically feasible, and equitable. The tax was originally planned to have the "double-dividend" effect by being "revenue neutral," meaning the revenues raised were to be returned or recycled or shifted to business and individuals by reducing other taxes.[400] The tax has in fact been revenue negative.[401] Although it raised about $880 million in 2010/2011, all revenues (and more) are recycled back to taxpayers.[402] In addition, when the tax was first imposed, all residents got a $100 dividend or rebate check as a "sweetener" to "reduce public opposition to the tax."[403] The tax also included a refundable Climate Action Tax Credit. [404] Thus, the tax was crafted to be politically palatable. But if these credits and rebates were not enough, by law, the Minister of Finance is required to outline how the revenues are to be recycled.[405] If the revenue neutrality cannot be ensured, the Minister's salary will be cut 15%.[406] Recent studies have found that the BC tax "does not disadvantage low-income residents" and is in fact is "highly progressive, an effect enhanced by the provinces' low-income tax credits."[407] It is also possible that consumers

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gasoline. By 2012, the tax increased gas prices by 6.7 cents per litre ($0.25/gallon *Proof Positive: The Mechanics and Ipacts of British Columbia's Carbont Tax. Clean Energy Canada., at 2 (GET WEB CITE)*

392 *Id.* This tax translated into roughly for $10---and C$7.23 per liter of gasoline. This is correct

393 Clean Energy Canada.

394There are some problems here with such linkage. *See* my later discussion.

395 Fuel whoseslers include fuel importers or domestic producers. "Wholesalers pass the tax on to retalers who pass it on to consumer—who see it itemized on their recipts at the pump." Clean energy Cnada.

396 *Id. "carbon tax collected in the same way as motor fuel taxes….except for natural gas that is collected at theretail level." World bank at 86.*

397 Canada (nor forms to fill out."

398

399 Clean Energy Canada.

400 VT at98 (This is in contrast to Quebec, where revnues go to a Green Fund to support climate change initative.

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402 *Id. VT. 98. WA. Study at 4.*

403 Vt. At 99.

404 *FIND CITE I HAVE FN 169 AT PAGE 54????? Vt. At 99.*

405 World Bank, at 86

406 World Bank, at 86

407 Clean Energy Canada. (last page)

can substitute public transportation for cars and thus reduce the regressive impact of the tax.[408]

In 2012, British Columbia conducted a five-year review of its carbon tax.[409] Their economic analysis showed it had only a small impact on the economy and that the province continued to grow well compared to other Canadian provinces.[410] Furthermore, statistics showed that the tax had reduced emissions by making carbon-intensive activities more expensive.[411] Consumption of petroleum products declined by 19%[412] compared to an increase of 3% in the rest of Canada.[413]

The public has generally supported the BC tax.[414] Polls have shown that a majority of British Columbians supported the tax at the beginning and a majority continue to support it today.[415] In the 2009 election the governing party's opposition ran on an "Axe the Tax" campaign to kill the carbon tax, but lost the election and later dropped their opposition to the tax.[416] Even the business community has been "mildly supportive" of the tax.[417] When interest groups complained after the 2012 review, the government made several concessions through grants and exemptions.[418] Thus, it seems the BC tax is flexible in its implementation and integral to BC fiscal policy. Thus, it is likely to remain in place.[419]

However, this tax alone is not enough to effect significant climate change. The BC legislature specifically designed the carbon tax to be integrated with other measures, such as cap-and-trade programs.[420] Because the carbon tax rate is frozen and the tax does not cover those industries that would have been subject to a cap-and-trade, BC should sign on to the California and Quebec cap-and-trade system.[421] They could also link up with the Alberta system.[422] In the alternative, the BC carbon tax base should be expanded and the rates increased.

b. *Boulder's Carbon Tax*

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408 Tax on certain fuels, however, might not be inelastic, meaning the consumer might be able to substitute another energy form.
409 *Id.*
410 *Id.*
411 *WAS study at 18*
412 World Ban at 87.
413 World Bank, "British Columbia's Carbon Tax Shift: An Environmental and Economic Success: (Sept. 10,2014 (GET CITE)
414 World Bankd at 87.
415 Canada. 54 percent at the beginning and 52% now. *"In 2012 the public support for th tax reache a high of 64 percent just as the tax reached its maximum level. Businesses "cautiously acceting" of the tax when first introduced.*
416 Clean Energy Canada.
417 World Bank at 87.
418 *Id. For example [atrial grants to for colored gasoline and disel for farmers following the 2012 review. No concessions to the energy-intensive industryies.*
419 World Bank at 87.
420 World Bank at 86.
421 Vt at 97 Fn 71World Bank at 86.
422 Later discussion

One city that has successfully implemented a carbon tax is Boulder Colorado. The carbon tax in Boulder Colorado was implemented in 2012 and will expire in 2018.[423] Boulder's carbon tax, which is officially called the Climate Action Plan Excise Tax, charges very low rates of $0.0049 per kWh for residential, $0.0009 per kWh for commercial, and $0.0003 per kWh for industrial consumers.[424] Boulder effectuates this tax by stating directly in the City Code, §3-12-1 that "the City Council determines and declares that the consumption of electricity within the City is the exercise of a taxable privilege."[425] Revenues are to be reinvested in environmental initiatives.[426] Thus, Boulder's implementation of the Climate Action Plan Excise Tax demonstrates that a city can declare energy usage within its jurisdictional boundaries to be a privilege that can be subject to taxation. Furthermore, by taxing centralized power consumption, cities can reinvest that money in policies that provide tax incentives for consumers who invest in localized power sources or green buildings that require less power to operate. Therefore, instituting a carbon tax can be the first step in creating a sustainable, GHG reduction plan for many cities.[427]

c. San Francisco Carbon Tax

In 2008, San Francisco approved a carbon tax.[428] Pursuant to this tax, more than 2,500 businesses were required to pay a low rate of 4.4 cents per ton for the carbon dioxide they emitted.[429] Despite the relatively low tax rate, about seven power plants and oil refineries had to pay more than $50,000.[430] These fees are expected to generate $1.1 million in the first year, which will be used to pay for emissions-reduction programs around the city.[431]

Policy analysts say the relatively small fee probably will not cause business to change their practices or incentivize new clean technologies.[432] However, these programs have already brought remarkable gains in climate change mitigation. By 2010, the programs contributed to a reduction in carbon emissions by 12% below the 1990 levels.[433] Specifically, in 2010, San Francisco's citywide carbon footprint totaled 5.4 million metric tons of carbon dioxide equivalent (CO2e).[434] In 1990, San Francisco's CO2 totaled 6.2 million metric tons.[435] This

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[423] Boulder Revised. Code, Chapter 3-12: Climate Action Plan Excise Tax §§ 3-12-1,3-12-2 (2012).
[424] Cassandra Profita, *A Carbon Tax in Oregon?* at 2 (Jan. 8, 2013) *available at* http://www.opb.org/news/blog/ecotrope/a-carbon-tax-in -oregon.
[425] *Id.*
[426] *Id.*
[427] Boulder is also proposing a 2.16 cents per KWh charge for cannabis growers.According to one industry source, it takes about 5,000 kilowatt hours of electricity to grow about 2.2 pounds of good-quality pot.. Also pesticide pollution is problem Not yet clear how the tax will be used. *See. Jan Lee* Boulder County Proposes Cannabis carbon "Tax" *available at* http://www.triplepundit.com/author/jan-lee) Tuesday Nov. 25, 2014). Or ww.triplepundit.com/2014/11/boulder-county-imposes-cannibis-carbon-tax/
[428] *Id.*
[429] Sustainable Business.com, *San Francisco Approves Carbon Tax*, (May 22, 2008). Available online at http://www.sustainablebusiness.com/index.cfm/go/news.display/id/16079.
[430] Sustainable Business.com, *San Francisco Approves Carbon Tax*, (May 22, 2008). Available online at http://www.sustainablebusiness.com/index.cfm/go/news.display/id/16079.
[431] Sustainable Business.com, *San Francisco Approves Carbon Tax*, (May 22, 2008). Available online at http://www.sustainablebusiness.com/index.cfm/go/news.display/id/16079.
[432] *Id.*
[433] The Global Compact Cities Programme, *San Francisco's Leadership in Carbon Emission Reduction*, (accessed Feb. 16, 2014). Available online at http://citiesprogramme.com/archives/1426.
[434] *Id.*

reduction translates to taking roughly 128,000 cars off the road, or avoiding burning 1.5 million barrels of oil per year.[436] These tremendous reductions have exceeded emission reduction goals set forth by both the United Nations at the Kyoto Protocol, which called for emissions reductions of 7% by 2012.[437] Furthermore, San Francisco's impressive reduction in CO2 was achieved despite a growth in the City's population.[438] In addition, all the revenues are to be reinvested in green programs.[439] Thus, the tax has set a precedent and raises significant revenue that can be reinvested in additional green initiatives that can help prevent climate change.

The Bay Area Air Quality Management District's board of directors voted 15-1 in favor of the tax.[440] Thus, San Francisco has demonstrated that government policy makers do not have to wait for federal and state mandates before taking action. Cities can pursue grass-roots local-initiative that exceed the expectations of the larger governmental bodies and achieve exceptional results by implementing minimally intrusive carbon taxes.

3. <u>Oregon and Washington's Proposed Carbon Taxes</u>

In 2009, the Oregon Legislature considered a cap-and-trade program, but the bill did not make it out of committee.[441] Then, in 2014, the Legislature proposed a carbon tax which would have taxed fuel suppliers (coal, natural gas and petroleum products) and utilities (on electricity). Exemptions were provided for fuels transported out of state and for fuels used in interstate commerce, such as maritime and aviation fuel.[442] The funds from the tax were to fund tax credits that would reduce personal income and corporate excise tax. In addition, a part of the funds were to be used for the "construction or installation of alternative energy systems" and for "implementation of systems or programs that result in the reduction of the use of carbon fuels."[443] The tax was to start at $10/metric ton and increase until $60/metric ton by 2015.[444]

The legislature commissioned the Northwest Economic Research Center at Portland State to study various combinations of tax rates and revenue uses.[445] The study used various carbon prices (up to $60/ton) with reinvestment into energy efficiency programs of 10% and 25%. The study concluded that a "BC-style carbon tax and shift could generate significant amount of revenue and reduce tax distortions while raising new jobs and reducing carbon emission."[446] Despite these favorable findings, the tax was never passed.

A similar scenario happened in Washington State where Governor Jay Inslee proposed a carbon tax plan[447] and Washington State Senator Kevin Ranker (D-Orcas Island) introduced a bill into Washington legislature creating a carbon tax system similar to the one in British

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435 *Id.*
436 *Id.*
437 *Id.*
438 The Global Compact Cities Programme, where complaint was that San Francisco polieis could complicate a "larger, more effective state-wide system" of the state of California. (accessed February 16, 2014). Available online at http://citiesprogramme.com/archives/1426.
439 *Find Cite*.
440 *Id.*
441 http://sustainablebsinessoregon.com/articles/2011/11/oregon-steps-back-rom-western-climate.html?;age=all.
442 HB 2082 Secton 2.
443 Section 3.
444 Section 3.
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Columbia.[448] The tax would be on fossil fuels but also the carbon content in electricity consumed within the state. The tax rate was $15 per metric ton of carbon dioxide and increase to $25 by July 1, 2018, with automatic increases thereafter by 3 1/5 % plus inflation.[449] All the revenue would go to the general budget, but unlike BC , there is no income tax in Washington. Thus, the general sales tax could be reduced. Like Oregon, the Washington legislature requested a study be done to assess the economic and equitable consequences.[450] The study concluded, as did the Oregon economic study, that a tax system similar to British Columbia could be effective to help carbon emissions while maintaining a balance between economic growth and equity to low-income energy consumers.[451] As of this writing, nothing has been passed, or is likely to pass in Washington or in Oregon.

PART IV: ASSESSMENT AND CHALLENGES TO REFORM

Overall, my study of carbon tax and cap-and-trade initiatives results in the following conclusions:

(1) The number of world-wide carbon initiatives is disappointing.
(2) Cap-and-trade seems to be the dominant system world-wide, rather than carbon taxation.
(3) Often the cities, states and regions most affected by climate change have the least amount of initiatives.
(4) Many of the countries taking action are the richer countries that have benefited from GHG emissions in the past.
(5) Many cities, states, and regions propose policies that are never implemented.
(6) Because of economic, business, and political concerns, many carbon initiatives are not that effective.
(7) These initiatives can only work with community support and political leadership.
(8) Market mechanisms, mandates, and other environmental policies will work best in combination to effectively combat climate change.
(9) Therefore, North America should link and expand all cap-and-trade systems throughout the region and local states and cities should pass carbon taxes (while additional environmental initiatives are being pursued.)

The challenges to a North American comprehensive global warming regional and carbon tax initiative are many. First, constitutional issues arise as to whether these state and regional plans violate the interstate commerce or other constitutional doctrines. Second, design issues arise as to how different cap-and-trade regimes can work together and along side carbon taxes. Third, political issues arise as to whether cities, states and regions have the will to pass these measures. What is clear is that ethically North America should move forward with these initiatives on a city, state and regional level.

A. Constitutional Hurdles

[448] *Id.* at 3-12-2.
[449] Section 4Initative Measure No. 732.March 20, 2015.
[450]
[451]

Most local/regional tax and cap-and-trade programs in the U.S. are not going to violate the Commerce Clause or the EPA's authority under the Clean Air Act if they are crafted appropriately. Under the standards established by the courts, if the state regulates "even-handedly to effectuate a legitimate local public interest" affecting interstate commerce in an insignificant manner, it "will be upheld unless the burden imposed on such comer is clearly excessive in relation to the putative local benefits."[452] State regulations that regulates some interstate commerce but that does not discriminate against interstate commerce will be upheld.[453]

Usually, the carbon system will exempt aviation and maritime activities in interstate commerce, exempt exports and only tax imports. This is done so the businesses within the state can compete fairly with businesses bringing their products into the state. However, care must be taken to craft the carbon system appropriately.

A recent 2013 case, *Rocky Mountain Farmers Union v. Corey*[454] challenging the California Air Resources Board's (CARB) Low Carbon Fuel Standard (LCFS) under the Commerce Clause illustrates this issue. The challengers were arguing that LCFS discriminated against ethanol producers from out-of-state. The Ninth Circuit Court of Appeals remanded stating that the LCFS did not "facially discriminate against out-of-state commerce" but calling on the lower court to determine if LCFS discriminated in purpose or effect against out-of-state commerce. On remand the court granted defendants motion for summary judgment stating that LCFS in fact facially discriminated.

Many law reviews have been written on this topic, so it is beyond the scope of this paper to delve deeply into this issue.[455] However, both Washington and Oregon governors are contemplating executive orders to implement a LCFS in their respective states.[456] Thus, if constitutional issues do impose obstacles, then state and city initiatives must be designed to alleviate those issues.

As for the issue of whether the EPA CAA (Clean Air Act) preempts state cap-and-trade and carbon tax proposals, consensus of commentator is that it does not.[457] The EPA recently took steps to encourage states to use cap-and-trade programs and in its regulations encouraged additional linkage opportunities.[458] Furthermore, EPA officials reported in the New York Times

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[452] Pike v. Bruce Church, Inc., 397 U.S. 137, 142 (1970).

[453] Exxon Corp. v. Govenor of Maryland, 437 U.S. 117, 126 (1978)And a recent case challenging

[454] 730 F.3d 1070 (9th Cir. 2013)

[455]*See* Kathryn Abbott, *The Dormant Commerce Clause and California's Low Carbon Fuel Standard,* 3 MICH. J. ENVTL. & ADMIN. L. 179 (2013); Ross Astoria, *The Export Clause and the Constitutionality of a National Cap and Trade Co2 Mitigation Policy,* 26 GEO. INT'L ENVTL. L. REV. 117 (2014); Heddy Bolster, *The Commerce Clause Meets Environmental Protection: The Compensatory Tax Doctrine as a Defense of Potential Regional Carbon Dioxide Regulation,* 47 B.C.L.REV. 737 (2006); Steven FFerrey, *Carbon Outlast the Law: States Walk the Constitutional Line,* 41 B.C. ENVTL. AFF. L. REV. 309 (2014); Ilam W. Gutherz, *Cap and Trade Meets the Interstate Commerce Clause: Are Greenhouse Gas Regulations Constitutional After Lopez and Morrison?* 29 PACE ENVTL. L. REV. 289 (2011);Keith Kendall, *Carbon Taxes and the WTO: A Carbon Charge Without Trade Concerns?* 29 ARI. J. INT'L & COMP..L. 49 (2012); Janet E. Milne, *The U.S. Supreme Court Opens a Door: Expanded Opportunities for Environmental Taxes,* 43 ENVTL. L. REP. NEWS & ANALYSIS 10406 (2013);Richard J. Pierce, Jr., *The Constitutionality of State Environmental Taxes,* 58 TUL. L. REV. 169(1983);.Darien Shanske, *State-Level Carbon Taxes and the Dormant Commerce Clause: Can Formulary Apportionment Save the World?* 18 Chap. L. Rev. 191 (2014).

[456] Santa Clara at 235 n. 129.

[457] *See* Shanske, *supra* note 455, at 192.

[458] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,832 (proposed June 18, 20 (codified at 40 C.RF.R. 60.5700), *available at* http://www.gpo.gov/fdsys/FR-2014 13726.pdf.

that states could comply with the act by "enacting state-level carbon tax on carbon pollution."[459] Thus, experts conclude: "EPA's proposed regulations pursuant to section 111d of the CAA recognize the legitimacy of regional cap and trade programs and Congress is unlikely to develop a comprehensive cap-and-trade law, state-administered cap and trade programs linked with foreign governments do not conflict with the federal foreign affairs power."[460]

B. Design Issues

In addition to making the carbon and cap-and-trade systems consistent with interstate commerce and international trade rules, the cap-and-trade and carbon tax systems themselves must be designed to be effective with broad coverage, reasonable allocation of permits, tight caps or rates (with incremental phase-ins), and limited exemptions.[461]   These systems must also be coordinated with other exiting tax and fee structures within the jurisdiction. In addition, any cap-and-trade regime should be coordinated with any carbon tax within that same region. Lastly, if a cap-and-and trade system within one jurisdiction is to be linked to another cap-and-trade system in another jurisdiction, then their design must be effectively integrated.

1. Coordination Issues

Any carbon tax or cap-and-trade fee must be coordinated with each other and with other existing taxes and fees within the city, state or region. Most jurisdictions have sales, consumption or VAT taxes, pollution taxes, or gas and motor fuel fees. Often these overlapping taxes are common and acceptable.[462] But to reduce any negative effects on the economy and the competitiveness of the industry groups in the region, all taxing and fee systems must be analyzed to assess the risks from this harmful double taxation on business.[463] Exemptions and reduced rates may be one way to handle this issue. For example, the Scandinavian countries that are part of the EU illustrate this approach through exemptions, discounts and phase-in rules.[464]   Some countries, like Finland, just exempt all electricity covered by EU ETS, while other countries, like Sweden and Denmark have limited exemptions, discounts and phase-ins.

Any adverse impact on the consumer from these double taxes and fees should also be assessed. When low-income taxpayers are faced with unfair burdens because of the inelasticity of the energy source, the government needs to be creative and come up with other mechanisms or programs to solve these issues. For example, the California cap-and-trade system is a fee where all the funds have to go into a green fund. In order to make the overall system fair to low-

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[459] Coral Davenport & Peter Baker, Taking Page from Health Care Act, Obama Climate Plan Relies on States, N.Y. Times, June 3, 20140, at A 16. *Also see* Samuel D. Eisenberg, Michael Wara, Adele Morris, Marta R. Darby & Joel Minor, *A State Tax Approach to Regulating Greenhouse Gases Under the Clean Air Act* (1014*), available at* http://www.brookings.edu/research/papers/2014/05/22-state-tax-regulating-greenhouse-gas-clean-air-morris.
[460] Santa Clara at 238. MORE HERE
[461] *See* my earlier discussion, *supra.*
[462] *See* Duff, *supra* note 7. (discussing automotive fuel taxes, motor vehicle taxes, , etc, as well as fertilizer taxes and sulfur taxes, etc.)
[463] *See* Deng, *supra* note 162, at ("Above all, the integration of a carbon tax into the current tax system will achieve self-consistency and double dividend effects. In other words, the seamless implementation of a carbon tax into the current taxy system is as important as devising a good tax plan."
[464] *See supra* notes 95, 96, 109, 110, and 128.

income taxpayers, the state required the utility companies to give rebates. Also much of the money is to go into alternative transportation systems that could benefit the low-income citizen.

For the same reasons, it makes sense to coordinate a carbon tax and cap-and-trade system in the same region. A cap-in-trade in one region could also be coordinated with a carbon tax in another jurisdiction. Some have states that linking these systems "would be relatively easy, as the price in each is explicit." [465] For example, a business in a carbon tax country could purchase a permit in the country with a cap-and trade, and then remit it in lieu of making a tax payment in their country. Conversely, a business in a cap-and-trade could remit carbon tax payments to its government in excess of its emissions and receive emissions-tax-payment credits for the excess tax payment which could be sold to firms in the country with a cap-and-trade and which that country could use in place of permits.

2. Linkage Issues

As we mentioned earlier California and Quebec have effectively linked their cap-and trade system. Both systems accept allowances from either regime to cover the businesses' emissions. [466] EU has bilaterally linked with New Zealand and with Australia and uses Kyoto credits interchangeably. Canada and the United States, and other countries not signed on to the Kyoto Protocol "are not able to offer participants the option of submitting Kyoto units in place of domestic allocation." [467]

Allocation differences can cause competitive disadvantages if they have two different allocation methods. If one system auctions the majority of allowances, like the RGGI, and the other, like the EU EST, gives them out free, then the cost to the participant in the RGGI would be higher and would hurt their business as the consumer would have to pay a higher price for their product. Although these systems do not compete, this illustrates the potential problem of linkage of two systems in one region. Similar competitive problems arise when the two systems do not cover the same sectors. Again, the sector covered by the tax or cap-and-trade would have a higher cost and be more expensive to its consumers, causing them to shift to the lower priced competitor. A similar inequity might occur if the systems have different monitoring or enforcement mechanisms. In addition, a system with lower caps will result in a participant benefiting from having more allowances to cover their emissions that will give them a competitive advantage.

3. Coordination with Other Policies

To become effective in significant GHG emissions, not only cap-and-trade and carbon taxes need to be passed, but other policies must be adopted.[468] Sweden, Denmark illustrate this comprehensive approach as these countries uses carbon taxes, in addition to gas taxes and other fees and taxes. For example, Sweden as a fertilizer tax and Denmark has a sulfur tax. These

[465]Discuss binary vs unilateral.
[466] World Bank, *supra* note 20, at 93. (excerpt of Gilbert E. Metcalf, Harvard Environmental Economics Program).
[467] O'Connell, *supra* note at 368.
[468] World Bank, *supra* note 20, at 93. (excerpt of Gilbert E. Metcalf, Harvard Environmental Economics Program).

countries also use tax incentives and other green environmental initiatives. In North America, British Columbia and California also adopt this comprehensive approach.[469]

C. Ethical/Political Hurdles

In order for effective community and local tax initiatives to occur and succeed, several things need to happen. First, the citizens must be connected to their community and its needs. Second, local governments must be willing to rid itself of its economic growth mindset—giving tax incentives for negative economic behavior. Third, an integrated plan must be developed, implemented, and monitored. Environmental taxes combined with cap-and-trade and other nontax policies provide the best approach, as illustrated by the Western North America initiatives.

We in North America have an ethical responsibility to act. First, we are not immune from the effects of global warming. Those in the western U.S. have experienced droughts. Those in the south and east have experienced severe storms. Rising sea levels will impact Florida, New York City, and many other coastal communities. In the U.S. "millions of people depend on glaciers and winter snowfall." Southern California depends on the Colorado River that is in danger of losing 40 percent of its water supply by the 2020s. Hopefully, our "collective fear" of the impact of global warming on our children and grandchildren will push us into a leadership role.[470]"

Second, the U.S. and Canada have been (and still are) the biggest consumers of carbon and have been the greatest beneficiaries of carbon emissions.[471] The U.S. has the most emissions and is the largest contributor to climate change.[472] Thus, based on this past and present usage in North America, we have the ethical duty to act. If all the states and provinces in North America signed on to a regional cap-and-trade and carbon tax program, they could together, reduce global emissions by one third.[473]

Third, Canada and the U.S. are going to be two of the biggest beneficiaries of the melting ice at the North Pole. The five nations with Arctic frontage—Canada, Denmark, Norway Russia and the United States—will be the winners.[474] In addition, many businesses will reap huge profits from this tragedy.[475] Many of these companies are from the U.S. and Canada.[476]

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[469] California has passed Senate Bill 375 "which requires the state's Metropolitan Planning Organizations to include as part of their long-range transportation plans a sustainable community's strategy that is designed to meet greenhouse gas reduction targets set by the state. Air Resources Board. Keith Batholomew, Cities and Accessibility: The Potential for Carbon Reductions and the Need for National Leadership, 36 FORDHAM URB. L. J. 159, 209 (2009) citing 2008 Cal. Adv. Leg. Serv. 728.

[470] *Id.* at 7 and 867. "conservation, less consumption, green roofs, carbon caps, green cars, solar panels, bicycles, insulation, florescent bulbs, recycling light rail, smaller homes and smaller families."

[471] *Id.*

[472] Followed by China. Get cite.

[473] Check this. Santa Clara at 243. Second leading way in technological development that could help developing nations most affected by global warming. Reduce price gap between renewable and traditional making renewable more attractive. Signal a united front and commitment that further federal and international mitigations efforts are needed. More uniform system would reduce administrative expense, compliance costs etc. Market forces could help states with smaller economies---benefit from offset projects upgrading railroad system and electric grid incentive to preserve forests. Introducing cheaper allowances provides for mitigation gains at less cost increases than the efficiency of GHG reductions achieved.

[474] *See* WINDFALL, *supra* note 7.

[475] *Id.*

[476] *Id.*at 9, 740.

The countries that will be hit the hardest from global warming are mostly tropical and poor. For example, Bangladesh is second on the Climate Change Vulnerability Index,[477] yet the average person there emits 0.3 tones of carbon a year. This is one seventieth of the average American rate.[478] Other losers include the Maldives, Tuvalu, Kiribati, Seychelles, Bahamas and the Carterets.[479] Cities, such as "Manila, Alexandria, Lagos, Karachi, Kolkata, Jakarta, Dakar, Rio, Miami, and Ho Chi Minh city, are probably doomed."[480] According to estimates, by "2050, a billion people would be pushed from their homes by global warming."[481] Already, large segments of these societies are struggling to relocate. Under New Zealand immigration quotas, "[s]eventy-five Tuvaluans and seventy-five Kiribatians" are able to relocate each year.[482] The "first five of seventeen hundred Carteret Islanders moved to newly purchased land in Bougainville.[483]

Ironically, these countries were the least responsible for the consumption of the fuels that produced the emissions that caused the global warming.[484] And they will be the least able to afford the technology to adapt to it.

"Climate change is different for those who can afford to adapt."[485] The rich countries will be able to afford "the desalination plants, the seawalls," artificial islands floating beaches, etc.[486] These countries, their companies, and wealthy citizens will most likely be the beneficiaries of technology advancement. The wealthy will "be the first to afford them, those who are emitting the most carbon, who are taking care of themselves before turning to the developing world."[487] Even geoengineering can result in winners and losers and that technology in the hands of the richer nations.[488] "A blueprint for disaster in any society is when the elite are capable of insulating themselves."[489]

There is no reason that the policies that have been proven to be effective in one community could not be just as effective in another community on the other side of the country or world. While these goals might present tall orders for many localities around the world, North American initiatives demonstrate that with a little creativity and innovation, sustainable and effective environmental policies can be created.

It may be difficult to translate what has happened in the developed North America to rural areas and to the undeveloped world. It may be even harder to translate these local policies into effective federal or international policies.[490] Without action at the U.S. federal level,

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[477] *Id.* at 205.
[478] *Id.* at 199.
[479] *Id.* at 64.
[480] *Id.*
[481] *Id.* at 66.
[482] *Id.*
[483] Id at 65.
[484] Frontline states, such as Spain Italy, Malta and Greece are policing the border of all of Europe –people from Africa and Syria, etc. *Id.* at 181 Those from Arab spring going to Malta went to jail no asylum for those feeling mere economic and environmental chaos
[485] *Id.* at 232.
[486] *Id.* at 10
[487] *Id.* at 82.
[488] *Id.* at 280
[489] *Id.* at 185.
[490]. One way that local governments can advocate for change outside their jurisdictional boundaries, however, is through their purchasing power in the international community. Take for example, San Francisco and the passage of Ordinance 88-04 that prohibits the use of rainforest lumber in new city projects; by passing ordinances such as 88-04, cities can reduce the degradation of rainforests thousands of miles away. However, that does not mean that local

however, local jurisdictions may not be able to effectively impact agricultural policies, forestry policies, natural resource extraction and other issues outside their boundaries.[491] Therefore, for large-scale issues to be addressed, the U.S. federal government is the only entity with jurisdiction to make a positive change.[492] Thus, the federal government should play a larger role in engaging local policymakers to foster local climate change efforts.[493] Perhaps these North American initiatives can send a clear and consistent message to the federal government and to Paris to supports climate change reduction initiatives.

PART IV: CONCLUSION

Although programs at the state, local levels and regional levels are critical for providing creative solutions to the climate change crisis, what is needed is a U.S. federal and international response. Nonetheless, local governments should continue to pass innovative market initiatives, combining both a cap-and-trade with a carbon tax, along with other environmental policies to help stop widespread climate change.

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governments can't work with countries that supply lumber from rainforests. Local governments can push foreign countries to replant the forests that they clear-cut and engage in sustainable forestry processes. Local governments can do so by pledging to buy sustainable lumber or other sustainably harvested goods in exchange for a pledge that the country follows sustainable environmental practices.

[491] *Id.*

[492] *See* Paul Krugman, "China' Great Leap forward on Cargon Tariffs." (New York Times). (One promising development is the carbon tariffs proposed against the exports of countries that refuse to join the international efforts to limit COS emissions. "Such tariffs probably wouldn't even require any change in existing trade law, and they would provide a powerful incentive for handouts to get with the program.")

[493] One way the federal government could be effective at promoting more local climate change tax policies is by creating a national adaptation fund. A national adaptation fund could award grants for local projects to better integrate transportation, land use and natural resource planning. Additionally, such a fund could help local governments phase-out antiquated travel demand models and make realistic assessments of how planned development will affect the local water supply and air shed as the climate changes. National adaptation funds could help in areas where there is local opposition, such as revising zoning codes to relax requirements such as parking setbacks. Such reforms are often difficult for local policymakers to undertake because of local opposition. The enticement of federal funding could matter here and perhaps the prospect of creating jobs could also win support from local partners. By creating a national adaptation fund, the federal government could finally make a meaningful contribution to the omnipresent need to halt climate change.
Thomas M. Gremillion, Setting The Foundation: Climate Change Adaptation At the Local Level, 41 ENVTL. L. 1221, 1247 (2011).

Appendix A

Chart 1: Eastern Hemisphere Carbon Tax Policies

COUNTRY/ JURISDICTION	START DATE	TAX RATE ($USD UNLESS NOTED OTHERWISE)	ANNUAL REVENUE	REVENUE DISTRIBUTION
FINLAND[494]	1990	$48/metric ton CO2	$750 million (500 million euros)	government budget; accompanied by independent cuts in income taxes
NETHERLANDS[495]	1990	~$20/metric ton CO2 in 1996	$4.819 billion (3.213 billion euros)	reductions in other taxes; climate mitigation programs
NORWAY[496]	1991	$33/metric ton CO2	$900 million (1994 estimate)	government budget
SWEDEN[497]	1991	$168/metric ton of CO2	$3.665 billion (25 billion SEK)	government budget
DENMARK[498]	1992	$31/metric ton CO2	$905 million	environmental subsidies and returned to industry
UNITED KINGDOM[499]	2013	$15.75/metric ton of CO2	$1.191 billion (714 million pounds)	reductions in other taxes
FRANCE[500]	2014	$10/metric ton of CO2 (12 euros) increasing to 22 euros in 2016	$4.499 billion (3 billion euros)	reductions in other taxes
IRELAND[501]	2010	$28/metric CO2 (20 euros)	$448 million (400 million euros)	reduction on taxes
ICELAND[502]	2005	$10/metric ton of CO2		paid to treasury
SWITZERLAND[503]	2008	$68/metric ton CO2		
PORTUGAL[504]	2014	$5/metric of CO2		

494 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
495
496 http://www.ssb.no/a/publikasjoner/pdf/DP/dp337.pdf
497 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf; http://www.iea.org/publications/freepublications/publication/Sweden2008.pdf
498 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
499 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
500 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
501 http://www.irishstatutebook.ie/eli/2010/act/5/enacted/en/html
502 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
503 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf

SOUTH AFRICA[505]	proposed	120 R/metric ton of CO2
JAPAN[506]	2012	$2/metric ton of CO2
AUSTRALIA[507]	2012; repealed 2014	$19.60/metric ton CO2 (A$23)
CHINA[508]	2016	$3-13/metric ton of CO2

Chart 2: Western Hemisphere Carbon Tax Policies

COUNTRY/ JURISDICTION	**START DATE**	**TAX RATE ($USD UNLESS NOTED OTHERWISE)**	**ANNUAL REVENUE**	**REVENUE DISTRIBUTION**
BOULDER, CO[509]	2007	$7/metric ton CO2	$1 million	climate mitigation programs
QUEBEC[510]	2007	$13/metric CO2	$191 million (C$200 million)	climate mitigation programs
BRITISH COLUMBIA[511]	2008	$28.64/metric ton CO2 (C$30)	$1 billion (C$306 million)	reductions in other taxes
ALBERTA[512]	2007	$15/metric ton CO2		
CALIFORNIA (CARB)[513]		$13/metric CO2		
MARYLAND[514]	2010; repealed 2012	$5/metric ton CO2		residential energy efficiency upgrades
WASHINGTON[515]	proposed	$15/metric ton of CO2	Expected $1.7 billion	offset state sales tax and fund Working Families

504 http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
505 http://en.people.cn/90001/90777/90855/7106312.html; http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
506 http://www.env.go.jp/en/policy/tax/env-tax.html; http://www.worldbank.org/content/dam/Worldbank/document/Climate/background-note_carbon-tax.pdf
507 http://www.theguardian.com.au/story/2423463/carbon-price-helped-curb-emissions-anu-study-finds/?cs=8
508 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
509 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
510 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
511 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
512 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
513 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
514

				Rebate
OREGON[516]	2016	$10/metric ton of CO2		Generate $2.1-2.2 billion each year
NEW YORK[517]	proposed	$35/metric ton of CO2		60% goes to low income households, the rest goes to climate change programs
SAN FRANSICO, CA (BAAQMD)[518]	2008			
COSTA RICA[519]	1997	$1-14/metric ton of CO2	$15 million	climate mitigation programs
CHILE[520]	proposed	$5/metric ton CO2		
MEXICO[521]	2012	$3/metric ton of CO2		
RGGI[522]		$5/metric ton CO2		

Appendix B
Chart 3:

RANK FOR BEST CARBON TAX	**JURISDICTION**	**START DATE**	**CHANGE IN CO2 EMISSIONS**
1	Sweden[523]	1991	Emissions decreased 19% since 2003
2	United Kingdom[524]	2001	Emissions decreased by 13% since 2007

515 http://carbonwa.org/
516
517
518
519 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
520 http://www.nytimes.com/2014/10/30/business/international/climate-change-concerns-push-chile-to-forefront-of-carbon-tax-movement.html?_r=0
521 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
522 http://daily.sightline.org/files/2014/11/global-carbon-programs-map-still-111714.png
523 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html
524 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

3	Demark[525]	1992	Emissions decreased by 33% since 2006
4	Finland[526]	1990	Emissions decreased 23% from 2007 to 2011
5	Netherlands[527]	1990	Emissions were expected to be reduced by 1.7 to 2.7 million metric tons CO2 annually in 2000. In covered sectors, emissions were expected to be reduced by approximately 5%.
6	Norway[528]	1991	Emissions increased by 32% from 1991 to 2014
7	Ireland[529]	2010	Emissions have dropped 15% since 2008
8	Iceland[530]	2005	Increased 17% since 2005
9	Switzerland[531]	2008	Emissions have decreased 5% since 2008
10	France[532]	2005	Emissions decrease 13% since 2005
11			
12			
13			
14			
15			

Chart 4

RANK FOR BEST CARBON TAX	**JURISDICTION**	**START DATE**	**CHANGE IN CO2 EMISSIONS**

525 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

526 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

527 Netherlands Ministry of Housing, Spatial Planning and the Environment

528 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

529 Rosenthal (2012)

530 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

531 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

532 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

1	British Columbia[533]	2008	GHG emissions were expected to be reduced emissions by up to 3 million metric tons CO2 annually in 2020 due to the tax.
2	San Francisco, CA[534]	2008	By 2010, the program reduced emissions by 12% below 1900 levels
3	Boulder, CO[535]	2007	Emissions in 2007 and 2008 decreased from 2006 levels. Greatest reductions due to programs funded but the carbon tax: 1)Renewables energy activities (60,000metric tons of CO2), 2)Transportation (33,000 metric tons CO2), and 3)Energy efficiency (6,700 metric tons CO2)
4	Quebec[536]	2007	Emissions were expected to be reduced by 11.2 million metric tons CO2 by 2012 due to the carbon tax.
5	California[537]	2008	
6	Chile[538]	2018	Predicts to reduce its emissions 20% by 2020 below 2007 levels this includes reduction by increase in renewable energy
7	Oregon[539]	2016	Reduce emissions by 12-13% below baseline projections
8			
9			
10			
11			
12			
13			
14	Costa Rica[540]	1997	increased 17% from 2000 to 2005

533 Ministry of Finance, British Columbia (2008)

534

535 City of Boulder (2009)

536 Quebec (2008)

537

538 http://www.nytimes.com/2014/10/30/business/international/climate-change-concerns-push-chile-to-forefront-of-carbon-tax-movement.html?_r=0

539 http://www.pdx.edu/nerc/carbontax2013.pdf

540 http://www.americanthinker.com/blog/2015/02/the_devil_and_the_details_of_national_carbon_tax_experiments.html

Appendix C

Chart 5: Major Taxed Sections in Existing and Proposed Carbon Tax Systems in the Eastern Hemisphere

JURISDICTION/ COUNTRY	FINLAND	NETHERLANDS	NORWAY	SWEDEN	DEMARK	UNITED KINGDOM	FRANCE	IRELAND	ICELAND	JAPAN	SOUTH AFRICA	SWITZERLAND
TYPE OF CARBON FUEL												
NATURAL GAS	x	x	x	x	x	x	x	x		x	x	x
GASOLINE	x		x	x	x	x	x	x	x	x	x	x
COAL	x			x	x	x	x	x		x	x	x
ELECTRICITY	x	x			x	x						
DIESEL	x		x				x	x	x			x
LIGHT AND HEAVY FUEL OIL	x	light only	x	x	x		x	x	x			x
LIQUIFIED PETROLEUM GAS			x	x		x		x	x			x
HOME HEATING OIL	x	x		x			x	x	x			x
SOLID FUEL						x		x				

Chart 6: Major Taxed Sections in Existing and Proposed Carbon Tax Systems in the Western Hemisphere

JURISDICTION/ COUNTRY	QUEBEC	BRITISH COLUMBIA	BOULDER, CO	CALIFORNIA	SAN FRANCISCO, CA	CHILE	COSTA RICA	MEXICO
TYPE OF CARBON FUEL								
NATURAL GAS	x	x				x	x	
GASOLINE	x	x					x	x
COAL	x					x	x	x
ELECTRICITY	x		x			x		
DIESEL	x	x						
LIGHT AND HEAVY FUEL OIL	x							
LIQUIFIED PETROLEUM GAS	x							
HOME HEATING OIL	x							
PERMITTED FACILTIES	x			x	x			

California to Ontario, British Columbia and Quebec: Linking Climate Policy at the Subnational Level to Achieve International Goals

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As the recent climate talks in Lima Peru have demonstrated, reaching effective climate consensus at the 2015 Conference of the Parties in Paris will not be easy. Despite committing over 20 years ago in the UNFCCC to take the lead in mitigating greenhouse gas emissions, to date many rich developed countries have demonstrated a reluctance to do so. Canada serves as an example of such a country – having withdrawn from Kyoto, seemingly failed to implement a legislative regime to deliver on its voluntary 2020 Copenhagen commitments and failed to propose ambitious 2030 targets in its recently submitted Intended National Determined Contribution. However, working in collaboration with California and the Western Climate Initiative, the Canadian provinces of British Columbia, Ontario and Quebec are putting in place legislative measures to pick up the policy slack left by the Canadian Federal Government. This paper will examine the policy and legislative measures in place in these three Canada provinces to mitigate climate change and explore the importance of the Western Climate Initiative and leadership from California in driving this change. Finally, this paper will consider whether these bilateral regional arrangements can circumvent the policy gap left at the national level – allowing these four subnational jurisdictions to demonstrate the leadership and collective action on climate change needed to achieve international goals.